ELECTRONIC TRANSMISSION DISCLAIMER

IMPORTANT: You must read the following disclaimer before continuing. This electronic transmission applies to the attached document and you are therefore advised to read this disclaimer carefully before reading, accessing or making any other use of the attached prospectus (the "**Prospectus**") relating to Diversified Gas & Oil Plc (the "**Company**") dated 13 May 2020 accessed from this page or otherwise received as a result of such access . In accessing the attached document, you agree to be bound by the following terms and conditions, including any modifications to them from time to time, each time you receive any information from us as a result of such access.

The Prospectus has been prepared and published solely in connection with the admission of the ordinary shares of the Company (the "**Shares**") to the premium listing segment of the Official List of the UK Financial Conduct Authority (the "**FCA**") and to trading on the London Stock Exchange plc's main market for listed securities (together, "**Admission**"). This Prospectus has been approved by the FCA, as competent authority, in accordance with section 87A of Financial Services and Markets Act 2000, as amended ("**FSMA**") and has been made available to the public as required by Rule 3.2.1 of the prospectus regulation rules (the "**Prospectus Regulation Rules**") of the FCA made under section 73A of the FSMA. The FCA, as the competent authority under European Union Regulation (EU) 2017/1129, as amended (the "**Prospectus Regulation**"), only approves this Prospectus as meeting the standards of completeness, comprehensibility and consistency imposed by the Prospectus Regulation and such approval should not be considered as an endorsement of the Company or the quality of the ordinary shares in the capital of the Company that are the subject of this Prospectus. Investors should make their own assessment as to the suitability of investing in the Ordinary Shares. The Prospectus has been published and is available on the Company's website at https://www.dgoc.com/. Investors should make their own assessment as to the suitability of investing in the Shares.

Restriction: Nothing in this electronic transmission constitutes, and this electronic transmission may not be used in connection with, an offer of securities for sale to any persons.

In particular, nothing in this electronic transmission constitutes an offer of securities for sale in the United States. The Shares have not been and will not be registered under the US Securities Act of 1933, as amended (the "US Securities Act") or with any securities regulatory authority of any state or other jurisdiction of the United States, and may not be offered or sold in the United States absent registration except pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the US Securities Act, and in compliance with any applicable securities laws of any state or other jurisdiction of the United States. There will be no public offering of the Shares in the United States.

The attached Prospectus has been made available to you in an electronic form. You are reminded that documents transmitted via this medium may be altered or changed during the process of electronic transmission. By accessing the attached Prospectus, you consent to receiving it in electronic form. A hard copy of the attached Prospectus will be made available to you only upon request to the Company.

You are responsible for protecting against viruses and other destructive items. Your receipt of this document via electronic transmission is at your own risk and it is your responsibility to take precautions to ensure that it is free from viruses and other items of a destructive nature.

DIVERSIFIED GAS & OIL

PLC

Prospectus

Introduction to the premium listing segment of the Official List and admission to trading on the main market of the London Stock Exchange

May 2020

This document comprises a prospectus (the "**Prospectus**") for the purposes of Article 3 of European Union Regulation (EU) 2017/1129, as amended (the "**Prospectus Regulation**") relating to Diversified Gas & Oil plc (the "**Company**") and has been prepared in accordance with the prospectus regulation rules (the "**Prospectus Regulation Rules**") of the Financial Conduct Authority (the "**FCA**") made under section 73A of the Financial Services and Markets Act 2000, as amended ("**FSMA**"). This Prospectus has been approved by the FCA, as competent authority, in accordance with section 87A of FSMA and has been made available to the public as required by Prospectus Regulation Rule 3.2.1. The FCA, as the competent authority under the Prospectus Regulation, only approves this Prospectus as meeting the standards of completeness, comprehensibility and consistency imposed by the Prospectus Regulation and such approval should not be considered as an endorsement of the Company or the quality of the ordinary shares in the capital of the Company (the "**Ordinary Shares**") that are the subject of this Prospectus. Investors should make their own assessment as to the suitability of investing in the Ordinary Shares.

This Prospectus is not an offer or invitation to the public to subscribe for or purchase Ordinary Shares but is issued solely in connection with the admission of the Ordinary Shares to the premium listing segment of the Official List of the FCA and to the main market for listed securities of the London Stock Exchange plc (the "**London Stock Exchange**"). The Ordinary Shares are currently admitted to trading on the AIM Market of the London Stock Exchange ("**AIM**"). Applications will be made to the FCA for all of the Ordinary Shares to be admitted to the premium listing segment of the Official List of the FCA and to the London Stock Exchange for such Ordinary Shares to be admitted to trading on the London Stock Exchange's main market for listed securities ("**Admission**"). The admission of the Ordinary Shares to trading on AIM will be cancelled no later than Admission.

Admission to trading on the London Stock Exchange's main market for listed securities constitutes admission to trading on a regulated market. Dealings in the Ordinary Shares are expected to commence on the London Stock Exchange at 8.00 a.m. (London time) on 18 May 2020. It is expected that Admission will become effective, and that dealings in the Ordinary Shares on the London Stock Exchange will commence, at 8.00 a.m. (London time) on 18 May 2020. No application has been made or is currently intended to be made for the Ordinary Shares to be admitted to listing or dealt with on any other exchange.

The Company and Directors (whose names appear on page 30 of this Prospectus) accept responsibility for the information contained in this Prospectus. To the best of the knowledge of the Company and the Directors, the information contained in this Prospectus is in accordance with the facts and makes no omission likely to affect the import of such information.

This Prospectus should be read in its entirety. In particular, see Part II "*Risk Factors*" of this Prospectus for a discussion of certain risks and other factors relating the business of the Company and its subsidiaries.

DIVERSIFIED GAS & OIL

PLC

Diversified Gas & Oil Plc

(Incorporated under the UK Companies Act 2006 and registered in England with registered number 09156132)

Introduction to the premium listing segment of the Official List and admission to trading on the main market of the London Stock Exchange

Sole Sponsor

Stifel Nicolaus Europe Limited

Ordinary share capital immediately following Admission

Number	Nominal Amount
707,085,502	£0.01

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

Apart from the responsibilities and liabilities, if any, which may be imposed on Stifel under 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 any of its affiliates accepts any responsibility or liability whatsoever for, nor makes any representation or warranty, express or implied, concerning the contents of this Prospectus, including its accuracy, completeness or verification, or for any other statement 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 Admission and nothing in this Prospectus is, or shall be relied upon as, a promise or representation in this respect, whether as to the past or future. To the fullest extent permitted by law, each of Stifel and its affiliates disclaims all and any duty, liability or responsibility whatsoever, whether direct or indirect and whether in contract, in tort, under statute or otherwise (save as referred to above), which they might otherwise have in respect of this Prospectus or any such statement.

The Ordinary Shares have not been and will not be registered under the US Securities Act of 1933, as amended (the "**US Securities Act**") or with any securities regulatory authority of any state or other jurisdiction of the United States, and may not be offered or sold in the United States absent registration except pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the US Securities Act, and in compliance with any applicable securities laws of any state or other jurisdiction of the United States.

Enforcement of judgments

The Company has been incorporated under English law and certain of the Company's Directors and officers reside outside of the United States. As a result, any judgment obtained in the United States against it or them may not be collectible within the United States. There is doubt as to the enforceability of certain civil liabilities under US federal securities laws in original actions in English courts, and, subject to certain exceptions and time limitations, English courts will treat a final and conclusive judgment of a US court for a liquidated amount as a debt enforceable by fresh proceedings in the English courts.

No incorporation of website information

Information contained on the Company's website or the contents of any website accessible from hyperlinks on the Company's website are not incorporated into and do not form part of this Prospectus.

This Prospectus is dated 13 May 2020.

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PART I

SUMMARY

SECTION A – INTRODUCTION

*This summary should be read as an introduction to this prospectus (the "**Prospectus**"). Any decision to invest in the securities of the Company should be based on consideration of the Prospectus as a whole by the investor. Investors could lose all or part of their invested capital.*

Where a claim relating to the information contained in the Prospectus is brought before a court, the plaintiff investor might, under the national law, have to bear the costs of translating the Prospectus before the legal proceedings are initiated. Civil liability attaches only to those persons who have tabled the summary including any translation thereof, but only where the summary is misleading, inaccurate or inconsistent when read together with the other parts of the Prospectus or where it does not provide, when read together with the other parts of the Prospectus, key information in order to aid investors when considering whether to invest in such securities.

The legal name of the Company is Diversified Gas & Oil plc. The Company's registered office is at 27-28 Eastcastle Street, London, W1W 8DH, United Kingdom and its LEI is 213800YR9TFRVHPGOS67.

The Ordinary Shares, when admitted to trading, will be registered with International Securities Identification Number ("**ISIN**") GB00BYX7JT74.

The Prospectus has been approved in accordance with the Prospectus Regulation on 13 May 2020 by the UK Financial Conduct Authority (the "**FCA**"), as competent authority, having its head office at 12 Endeavour Square, London, E20 1JN and telephone number +44 (0)20 7066 1000.

SECTION B – KEY INFORMATION ON THE ISSUER

Who is the issuer of the securities?

There is no offer of the Company's securities.

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

The Company is an independent owner and operator of producing natural gas and oil wells concentrated in the Appalachian Basin, the oldest hydrocarbon producing region within the United States. The Group's operations are located throughout the neighbouring states of Tennessee, Kentucky, Virginia, West Virginia, Ohio, and Pennsylvania, where the Company is one of the largest independent operators of conventional assets and also an operator of unconventional assets and midstream pipeline infrastructure. Diversified Gas & Oil plc was incorporated in 2014. The Diversified Gas & Oil plc predecessor business was founded in 2001 by the CEO Rusty Hutson, Jr. with an initial focus on gas and oil production in West Virginia. In recent years, Diversified Gas & Oil plc has grown rapidly by capitalising on opportunities to acquire and enhance producing assets, and leveraging the operating efficiencies that come with economies of scale. Since 2017, the Company has carried out 11 asset and business acquisitions for a combined purchase consideration of approximately $1.5 billion.

Major interests in Ordinary Shares

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

Shareholders	**Number of Ordinary Shares**	**Percentage of issued ordinary share capital**
Sand Grove Capital Management LLP	62,995,394	9.80
Aberdeen Standard Investments	53,170,038	8.27
AXA Framlington Investment Managers	44,182,709	6.87
Caius Capital	42,043,322	6.54
Pelham Capital Management	37,628,621	5.85
Premier Miton Investors	34,529,569	5.37
JO Hambro Capital Management	28,617,925	4.45
River and Mercantile Asset Management	24,850,800	3.87
GLG Partners	24,457,339	3.80
Santander Asset Management	23,667,532	3.68
Ninety One	21,149,457	3.29
Chelverton Asset Management	20,800,000	3.24
Robert Hutson Jr	20,860,000	3.24
Robert M. Post	20,350,000	3.17

Directors

The directors of the Company are: David Edward Johnson (*Independent Non-executive Chair*), Robert "Rusty" Russell Hutson, Jr. (*Chief Executive Officer*), Bradley Grafton Gray (*Chief Operating Officer*), Martin Keith Thomas (*Non-executive Vice Chairman*), David J. Turner, Jr. (*Independent Non-executive Director*), Sandra (Sandy) Stash (*Independent Non-executive Director*), and Melanie Little (*Independent Non-executive Director*).

Statutory Auditors

The Company's statutory auditor is Pricewaterhouse Coopers LLP, 1 Embankment Place, London, WC2N 6RH, United Kingdom. Pricewaterhouse Coopers LLP is a member of the Institute of Chartered Accountants in England and Wales and has no material interest in the Company.

What is the key financial information regarding the issuer?

Selected historical key financial information

The tables below set out selected key financial information for the Group as at and for the fiscal years ended 31 December 2019, 2018 and 2017.

Selected Consolidated Income Statement Data

	Fiscal Year ended 31 December		
(Amounts in thousands $)	**2019**	**2018**	**2017**
Revenue	462,256	289,769	41,777
Gross profit	161,732	139,988	13,333
Profit after tax	99,400	201,119	27,454
Year on year growth in revenue	59.53%	593.61%	144.48%
Earnings per Ordinary Share	$0.15	$0.52	$0.23

Selected Consolidated Balance Sheet Data

	As at 31 December		
(Amounts in thousands $)	**2019**	**2018**	**2017**
Total assets	2,005,940	1,556,972	253,650
Total equity	938,135	748,863	108,238
Total liabilities	1,067,805	808,109	145,412

Selected Consolidated Cash Flow Data

(Amounts in thousands $)	Fiscal Year ended 31 December		
	2019	**2018**	**2017**
Net cash from operating activities	279,156	86,564	6,844
Net cash used in investing activities	(466,887)	(765,678)	93,013
Net cash provided by financing activities	188,020	665,318	101,113

There are no qualifications to the accountant's report on the Group Financial Information.

The tables below set out selected key financial information for Alliance Petroleum for the year ended 31 December 2017 and the two-month period ended 28 February 2018. Alliance Petroleum was acquired by the Group in March 2018 and has been consolidated with the Group since 1 March 2018.

Selected Income Statement Data

(Amounts in thousands $)	**Two-month period ended 28 February 2018**	**Fiscal Year ended 31 December 2017**
Revenue	8,516	45,946
Gross profit	2,607	16,037
Profit after tax	3,144	28,985
Earnings per share	$31,440	$289,850

Selected Balance Sheet Data

(Amounts in thousands $)	**As at 28 February 2018**	**As at 31 December 2017**
Total assets	118,962	114,929
Total equity	30,583	27,439
Total liabilities	88,379	87,490

Selected Cash Flow Data

(Amounts in thousands $)	**Two-month period ended 28 February 2018**	**Fiscal Year ended 31 December 2017**
Net cash from operating activities	1,251	16,888
Net cash from/(used in) investing activities	18	(4,106)
Net cash used in financing activities	(492)	(8,695)

There are no qualifications to the accountant's report on the Alliance Petroleum Financial Information.

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

The key risks specific to the issuer are as follows:

- Volatility and future decreases in gas, natural gas liquids and oil prices could materially and adversely affect the Group's business, results of operations, financial condition or prospects.
- The Group may experience delays in production, marketing and transportation.
- There are risks inherent in the Group's acquisitions of gas and oil assets and there can be no assurance that the Group's prior acquisitions or any other potential acquisition by the Group will be profitable and the value of any business, company or property that the Group acquires or invests in may actually be less than the amount paid for it or its estimated production capacity.
- Climate change legislation or protests against fossil fuel extraction may have a material adverse effect on the Group's industry.
- The Group faces production risks and hazards that may affect its ability to produce gas, natural gas liquids and oil at expected levels, quality and costs and that may result in additional liabilities to the Group.

- The Group is obligated to comply with operational, health and safety and environmental regulations and cannot guarantee that it will be able to comply with these regulations.
- The Group carries out business in a highly competitive industry and if the Group is unsuccessful in competing against other companies, its business, results of operations, financial condition or prospects could be materially adversely affected.
- The levels of the Group's gas and oil reserves and resources, their quality and production volumes may be lower than estimated or expected.
- The Group may not have good title to all its assets and licences.
- The Group may face unanticipated increased or incremental costs in connection with decommissioning obligations such as plugging.

SECTION C – KEY INFORMATION ON THE SECURITIES

What are the main features of the securities?

The Ordinary Shares are ordinary shares of the Company of £0.01 each. When admitted to trading on the main market for listed securities of the London Stock Exchange, the Ordinary Shares will be registered with ISIN GB00BYX7JT74, Stock Exchange Daily Official List ("**SEDOL**") number BYX7JT7 and will trade under the symbol "DGOC" on the London Stock Exchange. The rights attaching to the Ordinary Shares will be uniform in all respects and they will form a single class for all purposes, including with respect to the right to vote and the right to receive all dividends and other distributions declared, made or paid in respect of the Company's share capital after Admission (as defined below).

The Ordinary Shares are denominated in Pounds Sterling. The Ordinary Shares will be quoted and traded in Pounds Sterling on the London Stock Exchange. As at the date of this Prospectus, the issued and outstanding share capital of the Company is 642,805,002 Ordinary Shares of £0.01 par value each (all of which were fully paid) and following Admission, the share capital of the Company will be 707,085,502 Ordinary Shares of £0.01 par value each (all of which will be fully paid).

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

Restrictions on free transferability of Ordinary Shares

There are no restrictions on the free transferability of the Ordinary Shares, other than certain transfer restrictions under: (i) the UK Companies Act for persons failing to respond to statutory notices issued by the Company requesting for information on interest in a particular holding of shares; and (ii) the Articles, under which the Board may, in its absolute discretion, refuse to register any instrument of transfer of any certificated share in certain circumstances. In addition, the Board may, in its absolute discretion, refuse to register any instrument of transfer of any certificated share which is not fully paid up but, in the case of a class of shares which has been admitted to the Official List of the FCA, not so as to prevent dealings in those shares from taking place on an open and proper basis or on which the Company has a lien. The Board may also refuse to register any instrument of transfer of a certificated share unless it is left (duly stamped) at the registered office, or such other place as the Board may decide, for registration, accompanied by the certificate for the shares to be transferred and such other evidence (if any) as the Board may reasonably require to prove title of the intending transferor or their right to transfer the shares; and it is in respect of only one class of shares and not in favour of more than four transferees.

Dividend policy

The Board's target is to return not less than 40 per cent. of free cash flow to Shareholders by way of dividend, on a quarterly basis, in line with the strength and consistency of the Group's cash flows.

For the three months ended 31 March 2019, the Company paid a dividend of 3.42 cents per Ordinary Share on 27 September, 2019. For the three months ended 30 June 2019, the Company paid a dividend of 3.50 cents per Ordinary Share on 18 December 2019. For the three months ended 30 September 2019, the Company paid a dividend of 3.50 cents per Ordinary Share in March 2020. For the three months ended 31 December 2019, the Company expects to pay a dividend of 3.50 cents per Ordinary Share in June 2020. For the three months ended 31 March 2020, the Company expects to pay a dividend of 3.50 cents per Ordinary Share in September 2020.

The Directors may further revise the Group's dividend policy from time to time in line with the actual results and financial position of the Group.

The Board's dividend policy reflects the Company's current and expected future cash flow generation potential.

Where will the securities be traded?

An application will be made to the London Stock Exchange for all of the Ordinary Shares to be admitted to trading on the London Stock Exchange's main market for listed securities (the "**Admission**"). Upon Admission, the admission of the Ordinary Shares to trading on the AIM Market of the London Stock Exchange will be cancelled.

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

The key risks specific to the securities are as follows:

- The Group's share price may be volatile and purchasers of the Ordinary Shares could incur substantial losses.
- The concentration of the Group's share capital ownership among its largest shareholders could conflict with the interests of other shareholders.
- Shareholders may be subject to US withholding tax depending on their country of residence.
- There is no guarantee that the Company will continue to pay dividends in the future.
- The issuance of additional Ordinary Shares in the Company in connection with future acquisitions or other growth opportunities, any share incentive or share option plan or otherwise may dilute all other shareholdings.

SECTION D – KEY INFORMATION ON THE OFFER AND/OR THE ADMISSION TO TRADING ON A REGULATED MARKET

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

This Prospectus does not constitute an offer or invitation to any person to subscribe for or purchase any shares in the Company. It is expected that Admission of the Ordinary Shares to trading on the London Stock Exchange's Main Market for listed securities will become effective at 8.00 a.m. (London time) on 18 May 2020.

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

The Company will apply to the London Stock Exchange for all of the Ordinary Shares to be admitted to trading on the London Stock Exchange's main market for listed securities.

Why is this prospectus being produced?

Reasons for the Offer

There is no offer of the Company's securities and the Prospectus is being produced in connection with the Admission. This Prospectus does not constitute an offer or invitation to any person to subscribe for or purchase any shares in the Company.

Material conflicts of interest

There are no conflicting interests which are material in connection with the Admission.

PART II

RISK FACTORS

Any investment in the Ordinary Shares is subject to a number of risks. The risk factors associated with any investment in the Ordinary Shares, the Group's business and the industry in which it operates, together with all other information contained in this Prospectus including, in particular, the risk factors described below should be carefully considered in light of Admission.

The risks relating to the Group, its industry and the Ordinary Shares summarised in the section of this Prospectus headed "Summary" are the risks that the Directors and the Company believe to be the most essential to an assessment of the Ordinary Shares. However, as the risks which the Group faces relate to events and depend on circumstances that may or may not occur in the future, the information on the key risks summarised in the section of this Prospectus headed "Summary" as well as, among other things, the risks and uncertainties described below should be considered.

The risk factors described below are not an exhaustive list or explanation of all risks which investors may face when making an investment in the Ordinary Shares. The risk factors detailed below and additional risks and uncertainties relating to the Group that are not currently known to the Group, or that the Group currently deems immaterial, may individually or cumulatively also have a material adverse effect on the Group's business, results of operations, financial condition or prospects and, if any such risk should occur, the price of the Ordinary Shares may decline. The suitability of investment in the Ordinary Shares should be considered in the light of the information in this Prospectus and personal circumstances of the investor.

RISKS RELATING TO THE GROUP'S BUSINESS AND INDUSTRY

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

The Group's business, operating results, financial condition and prospects depend substantially upon prevailing gas, natural gas liquids and oil prices, which may be adversely impacted by unfavourable global, regional and national macroeconomic conditions, including instability related to trade tensions between the US and China. Gas, natural gas liquids and oil are commodities for which prices are determined based on world and localised demand, supply and other factors, all of which are beyond the Group's control. In March 2020, the market experienced a significant decline in oil prices in response to oil demand concerns due to the economic impact of the spread of the COVID-19 virus and anticipated increases in supply following the OPEC Russia oil price confrontation and travel restrictions globally. COVID-19 is expected to result in a reduction of demand for all energy sources until the virus' impact is largely mitigated. See risk factor below entitled "*The recent COVID-19 outbreak could have an adverse effect on the Group's business.*"

Historically, prices for gas, natural gas liquids and oil have fluctuated widely for many reasons, including:

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

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

It is impossible to accurately predict future gas, natural gas liquids and oil price movements. Historically, gas prices have been highly volatile and subject to large fluctuations in response to relatively minor changes in the demand for gas. The spike in US natural gas prices to nearly $5.00 per MMBtu in December 2018 and subsequent fall back to approximately $2.14 per MMBtu in August 2019 highlights the volatile nature of commodity prices.

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

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

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

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

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

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

Acquisitions are an essential part of the Group's strategy for protecting and growing cash flow, particularly in relation to the risk that some of the Group's wells may have a higher than anticipated production decline rate. The Group has undertaken a number of acquisitions of gas and oil assets (and of companies holding such assets), including, but not limited to, the Alliance Petroleum Acquisition, the CNX Assets Acquisition, the EQT Assets Acquisition, the HG Energy Assets Acquisition, and the EdgeMarc Energy Acquisition. The Group's ability to complete future acquisitions will depend on it being able to identify suitable acquisition candidates and negotiate favourable terms for their acquisition, in each case, before any attractive candidates are purchased by other parties such as private equity firms, some of whom have substantially greater financial and other resources than the Group. The Group may face competition for attractive acquisition targets that may also increase the price of the target business. As a result, there is no assurance that the Group will always be able to source and execute acquisitions in the future at attractive valuations.

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

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

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

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

Climate change legislation or protests against fossil fuel extraction may have a material adverse effect on the industry.

Continued public concern regarding climate change, the extent to which it is caused by human activity and potential mitigation through regulation could have a material impact on the Group's business. International agreements, national and regional legislation, and regulatory measures to limit greenhouse gas ("**GHG**") emissions are currently in place or in various stages of discussion or implementation. Given that certain of the Group's operations are associated with emissions of GHGs, these and other GHG emissions-related laws, policies and regulations may result in substantial capital, compliance, operating and maintenance costs. The level of expenditure required to comply with these laws and regulations is uncertain and is expected to vary depending on the laws enacted by particular countries. For an overview of the regulatory environment in which the Group operates, please see Part VIII "*Regulatory Overview*" of this Prospectus.

The emission reduction targets and other provisions of legislative or regulatory initiatives and policies enacted in the future by the United States or states in which the Group operates, could adversely impact the Group's business by imposing increased costs in the form of higher taxes or rises in the prices of emission allowances, limiting the Group's ability to develop new gas and oil reserves, transport hydrocarbons through pipelines or other methods to market, decreasing the value of the Group's assets, or reducing the demand for hydrocarbons and refined petroleum products. In addition, the Group may be subject to activism from groups campaigning against fossil fuel extraction, which could affect the Group's reputation, disrupt its campaigns or programs, require the Group to incur significant, unplanned expense to respond or react to intentionally disruptive campaigns, result in limitations or restrictions on certain sources of funding (including investment from current or other potential investors as well as funding from commercial banks), create blockades to interfere with operations or otherwise negatively impact the Group's business, results of operations, financial condition or prospects.

The Group faces production risks and hazards that may affect its ability to produce gas, natural gas liquids and oil at expected levels, quality and costs and that may result in additional liabilities to the Group.

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

If any of the above events occur, environmental damage, including biodiversity loss or habitat destruction, injury to persons or property and other species and organisms, loss of life, failure to produce gas, natural gas liquids and oil in commercial quantities or an inability to fully produce discovered reserves could result. These events could also cause substantial damage to the Group's property and its reputation and put at risk some or all its interests in licences, which enable the Group to produce, and could result in incurrence of fines or penalties, criminal sanctions potentially being enforced against the Group and its management, as well as other governmental and third-party claims. Consequent production delays and declines from normal field operating conditions and other adverse actions taken by third parties may result in revenue and cash flow levels being adversely affected.

Moreover, should any of these risks materialize, the Group could incur legal defence costs, remedial costs and substantial losses, including those due to injury or loss of life, human health risks, severe damage to or destruction of property, natural resources and equipment, environmental damage, unplanned production outages, clean-up responsibilities, regulatory investigations and penalties, increased public interest in the Group's operational performance and suspension of operations.

The Group is obligated to comply with operational, health and safety and environmental regulations and cannot guarantee that it will be able to comply with these regulations.

The Group operates in an industry that has certain hazardous risks and consequently is subject to comprehensive laws and regulations, especially with regard to the protection of health, safety and the environment. For example, the Group is subject to laws and regulations related to occupational safety and health, hydraulic fracturing activities, air emissions, water quality, the protection of endangered animal species and the safety of gas transmission and gathering pipelines. For an overview of the regulatory environment in which the Group operates, please see Part VIII "*Regulatory Overview*" of this Prospectus. Although the Directors believe that the Group has adequate procedures in place to mitigate operational risks and keep these under review, there can be no assurances that these procedures will be adequate to address every potential health, safety and environmental hazard and a failure to adequately mitigate risks may result in loss of life, injury, or adverse impacts on health of employees, contractors and third-parties or the environment. Any failure by the Group or one of its sub-contractors, whether inadvertent or otherwise, to comply with applicable legal or regulatory requirements may give rise to civil, administrative and/or criminal liabilities, civil fines and penalties, delays or restrictions in acquiring or disposing of assets and/or delays in securing or maintaining the required permits, licences and approvals. A lack of regulatory compliance may even lead to denial or termination of licences the Group requires for operating its sites or could result in other operational restrictions or obligations. The Group's health, safety and environmental policy is to observe local, state, and national, legal and regulatory requirements and to apply generally accepted industry best practices where legislation does not exist.

The terms of licences, permits, regulatory orders, or permissions may include more stringent operational, environmental and/or health and safety requirements. The Group's operations have the potential to impact soil, air and water quality, biodiversity and ecosystems. Obtaining development or production licences and permits may become more difficult or may be delayed due to governmental, regional or local environmental consultation, scientific studies, approvals or other considerations or requirements. Furthermore, third-parties such as environmental organizations may judicially contest licences and permits already granted by relevant authorities and operations may be subject to other administrative or judicial challenges.

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

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

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

The Group carries out business in a highly competitive industry.

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

- engagement of third-party service providers whose capacity to provide key services may be limited;
- acquisition of other companies that may already own licences or existing producing assets;
- acquisition of assets offered for sale by other companies;
- access to capital (debt and equity) for financing and operational purposes;
- purchasing, leasing, hiring, chartering or other procuring of equipment that may be scarce; and
- employment of qualified and experienced skilled management and gas and oil professionals and field operations personnel.

Competition in the Group's markets is intense and depends, among other things, on the number of competitors in the market, their financial resources, their degree of geological, geophysical, engineering and management expertise and capabilities, their degree of vertical integration, and pricing policies, their ability to develop properties on time and on budget, their ability to select, acquire and develop reserves and their ability to foster and maintain relationships with the relevant authorities.

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

The effects of operating in a competitive industry may include:

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

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

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

Unless stated otherwise, the reserves and resources set forth in this Prospectus represent estimates only and are based on data taken from the Competent Person's Report. The resources data contained in this Prospectus has been certified by the Competent Person unless stated otherwise. The standards utilised to prepare the reserves and resources information that has been extracted in this Prospectus, are different from the standards of reporting adopted in other jurisdictions. Investors, therefore, should not assume that the data found in the reserves and resources information set forth in this Prospectus is directly comparable to similar information that has been prepared in accordance with the reserve and resource reporting standards of other jurisdictions.

In general, estimates of economically recoverable gas, natural gas liquids and oil reserves and resources are based on a number of factors and assumptions made as of the date on which the reserves and resources 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 gas and oil reserves and resources, rates of production and 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 gas, natural gas liquids and oil prices;
- capital investments;
- effectiveness of the applied technologies and equipment;
- effectiveness of the Group's field operations employees to extract the reserves;
- natural events or the negative impacts of natural disasters;
- future operating costs, tax on the extraction of commercial minerals, development costs and workover and remedial costs; and
- the judgment of the persons preparing the estimate.

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

- the quantities and qualities that are ultimately recovered;
- the timing of the recovery of gas and oil reserves;
- the production and operating costs incurred;
- the amount and timing of development expenditures;
- 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 and resources are beyond the Group's control and therefore these estimates may prove to be incorrect over time. Evaluations of reserves necessarily involve multiple uncertainties. The accuracy of any reserves or resources evaluation depends on the quality of available information and gas, natural gas liquids and oil engineering and geological interpretation. Furthermore, less historical data is available for unconventional wells because they have only become technologically viable in the past decade. In comparison, some conventional wells in the Group's portfolio have been productive for a much longer time. As a result, there is a risk that estimates of the Group's shale reserves are not as reliable as estimates of the conventional well reserves that have a longer historical profile to draw on. Interpretation, testing and production after the date of the estimates may require substantial upward or downward revisions in the Group's reserves and resources data. Moreover, different reserve engineers may make different estimates of reserves, resources and cash flows based on the same available data. Actual production, revenues and expenditures with respect to reserves and resources will vary from estimates and the variances may be material.

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

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

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

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

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

The recent COVID-19 outbreak could have an adverse effect on the Group's business.

Concerns are rapidly growing about the global outbreak of COVID-19. The virus has spread rapidly across the globe, including in the continents of Europe and North America. The pandemic is having an unprecedented impact on the global economy as the respective levels of government react to this public health crisis, which has created significant uncertainties. As the pandemic continues to grow, consumer fears about becoming ill with the virus and recommendations and/or mandates from authorities to avoid large gatherings of people or self-quarantine may continue to increase, which has already affected, and may continue to affect aggregate energy consumption and economic activity generally. The extent of the impact of the pandemic on the Group's business, results of operations, financial condition or prospects will depend largely on future developments, including the duration of the spread of the outbreak, the impact on capital and financial markets and the related impact on consumer behavior, all of which are highly uncertain and cannot be predicted. This situation is changing rapidly, and additional impacts may arise that the Group is not aware of currently.

The Group relies on third-party infrastructure such as TC Energy (formerly TransCanada), Enbridge, CNX, Dominion Energy Transmission and MarkWest that it does not control and/or, in each case, is subject to tariff charges that it does not control.

The majority of the Group's production passes through third-party owned and controlled infrastructure. If these third party pipelines or liquids processing facilities experience any event that causes an interruption in operations or a shut-down such as mechanical problems, an explosion, adverse weather conditions, a terrorist attack or labour dispute, the Group's ability to produce or transport natural gas could be severely affected. For example, the Group has an agreement with MarkWest Energy Partners, L.P., ("**MarkWest**") where approximately 90 per cent. of the natural gas liquids sold by the Group are processed at MarkWest's facility in Kentucky. Any material decrease in the Group's ability to process or transport its natural gas through third party infrastructure such as MarkWest's could have a material adverse effect on the Group's business, results of operations, financial condition or prospects.

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

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

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

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

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

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

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

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

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

The Group's operations must be carried out in accordance with the terms of licences, operating agreements, annual work programs and budgets together with any conditions incumbent on the Group at the time the relevant asset was acquired such as ongoing royalty and other rental payments. Relevant legislation provides that fines may be imposed and a licence may be suspended or terminated if a licence holder, or party to a related agreement, fails to comply with its obligations under such licence or agreement, or fails to make timely payments of levies and taxes for the licensed activity, provide the required geological information or meet other reporting requirements. It may from time to time be difficult to ascertain whether the Group has complied with obligations under licences as the extent of such obligations may be unclear or ambiguous and regulatory authorities in jurisdictions in which the Group does business, or in which it may do business in the future, may not be forthcoming with confirmatory statements that work obligations have been fulfilled, which can lead to further operational uncertainty.

In addition, the Group and its commercial partners, as applicable, have obligations to operate assets in accordance with specific requirements under certain licences and related agreements, field development agreements, laws and regulations. If the Group or its partners were to fail to satisfy such obligations with respect to a specific field, the licence or related agreements for that field may be suspended, revoked or terminated. Although the Group is now acquiring shale assets, the Group's primary source of natural gas and crude oil remains conventional wells. In some instances, these conventional wells are located on the same property as unconventional wells that produce shale oil. In these cases, the rights to access the shale layers of the property will typically be conditioned on the ongoing productivity of conventional wells on the property. Furthermore, the shale rights may be owned by a third party, and the Group will typically have a joint operating agreement with the third party. This joint agreement will typically stipulate that in consideration for the Group being permitted to operate the conventional wells, the Group is required to maintain production so that the third party retains the shale licenses. If the Group fails to maintain production in the conventional wells, under the joint agreement, the Group will be liable to the third party for a percentage of the reserve value of the shale oil. Among others, the Group has such joint agreements with CNX and EQT. The relevant authorities are typically authorized to, and do from time to time, inspect to verify compliance by the Group or its commercial partners, as applicable, with relevant laws and the licences or the agreements pursuant to which the Group conducts its business. There can be no assurance that the views of the relevant government agencies regarding the development of the fields that the Group operates or the compliance with the terms of the licences pursuant to which the Group conducts such operations will coincide with the Groups views, which might lead to disagreements that may not be resolved.

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

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

The gas and oil industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies, such as emissions controls and processing technologies. As others use or develop new technologies, the Group may be placed at a competitive disadvantage or may be forced by competitive pressures to implement those new technologies at substantial costs. In addition, other gas and oil companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages, which may in the future allow them to implement new technologies before the Group can. The Group may not be able to respond to these competitive pressures or implement new technologies on a timely basis or at an acceptable cost or even at all given the personnel resources that are available to it. In addition to implementing new accounting and royalty management software, the Group is also implementing technology that aims to improve field data capture for its approximately 60,000 wells so as to grant efficient access to information for decision-making. These efforts to upgrade the Group's enterprise technology represent a significant undertaking and may have unforeseen adverse consequences. If one or more of the technologies used now or in the future were to become obsolete, the Group's business, results of operations, financial condition or prospects could be materially adversely affected if competitors gain a material competitive advantage.

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

The Group's future operating results depend in significant part upon the continued contribution of its board of directors, key senior management and technical, financial and operations personnel. Management of the Group's growth will require, among other things, stringent control of financial systems and operations, the continued development of its management control, the ability to attract and retain sufficient numbers of qualified management and other personnel, the continued training of such personnel and the presence of adequate supervision.

In addition, the personal connections and relationships of the Group's board of directors and key management are important to the conduct of its business. If the Group were to unexpectedly lose a member of its key management or fail to maintain one of the strategic relationships of its key management team, the Group's business, results of operations, financial condition or prospects could be materially adversely affected. In particular, the Group is highly dependent on its Chief Executive Officer, Rusty Hutson, Jr. Acquisitions are key part of the Group's strategy and Mr. Hutson has been instrumental in sourcing them and securing their financing. Furthermore, as the Group's founder, Mr. Hutson is strongly associated with the Group's success and if he were to cease being the Chief Executive Officer, perception of the Group's future prospects may be diminished.

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

Completion of the potential acquisition of assets from third parties, including from Carbon and EQT, is uncertain and subject to a significant number of conditions which may not be satisfied or waived and may result in the acquisition being delayed or not being completed at all.

In pursuance of its acquisition strategy, the Company continues to explore potential acquisition targets from third parties. Diversified Gas & Oil Corporation, a subsidiary of the Company, executed a conditional purchase and sale agreement dated 7 April 2020 (the "**Carbon PSA**") with Carbon Energy Corporation ("**Carbon**") in connection with the possible acquisition of certain upstream and midstream assets of Carbon in the Appalachian Basin, including approximately 6,100 net conventional wells located in Appalachia (Tennessee, Kentucky, West Virginia), as well as various non-operated wells, midstream pipeline systems and facilities (including intrastate gathering pipeline of approximately 4,700 miles in West Virginia and two active natural gas storage fields) (the "**Carbon Assets**") from Carbon. The acquisition of the Carbon Assets is at a preliminary stage and is subject to a significant number of conditions. The satisfaction of certain of these conditions are within the sole control of the Group such as completion of due diligence (including all title, environmental, contractual, credit, litigation, and regulatory diligence) to the Company's satisfaction and the Company's right to not complete the acquisition if there is a material change in the conditions, assets, or operational matters of the Carbon Assets prior to completion of the acquisition. In addition, the acquisition is also conditional upon satisfaction of various other conditions, including receipt of all necessary shareholder consents, approvals, authorisations and permits (including any authorisations required from the Federal Energy Regulatory Commission and various State Public Service Commissions).

In addition, the Company executed a conditional purchase and sale agreement dated 11 May 2020 (the "**EQT PSA**") with certain subsidiaries of EQT in connection with the possible acquisition of certain assets of EQT in the Appalachian Basin, including approximately 900 net operated wells, including 67 horizontal producing wells in Pennsylvania, with the majority of the balance being conventional vertical producing wells in West Virginia, and associated midstream infrastructure as well as a further 13 drilled and completed wells that are not yet connected to the gathering infrastructure (the "**EQT Corporation Assets**") from EQT. The acquisition of the EQT Corporation Assets is at a preliminary stage and is subject to a significant number of conditions. The satisfaction of certain of these conditions are within the sole control of the Group such as completion of due diligence (including all title, environmental, contractual, credit, litigation, and regulatory diligence) to the Company's satisfaction and the Company's right to not complete the acquisition if there is a material change in the conditions, assets, or operational matters of the EQT Corporation Assets prior to completion of the acquisition. In addition, the acquisition is also conditional upon satisfaction of various other conditions, including receipt of all necessary shareholder consents, approvals, authorisations and permits.

Under the terms of the Carbon PSA and the EQT PSA, although the Company has a right to exclusivity pursuant to which Carbon and EQT respectively have agreed to not enter into any negotiations or discussions with any third party in connection with the disposal of the Carbon Assets for a period ending on 30 June 2020 and the EQT Corporation Assets for a period ending on 28 May 2020, the Company cannot predict definitively how long it will take to fully complete its due diligence and satisfy all the conditions under each of the Carbon PSA and the EQT PSA. In addition, satisfying the conditions could also cost more than the Company currently expects and there may be further additional and unforeseen expenses incurred in connection with the acquisitions, which may make the acquisitions financially unviable or unattractive.

There can be no guarantee that the conditions will be satisfied (or waived, if applicable) in the necessary time frame and whether the Company will acquire the Carbon Assets, the EQT Corporation Assets or any other potential third party assets on satisfactory terms, or at all. Any delay in completing the acquisition of the Carbon Assets, the EQT Corporation Assets or any other assets from third parties may adversely affect the synergies and other benefits that the Group expects to achieve if the acquisition and integration of these assets into the Group is completed within the expected timeframe. In addition, the Group's management would have spent significant time in connection with these acquisitions, which could otherwise have been spent in connection with the other activities of the Group.

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

The Group insures its operations in accordance with industry practice and plans to continue to insure the risks it considers appropriate for the Group's needs and circumstances. However, the Group may elect not to have insurance for certain risks, due to the high premium costs associated with insuring those risks or for various other reasons, including an assessment in some cases that the risks are remote.

No assurance can be given that the Group will be able to obtain insurance coverage at reasonable rates (or at all), or that any coverage it or the relevant operator obtains, and any proceeds of insurance, will be adequate and available to cover any claims arising. The Group may become subject to liability for pollution, blow-outs or other hazards against which it has not insured or cannot insure, including those in respect of past activities for which it was not responsible. Any indemnities the Group may receive from such parties may be difficult to enforce if such sub-contractors, operators or joint venture partners lack adequate resources.

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

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

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

From time to time, the Group may be subject, directly or indirectly, to litigation arising out of its operations and the regulatory environments in its areas of operations. Historically, categories of litigation that the Group has faced included actions by royalty owners over payment disputes, personal injury claims and property related claims, including claims over property damage, trespass or nuisance. Although the Group currently faces no material litigation, damages claimed under such litigation in the future may be material or may be indeterminate, and the outcome of such litigation may materially impact the Group's business, results of operations, financial condition or prospects. While the Group assesses the merits of each lawsuit and defends itself accordingly, it may be required to incur significant expenses or devote significant resources to defending itself against such litigation. In addition, the adverse publicity surrounding such claims may have a material adverse effect on the Group's business.

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

The Group may face attempted cyber-attacks. Such cyber-attacks are designed to penetrate the Group's network security or the security of its internal systems, misappropriate proprietary information and/or cause interruptions to its services and expect to continue to face similar threats in the future. While the Group has successfully prevented attacks faced to date from being successful, it cannot guarantee that it will be able to do so in the future. Such future attacks could include hackers obtaining access to the Group's systems, the introduction of malicious computer code or denial of service attacks. If an actual or perceived breach of the Group's network security occurs, it could adversely affect its business or reputation, and may expose the Group to the loss of information, litigation and possible liability. An actual security breach could also impair the Group's ability to operate its business and provide products and services to its customers. Additionally, malicious attacks, including cyber-attacks, may damage the Group's assets, prevent production at its producing assets and otherwise significantly affect corporate activities. For example, the Group utilises electronic monitoring of meters and flow rate devices to monitor pressure build-up in its production wells. If there were a cyber-attack that penetrated the Group's monitoring systems such that they provided false readings, this could result in an unknown pressure build-up, creating a dangerous situation which could end up in an explosion. Such an outcome would have a material adverse impact on the Group's business, results of operations, financial condition or prospects.

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

The Group is subject to certain tax risks.

There can be no certainty that the current taxation regime in the UK or overseas jurisdictions within which the Group currently operates or may operate in the future will remain in force or that the current levels of corporation taxation will remain unchanged. For example, in the US certain localities maintain a severance or impact tax on the removal of oil and natural gas from the ground. Such tax rates may be increased or new severance or impact taxes implemented. In addition to marginal well tax credits available under US federal tax law, the Group has also been able to offset its tax burden against net operating losses generated by its historic drilling activity and the acquisition of certain fixed assets such as EQT's midstream assets. There can be no assurance that there will be no amendment to the existing taxation laws applicable to the Group, which may have a material adverse effect on the Group's financial position. Any change in the Group's tax status or in taxation legislation in the UK or the US could affect the Group's ability to provide returns to Shareholders. Statements in this Prospectus concerning the taxation of investors in shares are based on current law and practice, which is subject to change. The taxation of an investment in the Group depends on the individual circumstances of investors.

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

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

Finally, due to the Group's parent company being a UK based entity with operations and assets in the US, any changes in US federal tax law or tax rulings unfavourable to the Group structure related to non US owned parent companies could negatively impact the Group's effective tax rate and cash flows, which could cause the Group's business, results of operations, financial condition or prospects to be materially adversely affected. Investors who are in any doubt as to their tax position or who are subject to tax in jurisdictions other than the UK are strongly advised to consult their professional advisers.

RISKS RELATING TO THE ORDINARY SHARES

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

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

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

- the price of gas, natural gas liquids and oil;
- conditions generally affecting the oil and gas industry;
- actual or anticipated quarterly variations in the Group's operating results;

- changes in expectations as to the Group's future financial performance or changes in financial estimates or past financial or accounting practices or reports, if any;
- announcements relating to the Group's business or the business of its competitors;
- operational incidents;
- the global macroeconomic environment;
- "Brexit";
- fund redemptions;
- irrational investor behaviour; and
- the operating and stock performance of other comparable companies.

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

The concentration of the Group's share capital ownership among its largest shareholders could conflict with the interests of other shareholders.

The Group's Significant Shareholders collectively own approximately 71 per cent. of its issued and outstanding Ordinary Shares as of the Last Practicable Date. Consequently, these Shareholders have significant influence over all matters that require approval by the Shareholders, including the re-election of directors and approval of significant corporate transactions. This concentration of ownership will limit the Shareholders' ability to influence corporate matters, and as a result actions may be taken that Shareholders may not view as beneficial.

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

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

As a US corporation, dividends paid by the Company to non-US Shareholders are generally subject to US withholding taxes applied on the gross amount of such dividends. The statutory rate of withholding under the Code is 30 per cent. to non-US Shareholders, which may be reduced by an applicable treaty (however, as described in detail in the "*Material US Federal Income Tax Considerations*", in certain situations will not be less than 15 per cent). Furthermore, Sections 1471 through 1474 of the Code (commonly referred to as "**FATCA**") generally impose a withholding tax of no more than 30 per cent. on the gross amount of dividends paid to non-US financial institutions and certain other non-US entities on Ordinary Shares in a United States corporation unless certain conditions are met.

Due to the nature of its assets and operations, the Company believes it is a US Real Property Holding Corporation ("**USRPHC**") under the Code and Ordinary Shares constitute a US real property interest ("**USRPI**"). Non-US Shareholders in their capacity as sellers or transferors are subject to US federal income tax in respect of a gain on their Ordinary Shares and are required to file a US tax return. Furthermore, the amount realised from any disposition is subject to a withholding tax of 15 per cent. required to be collected from disposition proceeds, unless the Ordinary Shares qualify as "regularly traded on an established securities market." Non-US Shareholders may, by filing a US tax return, be able to claim a refund for any withholding tax deducted in excess of the tax liability on gain. Furthermore, non-US Shareholders will be required to pay, by filing a US tax return, any tax liability on gain that is not satisfied by withholding. A non-US Shareholder that has owned 5 per cent. or less of the Ordinary Shares during the relevant period under these rules, taking into account applicable constructive ownership rules, may treat its ownership of the Ordinary Shares as not constituting a USRPI and thereby avoid net income tax payment and tax return filing obligations if the Ordinary Shares are treated as "regularly traded on an established securities market." The Company makes no representations as to whether the Ordinary Shares have been and will be treated as "regularly traded on an established securities market."

For further details, see "*Material US Federal Income Tax Considerations*."

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

The dividend policy of the Company is dependent upon its financial condition, cash requirements, future prospects, compliance with the financial covenants in the Amended KeyBank Facility Agreement, profits available for distribution and other factors deemed to be relevant at the time and on the continued health of the markets in which it operates. Although the Board's target is to return not less than 40 per cent. of free cash flow to Shareholders by way of a dividend and the Board's dividend policy reflects the Company's current and future expectation of future cash flow generation potential, there can be no guarantee that the Company will continue to pay dividends in the future.

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

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

The Company has issued options under its equity incentive plans to employees and Executive Directors for a total of 23,220,000 new Ordinary Shares of the Company which are currently outstanding, and has also entered into restricted stock unit agreements with certain employees, of which 1,816,209 restricted stock units are currently outstanding. In addition, on 30 January 2017 and 15 June 2017, the Company issued Warrants to Mirabaud over 3,543,769 Ordinary Shares, which are currently outstanding. The Company may, in the future, issue further options and/or warrants to subscribe for new Ordinary Shares to certain advisers, employees, Directors, senior management and/or consultants of the Group. The exercise of any such options and warrants would result in a dilution of the shareholdings of other investors. Additionally, although the Company has no current plans for an offering of Ordinary Shares, it is possible, that the Company may decide to offer additional Ordinary Shares in the future. Subject to any applicable pre-emption rights, any future issues of Ordinary Shares by the Company may have a dilutive effect on the holdings of Shareholders and could have a material adverse effect on the market price of Ordinary Shares as a whole.

Overseas shareholders may be subject to exchange rate risk.

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

There is no guarantee that an active trading market for the Ordinary Shares will develop or that the Main Market will provide an increased liquidity in the Ordinary Shares.

The liquidity of the Ordinary Shares on the Main Market will be influenced by a large number of factors, some specific to the Group and its operations and others outside its control and unrelated to the Group's operating performance, such as the operating and share price performance of other companies that investors may consider comparable to the Company, speculation about the Company in the press or the investment community, strategic actions by competitors, changes in market conditions and regulatory changes in any number of countries. There can be no guarantee that, following Admission, an active trading market for the Ordinary Shares will develop or, if developed, that it will be maintained or that Admission will result in an increase in the liquidity of the Ordinary Shares. If an active trading market is not maintained, the trading price of the Ordinary Shares could be adversely affected. The market price for the Ordinary Shares may fall, perhaps substantially. As a result of fluctuations in the market price of the Ordinary Shares, investors may not be able to sell their Ordinary Shares.

Shareholders in the United States and other jurisdictions may not be able to participate in future equity offerings.

The Articles provide for pre-emption rights to be granted to shareholders in the Company in certain circumstances, unless such rights are dis-applied by a shareholder resolution. However, securities laws of certain jurisdictions may restrict the Group's ability to allow participation by shareholders in future offerings. In particular, shareholders in the United States may not be entitled to exercise these rights, unless either the Ordinary Shares and any other securities that are offered and sold are registered under the US Securities Act, or the Ordinary Shares and such other securities are offered pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the US Securities Act. The Company cannot assure prospective investors that any exemption from such overseas securities law requirements would be available to enable US or other Shareholders to exercise their pre-emption rights or, if available, that the Company will utilise any such exemption.

PART III

PRESENTATION OF FINANCIAL AND OTHER INFORMATION

Historical financial information

The Group's financial year runs from 1 January to 31 December. The historical financial information presented in this Prospectus consists of audited consolidated financial information of the Group for each of the financial years ended 31 December 2017, 31 December 2018 and 31 December 2019. Unless otherwise stated, no other financial information presented in this Prospectus has been audited.

The historical financial information in Section B "*Historical financial information relating to the Group*" of Part XIV "*Historical Financial Information*" of this Prospectus has been prepared in accordance with the requirements of the Listing Rules and the International Financial Reporting Standards as adopted by the European Union ("**IFRS**"). The basis of preparation and the significant accounting policies applied are further explained in Section B "*Historical financial information relating to the Group*" of Part XIV "*Historical Financial Information*" of this Prospectus.

Non-IFRS financial measures

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

The following information should be read in conjunction with Part XI "*Operating and Financial Review*" and Part XIV "*Historical Financial Information*" of this Prospectus.

EBITDA (hedged) and EBITDA (unhedged)

EBITDA is defined by the Group as earnings before interest, tax, depreciation and amortisation.

Adjusted EBITDA (hedged) and Adjusted EBITDA (unhedged) are defined by the Company as 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 Group's hedge portfolio, non-cash equity compensation charges and items of a similar nature. The Directors believe that Adjusted EBITDA (hedged) and Adjusted EBITDA (unhedged) are useful measures as they enable a more effective way to evaluate operating performance and compare the results of operations from period-to-period and against its peers without regard to the Group's financing methods or capital structure. The Group excludes the items listed in the table below from operating profit in arriving at Adjusted EBITDA (hedged) and Adjusted EBITDA (unhedged) because these amounts can vary substantially from company to company within the industry, depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired.

The table below shows the calculation of Adjusted EBITDA (hedged) and Adjusted EBITDA (unhedged) for each of the periods presented:

(Amounts in thousands $)	Fiscal Year ended 31 December		
	2019	2018	2017
Operating profit	**180,507**	**294,997**	**41,161**
Amortisation, depreciation and depletion	98,139	41,988	7,536
Gain on bargain purchase	(1,540)	(173,473)	(37,093)
Gain on oil and gas programme and equipment	—	(4,079)	(95)
(Gain) loss on derivative financial instruments	(20,270)	(33,636)	1,965
Non-recurring costs associated with acquisitions	9,210	19,637	3,349
Other non-recurring costs	7,542	—	—
Provision for working interest owners receivable	730	—	632
Non-cash equity issuance included in administrative expense	3,065	783	59
Gain on foreign currency hedge	(4,117)	—	—
Adjusted EBITDA (*hedged*)	**273,266**	**146,217**	**17,514**
Cash portion of settled hedges	(53,584)	15,655	(1,524)
Adjusted EBITDA (*unhedged*)	**219,682**	**161,872**	**15,990**

Operating Margin

Operating Margin is defined as total realised price less total cash costs and Percentage Operating Margin is defined as the Operating Margin as a percentage of total realised price.

The table below shows the calculation of Operating Margin and Percentage Operating Margin for each of the periods presented.

(Amounts in $ per boe)	Fiscal Year ended 31 December		
	2019	2018	2017
Realised price (including impact of cash-settled derivatives)	15.76	17.69	17.12
Other revenue	0.77	0.64	0.93
Base lease operating expense	(3.31)	(4.73)	(7.02)
Gathering and compression, owned	(1.42)	(1.00)	—
Recurring administrative expenses	(1.17)	(1.34)	(2.03)
Production taxes	(0.53)	(0.80)	(0.56)
Gathering and transportation, 3rd party	(1.28)	(0.68)	(1.14)
Operating margin	8.82	9.78	7.30
Percentage Operating margin	53.4%	53.4%	40.4%

Free Cash Flow (adjusted)

Free Cash Flow (adjusted) is defined by the Group as Adjusted EBITDA (hedged) further adjusted for capital expenditures, plugging costs and cash paid for interest. The Directors view Free Cash Flow (adjusted) as a key liquidity measure, as this measure represents the amount of discretionary cash available to service debt principal, pay dividends and to possibly buyback stock shares.

The table below shows the calculation of Free Cash Flow (adjusted) for each of the periods presented.

(Amounts in thousands $)	Fiscal Year ended 31 December		
	2019	2018	2017
Adjusted EBITDA (*hedged*)	273,266	146,217	17,514
Capital expenditures and plugging costs	(32,313)	(18,515)	(2,935)
Finance expense (interest)	(32,715)	(15,433)	(3,298)
Asset retirement (plugging)	(2,541)	(1,171)	(78)
Free Cash Flow (*adjusted*)	**205,697**	**111,098**	**11,203**

Leverage (hedged) and Leverage (unhedged)

Leverage is calculated by dividing Adjusted EBITDA (hedged) and Adjusted EBITDA (unhedged) (as defined above) of the Group for the last 12 months by Net Debt at the period end. The Directors view leverage as a key measure of the Group's ability to pay off its debt as well as it being used in the covenant calculations for the Group's external borrowings.

The table below shows the calculation of Leverage (hedged) and Leverage (unhedged) for each of the periods presented:

	Fiscal Year ended 31 December		
(Amounts in thousands $)	**2019**	**2018**	**2017**
Adjusted EBITDA (hedged)	273,266	146,217	17,514
Net Debt	643,258	496,535	58,657
Leverage (*hedged*)	**42.8%**	**29.4%**	**29.9%**
Adjusted EBITDA (unhedged)	219,682	161,872	15,990
Net Debt	643,258	496,535	58,657
Leverage (*unhedged*)	**34.2%**	**32.6%**	**27.3%**

Net Debt

Net Debt is defined as the sum of Group's borrowings, excluding leases, less cash and cash equivalents. The table below shows the calculation of Net Debt for each of the periods presented.

	Fiscal Year ended 31 December		
(Amounts in thousands $)	**2019**	**2018**	**2017**
Total borrowings	644,919	497,907	73,825
Less:			
Cash and cash equivalents	(1,661)	(1,372)	(15,168)
Net Debt	**643,258**	**496,535**	**58,657**

Revenue (hedged)

Revenue (hedged) is defined as revenue adjusted for impact of any gains/losses on derivative settlements. The table below shows the calculation of Revenue (unhedged) for each of the periods presented:

	Fiscal Year ended 31 December		
(Amounts in thousands $)	**2019**	**2018**	**2017**
Revenue	462,256	289,769	41,777
Less:			
Net gain/(loss) on derivative settlements	49,467	(15,655)	1,524
Revenue (*hedged*)	**511,723**	**274,114**	**43,301**

Base Lease Operating Expense

Base Lease Operating Expense is defined as the sum of employee and benefit expenses, well operating expense (net), automobile expense and insurance cost, divided by boe production for the fiscal year. The metric is expressed on a per barrel basis. The table below shows the calculation of Base Lease Operating Expense for each of the periods presented:

	Fiscal Year ended 31 December		
(Amounts in $ per boe)	**2019**	**2018**	**2017**
Employee and benefit expenses	55,947	35,061	8,539
Well operating expense, net	29,643	25,315	6,380
Automobile expense	10,504	5,569	1,441
Insurance	6,208	4,698	491
Total expense	**102,302**	**70,643**	**16,851**
Production (boe)	30,944	14,950	2,400
Base Lease Operating Expense	**3.31**	**4.73**	**7.02**

Total Lease Operating Expense

Total Lease Operating Expense is defined as the Base Lease Operating Expense, plus the owned gathering and compression expense, third-party gathering and transportation expense and production taxes, divided by boe production for the fiscal year. The metric is expressed on a per barrel basis. The table below shows the calculation of Total Lease Operating Expense for each of the periods presented:

	Fiscal Year ended 31 December		
(Amounts in $ per boe)	**2019**	**2018**	**2017**
Base Lease Operating Expense	**102,302**	**70,643**	**16,851**
Owned gathering and compression expense	44,060	14,951	—
Third-party gathering and transportation expense	39,596	10,221	2,712
Production taxes	16,427	11,978	1,345
Total expense	**202,385**	**107,793**	**20,908**
Production (boe)	30,944	14,950	2,400
Total Lease Operating Expense	**6.54**	**7.21**	**8.71**

Adjusted G&A Expense

Adjusted G&A Expense is defined as the recurring administrative expenses divided by boe production for the fiscal year. The metric is expressed on a per barrel basis. The table below shows the calculation of Adjusted G&A Expense for each of the periods presented:

	Fiscal Year ended 31 December		
(Amounts in $ per boe)	**2019**	**2018**	**2017**
Recurring administrative expenses	**36,073**	**20,104**	**4,879**
Production (boe)	30,944	14,950	2,400
Adjusted G&A Expense	**1.17**	**1.35**	**2.03**

Unit Recurring G&A

Unit Recurring G&A is defined as the total administrative expenses divided by boe production for the fiscal year. The metric is expressed on a per barrel basis. The table below shows the calculation of Unit Recurring G&A for each of the periods presented:

	Fiscal Year ended 31 December		
(Amounts in $ per boe)	**2019**	**2018**	**2017**
Total administrative expenses	**56,619**	**40,524**	**8,919**
Production (boe)	30,944	14,950	2,400
Adjusted G&A Expense	**1.83**	**2.71**	**3.71**

Market, industry and other statistical data

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

- the Energy Information Administration;
- the International Energy Agency;
- Direct Energy Business Marketing;
- FactSet; and
- Bloomberg.

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

All such data sourced from third parties contained in this Prospectus have been accurately reproduced and, so far as the Company is aware and is able to ascertain from information published by that third party, no facts have been omitted that would render the reproduced information inaccurate or misleading. No material changes have occurred since the date of the Competent Person's Report included in Part XV of this Prospectus, the omission of which would make the Competent Person's Report misleading.

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

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

Rounding

Percentages and certain amounts included in this Prospectus 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 Prospectus 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.

Currencies

In this Prospectus, unless otherwise indicated, references to "Pounds Sterling", "Sterling", "£" or "pence" are to the lawful currency of the United Kingdom; "US Dollars", "USD", "US$", "$" or "cents" are to the lawful currency of the United States.

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

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

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

Period (Year/Month) *(GBP per $1.00)*	**Period end**	**Average**	**High**	**Low**
2017	0.7395	0.7767	0.8337	0.7344
2018	0.7846	0.7500	0.7991	0.6981
2019	0.7543	0.7837	0.8314	0.7497
January 2020	0.7578	0.7645	0.7695	0.7544
February 2020	0.7836	0.7719	0.7836	0.7659
March 2020	0.8065	0.8107	0.8656	0.7621
April 2020	0.8042	0.8055	0.8179	0.7932
May 2020 (to 11 May 2020)	0.8101	0.8058	0.8101	0.7991

Source: Bloomberg

Times

All times referred to in this Prospectus are, unless otherwise stated, references to the time in London, UK.

Definitions and Glossary of Technical Terms

Certain terms used in this Prospectus, including all capitalised terms and certain technical and other items, are defined and explained in Part XVII "*Definitions*" and Part XVIII "*Glossary of Technical Terms*" of this Prospectus.

Information not contained in this Prospectus

No person has been authorised to give any information or make any representation other than those contained in this Prospectus and, if given or made, such information or representation must not be relied upon as having been so authorised. Without prejudice to any obligation of the Company to publish a supplementary prospectus pursuant to section 87G of FSMA and Prospectus Regulation Rule 3.4.1, the delivery of this Prospectus shall not, under any circumstances, create any implication that there has been no change in the business or affairs of the Company or the Group since the date of this Prospectus or that the information in this Prospectus is correct as of any time subsequent to the date hereof.

The Company will update the information provided in this Prospectus by means of a supplementary prospectus if a significant new factor occurs prior to Admission or if this Prospectus contains any material mistake or inaccuracy. Any supplementary prospectus will be subject to approval by the FCA and will be made public in accordance with the Prospectus Regulation Rules.

Forward-looking statements

This Prospectus includes forward-looking statements. These forward-looking statements involve known and unknown risks and uncertainties, many of which are beyond the Group's control and all of which are based on management's current beliefs and expectations about future events. Forward-looking statements are sometimes identified by the use of forward-looking terminology such as "believe", "expects", "targets", "may", "will", "could", "should", "shall", "risk", "intends", "estimates", "aims", "plans", "predicts", "continues", "assumes", "positioned" or "anticipates" or the negative thereof, other variations thereon or comparable terminology. These forward-looking statements include all matters that are not historical facts. They appear in a number of places throughout this Prospectus and include statements regarding the intentions, beliefs or current expectations of management or the Company concerning, among other things, the results of operations, financial condition, prospects, growth, strategies and dividend policy of the Company and the industry in which it operates. In particular, the statements included in Part I "*Summary*", Part II "*Risk Factors*", Part VII "*Business*" and Part XI "*Operating and Financial Review of the Group*" of this Prospectus regarding the Company's strategy, targets and expectations in respect of the Group's expected revenue, profit, growth, accounting tax rates, and capital expenditure upon the operating results of the Group as well as other expressions of the Group's targets and expectations and other future events or prospects are forward-looking statements.

These forward-looking statements, and other statements contained in this Prospectus regarding matters that are not historical facts, involve predictions. No assurance can be given that such future results will be achieved; actual events or results may differ materially as a result of risks and uncertainties facing the Group. Such risks and uncertainties could cause actual results to vary materially from the future results indicated, expressed or implied in such forward-looking statements. Important factors that could cause the Group's actual results to so vary include, but are not limited to:

- volatility and future decreases in gas, natural gas liquids and oil prices could materially and adversely affect the Group's business, results of operations, financial condition or prospects;
- the Group may experience delays in production, marketing and transportation;
- there are risks inherent in the Group's acquisitions of gas and oil assets and there can be no assurance that the Group's prior acquisitions or any other potential acquisition by the Group will be profitable and the value of any business, company or property that the Group acquires or invests in may actually be less than the amount paid for it or its estimated production capacity;
- climate change legislation or protests against fossil fuel extraction may have a material adverse effect on the Group's industry;
- the Group faces production risks and hazards that may affect its ability to produce gas, natural gas liquids and oil at expected levels, quality and costs and that may result in additional liabilities to the Group;
- the Group is obligated to comply with operational, health and safety and environmental regulations and cannot guarantee that it will be able to comply with these regulations;
- the Group carries out business in a highly competitive industry and if the Group is unsuccessful in competing against other companies, its business, results of operations, financial condition or prospects could be materially adversely affected;
- the levels of the Group's gas and oil reserves and resources, their quality and production volumes may be lower than estimated or expected;
- the Group may not have good title to all its assets and licences; and
- the Group may face unanticipated increased or incremental costs in connection with decommissioning obligations such as plugging.

For more information regarding these uncertainties, please see Part II "*Risk Factors*" of this Prospectus.

The forward-looking statements contained in this Prospectus speak only as at the date of this Prospectus. Subject to the requirements of the Prospectus Regulation Rules, the Disclosure Guidance and Transparency Rules the Listing Rules, the Market Abuse Regulation or applicable law, the Directors, the Company and the Group explicitly disclaim any intention, obligation or undertaking to publicly release the result of any revisions to any forward-looking statements in this Prospectus that may occur due to any change in the Directors', the Company's or the Group's expectations or to reflect events or circumstances after the date of it.

PART IV

DIRECTORS, SECRETARY, REGISTERED OFFICE AND ADVISERS

Directors	David Edward Johnson (*Independent Non-executive Chair*) Robert "Rusty" Russell Hutson Jr. (*Chief Executive Officer*) Bradley Grafton Gray (*Chief Operating Officer*) Martin Keith Thomas (*Non-executive Vice Chairman*) David Jackson Turner, Jr. (*Independent Non-executive Director*) Sandra (Sandy) Mary Stash (*Independent Non-executive Director*) Melanie Little (*Independent Non-executive Director*)
Company secretary	Cargil Management Services Limited
Registered office	27-28 Eastcastle Street London W1W 8DH United Kingdom
Sponsor	Stifel Nicolaus Europe Limited 150 Cheapside London EC2V 6ET United Kingdom
Legal adviser to the Company as to English law	Latham & Watkins (London) LLP 99 Bishopsgate London EC2M 3XF United Kingdom
Legal adviser to the Sponsor as to English law	Ashurst LLP London Fruit & Wool Exchange 1 Duval Square London E1 6PW United Kingdom
Auditors and Reporting Accountants to the Company	PricewaterhouseCoopers LLP 1 Embankment Place London WC2N 6RH United Kingdom
Reporting Accountants to the Company in respect of the Alliance Petroleum Financial Information	Crowe U.K. LLP St Brides House 10 Salisbury Square London EC4Y 8EH United Kingdom

PART V

EXPECTED TIMETABLE OF PRINCIPAL EVENTS FOR ADMISSION

Event	**Date**
	2020
Publication of Prospectus	13 May
Last day of trading of the Ordinary Shares on AIM	15 May
Expected cancellation of the Shares from trading on AIM	8.00 a.m. on 18 May
Admission of the Shares to the Official List	8.00 a.m. on 18 May
Admission and commencement of dealings in Ordinary Shares on the Main Market	8.00 a.m. on 18 May

All references to times in this Part V "*Expected Timetable of Principal Events for Admission*" of this Prospectus are to London times. Each of the times and dates in the above timetable is subject to change without further notice.

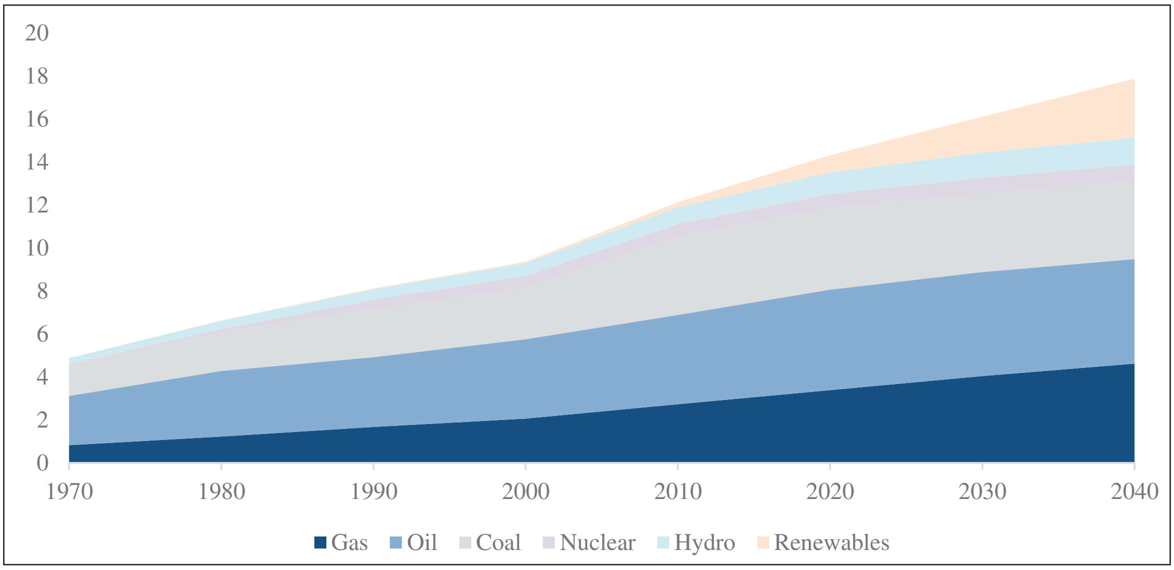
PART VI

INDUSTRY OVERVIEW

1. GLOBAL ENERGY MARKETS

Global population growth and continuing improvement in global living standards, particularly in developing nations, is expected to drive ongoing growth in demand in the global energy markets. Despite the drive towards cleaner energy, the supply of hydrocarbon products is expected to continue to be a significant contributor to this growth with both gas and oil supply anticipated to grow in absolute terms. Natural gas is expected to be a significant contributor to the global energy mix, and key in the energy transition as a partner to wind and solar, with the ability to provide quick, reliable, and continuous power without depending on sun light or wind speeds whilst releasing lower emissions than other hydrocarbon sources including oil and coal.

Primary Energy Consumption by Fuel (Billion toe)



Source: BP Energy Outlook 2019

2. US OIL & GAS INDUSTRY

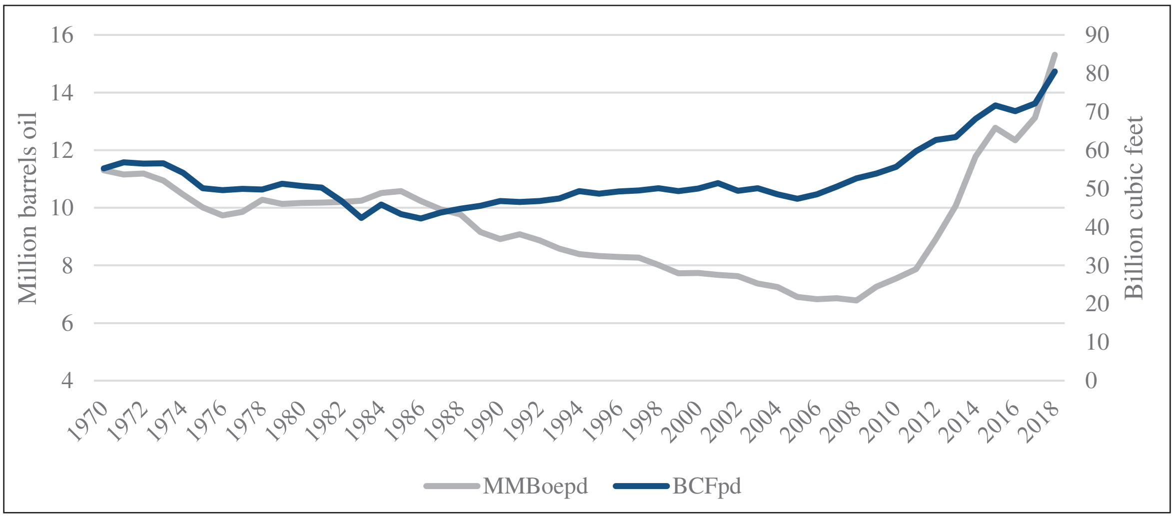
Overview

The beginning of the US oil and gas industry started in 1859 with the discovery of oil in the Edwin Drake well located in northwestern Pennsylvania. Oil in this well was produced from the Upper Devonian sandstone at a depth of approximately 70 feet. This discovery well opened a trend of oil and gas fields producing from the Upper Devonian, Mississippian, and Pennsylvanian sandstones across many parts of the states of Kentucky, New York, Ohio, Pennsylvania and West Virginia. The production of hydrocarbons in the US has grown substantially from these initial production wells, initially peaking in the 1970s with the rate of growth taking a step-change in the early 2000s. In 2018 the US set a new annual production record of nearly 15 million barrels of oil per day and 80.5 billion cubic feet per day of dry natural gas[(1)]. This growth has resulted in the US being the world's largest producer of oil and natural gas.

Notably, technological improvements in the oil and gas industry have opened up new resources that were previously inaccessible or uneconomical for development. Ongoing cost reductions in the industry, partly driven by a lower price environment has compounded this further, with companies increasingly targeting unconventional resources, using horizontal drilling techniques and hydraulic fracturing, resulting in a dramatic shift away from their traditional conventional asset base.

[(1)] *Source: BP Statistical Review of World Energy 2019*

US Oil & Gas Production



Source: BP Statistical Review of World Energy 2019

Appalachian Basin

The Appalachian Basin covers an area of approximately 185,500 square miles. This area came to prominence following the discovery of significant shale gas reserves in 2009, although it has been a major producer of oil and gas from conventional vertical well development since the 19th century. Growth in natural gas production in the Northeast of the US has come mainly from the Marcellus and Utica shale plays in the Appalachian Basin, which collectively accounted for about 29 per cent of total US production in July 2018 according to the US Energy Information Administration.

The depositions for the Appalachian Basin are the erosional sediments from the once Acadian Mountains into the lower basin. The basin was limited to the west by an uplift in rock formation from the Late Ordovician and through the Devonian period known as the Cincinnati Arch. As the mountains eroded over time, the sediment was deposited in the basin with alternating layers of carbonates, limestones, sandstone, siltstone, and shale intervals.

The Marcellus shale extends from New York in the north to Kentucky and Tennessee in the south and is the most productive natural gas-producing formation in the Appalachian Basin. The formation's footprint covers about 95,000 square miles. Dry natural gas wells in the Marcellus are mostly located in the eastern portion of the play, and liquids-rich wells are typically located in the western portion. The Utica Play consists of two stacked geological units: the Utica and Point Pleasant formations. These formations are older and deeper than the Marcellus formation. The Utica play spans about 60,000 square miles across Ohio, West Virginia, Pennsylvania, and New York.

Shale gas production in the Appalachia region has increased rapidly since 2012, driving an overall increase in US natural gas production. Appalachian natural gas production grew from 7.8 billion cubic feet per day in 2012 to 32.1 billion cubic feet per day in November 2019. This, alongside production growth across the US, has resulted in highly volatile gas pricing and subject to large fluctuations in response to relatively minor changes in the demand for gas. Between 2012 and 2019, the maximum and minimum gas prices were $5.56 and $1.71, respectively, with an average price of $3.26.

The shift away from conventional development to unconventional (as defined in Part XV "*Competent Person's Report – Conventional and Unconventional Reservoirs*") of this Prospectus has created what some have termed a "Shale Revolution" leading to a number of structural shifts in the Oil & Gas industry. In particular in Appalachia, this has resulted in:

- a bifurcation of assets along the lines of conventional and unconventional, with an increasing proportion of the companies and capital focused on unconventional;
- an increasing use of the designation of assets as core or non-core, with conventional, often older assets typically more likely to be considered non-core within the asset portfolios in which they sit; and
- an increase in the demand for capital due to the capital intensity of unconventional development. The has led to a significant supply of conventional and unconventional assets available for sale, which has corresponded with a more limited demand for these assets due to a lack of appropriate buyers.

PART VII

BUSINESS

This section of this Prospectus should be read in conjunction with the more detailed information contained in this Prospectus, including the financial and other information appearing in "Operating and Financial Review". Where stated, financial information in this section of this Prospectus has been extracted from the Group's financial information as described in "Presentation of Information".

1. OVERVIEW

The Company is an independent owner and operator of producing natural gas and oil wells concentrated in the Appalachian Basin, the oldest hydrocarbon producing region within the United States. The Group's operations are located throughout the neighbouring states of Tennessee, Kentucky, Virginia, West Virginia, Ohio, and Pennsylvania, where the Company is one of the largest independent operators of conventional assets and also an operator of unconventional assets and midstream pipeline infrastructure. Diversified Gas & Oil plc was incorporated in 2014. The Diversified Gas & Oil predecessor business was founded in 2001 by the CEO Rusty Hutson Jr with an initial focus on gas and oil production in West Virginia. In recent years, Diversified Gas & Oil plc has grown rapidly by capitalising on opportunities to acquire and enhance producing assets, and leveraging the operating efficiencies that come with economies of scale. Since 2017, the Company has carried out 11 asset and business acquisitions for a combined purchase consideration of approximately $1.5 billion.

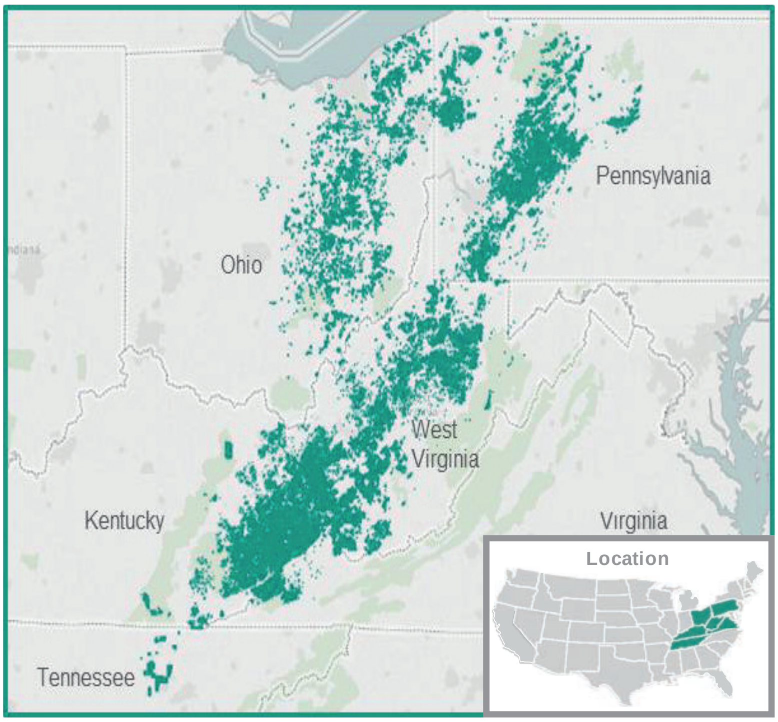
The Company's strategy is to acquire and manage gas and oil properties and certain associated midstream assets to generate cash flows and provide cash distributions to its shareholders. The Company seeks to acquire high-quality producing conventional and unconventional gas and oil assets with synergistic opportunities, from industry players who are seeking to re-focus resources elsewhere, typically to US onshore shale reservoirs, or who are experiencing financial difficulties and wish to sell non-core assets. The Company seeks to acquire long-life producing assets at accretive valuations, typically allocating value only to the Proved Developed Producing ("**PDP**") portion of 1P reserves and allocating no value to the proved undeveloped ("**PUD**") portion of 1P reserves or to probable or possible resources. The Company further seeks to operate and enhance those acquired assets, and then distribute natural gas, natural gas liquids and oil to achieve optimal pricing. The Group's target assets are characterized by highly visible production rates, long-life (in excess of 50 remaining production years), and low decline rates.

The Group seeks to improve the performance of its acquired assets which have often not received an optimal level of focus and investment from their former owners. The Company enhances its production through the deployment of rigorous field management programs and accelerating or extending production by deploying new extraction technology and/or refreshing decayed infrastructure on poorly maintained wells. Through operational efficiencies, the Company demonstrates its ability to maximise value by enhancing production while lowering costs and improving well productivity. The Group's gas, natural gas liquids and oil production is distributed in a way that manages price by leveraging the Group's midstream pipeline infrastructure to take advantage of pricing differentials.

The Company adheres to best-in-class operating standards, with a strong focus on health, safety and the environment to ensure the safety of its employees, local communities and the environment in which the Company operates. The Company aims to maintain its committed approach to long term sustainability which, alongside its strict fiscal discipline and stewardship, maximises returns to its shareholders.

Assets and Operations

The map below shows the geographic location of the Group's assets.



The table below presents a summary the Group's Total Proved Developed Reserves.

Evaluation of DGO Assets Utilizing Specified Economics Northern + Southern Divisions	Total Proved Developed Northern Division	Total Proved Developed Southern Division	Total Proved Developed
Net Reserves to the Evaluated Interests			
Oil, Mbbl	3,387	1,404	4,791
Gas, MMcf	1,309,953	1,632,645	2,942,598
NGL, Mbbl	493	67,716	68,209
Oil Equivalent, MBOE(1) (6 Mcf = 1 BOE)	222,205	341,227	563,432
Number of Wells	42,445	17,373	59,818

Note:

(1) *For purposes of the CPR, quantities of natural gas are converted into equivalent quantities of oil at the ratio of 6,000 standard cubic feet of gas equal 1 barrel of oil equivalent (BOE). For additional information see the GENERAL INFORMATION section of the Competent Person's Report.*

The estimates of reserves were determined by methods set forth by the PRMS.

Source: Competent Person's Report as set out in Part XV "Competent Person's Report" of this Prospectus.

The Group's asset base is comprised of approximately 60,000 conventional and unconventional natural gas and oil producing wells. The Group's shallow-depth vertical and long-lateral horizontal wells produce from low permeability reservoirs sitting above and within the prolific Marcellus and Utica shale plays of the Appalachian Basin. These mature wells benefit from simple and low-cost maintenance operations and require low ongoing capital expenditures. The wells exhibit long-term low decline rates of approximately three to seven per cent., with little water content, resulting in an average well life of over 50 remaining years. In addition to the upstream assets, the Group's portfolio contains approximately 12,000 miles of natural gas gathering pipelines and a network of compression stations and processing facilities.

The Group's experienced management team has a proven track record of consistently delivering strong revenue growth, profitability and cash flow generation. As a result of the Group's competitive strengths, the Directors believe that the Group is well-positioned for continued strong growth and financial returns. For FY2017, FY2018 and FY2019, the Group's revenue was $41.8 million, $289.8 million and $462.3 million respectively, representing a CAGR of 233 per cent. For FY2017, FY2018 and FY2019, the Group's Adjusted EBITDA (hedged) was $17.5 million, $146.2 million and $273.3 million respectively, representing a CAGR of 295 per cent. For FY2017, FY2018 and FY2019, the Group's Adjusted EBITDA (unhedged) was $16.0 million, $161.9 million and $219.7 million respectively, representing a CAGR of 271 per cent.

2. STRENGTHS

The Group benefits from the following key competitive strengths:

Low risk and low cost portfolio of assets

The Group benefits from a highly diversified portfolio of low risk and low cost assets. These assets include approximately 60,000 conventional and unconventional gas and oil producing wells located across the geologically and politically low-risk US states of Tennessee, Kentucky, Virginia, West Virginia, Ohio, and Pennsylvania. As a result, Group performance is not materially impacted by the performance of any individual well. In addition to these upstream assets, the Group's portfolio contains approximately 12,000 miles of natural gas gathering pipelines and a network of compression and processing facilities which are complementary to the Company's assets and enhance margins by reducing third-party tariffs and allowing the Company to optimise pricing through route selection. The Group does not depend on exploration or significant development activity to increase resources or drive production. As a result, the Group is not as exposed to the higher risks that accompany exploration or development nor the greater capital expenditure that is typical of such activity.

The Group's wells are mature and benefit from simple and low-cost maintenance operations and require low ongoing capital expenditures meaning the Group's production base is highly cash generative. The Group's capital expenditure in 2020 is expected to be approximately $28 million, substantially in line with the prior year. As a result of the Group's wells maturity and significant remaining asset life, the Group is positioned to effectively manage the nature, timing, and amount of capital expenditure invested in its assets. This provides the Group control and flexibility over future investment programs, which is a key advantage in light of historic volatility in commodity prices.

Long life and low decline production

The Group benefits from stable, long life and low decline production providing a high-quality, highly visible and reliable source of revenue and cash generation and allowing for sustainable returns to shareholders. The Company's wells have been producing for an average of 25 years. This means they are typically past their high decline phase, an earlier period in a well's life where production declines at a steep rate leading to significant production volatility, and into their period of exponential decline, a later period in a well's life where decline rates are low and steady leading to more stable production. Notwithstanding their maturity, due to their long-term low decline rates and limited water content, the Group's wells have an average remaining producing life of over 50 years. In 2019, the Group's portfolio delivered strong production performance, with actual production arresting forecasted declines due to the Group's robust Smarter Well Management programme of enhancing production from producing wells and returning other non-producing wells to a productive state. In 2019, the Group returned approximately 750 non-producing wells to production. This performance is underpinned by Smarter Well Management, the Group's proactive approach to extending well life, involving wellhead compression management, fluid load deduction, and pumpjack optimization, among other techniques. The Group has adopted a conservative hedging policy which further protects and provides visibility over cash flows, dividends and leverage. The Group's commodity risk hedging program covers both gas and oil price exposures and seeks to protect a significant portion of the Group's underlying post-tax production revenues. The Group adjusts the proportion of hedged revenues and choice of hedging instruments based on a number of factors, including levels of leverage and committed capital expenditures, but does not seek to trade speculatively.

High margin assets benefiting from significant scale

The Group benefits from high quality assets and significant scale that gives rise to high profit margins and consistent cash flows. The concentration of the Group's assets in the Appalachian Basin allows it to run highly efficient operations, with employees able to service a large number of assets reducing operating expenditures. It also allows the Group to leverage the extensive expertise of its engineers and the experience accumulated by the Group's employees from operating in this region for many years driving innovation and best practice. The asset acquisitions made by the Group complement the larger portfolio by delivering operating efficiencies to drive down operating costs and enhance the Group's profit margins. For example, the impact of the acquisitions made in 2018 is illustrated by the Group's lease operating expenses (defined as daily costs incurred to extract oil and natural gas and maintain the producing properties) which fell from $7.02/boe in 2017 to $4.83/boe in 2018.

The Group's significant operational scale is enhanced by its 12,000 miles of midstream infrastructure. The margin-enhancing benefits of owning and operating these midstream assets arise from increased control of the Group's production flow, where it can identify both optimum routes and improved pricing points; increased operational efficiencies through ongoing optimization efforts; and increased third-party revenue streams.

Highly experienced management and operational team

The Group's senior management team is comprised of highly experienced individuals with a combined ten decades of experience in the gas and oil sector, including in the Appalachian Basin where the Group's operations are concentrated. In particular, the Group benefits from the experience of its Chief Executive Officer, Rusty Hutson, Jr., who is highly experienced in sourcing acquisitions and securing their financing. The management team is complemented by an operational team with unmatched experience in the Appalachian Basin with an average of over 25 years of operational experience. These experienced employees have a relentless focus on execution and an in-depth understanding of, and extensive experience working with, the Group's assets. For example, the Group's operations team developed the Smarter Well Management program, which enhances the Group's production by slowing production declines and returning shut-in wells to production. The Group's management team remains focused on efficient and effective management of production and operations whilst carefully controlling the Group's general and administrative expenses.

Track record of successful consolidation and integration of acquired assets

Following the development of the US onshore oil & gas industry through the 'shale revolution' (as set out in the Industry section on page 32), there has been a significant supply of conventional and unconventional assets that have become available as a result of a number of US onshore energy companies selling acreage not seen as core to their operations and of asset owners experiencing cash flow difficulties. Simultaneously, this increase in supply of assets has been met by limited demand due to a lack of appropriate buyers. The Group is well positioned to exploit these continued consolidation opportunities. The Group's management has a strong track record of successful acquisitions of assets and businesses and has demonstrated its ability to source, fund and execute acquisitions in a manner that creates value for the Group. The Group has demonstrated its ability to source opportunities and access to capital as one of the few buyers of scale in the Appalachian Basin, completing eleven acquisitions since 2017 with a combined purchase consideration of approximately $1.5 billion while maintaining Leverage (unhedged) of less than 2.5 times Adjusted EBITDA (unhedged).

Strong organic growth upside potential due to the Group's vast land bank

The Group's current strategic focus remains on the maximisation of its existing portfolio of operational wells. However, the Group has a vast land bank of 7.8 million acres which present organic growth opportunities through infill drilling. In a higher commodity price environment, the Group would consider the drilling opportunities provided by its land bank if economically attractive to do so. Within the Group's portfolio of existing exploration and appraisal opportunities, the Group has a number of attractive near-term drilling opportunities. As the wells are onshore and shallow, development wells are low cost and quick to drill. In the near term, the Group's exploration is likely to be mainly focused on near-field opportunities that leverage its existing assets and operating capabilities and require relatively short development periods. The Group has a historic track record of successfully drilling and operating new wells. As a privately held company, the Group drilled 150 wells across its then-existing portfolio and all were productive.

3. STRATEGY

The Group has the following key business strategies:

Target Proved Developed Producing (PDP) asset acquisitions while focusing on returns and accretive dividends

The Group seeks to capitalise on opportunities to acquire producing conventional and unconventional gas and oil assets. To achieve this strategy, the Group intends to continue employing its disciplined approach to evaluating acquisition opportunities. The Company seeks to acquire long-life producing assets at accretive valuations, typically allocating value only to the PDP portion of 1P reserves and allocating no value to the PUD portion of 1P reserves or to probable or possible resources. The Company further seeks to operate and enhance those acquired assets, and then distribute natural gas, natural gas liquids and oil to achieve optimal pricing. This approach ensures that the Group pursues opportunities that support its cash flow and dividend policy. The Group intends to continue pursuing this strategy as it is well-positioned to benefit from ongoing trends in the US industry where incumbent industry players are seeking to divest assets due to financial distress or a shift in strategy. The Group has a track record as an established consolidator in the Appalachian Basin and is one of the few operators with access to sufficient capital to make acquisitions at scale. The Group is willing to explore acquisition opportunities outside the Appalachian Basin on an opportunistic basis if they become available and present a compelling and scalable proposition.

Maximise value by seeking operational efficiencies

The Group aims to maximise value for its shareholders by realising operational efficiencies. To achieve the strategy, the Group seeks to leverage its scale and cost efficiencies, reducing operating costs and improving margins, including by extending the life of its assets through Smarter Well Management. Smarter Well Management uses a precautionary approach that employs a number of techniques to extend well life and limit the rate of asset depletion. The Group seeks to proactively manage its operating costs and the Directors believe that there is further room to optimise the operating cost base of the business given its scale and that it can achieve savings by focusing on simplification of processes, procedures and standards. The Group's midstream assets also help to support cost reduction by providing operational control over the flow of the Group's production, thus allowing the Group to optimise pricing through selection of delivery points. Further, the Group intends to achieve operational efficiencies through proactive regulatory engagement, including with regard to asset retirement. The Group plans to safely and systematically retire wells supported by long-term agreements with the states of Pennsylvania, Ohio, Kentucky and West Virginia, its four largest wellbore states, setting forth plugging and abandonment schedules and thus providing visibility on asset retirement costs for the majority of its wells.

Optimise operations for cash flow growth

The Group intends to continue optimising its operations in a manner that prioritises cash generation. The Group's principal focus is on operating assets, not drilling new production wells, allowing it to optimise PDP revenues and cost streams. In 2019, the Group generated $205,697 in Free Cash Flow (adjusted), an increase of $94,599 or 85.1 per cent from 2018. The Group intends to maintain its disciplined approach to acquisitions and, whilst it will pursue opportunistic, synergistic, growth, will focus on those assets that provide long-term cash flow generation that supports the Company's cash generation and dividend policy.

Maximise shareholder returns

The Group intends to continue its strategy of delivering value to shareholders through a combination of paying dividends, buybacks and repaying debt. The Group also seeks to prudently invest part of the earnings the Group retains by prudently reinvesting into other accretive and strategically compatible growth opportunities. The Group will seek to continue to operate in a disciplined manner that maximizes investment returns and sustains the Group's dividend policy of returning not less than 40 per cent. of free cash flow to shareholders. From time-to-time, the Group also evaluates share buyback opportunities and is willing to engage in such returns of value to the Group's shareholders. The Group aims to enhance its liquidity through deleveraging, which will create additional debt capacity upon which the Group can draw for general corporate purposes or acquisitions while also reducing cash interest expense.

4. HISTORY AND STRUCTURE OF THE GROUP

Diversified Gas & Oil plc was incorporated in 2014, however, the CEO Rusty Hutson, Jr. began the business in 2001, which in its initial form was a West Virginian gas and oil production company. In recent years, Diversified Gas & Oil plc has grown rapidly by capitalising on opportunities to acquire and enhance producing assets, and leveraging the operating efficiencies that come with economies of scale.

The Group owns and operates gas, natural gas liquids, oil production and midstream assets across Tennessee, Kentucky, Virginia, West Virginia, Ohio, and Pennsylvania, within the Appalachian Basin, one of the largest gas and oil fields in the United States. The Directors believe that, as a specialist operator of conventional gas and oil assets as well as more recent acquisition of stable and mature unconventional assets, the Group is able to identify operational cost savings and to improve production efficiency in areas often overlooked by the larger operators that shifted their focus to the development and drilling of shale formations.

The key milestones of the Group's history are set out in the table below.

Year	Milestone
2001	**Acquisition of West Virginian gas and oil company** Rusty Hutson, Jr. began the business as a West Virginian oil and natural gas production company, whilst still working for a large financial institution in Birmingham, Alabama.
2003	**Partnership through combination of drilling and acquisitions** Robert Post partnered with Rusty Hutson, Jr. and together they continued to expand the business within West Virginia, through a combination of drilling existing leases and the acquisition of operating assets.
2003-2008	**Drilling activity funding** The Group drilled a number of shallow, conventional wells at a cost ranging from $150,000 to $350,000 per well. The Group's capital for the drilling of the wells was funded by Robert Post and Rusty Hutson, Jr. personally and supplemented by bank financing.
2006	**Asset acquisition** Rusty Hutson, Jr. and Robert Post acquired the assets of Diversified Resources, Inc. in West Virginia, paying $5.2 million for 100 wells and several hundred acres of drilling leases, forming the branded name of "Diversified".
2010	**Acquisitions and geographical expansion** The Group expanded into Ohio by acquiring the conventional gas and oil producing wells and leased acreage for conventional drilling from AB Resources for a total consideration amount of $14.5 million. This acquisition was followed by the $5.2 million acquisition of Deep Resources Inc., resulting in additional oil and gas producing wells in Ohio.
2014	**Fund 1 acquisition and further expansion** The acquisition of Operated Equity Investment ("**Fund 1**") was completed in September 2014. The transaction included the acquisition of conventional oil and gas producing wells in West Virginia and an equity interest in four horizontal Marcellus wells drilled and operated by Antero Resources. The total consideration amounted to $4.3 million.
2015	**Acquisition of Broadstreet Energy and Texas Keystone assets** In June 2015, the Group acquired conventional natural gas and oil wells from Broadstreet Energy based in Ohio. The total consideration amounted to $2.6 million. In November 2015, the Group acquired conventional natural gas and oil wells and operating facilities and assets in Pennsylvania and West Virginia from Texas Keystone Inc. As part of, and in connection with, the acquisition from Texas Keystone Inc., between December 2015 and January 2016, the Group also acquired certain overriding royalty interests in these wells and certain real estate in Indiana, Pennsylvania from Falcon Partners Trust and acquired certain of the leases and wells (including working interests and net revenue interests) related to those wells from Keystone Energy Oil & Gas, Inc. The total consideration for these transactions amounted to $725,000.
2016	**Acquisitions of Eclipse Resources and Seneca Resources** In April 2016, the Group acquired conventional natural gas and oil wells in Ohio, in addition to equipment, from Eclipse Resources. The total consideration amounted to $4.8 million, including cash of $1.3 million and a short-term note payable of $3.5 million. In June 2016, the Group acquired conventional natural gas and oil wells located in Pennsylvania from Seneca Resources. The Group paid consideration including cash financed by a short-term note payable of $3.5 million and an interest free obligation to the seller of $3.55 million.

Year	Milestone
2017	**Acquisition of assets from Titan Energy, LLC** In June 2017, the Group acquired conventional natural gas and oil wells, close to the Company's existing operations in the Appalachian Basin in the eastern United States, principally in the states of Ohio, Pennsylvania and northeast Tennessee. The Group paid total consideration of $84.2 million, excluding customary purchase price adjustments.
2018	**Alliance Petroleum Assets Acquisition from CNX** In March 2018, the Group acquired the entire share capital of Alliance Petroleum and producing natural gas and oil wells from CNX in the Appalachian Basin, principally in Pennsylvania and West Virginia, with some wells in Ohio. Alliance Petroleum was acquired for total consideration of $95.0 million and the assets from CNX were acquired for total consideration $85.0 million, excluding customary purchase price adjustments. Subsequent to the CNX Assets Acquisition, CNX agreed to retain a monthly tariff obligation applicable to the Appalachian assets that requires monthly cash payments to a pipeline transmission company through a portion of calendar year 2022. In exchange for CNX retaining this pipeline tariff obligation, the Company made a one-time payment of $17.0 million to CNX and received exclusive access to the relevant pipeline system.
2018	**EQT Assets Acquisition** In July 2018, the Group acquired all of the issued and outstanding membership interests of two new entities, Diversified Southern Production LLC and Diversified Southern Midstream LLC, which owned certain producing gas, oil, natural gas liquids and midstream assets located in the states of Kentucky, West Virginia and Virginia. The consideration for this acquisition amounted to $575 million and after customary purchase price adjustments the total cash consideration paid was $527 million.
2018	**Acquisition of Core** In October 2018, the Group acquired Core which included approximately 5,000 conventional natural gas wells and a wholly-owned midstream gathering and compression system with approximately 4,100 miles of pipeline and 47,000 horsepower of compression in the states of Kentucky, West Virginia and Virginia. The consideration for this acquisition amounted to $90.6 million.
2019	**HG Energy Assets Acquisition** In April 2019, the Group acquired certain producing gas assets from HG Energy, comprising 107 unconventional wells and related surface rights and gathering equipment, located in the states of Pennsylvania and West Virginia. The consideration for this acquisition amounted to $400 million, and after customary purchase price adjustments the total cash consideration paid was $388 million.
2019	**EdgeMarc Energy Assets Acquisition** In September 2019, the Group acquired certain oil and natural gas development, production and exploration assets located in Ohio from EdgeMarc Energy and certain of its subsidiaries. The consideration for this acquisition was $50 million, or $48 million in cash after customary purchase price adjustments, funded from existing debt facilities, to acquire 12 producing unconventional Utica natural gas wells and related facilities in Monroe and Washington counties within the State of Ohio and three drilled but uncompleted wells ("DUCS"), as well as undeveloped land containing deep Utica rights. In November 2019, the Group sold the three DUCS and certain undeveloped land rights to a third party for total consideration of $10 million.
2019	**Acquisition of assets from Dominion and Equitrans** In September 2019, the Group acquired natural gas gathering systems in Pennsylvania and West Virginia in two separate transactions, comprising approximately 1,700 miles of low-pressure wet and dry gas gathering pipelines together with compressors, measurement stations and related facilities and equipment. The total consideration paid for these two acquisitions was $7.7 million.

5. OVERVIEW OF ASSETS AND PRINCIPAL ACTIVITIES

The Group's current activities comprise the operation of approximately 60,000 conventional and stable/mature unconventional natural gas and oil wells in the Appalachian Basin in the north-eastern United States. The Group also operates over 12,000 miles of midstream pipelines and compression assets principally located in the states of Kentucky and West Virginia.

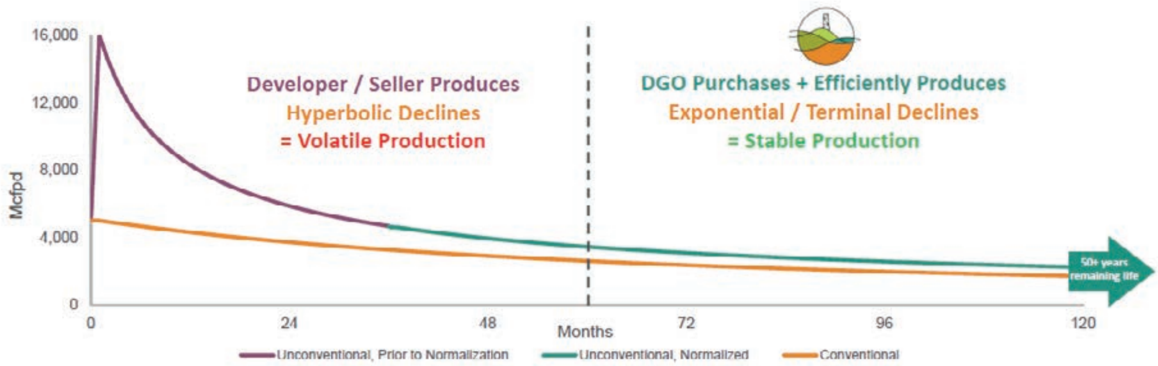
The Group has grown significantly since its initial formation in 2001, primarily through the acquisition of producing assets. The Group has an experienced team of professionals managing its operational assets and personnel. The Company has an experienced management team with proven ability to drive operational efficiency, creating opportunities for additional value for shareholders even during extended periods where commodity prices remain below historical trends.

As at the date of this Prospectus, the Group has total proved reserves of gas of approximately 2,942,598 mmcf (all producing), oil reserves of approximately 4,791 mbbl (all producing), and natural gas liquids of approximately 68,209 mbbl (all producing). For the three months ended 31 March 2020, the Group's total net daily production was 94,011 boepd. The Group has approximately 8 million acres under lease which are principally held by production ("**HBP**"). HBP means that the lease does not expire as long as the land is still producing. The overall average working interest for DGO's existing assets is approximately 89.3 per cent., the overall average net revenue interest is approximately 78.1 per cent. and the average royalty rate is approximately 12.6 per cent. (calculations presented on the basis of simple average interests).

The Group's assets provide:

- highly visible and consistent production profile;
- an average remaining producing life of over 50 years;
- proven low decline rates, with the majority of production declining on average at 5 per cent.;
- low operational costs; and
- low operational risks and production concentration.

The chart below demonstrates the Group's strategy across conventional and unconventional wells.

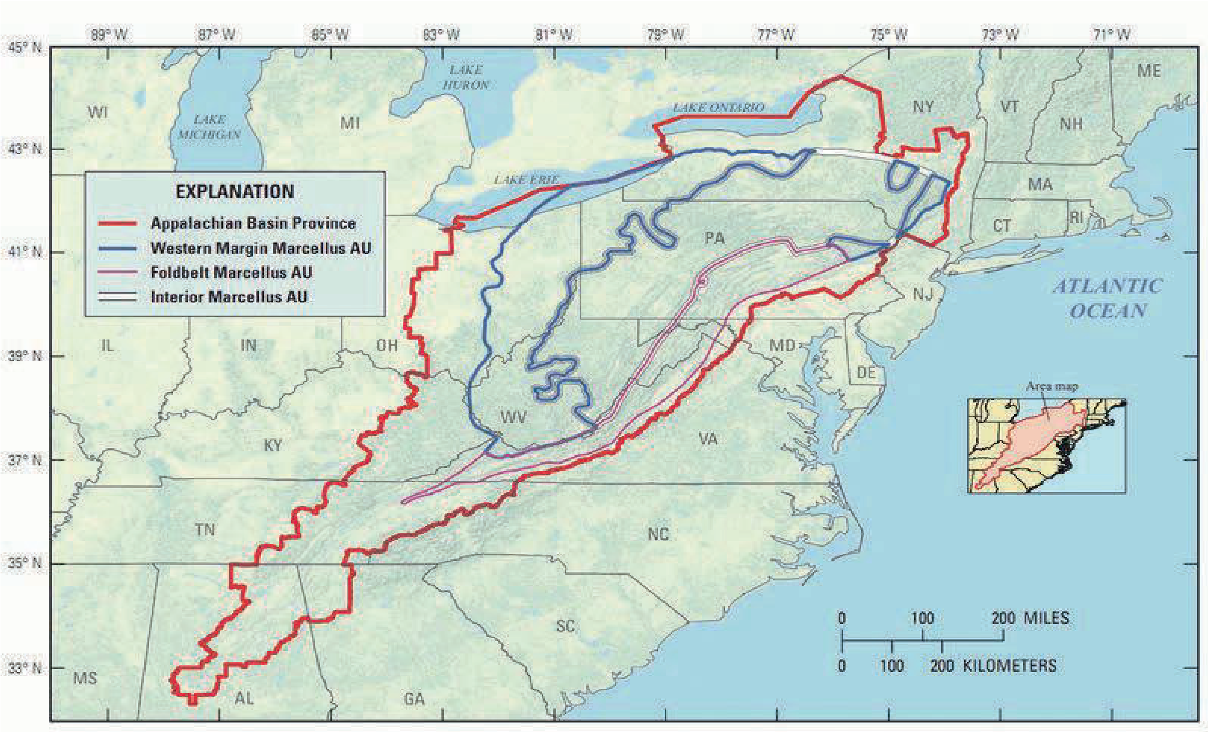


The chart below compares the attributes of conventional and unconventional wells.

Well Attribute	Conventional Well	Unconventional Well
Initial Decline	Exponential	Hyperbolic
Terminal Decline	Exponential	Exponential
Well Life	50+ Years	50+ Years
Complementary OpEx	Lower Variable	Lower Fixed
Operation Method	Consistent Smarter Well Management Techniques	
Retirement Cost ($/well)	$25K-30K	$75K-$80K

Appalachian Basin

The Group operates within the Appalachian Basin, an area of the north-eastern United States that underlies ten states including Tennessee, Kentucky, Virginia, West Virginia, Ohio and Pennsylvania.



The Appalachian Basin covers an area of some 185,500 square miles. Whilst the area has come to prominence in recent years following the discovery of significant shale gas reserves in 2009, known as the Utica and Marcellus Shales, it has been a major producer of oil and gas from conventional vertical well development since the late 19th century, making it the oldest producing basin within the United States.

The depositions for the Appalachian Basin are the erosional sediments from the once Acadian Mountains into the lower basin. The basin was limited to the west by the Cincinnati Arch. As the mountains eroded over time, the sediment was deposited in the basin with alternating layers of carbonates, limestones, sandstone, siltstone, and shale intervals.

The oil and gas industry started in the basin in 1859 with the discovery of oil in the Edwin Drake well located in north-western Pennsylvania. Oil in this well was produced from the Upper Devonian sandstone at a depth of approximately 70 feet. This discovery well opened a trend of oil and gas fields producing from the Upper Devonian, Mississippian, and Pennsylvanian sandstones across many parts of the states of Kentucky, New York, Ohio, Pennsylvania and West Virginia.

Detailed information on the Group's assets is set out in the Competent Person's Report in Part XV "*Competent Person's Report*" of this Prospectus.

Reserves

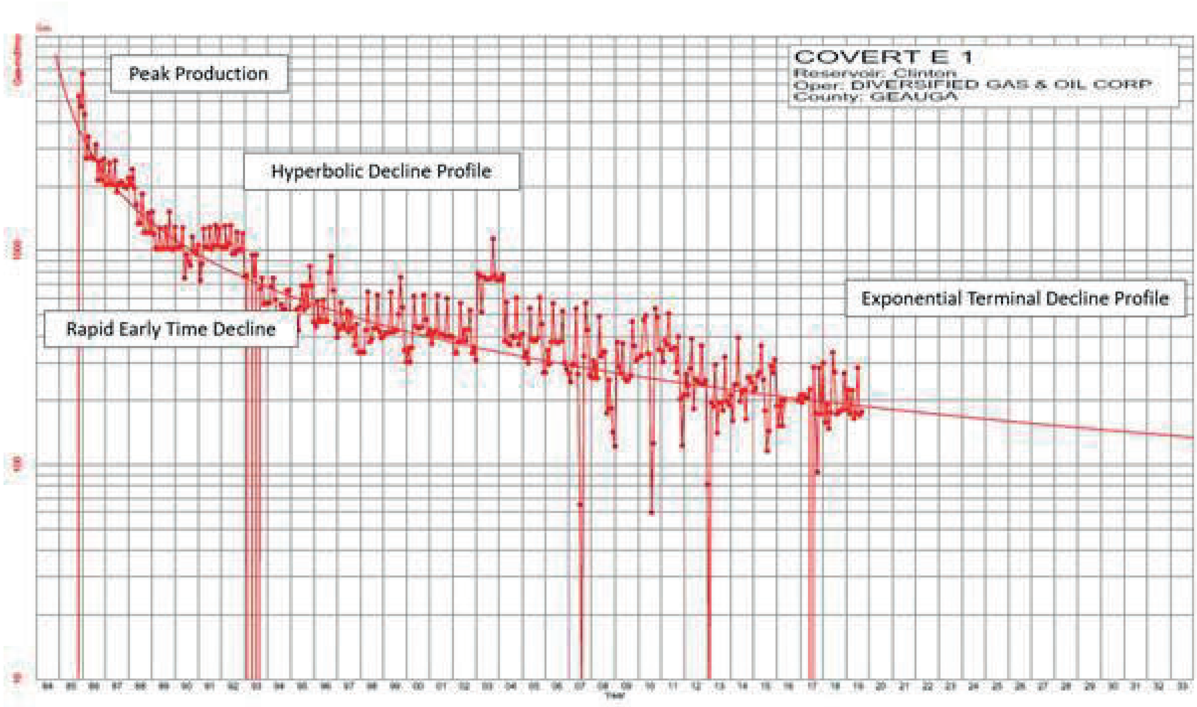
Since 2009, the primary target in the Appalachian Basin for the development of natural gas, natural gas liquids and oil for most companies operating in the area has been the horizontal drilling of the Marcellus and the Utica shale formations. These horizontal wells have long laterals that allow more contact with the reservoirs.

The Group's focus continues to be producing natural gas, natural gas liquids and crude oil from established conventional and mature unconventional wells. Most of the properties owned and/or operated by the Group are vertical wells. These vertical wells are typically shallow at depths ranging from 2,200 feet to 6,000 feet. The Group operates a smaller set of unconventional vertical and horizontal wells at depths ranging from 6,000 to 10,000 feet. A number of the Group's wells are completed in multiple formations and production is sourced from numerous zones in the wellbore. Most of these properties may have additional productive formations up-hole from the existing producing formations, which may allow for future completion opportunities. These assets have been reported upon by Wright & Co in the Competent Person's Report set out in Part XV

"*Competent Person's Report*" of this Prospectus. The Directors believe that drilling and recompletion opportunities are relatively low risk, due to the geology and the extensive mapping of the formations. Drilling is relatively straight forward, quick to execute and low cost with the cost of drilling and completing new conventional wells in the range of $118,000 to $1.3 million depending primarily on depth.

The production profiles of the wells across these formations demonstrate very similar characteristics. Most of these formations produce gas and/or oil on a hyperbolic curve with an initial rapid decline followed by gradual decline of production over a very long period of time. This rate of decline enables the Company to predict and plan with a high level of confidence the future production profile of its producing assets.

The following chart illustrates production flow rates at the Company's "Covert E 1" well in Geauga County, Ohio, since the well commenced production in 1985 through to 2019:



A majority of the wells are expected to have an average remaining producing life of over 50 years, with some lasting in excess of 80 years. The conventional wells and the mature unconventional wells produce very little, if any, water.

The aggregate valuation of the total proved existing reserves of the Group is $1.86 billion (pretax PV10) and $1.38 billion (post-tax PV10) as reported on by Wright & Co in the Competent Person's Report in Part XV "*Competent Person's Report*" of this Prospectus. The valuation set out in the Competent Person's Report is based only on proved reserves of the Group only.

6. ACQUISITIONS AND CONSOLIDATION

The Company's strategy is to acquire and to manage gas and oil properties and certain associated midstream assets to generate cash flows and provide cash distributions to its shareholders. The Company has capitalised upon opportunities to acquire conventional, mature, low risk oil and gas producing assets. The acquisition of assets from Titan Energy, LLC in June 2017 introduced unconventional assets into the Company's portfolio, following which the Company embraced a broader acquisition strategy that included unconventional assets while remaining focused on the Appalachian Basin, though the Company may explore acquisitions outside the Appalachian Basin on an opportunistic basis. The Company believes that it is well positioned to acquire further conventional and stable and mature unconventional assets and intends to continue its growth strategy through the acquisition of proven producing assets.

Advances in shale production caused a significant shift in emphasis of many US investors and US domestic exploration and production companies in the US, resulting in conventional, mature gas and oil assets becoming available at reasonable prices to credible and proven operators who can maintain production from the conventional reservoirs and in doing so, retain the HBP rights to the shale licences on behalf of the seller.

Concurrent to this increase in assets available for sale, there is a lack of demand due to a number of traditional onshore energy companies experiencing financial difficulties and thus being unable to purchase the assets that are becoming available. The Directors believe that value accretive opportunities lie in field optimisation and the application of optimised production techniques used across the existing portfolio. The Group has a proven track record in reducing the operating costs of acquired assets through the implementation of operating and financial efficiencies. The Group also has a proven track record in enhancing and in many cases increasing production from the acquired conventional wells. These factors combined with the Group's low cost corporate structure gives the Group a competitive advantage over its peers.

After purchasing existing conventional wells, the Group accelerates or extends production by refreshing decayed infrastructure on what are typically poorly maintained wells due to the wells not having been core assets for the prior owner. Conventional wells that are in production for over five years (mature wells) can have an average annual decline rate in the range of 3-7 per cent. The Group accelerates or extends production by repairing lines, recompleting wells, reconnecting wells, swabbing wells and adding or optimising compression. The Group has an established and proactive approach to the long-term sustainability of its wells through its deployment of experience, knowledge & resources throughout its entire portfolio, executed through its Smarter Well Management Programme and it's 'Safe & Systematic Asset Retirement Programme', which leverages the Group's portfolio's scale, diverse institutional knowledge from a growing body of professionals with unique experience and geographical proximity to extract maximum value. This program, tailored for each asset, focuses on optimising production from active wells and, where economically possible through a variety of means, returning inactive wells to production. The Company is committed to industry leading operating procedures and holds the safety and sustainability of the local communities and environment in which it works in the highest regards.

The Group continues to identify attractive acquisition and investment opportunities to purchase additional producing assets in or around the Group's existing footprint, although future acquisitions could fall outside of the states in which it currently operates. Each target acquisition is evaluated against a strict criteria and the Group's disciplined approach to evaluating opportunities ensures that it only pursues those acquisitions that possess a consistent asset profile, compelling upside and drive positive debt-adjusted cash flow per share that supports the Company's dividend policy. Sustained low oil and natural gas prices continue to result in companies divesting non-core and distressed assets, and the Group continues to explore these opportunities. Any additional assets purchased are expected to complement the Group's existing portfolio and provide an increase in revenue and net cash flow.

The Group maintains a pipeline of acquisition targets. This pipeline is developed through the relationships that members of the Company's management have maintained with industry personnel as well as investment banking advisors. As a part of its evaluation and diligence processes, the Group considers numerous financial and strategic factors to determine the consideration to be paid for the target. Of utmost priority, the Group will not provide value for undeveloped assets and will only consider assets with a reasonably low decline rate and prospective cash flows. Some of the other significant factors included in the evaluation process include the valuation of future reserves, geographic location, proximity to existing operations, market pricing for sales of produced units, experience of existing or available human resources, quality of the assets, historical environmental performance of the seller, financing resources required to fund the acquisition, regulatory environments for the assets and current or potential legal considerations. In considering these and other factors, the Group regularly works with its investment bankers, legal and accounting advisors, environmental consultants and third-party reserve engineers to assist in the evaluation and diligence processes prior to any acquisition. Once the evaluation process is completed, the Group's executive management team reviews its process and valuation perspective with the Board. The Board approves all material transactions prior to its consummation.

As part of its stated acquisition target evaluation process described above, the Company continues to explore potential acquisition targets from third parties. On 7 April 2020, Diversified Gas & Oil Corporation, a subsidiary of the Company, executed a conditional purchase and sale agreement with Carbon in connection with the possible acquisition of certain upstream and midstream assets of Carbon in the Appalachian Basin, including approximately 6,100 net conventional wells located in Appalachia (Tennessee, Kentucky, West Virginia), as well as various non-operated wells, midstream pipeline systems and facilities (including intrastate gathering pipeline of approximately 4,700 miles in West Virginia and two active natural gas storage fields with 3.5 Bcf of working capacity). The net production of the Carbon Assets for the year ended 31 December 2019, was approximately 9.1 Mboepd and if completed, the acquisition would potentially add PDP reserves of approximately 74 MMboe with an estimated pre-tax PV10 of approximately $189 million.

If the acquisition were to complete, the Company currently estimates that the consideration payable would comprise: (i) approximately $110 million, payable in cash at closing; and (ii) a further payment of up to $15 million, subject to the achievement of certain conditions with respect to future gas prices payable over a period of up to three years after closing. If completed, the initial consideration payable for the Carbon Assets would be at an approximate 42 per cent. discount to PDP PV10 of the Group for the year ending 31 December 2019 and the Company estimates that this would be 3.2 to 3.4 times the Adjusted EBITDA attributable to the Carbon Assets for the 12 months ending 31 May 2021 following management estimated closing adjustments of approximately $11 million. However, the final consideration payable may be less than currently estimated and will be determined following completion of due diligence by the Company and satisfaction of the other conditions under the Carbon PSA. If completed, the Carbon PSA will have a deemed effective date of 1 January 2020. The Company estimates that the Adjusted EBITDA attributable to the Carbon Assets for the 12 months ending 31 May 2021 will be approximately $29 million to $31 million.

In addition, on 11 May 2020, the Company executed a conditional purchase and sale agreement with certain subsidiaries of EQT in connection with the possible acquisition of certain assets of EQT in the Appalachian Basin, including approximately 900 net operated wells, including 67 horizontal producing wells in Pennsylvania, with the majority of the balance being conventional vertical producing wells in West Virginia, and associated midstream infrastructure as well as a further 13 drilled and completed wells that are not yet connected to the gathering infrastructure. The net production of the EQT Corporation Assets for the year ended 31 December 2019, was approximately 9 Mboepd and if completed, the acquisition would potentially add PDP reserves of approximately 48 MMboe with an estimated pre-tax PV10 of approximately $185 million.

If the acquisition were to complete, the Company currently estimates that the consideration payable would comprise: (i) approximately $125 million, payable in cash at closing; and (ii) a further payment of up to $20 million, subject to the achievement of certain conditions with respect to future gas prices, payable over a period of up to three years after closing. If completed, the initial consideration payable for the EQT Corporation Assets would be at an approximate 32 per cent. discount to PDP PV10 of the Group for the year ending 31 December 2019 and the Company estimates that this would be 3.5 to 3.7 times the Adjusted EBITDA attributable to the EQT Corporation Assets for the 12 months ending 31 May 2021 following management estimated closing adjustments of approximately $11 million. However, the final consideration payable may be less than currently estimated and will be determined post completion of due diligence by the Company and satisfaction of the other conditions under the EQT PSA. If completed, the EQT PSA will have a deemed effective date of 1 January 2020. The Company estimates that the Adjusted EBITDA attributable to the EQT Corporation Assets for the 12 months ending 31 May 2021 will be approximately $32 million to $34 million.

The potential acquisition of each of the Carbon Assets and the EQT Corporation Assets is at a preliminary stage and is subject to a significant number of conditions. The satisfaction of certain of these conditions are within the sole control of the Group such as completion of due diligence (including all title, environmental, contractual, credit, litigation, and regulatory diligence) to the Company's satisfaction and the Company's right to not complete the respective acquisitions if there is a material change in the conditions, assets, or operational matters of the Carbon Assets or the EQT Corporation Assets prior to completion of the respective acquisitions. In addition, the acquisitions are also conditional upon satisfaction of various other conditions, including receipt of all necessary shareholder consents, approvals, authorisations and permits (including any authorisations required from the Federal Energy Regulatory Commission and various State Public Service Commissions).

Carbon and EQT have provided customary commercial representations and warranties on the Carbon Assets and the EQT Corporation Assets respectively, which are also conditional upon satisfaction of the conditions under the Carbon PSA and the EQT PSA respectively and completion of the acquisitions.

Under the terms of the Carbon PSA and the EQT PSA respectively, the Company has a right to exclusivity pursuant to which Carbon and EQT respectively have agreed to not enter into any negotiations or discussions with any third party in connection with the disposal of the Carbon Assets and the EQT Corporation Assets for a period ending on 30 June 2020 and 28 May 2020 respectively to enable the Company to complete its due diligence and for the satisfaction of all the conditions under the Carbon PSA and the EQT PSA respectively.

The acquisitions of the Carbon Assets and the EQT Corporation Assets are expected to be partially financed by the net proceeds of the Placing, with the balance being financed by a new securitised term loan of up to $165 million, the terms of which are expected to be comparable to the Keybank Facility and the Amended Keybank Facility. These acquisitions are not expected to have a material impact on the Company's ratio of Net Debt to Adjusted EBITDA.

7. OPERATIONS

Infrastructure

The Group conducts operations in the states of Pennsylvania, West Virginia, Ohio, Kentucky, Virginia and Tennessee. Approximately 790 field employees operate the natural gas and oil wells as well as the Group's midstream assets, consisting of pipelines and compressor stations. An important aspect to the success of the Group's acquisition strategy is the hiring of the employees that are experienced with the acquired assets, and generally have worked with the assets for many years. By maintaining the experienced employees, the Group is able to mitigate integration risk that is inherent with acquisitions.

The Group has numerous field offices located throughout its six states of operation. These field offices allow the Group to deploy employees in distinct geographic locations in order to efficiently operate its assets. The Group field employees access the producing gas and oil well and midstream assets via transportation in company owned or leased vehicles, including pick-up trucks, service trucks and ATVs.

Natural gas produced from the Group's wells is delivered to sales points via gathering pipelines. These gathering pipelines may either be owned by the Group or by a third-party transporting the natural gas to a delivery point where the Group takes ownership of the natural gas. The Group monitors and measures this transportation of gas to ensure accuracy of sales at the point of ownership transfer. The Group's field employees maintain frequent communication with gathering and pipeline companies to ensure the consistent delivery of natural gas produced from the Group's wells. Natural gas is produced from numerous types of gas wells. The mechanical disposition of natural gas wells include pump jack equipment, artificial lift equipment and open flow wells. The type of equipment located on a well is generally determined based on the production profile of the producing formations. As the production profile of a well changes, the Group's employees determine if different equipment is needed and/or economical for the efficient production of future reserves.

NGLs maintained in the natural gas molecules are generally produced by third-party processing companies that perform fractionation processes to extract the NGLs. Fractionation processes generally involve lowering the temperature of the natural gas molecule to a below zero-degree temperature, which causes the NGLs to separate and "drop out" of the natural gas molecule. The NGLs produced by the third-party processor are generally sold into local petrochemical markets are transported by truck or rail car to larger petrochemical markets. The Group's largest processor of NGLs is the MarkWest owned plant located in Langley, Kentucky. MarkWest is a subsidiary of Marathon Petroleum Corporation.

Crude oil produced from the Group's wells is stored at the well pad in a bulk storage tank. Crude oil is accumulated in these bulk tanks until the point that a Company employee calls for a collection by the local collection company. The local collection company unloads the crude oil (and water) from the bulk storage tank and delivers the crude oil to a refinery or to a local storage hub.

The Group monitors the production of natural gas and crude oil via an extensive network of well head meters, electronic measurement, telecommunication networks, mobile devices and software applications. The Group invests in technology in support of its Smarter Well Management programme with a focus on driving safe operations, production improvement opportunities and cost savings. The Group also monitors the flow of natural gas on its midstream assets through compressor meters, electronic measurement, telecommunication networks and software applications. The Group services the measurement and monitoring devices and technology with a combination of its own employees and third party contractors.

The Group continues to invest in the appropriate capital infrastructure both at the well head, through the extensive network of Group owned pipeline, and at pumping and compression sites. The Group's operational structure enables it to generate significant operating free cash flow, even in the current low energy price environment, with an average lease operating cash cost in the third quarter of 2019 equivalent to $5.01/boe, falling from $5.75/boe and $8.54/boe in the fourth quarter of calendar years 2018 and 2017, respectively. Through the Company's Smarter Well Management programme, the Company's management constantly strives for cost savings and production enhancements to further mitigate rising costs during times of low commodity prices.

Distribution and Pricing

The Group sells natural gas directly into the local markets or into interstate transmission pipelines. The Group's customers are large regional utility companies and pipeline marketing companies that have operated in its markets for extensive periods. The Group's customers have been purchasing natural gas from its producing assets for numerous years. The Group's producing wells have direct connections into the pipeline systems of large regional utilities and pipeline companies such as Dominion Transmission, TC Energy (formerly TransCanada), Equitrans and Enbridge.

The Group sells natural gas to purchasers either at fixed prices or variable index prices. Whether the Group receives a fixed or variable price, the net price received by the Group is a combination of the commodity index price (principally "**Henry Hub**") plus or minus a local market differential. The local market differential is also known as the "basis" differential. The basis differential is typically generated by local market supply and demand factors as well as pipeline capacity factors. Revenues are generally received 30 to 60 days following the month end after the gas enters the local transmission pipelines. The Group sells natural gas to large institutions that have established credit and are financially capable of meeting their obligations to the Company.

Oil is sold by the Group to large regional, refining companies that utilise their fleet of vehicles or at times third-party collection companies to collect the Group's produced oil. Revenue is recognised at collection when the responsibility for the product is transferred to the distributor. Revenues are generally received 30 to 60 days following the month end after the crude oil is collected by the refining company. Pricing for crude oil sales is typically determined based on the price of West Texas Intermediate crude oil ("**WTI**") for the day the oil is collected less a deduction for the cost of collection, which is generally less than 10 per cent. of WTI.

The Group seeks to leverage its experience and market knowledge, along with the experience and skills of commodity price advisors to manage the issues caused by volatile gas and oil prices, which can be influenced by global trends as well as local supply and demand factors. The spike in US natural gas prices to nearly $5.00 per MMBtu in November 2018 and subsequent fall back to approximately $2.40 per MMBtu in August 2019 highlights the volatile nature of commodity prices. To protect its revenue, the Group utilises hedging strategies as well as forward fixed pricing purchase contracts with natural gas purchasers, which are designed to ensure that the Group maintains a clear visibility of its cash flow while minimising any exposure to downside risk.

The Company has entered into a variety of hedging and fixed price sale contracts for oil and gas production providing a degree of downside protection on revenues between 2019 and 2021 calendar years. Additionally, in November 2019, the Group entered into hedging arrangements that allow it to secure a fixed price for approximately 18 per cent. of its natural gas production for the next 10 years.

Capital Expenditure

The Group's strategy to acquire and operate producing assets that generate cash flow margins in excess of 50 per cent. allows the Group to continually invest capital back into its operations. The Group anticipates investing approximately 8 per cent. to 10 per cent. of its Adjusted EBITDA (hedged) in predominantly maintenance capital expenditures on an annual basis.

The majority of the Group's capital expenditures are focused on its midstream operations, which includes pipelines and compression, while the remaining capital expenditures are focused on fleet, technology, upstream operations and facilities. See Section 6.3 of Part IX "*Liquidity and Capital Resources — Capital Expenditure*" of this Prospectus.

Marketing

The Group markets and sells its natural gas through its wholly owned subsidiary, Diversified Energy Marketing LLC ("**DEM**"). DEM purchases produced natural gas from the Group's production company, Diversified Production LLC ("**DP**").

DEM markets the Company's natural gas to qualified purchasers and works to maximize netback pricing via a periodic bidding process or through other forms of negotiations that occur on a daily, monthly, and long-term basis. This includes DEM actively managing its transportation contracts to ensure full utilisation and effective cost rationalisation. DEM markets natural gas to purchasers on numerous gathering, intrastate, and interstate pipeline systems. DEM works closely with the Group'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.

8. EMPLOYEES

As of 4 May 2020, the Group had 929 full-time employees, with 772 production and/or operations employees and 157 production support and/or administrative employees.

The following table shows the Group's employees broken down by function as at each of 31 December 2019, 2018 and 2017.

Function	2019	2018	2017
Production/operations	128	220	260
Production support/administration	790	727	229
Total	**918**	**947**	**489**

The following table shows the Group's employees broken down by location as at each of 31 December 2019, 2018 and 2017.

Location	2019	2018	2017
AL	27	21	7
FL	1	1	2
IN	1	2	3
KY	222	251	111
OH	147	192	101
PA	243	195	87
TN	11	14	14
VA	18	22	1
TX	0	1	1
WV	248	248	162
Total	**918**	**947**	**489**

The Group's compensation structure is comprised of a fixed and variable performance-based component. The performance component includes an incentive plan, which provides a bonus when certain financial targets each financial year are met and is triggered once the business achieves a predetermined percentage of Adjusted EBITDA (hedged) and Adjusted EBITDA (unhedged) on a sliding scale, at which point discretionary bonuses are paid out. In addition, there are discretionary performance-related bonuses for all staff based on individual performance.

Approximately twenty-three percent of the Group's employees are represented by a collective bargaining agreement which provides for seniority, vacations, wages, schedule of hours, health & welfare benefits and retirement benefits. The employees working under this agreement are located in the states of Kentucky and West Virginia. The existing agreement terminates in December 2022. The Directors believe that the Group's relations with its employees are good.

9. HEALTH, SAFETY AND ENVIRONMENT

The Group is subject to various health, safety and environmental laws and regulations administered by local, national and other government entities, and similar agencies in the states in which the Group operates. The Directors believe that the Group is currently in compliance with all material governmental laws and regulations affecting its business and maintains all material permits and licences relating to its operations.

The Group is committed to protecting the health and safety of all individuals potentially affected by its activities, including its employees, contractors and the public. The Group strives to provide a safe and healthy working environment and not to compromise the health and safety of any individual.

The Group is also committed to managing the environmental impact of its business. The Group seeks to manage its operations in an environmentally sound manner, for the benefit of all stakeholders, taking the necessary precautions to protect the natural environments that surround its gas and oil assets and to prevent incidents. Such activities include, but are not limited to, water, emissions and biodiversity management.

The Group's operational processes focus on reducing risks, maintaining compliance, and seeking best practice and continuous improvement in its activities. The Group is in the process of establishing and formalising a

Group-wide Operations and Environmental, Health & Safety ("**EHS**") Management System to minimise the environmental impacts of its operating portfolio of upstream and midstream assets and to protect the natural environment in which it operates.

A strong health, safety and environmental performance is a key aspect of the Group's overall business success. A strong health, safety and environmental performance is a key aspect of the Group's overall business success. In 2019, the Group had a Total Recordable Incident Rate ("**TRIR**") of 2.06. TRIR is a U.S. mathematical measure of occupational safety and health defined as the number of work-related injuries per 100 full-time workers during a one-year period. The Group's total Scope 1 and Scope 2 GHG emissions for 2019 were 2.6 million metric tons, resulting in a GHG intensity factor of 0.014 metric tons of CO2e per million cubic feet equivalent of production.

10. REGULATION

For a detailed overview of the regulatory environment in which the Group operates, please see Part VIII "*Regulatory Overview*" of this Prospectus.

11. INSURANCE

The Company works with a large, national insurance broker with proven capabilities servicing the gas and oil industry in the United States. Working with its broker, the Company reviews its insurance coverages and policy limits as its needs change or at a minimum on an annual basis. The Group's insurance programme includes coverages for property, auto liability, general liability, workers' compensation, control of well, environmental and pollution, director's & officers insurance, loss business income for certain operations and employment practices liability. Coverage under the terms of its insurance package includes physical damage, operators' extra expense (including well control, seepage, pollution clean-up and redrill), business interruption related to NGL processing and third party liabilities. Coverage is placed in respect of oil and gas exploration and production activities. The Company has insurance coverage from the US insurance market as well as the Lloyds of London market.

The Group maintains the types and amounts of insurance coverage that it believes are consistent with customary industry practices in the jurisdictions in which it operates. The Directors believe that limits and deductibles in force are in line with applicable oil industry insurance standards. The Directors believe that the Group has adequately provisioned for, or otherwise protected its operations against, risks consistent with customary industry practices.

The Group may arrange other insurance from time to time in respect of its other operations as required and in accordance with industry practice and at levels which the Directors feel adequately provide for the Group's needs and the risks that it faces. The Group has not had any material claims under its insurance policies that would either make them void or materially increase their premiums.

12. COMPETITION

The US has an extremely well-developed gas and oil production and distribution market. The Company has many competitors locally who sell products into the gas and oil market. However, the Directors believe that the Company's steady supply and industry relationships put it in a strong position with buyers and its established and respected financial position will enhance its competitive advantage.

The acquisition and divestiture of gas and oil assets both within and outside the Appalachian Basin is highly fluid with high levels of corporate and asset level transactions taking place. The Group primarily faces competition for assets from certain private equity firms.

Having made numerous acquisitions, the Directors believe that the Company's proven acquisition and operating track record means that the Group is well positioned to attract those owners of operating assets both inside and outside the Appalachian Basin seeking to obtain value from their conventional or unconventional assets and portions of their midstream systems.

The scale of the Group's operations makes it an attractive partner or buyer. In the market, acquisition targets are currently being valued at attractive discounts of future cash flows and typically exclude any potential value from increased production achieved from well work-overs, re-completions and infill drilling. As such, the Directors believe that, as with historical acquisitions, should future acquisitions be completed, increases in production resulting from focused operational improvements should enhance the value of the acquired assets.

13. DIVIDEND POLICY

The Board's target is to return not less than 40 per cent. of free cash flow to Shareholders by way of dividend, on a quarterly basis, in line with the strength and consistency of the Group's cash flows.

For the three months ended 31 March 2019, the Company paid a dividend of 3.42 cents per Ordinary Share on 27 September, 2019. For the three months ended 30 June 2019, the Company paid a dividend of 3.50 cents per Ordinary Share on 18 December 2019. For the three months ended 30 September 2019, the Company paid a dividend of 3.50 cents per Ordinary Share in March 2020. For the three months ended 31 December 2019, the Company expects to pay a dividend of 3.50 cents per Ordinary Share in June 2020. For the three months ended 31 March 2020, the Company expects to pay a dividend of 3.50 cents per Ordinary Share in September 2020.

The Directors may further revise the Group's dividend policy from time to time in line with the actual results and financial position of the Group.

The Board's dividend policy reflects the Company's current and expected future cash flow generation potential.

14. LEGAL PROCEEDINGS

See Section 15 "*Litigation*" of Part XV "*Additional Information*" of this Prospectus.

15. FTSE ELIGIBILITY

Subject to satisfying the appropriate criteria, following Admission, the Company expects to be eligible for inclusion in the FTSE All-Share Index at the quarterly review in September 2020.

PART VIII

REGULATORY OVERVIEW

General

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

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

Environmental Laws

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

Hydraulic Fracturing Activities. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. Hydraulic fracturing involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. Hydraulic fracturing is typically regulated by state oil and natural gas commissions and similar agencies, but the US Environmental Protection Agency ("**EPA**") has asserted certain regulatory authority over hydraulic fracturing and has moved forward with various regulatory actions, including the issuance of new regulations requiring green completions for hydraulically fractured wells, and has disclosed its intent to develop regulations to require companies to disclose information regarding the chemicals used in hydraulic fracturing. Some states, including states in which the Group operates, have adopted regulations that could impose more stringent disclosure and/or well construction requirements on hydraulic fracturing operations, or otherwise seek to ban some or all of these activities.

If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for producers like the Company to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing is regulated at the federal level, fracturing activities could become subject to additional permitting requirements, and also to attendant permitting delays and potential increases in costs. Increased consumer activism against hydraulic fracturing or the prohibition or restriction of hydraulic fracturing could have a material adverse effect on the Group's business, results of operations, or financial condition.

Clean Air Act. The federal Clean Air Act and corresponding state laws and regulations regulate air emissions primarily through permitting and/or emissions control requirements. This affects natural gas production and processing operations. Various activities in the Group's operations are subject to regulation, including pipeline compression, venting and flaring of natural gas, and hydraulic fracturing and completion processes, as well as fugitive emissions from operations. The Group obtains permits, typically from state or local authorities, to conduct these activities. Additionally, the Group is required to obtain pre-approval for construction or modification of certain facilities, to meet stringent air permit requirements, or to use specific equipment, technologies or best management practices to control emissions. Further, some states and the federal government have proposed that emissions from certain proximate and related sources should be aggregated to provide for regulation and permitting of a single, major source. Federal and state governmental agencies continue to investigate the potential for emissions from oil and natural gas activities, and further regulation could increase the Group's cost or temporarily restrict the Group's ability to produce.

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

Endangered Species Act. The Endangered Species Act and related state regulations protect plant and animal species that are threatened or endangered. Some of the Group's operations are located in areas that are or may be designated as protected habitats for endangered or threatened species, which could have a seasonal impact on the Group's construction activities and operations. New or additional species that may be identified as requiring protection or consideration could also lead to delays in obtaining permits and/or other restrictions, including operational restrictions.

Safety of Gas Transmission and Gathering Pipelines. Natural gas pipelines serving the Group's operations are subject to regulation by the US Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("**PHMSA**") pursuant to the Natural Gas Pipeline Safety Act of 1968, ("**NGPSA**"), as amended by the Pipeline Safety Act of 1992, the Accountable Pipeline Safety and Partnership Act of 1996, the Pipeline Safety Improvement Act of 2002 ("**PSIA**"), the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the "**2011 Pipeline Safety Act**"). The NGPSA regulates safety requirements in the design, construction, operation and maintenance of natural gas pipeline facilities, while the PSIA establishes mandatory inspections for all US oil and natural gas transmission pipelines in high-consequence areas. Additionally, certain states, such as West Virginia, also maintain jurisdiction over intrastate natural gas lines. In October 2019, PHMSA published the first of three rules that, collectively, are referred to as the natural gas "mega rule." The first rule imposes additional safety requirements on natural gas transmission pipelines. PHMSA is expected to publish the third of the three rules that make up the "mega rule" in 2020, and such rule is expected to impose additional safety requirements on natural gas gathering pipelines. Depending on the specific requirements of the final PHMSA rule, the Group could be required to undertake costly capital upgrades and/or be subject to additional operating restrictions applicable to its natural gas gathering pipelines. Resource Conservation and Recovery Act. The federal Resource Conservation and Recovery Act ("**RCRA**") and corresponding state laws and regulations impose requirements for the management, treatment, storage and disposal of hazardous and non-hazardous wastes, including wastes generated by the Group's operations. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of natural gas and oil are currently regulated under RCRA's solid (non-hazardous) waste provisions. However, legislation has been proposed from time to time, and various environmental groups have filed lawsuits, that, if successful, could result in the reclassification of certain natural gas and oil exploration and production wastes as "hazardous wastes," which would make such wastes subject to much more stringent handling, disposal and clean-up requirements. A loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in an increase in the Group's costs to manage and dispose of generated wastes, which could have a material adverse effect on the industry as well as on the Group's results of operations and financial position.

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

Although CERCLA generally exempts "petroleum" from regulation, in the course of the Group's operations, it has generated and will generate wastes that may fall within CERCLA's definition of hazardous substances and may have disposed of these wastes at disposal sites owned and operated by others. The Group may also be the owner or operator of sites on which hazardous substances have been released. So far as the Directors are aware, neither the Group nor its predecessors have been designated as a PRP by the EPA under CERCLA. In the event contamination is discovered at a site on which the Group is or has been an owner or operator, or to which the Group sent hazardous substances, it could be liable for the costs of investigation and remediation and natural resource damages.

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

Federal Regulation of the Sale and Transportation of Natural Gas

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

Natural gas and crude oil prices are currently unregulated, but Congress historically has been active in the area of natural gas and crude oil regulation. The Company cannot predict whether new legislation to regulate sales might be enacted in the future or what effect, if any, any such legislation might have on the Group's operations.

Health and Safety Laws

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

Climate Change Laws and Regulations

Climate change continues to be a legislative and regulatory focus. There are a number of proposed and final laws and regulations at the international, federal, state, regional, and local level that limit greenhouse gas emissions, and regulations that restrict emissions could increase the Group's costs should the requirements necessitate the installation of new equipment or the purchase of emission allowances. These laws and regulations could also impact the Group's customers, including the electric generation industry, making alternative sources of energy more competitive and thereby decreasing demand for the natural gas and oil we produce. Additional regulation could also lead to permitting delays and additional monitoring and administrative requirements, as well as to impacts on electricity generating operations. In addition, activists concerned about the potential effects of climate change have directed their attention at sources of funding for energy companies, which has resulted in certain financial institutions, funds, and other sources of capital restricting or eliminating their investment in natural gas and oil activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040, and that natural gas and oil will continue to represent a substantial percentage of global energy use over that time. Finally, it should be noted that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as the increased frequency and severity of storms, floods, droughts, and other extreme climatic events. If any such effects were to occur, they could have an adverse effect on the Group's operations.

PART IX

DIRECTORS, SENIOR MANAGERS AND CORPORATE GOVERNANCE

1. DIRECTORS AND SENIOR MANAGERS

Directors

The directors of the Company as at the date of this Prospectus (the "**Directors**") are as follows:

Name	Age	Position
David Edward Johnson	59	Independent Non-executive Chair
Robert "Rusty" Russell Hutson, Jr.	51	Chief Executive Officer
Bradley Grafton Gray	51	Chief Operating Officer
Martin Keith Thomas	55	Non-executive Vice Chairman
David Jackson Turner, Jr.	56	Independent Non-executive Director
Sandra (Sandy) Mary Stash	61	Independent Non-executive Director
Melanie Little	50	Independent Non-executive Director

The business address of each of the Directors is 27/28 Eastcastle Street, London W1W 8DH, United Kingdom.

The management experience and expertise of each of the Directors is set out below.

David Edward Johnson

Mr. Johnson has enjoyed a long and successful career in the investment sector. He has worked at a number of leading City investment houses, as both an investment analyst and manager, and more recently in equity sales and management. During his career, Mr. Johnson has worked for Sun Life Assurance, Henderson Crosthwaite and Investec Securities, where he became head of sales and as an executive director of Investec Investment Bank. Mr. Johnson joined Panmure Gordon & Co in 2004 where he worked until 2013, including as Head of Sales from 2006 and then Head of Equities from 2009. Mr. Johnson joined Chelverton Asset Management in 2014 where he had responsibility for the Group's private equity investments. Mr. Johnson is a non-executive director of Bilby plc, a holding company providing a platform for strategic acquisitions in the gas heating and general building services industries, and also Chelverton Equity Partners, an AIM listed holding company.

Robert 'Rusty' Russell Hutson, Jr.

Mr. Hutson is the fourth generation of his family to be involved in the gas and oil industry but the first to hold an executive role. Mr. Hutson's father, grandfather and great grandfather all worked in various field operational roles within the industry. Prior to founding the Company in 2001, Mr. Hutson held finance and accounting roles for 13 years at Bank One (Columbus, Ohio) and Compass Bank (Birmingham, Alabama). Mr. Hutson concluded his career in banking as CFO of Compass Financial Services. Mr. Hutson has a B.S. degree in Accounting from Fairmont State College – West Virginia and received a CPA license (Ohio).

Bradley Grafton Gray

Prior to joining the Company in October 2016, Mr. Gray held the position of Senior Vice President and Chief Financial Officer for Royal Cup, Inc., a United States based commercial coffee roaster and wholesale distributor of tea and other beverage related products. Prior to Royal Cup, Inc., from 2006 to 2014, Mr. Gray worked in the petroleum distribution industry for The McPherson Companies, Inc. and held the position of Executive Vice President and Chief Financial Officer. Additionally, from 1997 to 2006, Mr. Gray worked in various financial and operational roles with Saks Incorporated, a previously listed New York Stock Exchange retail group in the United States. Mr. Gray began his career at Arthur Andersen, has a B.S. degree in Accounting from the University of Alabama and received a CPA license (Alabama).

Martin Keith Thomas

Mr. Thomas is a corporate partner heading the capital markets practice at Wedlake Bell LLP in London. Mr. Thomas specialises in advising on initial public offerings and secondary offerings of equity and debt on the London capital markets, corporate finance and mergers and acquisitions, including cross-border and domestic acquisitions and disposals, joint ventures and private equity transactions. Previously named one of The Lawyer's "UK Hot 100 Lawyers" and ranked by both Chambers and Partners and Legal 500, Mr. Thomas advises clients operating in a variety of sectors, including oil and gas, renewable energy, natural resources and mining, climate change, financial services and early stage technology. During his legal career of 30 years, Mr. Thomas has also held senior management positions including seven years as the European Managing Partner of a global law firm headquartered in the United States and was previously a corporate partner at Watson Farley & Williams LLP in London.

David Jackson Turner, Jr.

Mr. Turner serves as Regions Financial Corporation's Chief Financial Officer and is a member of the Regions Executive Leadership Team. Regions Financial Corporation is an NYSE Listed S&P 500 banking group. Mr Turner leads all finance operations, including financial systems, investor relations, corporate treasury, corporate tax, management planning and reporting and accounting. Mr Turner joined Regions in 2005 and led the Internal Audit Division for Regions before being named Chief Financial Officer in 2010. His responsibilities included overseeing various audits of the overall Corporation reporting to the Audit Committee of the Board of Directors. Prior to joining Regions, Mr Turner served as an audit partner of KPMG LLP and he previously served Arthur Andersen LLP in a number of positions, including audit partner, audit manager, senior auditor and staff auditor. His primary focus was auditing financial institutions. Mr Turner earned a bachelor's degree in Accounting from the University of Alabama and attended Tulane University in Louisiana.

Sandra (Sandy) Mary Stash

Ms. Stash has over 35 years' experience in the oil and gas and mining industries and has vast, global leadership experience in operations and engineering, risk and crisis management, external affairs and communications, sustainability, health and safety and litigation. Internationally, Ms. Stash spent many years advising businesses on natural resource, social and sustainability issues with audiences including general stakeholders, local and national media, and local, regional and national governments. A petroleum engineering graduate of the prestigious Colorado School of Mines, Ms. Stash spent her early career as one of the first women to work as a drilling engineer and well site supervisor at ARCO locations across North America. Ms. Stash's subsequent work in managing discontinued businesses for ARCO and then BP, broadened her experience to include all financial, operational, legal, strategic planning and government and media affairs. After a career with ARCO, Anaconda, TNK-BP, BP, and Talisman Energy, Ms. Stash joined Tullow Oil in October 2013 serving as Executive Vice President-Safety, Operations and Engineering, and External Affairs until moving into her present role as Executive Vice President and Executive Advisor in July 2019. Ms. Stash has also served on several Boards of Directors including the Federal Reserve Bank of Minneapolis, the International Women's Forum (IWF), the Colorado School of Mines and, as Chairman, on the Montana Tech Foundation Board of Directors.

Melanie Little

Ms. Little joined the Board of the Company on 18 December 2019 and has almost 20 years' experience in the energy industry. Ms. Little currently serves as Senior Vice President, Operations and Environmental, Health, Safety and Security for Magellan Midstream Partners L.P., and has served in this capacity since 2017. Ms. Little has previously served in Vice President level positions from 2011 to 2017 in Crude Oil Commercial and Operations. From 2007 to 2011, Ms. Little was Director of Transportation Services for Refined Products and Marine. From 2004 to 2007, Ms. Little served in Environmental, Health and Safety management roles at Magellan. Prior to that, she served as Manager of Environmental Compliance at The Williams Companies, Inc. and has also held project management positions in the areas of civil construction and environmental remediation projects on behalf of the U.S. Army. Ms. Little earned a Master of Science degree in Civil Engineering from the Georgia Institute of Technology and a Bachelor of Science degree in Environmental Engineering from the United States Military Academy at West Point.

Senior Managers

In addition to the Directors listed above, the following senior managers (the "**Senior Managers**") are considered relevant to establishing that the Company has the appropriate experience and expertise for the management of its business:

Name	Age	Position
Eric Williams	41	Executive Vice President & Chief Financial Officer (Finance director)
Benjamin M. Sullivan	41	Executive Vice President & General Counsel & Corporate Secretary
James Rode	65	Executive Vice President & Chief Commercial Officer
Michael Garrett	37	Senior Vice President of Accounting & Controller
Bryan Keith Berry	49	Vice President of Finance

The business address of each of the Senior Managers is 27/28 Eastcastle Street, London W1W 8DH, United Kingdom.

The management experience and expertise of each of the Senior Managers is set out below.

Eric Williams

Mr. Williams joined the Company in July 2017 from Callon Petroleum. During his tenure of more than seven years at Callon, the company grew significantly from a market capitalisation of $40 million to over $3.5 billion, successfully transforming itself from a deep-water asset focused company to an onshore, pure-play horizontal drilling operator in the Permian Basin. Mr. Williams was instrumental in developing and enhancing the company's external reporting streams and established a formal investor relations function serving more than 30 sell-side analysts and a growing base of institutional investors. Mr. Williams began his career at the widely renowned public auditing firm of Price Waterhouse Coopers in Birmingham, Alabama. Mr. Williams has served in various roles including internal audit with a focus on Sarbanes Oxley implementation and compliance, controllership and financial reporting for several US publicly-traded companies. Mr. Williams has a B.S. degree in Accounting from Samford University, a M.S. degree in Accounting from the University of Alabama and he is a licensed CPA (Alabama).

Benjamin M. Sullivan

Mr. Sullivan joined the Group in 2019 with oversight of the company's legal, land/real estate, and governmental affairs functions and works with the CEO and board on governance matters. Prior to joining the Group, Mr. Sullivan worked with Greylock Energy (an ArcLight Capital Partners portfolio company with extensive national holdings) and its predecessor (Energy Corporation of America) as Executive Vice President, General Counsel and Corporate Secretary with supervision of many business units. Prior to Mr. Sullivan's tenure at Greylock Energy, he worked as counsel for EQT as well as with a private law firm. He is a member of the leadership and board of directors of several commerce, legal, and industry groups, and has considerable experience in corporate governance and reporting/ESG, complex commercial transactions, land/real estate, acquisitions & divestitures, financing, government investigations, and corporate workouts and restructurings. Mr. Sullivan graduated from the University of Kentucky with a B.A. degree in History and received a J.D. degree from the West Virginia University College of Law. He holds licenses to practice law in several states, including Pennsylvania and West Virginia.

James Rode

Mr. Rode joined the Group in October 2016, bringing more than 30 years of experience in the founding, growth and maturation of various oil and gas companies. Immediately prior to joining the Company, Mr. Rode served as CEO and Chairman of the Board for Core, which he helped to co-found in 2016 and was later acquired by the Group. Prior executive experience included roles as Vice President and General Counsel of Hercules Petroleum; General Counsel of EnTrade Corporation; Executive Vice President, General Counsel and Director of Interenergy Corporation (also co-founder); and Business Development Consultant of MDU Resources. In addition to his executive tenure, Mr. Rode has served on the board of directors of the Kentucky Oil and Gas Association, the West Virginia Independent Oil and Gas Association, and is a member of the Kentucky Bar Association. He earned his Juris Doctor Degree from Gonzaga University School of Law and a Bachelor Business Administration degree from the University of Kentucky.

Michael Garrett

Mr. Garrett joined the Company in March of 2018 from Callon Petroleum, an independent energy company in the Permian Basin. Prior to his tenure at Callon, Mr. Garrett has served in various roles in Accounting for several US publicly-traded companies. Mr. Garrett earned a Bachelor's of Science in Accounting from Lambuth University and holds his CPA license. Mr. Garrett's oversight and direction of all accounting operations and financial reporting for DGO remains imperative to the corporate strategy of the company and the integration of new acquisitions.

Bryan Keith Berry

Mr. Berry joined the Company in November 2017 from Arlington Capital Advisors. Mr. Berry has over 20 years of experience in corporate finance, investment banking and public accounting. Prior to Arlington, Mr. Berry was Vice President of Financial Planning and Analysis at Colonial Properties Trust, a Real Estate Investment Trust with over $4 billion in assets. During his tenure, Colonial acquired, developed or disposed of over $1.5 billion in assets. Additionally, Mr. Berry was Director of Financial Planning at Saks Incorporated, a Fortune 500 retail company, and began his career in public accounting at Deloitte. Mr. Berry graduated from the University of Alabama with a Bachelor of Science in Accounting and a Masters of Accountancy. Mr. Berry's focus at the Company is on the analysis of the Company's future transaction opportunities and financial planning and analysis of the Company's ongoing operations.

2. CORPORATE GOVERNANCE

Compliance with applicable corporate governance rules and regulations

The Directors support high standards of corporate governance, and it is the policy of the Company to comply with current best practice in UK corporate governance to the extent appropriate for a company of its size.

Except as described below, as at the date of this Prospectus, the Company complies with the UK Corporate Governance Code published in July 2018 by the Financial Reporting Council, as amended from time to time, (the "**Corporate Governance Code**").

The Corporate Governance Code recommends that at least half the board of directors of a premium listed company, excluding the chair, should comprise non-executive directors determined by the board to be independent in character and judgement and free from relationships or circumstances which may affect, or could appear to affect, the director's judgement. The Board considers that the Company complies with the requirements of the Corporate Governance Code in this respect.

On Admission, the Board will comprise seven Directors, including the independent non-executive Chair, two Executive Directors, the Senior Independent Director, two further independent Non-executive Directors and one Non-executive Director.

The Corporate Governance Code also recommends that: (i) the chair of the board of directors should meet the independence criteria set out in the Corporate Governance Code on appointment; and (ii) the Board appoint one of the independent non-executive directors to be the senior independent director. On Admission, the Chair of the Company will be David Edward Johnson and the Senior Independent Director will be David J. Turner, Jr. The Board considers that David Edward Johnson, Sandra (Sandy) Stash, David J. Turner, Jr. and Melanie Little meet the independence criteria set out in the Corporate Governance Code.

The Corporate Governance Code also recommends that (i) the Audit & Risk Committee should comprise at least three members, who should all be independent non-executive directors, and that at least one member should have recent and relevant financial experience, (ii) the Remuneration Committee should comprise at least three members, all of whom should be independent non-executive directors, and (iii) a majority of the members of the Nomination Committee should be independent non-executive directors. The Board considers that the Company complies in full with the above requirements.

The Corporate Governance Code also recommends that the chair of the Remuneration Committee should have served on a remuneration committee previously for at least 12 months. While Melanie Little has not served as a board member on a remuneration committee for at least 12 months prior to her appointment as chair of the Remuneration Committee, she has experience in compensation matters engagement with board directors in the United States. Since January 2018, Melanie Little has regularly attended meetings of the Compensation Committee of Magellan Midstream Partners L.P., a company listed on the New York Stock Exchange, and is responsible for developing and briefing the committee on the annual Environmental and Safety framework and associated metrics for the annual incentive plan, which applies to all 1850+ employees and composes 25 per cent. of annual payout for all employees (executive and non-executive). She is responsible for providing the recommended annual payout, which is discretionary, for this component to the committee. In addition, she has extensive experience in the annual salary assessment process(es) as she is ultimately responsible for working with the appropriate internal and external stakeholders in order to establish all compensation for her team, which consists of approximately 1100 team members across a wide range of skills and applicable compensation, to include salary (approximately $100 million per year), bonus, and long term incentive plan awards. She also serves as chair of the Management Benefits Committee of Magellan Midstream Partners L.P., regularly dealing with matters relating to health insurance, pensions, 401Ks, ancillary employee benefits and other related matters. In light of Melanie Little's extensive experience of remuneration matters and her participation with compensation and benefits of a major public company, the Board believes that she has more than sufficient experience to chair the Remuneration Committee. The Board believes that with the current composition of the Remuneration Committee, including the Chair of the Board, and with Melanie Little as chair of the Remuneration Committee, the committee possesses the desirable range of skills and experience necessary for the effective functioning of the Remuneration Committee following Admission.

Except in relation to the requirement of the chair of the Remuneration Committee having served on a remuneration committee previously for at least 12 months, the Board intends to comply fully with the requirements of the Corporate Governance Code and will report to Shareholders on compliance with the Corporate Governance Code in accordance with the Listing Rules.

The Company has implemented internal procedures and measures designed to ensure compliance by it and other members of the Group with the Bribery Act.

Board Committees

The Directors have established an Audit & Risk Committee, a Remuneration Committee, a Nomination Committee and a Sustainability Committee. The members of these committees are appointed principally from among the independent directors and all appointments to these committees shall be for a period of one year. The terms of reference of the committees have been drawn up in line with prevailing best practice, including the provisions of the Corporate Governance Code. A summary of the terms of reference of the committees is set out below.

Each committee and each Director has the authority to seek independent professional advice where necessary to discharge their respective duties, in each case at the Company's expense.

Audit & Risk Committee

The Audit & Risk Committee assists the Board in discharging its responsibilities with regard to: (a) financial reporting; (b) external and internal auditors and controls, including reviewing the Company's annual and half year financial statements and accounting policies and, where requested by the Board, advising whether, taken as a whole, the annual report and accounts are fair, balanced and understandable; (c) reviewing and monitoring the scope of the annual audit and the extent of the non-audit work undertaken by external auditors; (d) advising on the appointment of external auditors; and (e) reviewing the effectiveness of the Company's internal audit activities, internal control and risk management systems. Where the Audit & Risk Committee is not satisfied with any aspect of the proposed financial reporting by the Company, it shall report its views to the Board. However, the ultimate responsibility for reviewing and approving the annual report and accounts, and the half yearly reports, remains with the Board.

The Corporate Governance Code recommends that the Audit & Risk Committee should comprise at least three members, who should all be independent non-executive directors, and that at least one member should have recent and relevant financial experience. The committee as a whole should have competence relevant to the sectors in which the Company operates. The Company's Audit & Risk Committee comprises three members: David J. Turner, Sandra (Sandy) Stash and Melanie Little, all of whom are independent Non-executive Directors. The chair of the Audit & Risk Committee is David J. Turner. No members of the Audit & Risk Committee have links with the Company's external auditors. The Company, therefore, considers that it complies with the Corporate Governance Code recommendation regarding the composition of the Audit & Risk Committee.

The Audit & Risk Committee will meet formally at least three times a year and otherwise as required.

Remuneration Committee

The Remuneration Committee is responsible for determining the policy for Executive Director remuneration, determining the level of remuneration for the Chair and all Non-executive Directors, recommending the remuneration for the Senior Managers and preparing an annual remuneration report for approval by the Shareholders at the annual general meeting. Non-executive Directors' fees will be determined by the full Board.

The purpose of the Company's remuneration policy is to establish a formal and transparent procedure for developing policy on executive remuneration and to set or oversee as appropriate the remuneration packages of individual Directors and senior management of the Company.

The Corporate Governance Code provides that the Remuneration Committee should comprise at least three members, all of whom should be independent non-executive directors. The membership of the Company's Remuneration Committee comprises three members: Melanie Litte, David Johnson and Sandra (Sandy) Stash, all of whom are independent Non-executive Directors. The chair of the Remuneration Committee is Melanie Little. Save as disclosed above, the Company considers that it complies with the Corporate Governance Code recommendations regarding the composition of the Remuneration Committee.

The Remuneration Committee will meet formally at least twice a year and otherwise as required.

Nomination Committee

The Nomination Committee assists the Board in discharging its responsibilities relating to reviewing the structure, size and composition of the Board. The Nomination Committee is responsible for leading the process for appointments, ensuring plans are in place for orderly succession to both the Board and senior management positions, and overseeing the development of a diverse pipeline for succession.

The Corporate Governance Code provides that a majority of the members of the Nomination Committee should be independent non-executive directors. The Company's Nomination Committee is comprised of three members: Martin K. Thomas, David E. Johnson and David J. Turner, all of whom are Non-executive Directors. The chair of the Nomination Committee is Martin K. Thomas. The Company, therefore, considers that it complies with the Corporate Governance Code's recommendations regarding the composition of the Nomination Committee.

The Nomination Committee will meet formally at least twice a year and otherwise as required.

Sustainability Committee

The Sustainability Committee oversees and reports to the Board on the Company's policies and strategies related to matters of sustainability and safety. The Committee considers and provides perspective and input to management on social, political, safety, and environmental trends in public debate, public policy, regulation, and legislation and considers additional corporate actions in response to such issues. It receives periodic reports from the Company's management regarding relationships with key external stakeholders that may have a significant impact on the Company's business activities and performance. The Committee oversees and provides input to the Audit and Risk Committee on the Company's management of risk associated with the Company's sustainability activities. It also oversees and provides safety performance targets to the Remuneration Committee.

The Sustainability Committee is comprised of four members, namely Sandra (Sandy) Stash, David Johnson, Melanie Little and Brad Gray. The chair of the committee is Sandra (Sandy) Stash.

The Sustainability Committee will meet formally at least twice a year and otherwise as required.

Share Dealing Code

The Company has adopted a code of securities dealings in relation to the Ordinary Shares which complies with the Market Abuse Regulation. The code applies to the Directors, Senior Managers and other relevant employees of the Group.

3. CONFLICTS OF INTEREST

There are no potential conflicts of interest between any duties owed by the Directors or Senior Managers to the Company and their private interests and/or other duties.

PART X

SELECTED FINANCIAL INFORMATION

SECTION A: SELECTED HISTORICAL FINANCIAL INFORMATION OF THE GROUP

The selected financial information set out below has been extracted without material adjustment from Section B *Historical financial information relating to the Group* of Part XIV "*Historical Financial Information*" of this Prospectus, where it is shown with important notes describing some of the line items.

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

The following information should be read in conjunction with Part XI "*Operating and Financial Review*" and Part XIV "*Historical Financial Information*" of this Prospectus.

Consolidated statements of comprehensive income

The audited consolidated statements of comprehensive income of the Group for each of the three years ended 31 December 2017, 2018 and 2019 are set out below:

	(Restated) Audited Year ended 31 December 2017 $'000	Audited Year ended 31 December 2018 $'000	Audited Year ended 31 December 2019 $'000
Revenue	41,777	289,769	462,256
Cost of sales	(20,908)	(107,793)	(202,385)
Amortisation, depreciation and depletion	(7,536)	(41,988)	(98,139)
Gross profit	**13,333**	**139,988**	**161,732**
(Loss)/gain on derivative financial instruments	(441)	17,981	73,854
Gain on bargain purchase	37,093	173,473	1,540
Gain on disposal of property and equipment	95	4,079	—
Administrative expenses	(8,919)	(40,524)	(56,619)
Operating profit	**41,161**	**294,997**	**180,507**
Accretion of asset retirement obligation	(1,764)	(7,101)	(12,349)
Finance costs	(5,225)	(17,743)	(36,667)
Loss on debt cancellation	(4,468)	(8,358)	—
Income before taxation	**29,704**	**261,795**	**131,491**
Taxation	(2,250)	(60,676)	(32,091)
Income after taxation	**27,454**	**201,119**	**99,400**
Other comprehensive income – gain on foreign currency conversion	355	1	—
Total comprehensive income for the year	**27,809**	**201,120**	**99,400**
Earnings per Ordinary Share – basic and diluted	$0.23	$0.52	$0.15

Consolidated statements of financial position

The audited consolidated statements of financial position of the Group as at 31 December 2017, 2018 and 2019 are set out below:

	(Restated) Audited Year ended 31 December 2017 $'000	*(Restated)* Audited Year ended 31 December 2018 $'000	*(Restated)* Audited Year ended 31 December 2019 $'000
ASSETS			
Oil and gas properties	215,325	1,092,951	1,490,905
Intangible assets	—	2,563	15,980
Property and equipment	6,947	325,186	325,866
Restricted cash	—	—	6,505
Other non-current assets	1,036	22,543	4,191
Indemnification receivable	—	2,133	2,133
Non-current assets	**223,308**	**1,445,376**	**1,845,580**
Trade receivables	13,917	78,451	73,923
Other current assets	513	30,043	83,568
Cash and cash equivalents	15,168	1,372	1,661
Restricted cash	744	1,730	1,207
Current assets	**30,342**	**111,596**	**160,360**
Total assets	**253,650**	**1,556,972**	**2,005,940**
EQUITY AND LIABILITIES			
Share capital	1,940	7,346	8,800
Share premium	76,026	540,655	760,543
Merger reserve	(478)	(478)	(478)
Capital redemption reserve	—	—	518
Share-based payment reserve	59	842	3,907
Retained earnings	30,691	200,498	164,845
Total equity	**108,238**	**748,863**	**938,135**
Asset retirement obligation	35,448	140,190	196,871
Capital leases	836	2,694	1,015
Borrowings	70,619	482,528	598,778
Deferred tax liability	17,399	95,033	124,112
Other non-current liabilities	2,278	1,060	18,041
Uncertain tax position	—	2,133	2,133
Total non-current liabilities	**126,580**	**723,638**	**940,950**
Trade and other payables	2,132	9,383	17,052
Borrowings	373	286	23,723
Capital leases	324	842	798
Other current liabilities	16,003	73,960	85,282
Total current liabilities	**18,832**	**84,471**	**126,855**
Total liabilities	**145,412**	**808,109**	**1,067,805**
Total liabilities and equity	**253,650**	**1,556,972**	**2,005,940**

Consolidated statements of changes in shareholders' equity

The audited consolidated statements of changes in shareholders' equity of the Group for each of the three years ended 31 December 2017, 2018 and 2019 are set out below:

	Share capital $'000	Share premium $'000	Merger reserve $'000	Capital Redemption reserve $'000	Share-based payment reserve $'000	Retained earnings $'000	Total equity $'000
Balance at 1 January 2017	**669**	**313**	**(478)**	**—**	**—**	**8,658**	**9,162**
Income after taxation	—	—	—	—	—	27,454	27,454
Gain on foreign currency conversion	—	—	—	—	—	355	355
Total comprehensive income	—	—	—	—	—	*27,809*	*27,809*
Issuance of Ordinary Shares, initial offering	768	43,550	—	—	—	—	44,318
Issuance of Ordinary Shares, secondary offering	503	32,163	—	—	—	—	32,666
Equity compensation	—	—	—	—	59	—	59
Dividends authorised and declared	—	—	—	—	—	(5,776)	(5,776)
Transactions with owners	*1,271*	*75,713*	—	—	*59*	*(5,776)*	*71,267*
Balance as at 31 December 2017	**1,940**	**76,026**	**(478)**	**—**	**59**	**30,691**	**108,238**
Income after taxation	—	—	—	—	—	201,119	201,119
Gain on foreign currency conversion	—	—	—	—	—	1	1
Total comprehensive income	—	—	—	—	—	*201,120*	*201,120*
Issuance of Ordinary shares	5,406	464,629	—	—	—	—	470,035
Equity compensation	—	—	—	—	783	—	783
Dividends authorised and declared	—	—	—	—	—	(31,313)	(31,313)
Transactions with owners	*5,406*	*464,629*	—	—	*783*	*(31,313)*	*(437,505)*
Balance as at 31 December 2018	**7,346**	**540,655**	**(478)**	**—**	**842**	**200,498**	**748,863**
Income after taxation	—	—	—	—	—	99,400	99,400
Total comprehensive income	—	—	—		—	*99,400*	*99,400*
Issuance of Ordinary Shares	1,972	219,888	—	—	—	—	221,860
Equity compensation	—	—	—	—	3,065	—	3,065
Repurchase of Ordinary Shares	(518)	—	—	518	—	(52,902)	(52,902)
Dividends authorised and declared	—	—	—	—	—	(82,151)	(82,151)
Transactions with owners	*1,454*	*219,888*	—	*518*	*3,065*	*(135,053)*	*89,872*
Balance as at 31 December 2019	**8,800**	**760,543**	**(478)**	**518**	**3,907**	**164,845**	**938,135**

Consolidated statements of cash flows

The audited consolidated statements of cash flows of the Group for each of the three years ended 31 December 2017, 2018 and 2019 are set out below:

	(Restated) Audited Year ended 31 December 2017 $'000	*(Restated)* Audited Year ended 31 December 2018 $'000	*(Restated)* Audited Year ended 31 December 2019 $'000
Cash flows from operating activities			
Income after taxation	27,454	201,119	99,400
Cash flow from operations reconciliation:			
Amortisation, depreciation and depletion	7,536	41,988	98,139
Accretion of asset retirement obligation	1,764	7,101	12,349
Income tax charge	2,250	60,676	32,091
Provision for working interest owners receivable	632	—	—
Loss/(gain) on derivative financial instruments	1,965	(32,768)	(20,270)
Asset retirement (plugging)	(78)	(1,711)	(2,541)
Gain on oil and gas program and equipment	(396)	(4,079)	—
Gain on bargain purchase	(37,093)	(173,473)	(1,540)
Finance costs	4,510	17,743	36,677
Loss on early retirement of debt	—	8,358	—
Gain on disposal of property and equipment	95	—	—
Non-cash equity compensation	59	783	3,065
Working capital adjustments:			
Change in trade receivables	(11,464)	(41,225)	4,528
Change in other current assets	798	(6,286)	2,606
Change in other assets	(38)	(1,732)	409
Change in trade and other payables	(2,495)	1,134	7,669
Change in other current and non-current liabilities	11,345	8,396	6,754
Net cash provided by operating activities	**6,844**	**86,564**	**279,156**
Cash flows from investing activities			
Business combinations net of cash acquired	(89,785)	(750,256)	(439,272)
Expenditures on oil and gas properties, intangible assets and property and equipment	(2,935)	(18,515)	(32,313)
Increase in restricted cash	(627)	(986)	(5,302)
Proceeds on disposal of oil and gas properties	334	4,079	10,000
Net cash used in investing activities	**(93,013)**	**(765,678)**	**(466,887)**
Cash flows from financing activities			
Repayment of borrowings	(42,514)	(280,890)	(618,010)
Proceeds from borrowings	75,000	581,221	765,236
Financing expense	(3,298)	(15,433)	(32,715)
Cost incurred to secure financing	—	(17,176)	(11,574)
Proceeds from capital lease	1,246	4,401	—
Repayment of capital lease	(529)	(1,093)	(1,724)
Proceeds from equity issuance, net	76,984	425,601	221,860
Dividends to Shareholders	(5,776)	(31,313)	(82,151)
Repurchase of Ordinary Shares	—	—	(52,902)
Net cash provided by financing activities	**101,113**	**665,318**	**188,020**
Net increase/(decrease) in cash and cash equivalents	**14,944**	**(13,796)**	**289**
Cash and cash equivalents – beginning of the year	*224*	*15,168*	*1,372*
Cash and cash equivalents – end of the year	**15,168**	**1,372**	**1,661**

SECTION B: SELECTED HISTORICAL FINANCIAL INFORMATION OF ALLIANCE PETROLEUM

The selected financial information set out below has been extracted without material adjustment from Section D "*Historical financial information of Alliance Petroleum*" of Part XIV "*Historical Financial Information*" of this Prospectus, where it is shown with important notes describing some of the line items.

The following information should be read in conjunction with Part XII "*Operating and Financial Review of Alliance Petroleum*" and Part XIV "*Historical Financial Information*" of this Prospectus.

Statements of comprehensive income

The audited statements of comprehensive income of Alliance Petroleum for the year ended 31 December 2017 and the two-month period ended 28 February 2018 are set out below:

	Audited Year ended 31 December 2017 $'000	Audited 2 months ended 28 February 2018 $'000
Revenue	45,946	8,516
Cost of sales	(26,928)	(5,136)
Depletion	(2,901)	(754)
Depreciation	(80)	(19)
Gross profit	**16,037**	**2,607**
Gain on derivative financial instruments	9,201	1,927
Gain on bargain purchase	21,421	—
Gain on disposal of oil and gas properties	1,522	82
Administrative expenses	(7,009)	(994)
Operating profit	**41,172**	**3,622**
Finance costs	(1,476)	(210)
Income before taxation	**39,696**	**3,412**
Taxation	(10,711)	(268)
Total comprehensive income for the year/period	**28,985**	**3,144**
Earnings per ordinary share – basic and diluted	$289,850	$31,440

Statements of financial position

The audited statements of financial position of Alliance Petroleum as at 31 December 2017 and 28 February 2018 are set out below:

	Audited As at 31 December 2017 $'000	Audited As at 28 February 2018 $'000
ASSETS		
Non-current assets		
Oil and gas properties	90,001	89,286
Property and equipment	2,172	2,079
	92,173	**91,365**
Current assets		
Inventories	248	248
Other current assets	964	785
Trade receivables	13,683	16,075
Derivative financial instruments	—	1,851
Cash and cash equivalents	7,861	8,638
	22,756	**27,597**
Total assets	**114,929**	**118,962**
EQUITY AND LIABILITIES		
Shareholders' equity		
Share capital	—	—
Retained earnings	27,439	30,583
Total equity	**27,439**	**30,583**
Non-current liabilities		
Borrowings	37,209	37,215
Asset retirement obligation	20,459	20,609
Deferred tax liability	7,500	7,672
Derivative financial instruments	—	109
Other non-current liabilities	105	10
Total non-current liabilities	**65,273**	**65,615**
Current liabilities		
Trade payables	3,819	5,821
Borrowings	434	146
Derivative financial instruments	535	—
Other current liabilities	17,429	16,797
	22,217	**22,764**
Total liabilities	**87,490**	**88,379**
Total liabilities and equity	**114,929**	**118,962**

Statements of changes in shareholders' equity

The audited statements of changes in shareholders' equity of Alliance Petroleum for the year ended 31 December 2017 and the two-month period ended 28 February 2018 are set out below:

	Share capital $'000	Retained earnings $'000	Total equity $'000
Balance at 1 January 2017	**—**	**(497)**	**(497)**
Income after taxation	—	28,985	28,985
Total comprehensive income for the year	—	*28,985*	*28,985*
Dividends authorised and declared	—	(1,049)	(1,049)
Transactions with owners	—	*(1,049)*	*(1,049)*
Balance as at 31 December 2017	**—**	**27,439**	**27,439**
Profit after taxation	—	3,144	3,144
Total comprehensive profit for the period	—	*3,144*	*3,144*
Balance as at 28 February 2018	**—**	**30,583**	**30,583**

Statements of cash flows

The audited statements of cash flows of Alliance Petroleum for the year ended 31 December 2017 and the two-month period ended 28 February 2018 are set out below:

	Audited Year ended 31 December 2017 $'000	**Audited 2 months ended 28 February 2018 $'000**
Cash flows from operating activities		
Income after taxation	28,985	3,144
Cash flow from operations reconciliation:		
Depletion of oil and gas properties	2,901	754
Depreciation of property, plant and equipment	523	118
Accretion of asset retirement obligation	1,474	150
Unrealised gain on derivative financial instruments	(3,690)	(2,277)
Gain on bargain purchase	(21,421)	—
Gain on disposal of oil and gas properties	(1,522)	(82)
Finance costs	1,476	210
Working capital adjustments:		
Change in inventories	27	—
Change in trade receivables	(6,089)	(2,392)
Change in other current assets	(127)	179
Change in trade payables	234	2,002
Change in other current liabilities	14,163	(632)
Change in other non-current liabilities	(46)	77
Net cash from operating activities	**16,888**	**1,251**
Cash flows from investing activities		
Purchase of property, plant and equipment	(553)	(25)
Proceeds from the sale of property, plant and equipment	—	82
Purchase of oil and gas properties	(5,075)	(39)
Proceeds from the sale of oil and gas properties	1,522	—
Net cash (used in)/from investing activities	**(4,106)**	**18**
Cash flows from financing activities		
Repayment of borrowings	(6,170)	(282)
Dividends to shareholders	(1,049)	—
Interest paid	(1,476)	(210)
Net cash used in financing activities	**(8,695)**	**(492)**
Net increase in cash and cash equivalents	**4,087**	**777**
Cash and cash equivalents – beginning of the period	*3,774*	*7,861*
Cash and cash equivalents – end of the period	**7,861**	**8,638**

PART XI

OPERATING AND FINANCIAL REVIEW OF THE GROUP

The following discussion of the Group's financial condition and results of operations should be read in conjunction with the Sections entitled "*Presentation of Information*" and "*Historical Financial Information*" of this Prospectus. This discussion contains forward-looking statements that reflect the current view of the Directors and involve risks and uncertainties. The Group's actual results could differ materially from those contained in any forward-looking statements as a result of factors discussed below and elsewhere in this Prospectus, particularly the risk factors discussed in Part II "*Risk Factors*" of this Prospectus. Certain regulatory and industry issues also affect the Company's results of operations and are described in Part VII "*Business*" and Part VII "*Industry Overview*" of this Prospectus.

The financial information in this Part XI "*Operating and Financial Review of the Group*" of this Prospectus has been extracted or derived without adjustment from the Group Financial Information contained in Section B "*Historical Financial Information of the Group*" of Part XIV "*Historical Financial Information*" of this Prospectus, save where otherwise stated.

1. OVERVIEW

The Company is an independent owner and operator of producing natural gas and oil wells concentrated in the Appalachian Basin, the oldest hydrocarbon producing region within the United States. The Group's operations are located throughout the neighbouring states of Tennessee, Kentucky, Virginia, West Virginia, Ohio, and Pennsylvania, where the Company is one of the largest independent operators of conventional assets and also an operator of unconventional assets and midstream pipeline infrastructure. Diversified Gas & Oil plc was incorporated in 2014. The Diversified Gas & Oil plc predecessor business was founded in 2001 by the CEO Rusty Hutson, Jr. with an initial focus on gas and oil production in West Virginia. In recent years, Diversified Gas & Oil plc has grown rapidly by capitalising on opportunities to acquire and enhance producing assets, and leveraging the operating efficiencies that come with economies of scale. Since 2017, the Company has carried out 11 asset and business acquisitions for a combined purchase consideration of approximately $1.5 billion.

The Company's strategy is to acquire and to manage gas and oil properties and certain associated midstream assets to generate cash flows and provide cash distributions to its shareholders. The Company seeks to acquire high-quality producing conventional and unconventional gas and oil assets with synergistic opportunities, from industry players who are seeking to re-focus resources elsewhere, typically to US onshore shale reservoirs, or who are experiencing financial difficulties and wish to sell non-core assets. The Company seeks to acquire long-life producing assets at accretive valuations, typically allocating value only to the PDP portion of 1P reserves and allocating no value to the PUD portion of 1P reserves or to probable or possible resources. The Company further seeks to operate and enhance those acquired assets, and then distribute natural gas, natural gas liquids and oil to achieve optimal pricing. The Group's target assets are characterized by highly visible production rates, long-life (in excess of 50 remaining production years), and low decline rates.

The Group seeks to improve the performance of its acquired assets which have often not received an optimal level of focus and investment from their former owners. The Company enhances its production through the deployment of rigorous field management programs and accelerating or extending production by deploying new extraction technology and/or refreshing decayed infrastructure on poorly maintained wells. Through operational efficiencies, the Company demonstrates its ability to maximise value by enhancing production while lowering costs and improving well productivity. The Group's gas, natural gas liquids and oil production is distributed in a way that manages price by leveraging the Group's midstream pipeline infrastructure to take advantage of pricing differentials.

For the year ended 31 December 2019, the Group's total revenue was $462.3 million, increasing by $172.5 million or 59.5 per cent. from $289.8 million for the year ended 31 December 2018. Revenue for the year ended 31 December 2018 represented a $248.0 million or 593.3 per cent. increase on revenue for the year ended 31 December 2017, which was $41.8 million. In 2019, gas sales accounted for 83.1 per cent. of revenue, while NGLs and oil accounted for 7.3 per cent. and 4.4 per cent. respectively.

The following table presents the Group's summary financial metrics:

Date	Unit	2017	2018	2019
Acquisitions	$m	88.7	938	440
Production	MBoed	6.6	41.0	84.8
Proved-developed-producing reserves	MMBoe	55	474	563
PV-10 reserves	$b	0.3	1.6	1.9
Revenue (Hedged)[(a)]	$m	43.3	274.0	536
Base lease operating expense	$ per Boe	7.02	4.73	3.31
Total lease operating expense[(b)]	$ per Boe	8.71	7.32	6.54
Adjusted G&A Expense	$ per Boe	2.03	1.35	1.17
Unit recurring G&A	$ per Boe	3.71	2.71	1.83
Adjusted EBITDA (hedged)	$m	17.5	146.2	273.3
Adjusted EBITDA Margin (hedged)	%	40%	53%	53%
Adjusted EBITDA (unhedged)	$m	16.0	161.9	219.7
Adjusted EBITDA Margin (unhedged)	%	38%	56%	48%

(a) *Includes the impact of settled hedges.*

(b) *Includes base lease operating expenses (such as maintenance, repairs, insurance, employee and benefits and automobile expenses), owned gathering and compression expense, third-party gathering and transportation expense and production taxes.*

2. SIGNIFICANT FACTORS AFFECTING THE GROUP'S RESULTS OF OPERATIONS

Production Volumes and Acquisitions

Acquisitions

The Group's revenues and results of operations depend significantly on the volumes of gas and oil it produces. As one of the Group's key business strategies is to capitalise on opportunities to acquire producing conventional and unconventional gas and oil assets, the Group's production has historically increased substantially from period to period as a result of acquisitions and the Group intends to continue pursuing attractive acquisition opportunities in the future. The Group's production volumes have grown significantly during the period under review due to several acquisitions that it has carried out. For the year ended 31 December 2017, the Group made three acquisitions which resulted in the Group's well count growing by 10,230 wells. During the same period, the Group's production increased by 10,620 boepd or 2042.3 per cent. from 520 boepd to 11,140 boepd, with an average daily production of 6,575 boepd.

For the year ended 31 December 2018, the Group made four acquisitions which resulted in the Group's well count growing by 40,250 wells. During the same period, the Group's production increased by 59,800 boepd or 536.8 per cent. from 11,140 boepd to 70,940 boepd, with an average daily production of 40,959 boepd. Primarily due to the increase in production, the Group's revenues also grew during the same period by 593.3 per cent. from $41.8 million to $289.8 million. Due to the growth in the Group's operational footprint, operating expense grew by $86.9 million or 415.8 per cent. from $20.9 million to $107.8 million and depreciation and depletion also grew by 457.2 per cent. or $34.5 million from $7.5 million to $42.0 million. However, due to the Group being able to leverage cost synergies from its acquisitions, the Group's Percentage Operating Margin grew from 40.4 per cent. to 53.4 per cent., despite the high growth in operating expenses and depreciation between the years ended 31 December 2017 and 31 December 2018.

For the year ended 31 December 2019, the Group made three acquisitions which resulted in the Group's well count growing by another 119 wells. During the same period, the Group's production increased by 35.2 per cent. or 25,000 boepd from 70,940 boepd to 94,832 boepd, with an average daily production of 84,778 boepd. Primarily due to the increase in production, the Group's revenues increased by 59.5 per cent. or $172.5 million from $289.8 million to $462.3 million. Due to the growth in the Group's operational footprint, operating expense grew by $94.6 million or 87.8 per cent. from $107.8 million to $202.4 million and depreciation and depletion also grew by $56.2 million or 133.7 per cent. from $42.0 million to $98.1 million. The Group's Operating Margin decreased by 96 cents or 9.8 per cent. from $9.78 per BOE to $8.82 per BOE. This was due to:

- Lower per boe lease operating expenses, which declined 30 per cent. or $1.42 per boe through a mixture of disciplined cost reductions and economies of scale whereby fixed operating costs were spread across a larger base of producing assets;

- Lower per boe production taxes, which decreased 34 per cent. or $0.27 per boe primarily due to taxes on the Group's midstream assets that are generally fixed and are spread across a larger base of producing assets;

- Lower per boe gathering, processing and transportation expenses, which declined 88 per cent. or $0.60 per boe; and

- Lower per boe administrative expenses, which decreased 32 per cent. or $0.88 per boe primarily due to the significant growth in our production base. Administrative expenses increased by $14.9 million due to costs related to the Company's acquisition efforts and the investment made in staff and systems to support the Company's growth.

The following table summarises the acquisitions made by the Group since 2017 for the years ended 31 December 2017, 31 December 2018 and 31 December 2019:

Event	Acquisition Type	Date	No. of Wells Acquired[(a)]	Production (boepd)	Total Production (boepd)	PDP Reserves (MMboe)
Pre-IPO	N/A	N/A	N/A	520	520	24.3
EnerVest	Asset	Apr. 2017	1,300	3,800	4,320	2.4
Titan	Asset	June 2017	8,380	6,600	10,920	35
NGO	Asset	Dec. 2017	550	220	11,140	1
Alliance Petroleum	Corporate	Mar. 2018	13,000	8,800	19,940	49
CNX	Asset	Mar. 2018	11,000	9,000	28,940	69
EQT	Asset	July 2018	11,250	32,000	60,940	230
Core	Corporate	Oct. 2018	5,000	10,000	70,940	100
HG Energy	Asset	Apr. 2019	107	20,000	90,940	92
EdgeMarc	Asset	Sept. 2019	12	5,000	94,832	13.5
Dominion & Equitrans	Asset	Sept. 2019	N/A	N/A	94,832	N/A

(a) Well counts represent the number of wells for the respective acquisitions as reported in "Note 5: Acquisitions" in Section B "Historical financial information relating to the Group" of Part XIV "Historical Financial Information" of this Prospectus

Prior to the Group's admission to AIM in February 2017, the Group's total well count was 9,698 and its total production was 520 boepd ("**Pre-IPO**"). In April 2017, the Group acquired approximately 1,300 gas and oil wells and PDP reserves of 2.4 MMboe in Ohio from EnerVest Limited ("**EnerVest**") for a purchase price of $1.75 million. At the time of acquisition, EnerVest's product mix was over 95 per cent. natural gas. For the year ended 31 December 2017, EnerVest's total operating expense was $1.1 million and $2.8 million for the year ended 31 December 2018. For the year ended 31 December 2019, EnerVest's operating expense was $3.1 million. The acquisition of EnerVest increased the Group's total production to 4,320 boepd.

In June 2017, the Group acquired approximately 8,380 gas and oil wells and PDP reserves of 35 MMboe in Pennsylvania, Ohio, and Tennessee from Titan Energy LLC ("**Titan**") for a purchase price of $84.2 million. At the time of acquisition, Titan's product mix was over 95 per cent. natural gas. For the year ended 31 December 2017, Titan's total operating expense was $10.4 million and $25.2 million for the year ended 31 December 2018. For the year ended 31 December 2019, Titan's operating expense was $27.3 million. The acquisition of Titan increased the Group's total production to 6,600 boepd.

In December 2017, the Group acquired approximately 550 gas and oil wells and PDP reserves of 1 MMboe in Ohio from NGO Development Corporation Inc ("**NGO**") for a purchase price of $3.1 million. At the time of acquisition, NGO's product mix was over 95 per cent. natural gas. For the year ended 31 December 2017, NGO's total operating expense was $276,384 and $1.3 million for the year ended 31 December 2018. For the year ended 31 December 2019, NGO's operating expense was $1.3 million. The acquisition of NGO increased the Group's total production to 11,140 boepd.

In March 2018, the Group acquired a 100 per cent. ownership interest in Alliance Petroleum Corporation ("**Alliance Petroleum**") including approximately 13,000 gas and oil wells and PDP reserves of 49 MMboe in Pennsylvania, West Virginia and Ohio for a purchase price of $95.0 million. At the time of acquisition, Alliance Petroleum's product mix was 98.8 per cent. natural gas and 1.2 per cent. oil. For the year ended 31 December 2018, Alliance Petroleum's total operating expense was $20.2 million and $23.1 million for the year ended 31 December 2019. The acquisition of Alliance Petroleum increased the Group's total production to 19,940 boepd.

In March 2018, the Group acquired approximately 11,000 gas and oil wells and PDP reserves of 69 MMboe in Pennsylvania and West Virginia from CNX Gas Company ("**CNX**") for a purchase price of $85.0 million. At the time of acquisition, CNX's product mix was 99.0 per cent. natural gas and 1 per cent. oil. For the year ended 31 December 2018, CNX's total operating expense was $13.3 million and $14.9 million for the year ended 31 December 2019. The acquisition of CNX increased the Group's total production to 28,940 boepd.

In July 2018, the Group acquired approximately 11,250 conventional natural gas and oil wells, PDP reserves of 230 MMboe and a wholly-owned midstream gathering and a compression system with approximately 6,400 miles of pipeline and 59 compressor stations in Kentucky, West Virginia and Virginia from EQT Corporation ("**EQT**") for a purchase price of $575.0 million. At the time of acquisition, EQT's product mix was over 76.9 per cent. natural gas, 22.6 per cent. natural gas liquids and 0.5 per cent. oil. For the year ended 31 December 2018, EQT's total operating expense was $27.6 million and $67.1 million for the year ended 31 December 2019. The acquisition of EQT increased the Group's total production to 60,940 boepd.

In October 2018, the Group acquired Core Appalachia Holding Co, LLC ("**Core**"), which included approximately 5,000 conventional natural gas and oil wells, PDP reserves of 100 MMboe and a wholly-owned midstream gathering and compression system with approximately 4,100 miles of pipeline and 47,000 horsepower of compression in Kentucky, West Virginia and Virginia for a purchase price of $90.6 million. At the time of acquisition, Core's product mix was over 97.1 per cent. natural gas, 1.5 per cent. natural gas liquids and 1.4 per cent. oil. For the year ended 31 December 2018, Core's total operating expense was $10.9 million and $28.3 million for the year ended 31 December 2019. The acquisition of Core increased the Group's total production to 70,940 boepd.

In April 2019, the Group acquired 107 gas wells, PDP reserves of 92 MMboe and related surface rights and gathering equipment in Pennsylvania and West Virginia from HG Energy Appalachia, LLC ("**HG Energy**") for a purchase price of $400.0 million. At the time of acquisition, HG Energy's product mix was 100 per cent. natural gas. For the year ended 31 December 2019, HG Energy's total operating expense was $18.9 million. The acquisition of HG Energy increased the Group's total production to 90,940 boepd.

In September 2019, the Group acquired certain gas and oil development, production and exploration assets located in Ohio from EdgeMarc Energy, that included 12 unconventional wells and PDP reserves of 13.5 MMboe for a price of $48.1 million. At the time of acquisition, EdgeMarc Energy's product mix was 100 per cent. natural gas. For the year ended 31 December 2019, EdgeMarc Energy's total operating expense was $3.9 million. The acquisition of the EdgeMarc Energy assets increased the Group's total production to 94,832 boepd.

In September 2019, the Group acquired natural gas gathering systems in Pennsylvania and West Virginia in two separate transactions, comprising approximately 1,700 miles of low-pressure wet and dry gas gathering pipelines together with compressors and measurement stations from Dominion Gathering and Processing and Equitrans. The combined purchase price of the assets was $7.7 million. For the year ended 31 December 2019, total operating expense of the assets was $1.3 million.

Managing Decline Rates

Following the acquisition of existing conventional wells, the Group enhances well production by refreshing decayed infrastructure on wells that have typically been poorly maintained by former owners for whom these were not core assets. Mature conventional wells that are in production for five years or more have an average decline rate that ranges from 3 per cent. to 7 per cent. per year. By leveraging the extensive operational experience of the Group's staff, many of whom who have had long careers in the Appalachian Basin, the Group is able to deploy a number of techniques to extend production by repairing lines, recompleting wells, reconnecting wells, swabbing wells and adding or optimising compression. The Group has an established and proactive approach to the long-term sustainability of its wells through its deployment of experience, knowledge and resources throughout its entire portfolio, executed through its Smarter Well Management and Safe & Systematic Asset Retirement programmes which harness the Group's scale and diverse institutional knowledge from a growing body of professionals with unique experience and geographical proximity to extract maximum value. These programs, tailored for each asset, focus on optimising production from active wells and, where economically possible through a variety of means, returning inactive wells to production. For example, in 2019, the Group returned approximately 750 non-producing wells to production. Through these approaches, the Group is able to achieve low-decline and steady production that creates stable unit operating costs over time.

Gas, Natural Gas Liquids and Oil Prices

In combination with production volumes, the prevailing prices of gas, natural gas liquids and oil are the key drivers of the Group's revenue. The prices of gas, natural gas liquids and oil also affect the Group's results of operations and the recoverability of its reserves. In addition to being subject to technical feasibility, the recoverability of the Group's reserves is also constrained by economic feasibility and therefore impacted by price changes in gas, natural gas liquids and oil. A decrease in gas, natural gas liquids and oil prices could lead to a reduction in the recoverability of the Group's reserves, thus reducing the expected economic life of a field. Hydrocarbon prices have historically been volatile and subject to supply and demand and, in the case of crude oil, particularly sensitive to OPEC production levels. The Group engages in the hedging of gas, natural gas liquids and oil prices in order to protect cash flows.

In the year ended 31 December 2019, the Group's total average realised price for gas, natural gas liquids and oil decreased by $4.58, or 24.4 per cent., to $14.16/boe from $18.74/boe in the year ended 31 December 2018. In the year ended 31 December 2018, the Group's revenue increased by $248.0 million, or 593.3 per cent., in the year ended 31 December 2017. During this period, the Group's total average realised price for gas, natural gas liquids and oil increased by $2.26, or 13.7 per cent., to $18.74/boe in the year ended 31 December 2018 from $16.48/boe in the year ended 31 December 2017. Although the 13.7 per cent. increase in total average realised price was significant, the increase in revenue for this period was primarily attributable to a 523.0 per cent. increase in produced volumes sold on a BOE equivalent basis as discussed in the section above. In a year where fewer acquisitions occur, commodity price changes are expected to be one of the primary factors affecting changes in revenue between periods.

Gas Prices

In 2019, gas sales accounted for 83.1 per cent. of the Group's revenue as compared to 75.6 per cent. in 2018 and 72.9 per cent. in 2017. The Group's gas sales are priced using the Henry Hub price benchmark. The average Henry Hub quoted price decreased by $0.46, or 14.8 per cent., to $2.63 per btu in the year ended 31 December 2019 from $3.09 per btu in the year ended 31 December 2018. The average Henry Hub quoted price decreased by $ 0.02, or 1 per cent., to $3.09 per btu in the year ended 31 December 2018 from $3.11 per btu in the year ended 31 December 2017.

The following table sets forth information on Henry Hub benchmark gas prices for each of the years ended 31 December 2017, 31 December 2018 and 31 December 2019:

	Year ended 31 December		
(in $/btu)	**2017**	**2018**	**2019**
Average price for the period	$3.11	$3.09	$2.63
Highest price for the period	$3.93	$4.72	$3.64
Lowest price for the period	$2.63	$2.64	$2.14

Source: US Energy Information Administration

Natural Gas Liquid Prices

In 2019, natural gas liquid sales accounted for 7.3 per cent. of the Group's revenue as compared to 14.4 per cent. in 2018 and 2.5 per cent. in 2017. The Group's natural gas liquid prices are priced using the Mont Belvieu benchmark. The weighted average Mont Belvieu quoted price decreased by $14.04, or 34.6 per cent., to $26.56 per barrel in the year ended 31 December 2019 from $40.60 per barrel in the year ended 31 December 2018. The weighted average Mont Belvieu quoted price increased by $5.30, or 15 per cent., to $40.60 per barrel in the year ended 31 December 2018 from $35.30 per barrel in the year ended 31 December 2017.

The following table sets forth information on Mont Belvieu benchmark natural gas liquid prices for the years ended 31 December, 2017, 2018 and 2019.

	Year ended 31 December		
(in $/bbl)	**2017**	**2018**	**2019**
Average price for the period	$35.30	$40.60	$26.56
Highest price for the period	$43.30	$48.70	$31.85
Lowest price for the period	$27.60	$31.00	$20.40

Source: FactSet

Crude Oil Prices

In 2019, crude oil sales accounted for 4.4 per cent. of the Group's revenue as compared to 6.6 per cent. in 2018 and 19.3 per cent. in 2017. The Group's crude oil prices are priced using the WTI benchmark. The average WTI quoted price decreased by $8.35, or 12.8 per cent., to $56.98 per barrel in the year ended 31 December 2019 from $65.33 per barrel in the year ended 31 December 2018. The average WTI quoted price increased by $15.11, or 30 per cent., to $65.33 per barrel in the year ended 31 December 2018 from $50.22 per barrel in the year ended 31 December 2017.

The following table sets forth information on WTI benchmark crude oil prices for each of the years ended 31 December 2017, 31 December 2018 and 31 December 2019.

	Year ended 31 December		
(in $/bbl)	**2017**	**2018**	**2019**
Average price for the period	$50.22	$65.33	$56.98
Highest price for the period	$56.09	$72.13	$65.70
Lowest price for the period	$43.23	$56.76	$47.20

Source: FactSet

Pricing Differentials

Gas prices are subject to regionalised benchmarks that are commonly referred to as differentials. The Group sells gas to 20 to 30 price pools, with approximately 95 per cent. of the Group's gas being marketed and sold at prices derived from the Dominion South, TCO, and TETCO M2 price pools. These regionalised benchmarks represent downward adjustments to the Henry Hub benchmark price discussed above and vary depending on market fundamentals in their respective regions. In the normal course of business, the Group attempts to capture the best pricing available in the market, often through the utilisation of its extensive midstream pipeline infrastructure to direct the flow of gas to delivery points with the best pricing.

The table below sets forth the average price differential for natural gas by price pool for the years ended 31 December 2017, 31 December 2018 and 31 December 2019. Historical data is unavailable for TETCO M2 because prior to the HG Energy Assets Acquisition in April 2019, the Group sold an immaterial amount of gas through that price pool.

	Year ended 31 December		
(in $/btu)	**2017**	**2018**	**2019**
TCO	-0.20	-0.22	-0.32
Dominion South	-0.76	-0.52	-0.44
TETCO M2	N/A	N/A	-0.48

Source: FactSet

Natural gas liquids and oil are also subject to pricing differentials; however, due to both the structure of those markets and the nature of Group's operations, the differentials do not operate in the same way they do for gas. Almost all of the Group's natural gas liquids are processed at MarkWest's plant in Langley, Kentucky. As a result, the Group effectively has a single delivery point for its natural gas liquids, and therefore a single key pricing differential, which is the difference between the US Natural Gas Liquid Composite Price and the processing fees charged by MarkWest. For the years ended 31 December 2017, 31 December 2018 and 31 December 2019, the pricing differential for natural gas liquids was approximately $12.00 per barrel on a weighted average basis and ranged between $3.50 and $5.00 per barrel for crude oil during the same period.

Hedging

The Group's proactive approach to hedging provides indirect tangible benefits for its shareholders. These benefits were evident in the year ended 31 December 2019, where hedge gains during the year added approximately $50 million in revenues. Historically, the Group has adopted a conservative hedging program, which covers a portion of gas, natural gas liquids and oil exposures and seeks to protect a significant portion of the Group's underlying production revenues, at the post-tax level, from commodity price fluctuations. Accordingly, the Group has historically entered into both commodity price swaps and certain fixed price marketing agreements to hedge a portion of its commodity price risks. The terms of these hedging transactions are designed to match as closely as practicable the underlying pricing structure of physical sales contracts, and the volume of hedges reflects production uncertainties and the fiscal impact of hedging. These derivative instruments have allowed the Group to reduce, but not eliminate, the variability in cash flow from operations due to fluctuations in commodity prices.

The table below outlines the attributes of the hedge structures used by the Group to protect cash flow:

Hedge Structure	Attributes
Swaps and Physicals	Fixes cash flows and provides no exposure to upside or downside
Collars	Limits downside and provides some upside exposure
Puts	Locks floor for a cost while providing full upside exposure
"Extendables" & "Double-Ups"	Provide an opportunity to pull forward value when the futures price of a commodity is higher than the spot price
Other	Bespoke structures with hedge counterparties that are tailored for the Group's portfolio

For the year ended 31 December 2019, the Group had total financial derivative contracts with a net asset value of $61.8 million, as compared to financial derivative contracts with a net asset value of $39.6 million for the year ended 31 December 2018. For the year ended 31 December 2017, the Company had total financial derivative contracts with a net liability value of ($2.9 million). The following table summarises the Group's calculated fair value of derivative financial instruments.

	Year ended 31 December		
(Amounts in thousands $)	2017	2018	2019
Natural gas			
Swaps	28	4,053	69,242
Collars	311	131	3,882
Basis swaps	(965)	(1,720)	(2,455)
Put options	—	7,292	(24,783)
Total natural gas financial derivative contracts	**(626)**	**9,756**	**45,886**
Natural gas liquids			
Swaps	—	26,208	15,859
Total natural gas liquids financial derivative contracts	**—**	**26,208**	**15,859**
Oil			
Swaps	(56)	676	(323)
Collars	(2,222)	2,929	380
Total oil financial derivative contracts	**(2,278)**	**3,605**	**57**
Total financial derivative contracts	**(2,904)**	**39,569**	**61,802**

As at the date of this Prospectus, the Group has two hedging programs, its Longstanding Hedging Program and its ABS Facility Hedging Program.

Longstanding Hedging Program

As required by its senior secured credit facility, the Group is required to hedge at least 50 per cent. of production for the first 12 months followed by 25 per cent. of production for months 13 to 24 on a rolling quarterly basis. At the end of each quarter, compliance with this policy is tested for the following 24 months. Typically, the Group exceeds these target levels and hedges 75-80 per cent. of production for the first 12 months and 25-50 per cent. of production for the second 12 months, where the Company's hedging is more opportunistic and will depend on the favourability of pricing.

The table below presents a summary of the average downside protection and volume that the Group has secured for gas, natural liquids and oil under its Longstanding Hedging Program.

	NATURAL GAS		NGL		OIL	
Period	**Average Downside Protection**	**Average Volume (MMBtu/day)**	**Average Downside Protection**	**Average Volume (bbls/day)**	**Average Downside Protection**	**Average Volume (bbls/day)**
FY20	$2.70	440,815	$32.71	4,528	$56.38	766
FY21	$2.66	296,738	$33.98	113	$52.65	585
FY22	$2.54	112,247	$—	—	$55.61	99
FY23	$2.52	96,274	$—	—	$—	—
FY24	$2.52	88,087	$—	—	$—	—

ABS Facility Hedging Program

In November 2019, the Group launched its ABS I facility, a securitised financing arrangement that is secured by 21.6 per cent. of the Group's reserves and requires 85 per cent. of production from those reserves to be hedged for ten years (the "**ABS I Facility**"). That hedge was executed at the close of the ABS structure as a price swap financial hedge. To facilitate the arrangement, the Group created a wholly-owned and fully consolidated (for accounting purposes) special purpose vehicle, Diversified ABS LLC, to issue $200 million of non-recourse asset-backed securities, collateralised by working interests, consisting of 21.6 per cent. of the Group's existing upstream proved developed producing asset portfolio. 85 per cent. of the production from Diversified ABS LLC reserve was hedged at a NYMEX price of $2.46 per MMBtu. and the Group will also maintain two rolling years of basis hedges initially swapped at -$0.43 per MMBtu.

In April 2020, the Group completed a second securitised financing arrangement with the launch of its ABS II facility, a securitised financing arrangement that is secured by a further 29.4 per cent. of the Group's reserves and requires at least 85 per cent. of production from those reserves to be hedged for six years (the "**ABS II Facility**"). Similar to the November 2019 structure, the hedge was executed at the close of the ABS structure as a price swap financial hedge. The Group also created a wholly-owned and fully consolidated (for accounting purposes) special purpose vehicle, Diversified ABS Phase II LLC, to issue $200 million of non-recourse asset-backed securities, collateralised by working interests, consisting of 29.4 per cent. of the Group's existing upstream proved developed producing asset portfolio. 85 per cent. of the production from Diversified ABS Phase II LLC reserve was hedged at a NYMEX price of $2.40 per MMBtu. and the Group will also maintain two rolling years of basis hedges initially swapped at -$0.43 per MMBtu.

Finance Costs

In the year ended 31 December 2019, total finance costs increased by $18.8 million or 106.2 per cent., to $36.7 million from $17.7 million in the year ended 31 December 2018. This increase was primarily due to the increased borrowings on the Company's credit facility. In the year ended 31 December 2018, total finance costs increased by $12.5 million or 240.4 per cent., to $17.7 million from $5.2 million in the year ended 31 December 2017. During this period, the Group made four acquisitions for the total consideration of approximately $845 million. The increase in finance costs in this period was primarily due to a 368.0 per cent. increase in interest costs and a 230.4 per cent. increase in bond financing costs.

The table below summarises the Group's finance costs for the years ended 31 December 2017, 2018 and 2019:

	Year Ended 31 December		
(Amounts in thousands $)	**2017**	**2018**	**2019**
Interest	$3,298	$15,433	$32,662
Amortisation of deferred finance cost	1,212	2,230	3,875
Other	715	80	130
Total finance costs	**$5,225**	**$17,743**	**$36,667**
Loss on early retirement of debt	**$4,468**	**$8,358**	**$—**

In H1 2017 the Group repaid its publicly traded bonds and certain other outstanding debt with proceeds from the Group's IPO. Accordingly, it incurred a non-recurring loss on the early extinguishment of debt, which primarily included a $3.3 million charge for the accelerated amortisation of the remaining deferred financing costs. The Group's finance costs include interest expense on borrowings and non-cash amortisation of deferred financing costs. Interest expense on borrowings of $15.4 million in 2018 increased $12.1 million compared to $3.3 million in 2017 primarily due to the increase in borrowings used to fund the Group's previously mentioned acquisitions.

In March 2018, the Group closed a new $500 million five-year credit facility, initially subject to a borrowing limit of $140 million that stepped up within the same month to $200 million following the closing of the acquisition of certain assets of CNX. Entry into this new senior secured revolving credit resulted in a non-recurring loss on early extinguishment of debt of $8.4 million, which primarily included a $2.6 million charge for the accelerated amortisation of the remaining deferred financing costs and $5.8 million related to an early payment fee. In July 2018, and in conjunction with the EQT Asset Acquisition, the Group closed on an enlarged $1 billion, five-year secured revolving credit facility with an initial borrowing base of $600 million, which replaced the existing $500 million facility. In December 2018 and following the October 2018 acquisition of Core, the Group closed on a further-enlarged $1.5 billion, five-year senior secured credit facility with an initial borrowing base of $725 million, and which replaced the $1 billion facility and fully extinguished Core's facility assumed as part of that acquisition. The facility maintained previous pricing but was amended in April 2019 to upsize the borrowing base to $950 million related to the HG Energy Assets Acquisition and reduced the pricing grid to 2.00 per cent to 3.00 per cent based on utilisation. In November 2019, the facility was further amended in relation to the $200 million securitisation agreement reducing the borrowing base to $650 million. The facility maintains the July 2023 maturity date of the replaced facility, and has an initial interest rate of 2.75 per cent. plus the one-month LIBOR and is subject to a grid that fluctuates from 2.25 per cent. to 3.25 per cent. plus LIBOR based on utilisation.

Asset Retirement Obligation

The Group's asset portfolio consists of approximately 60,000 wells and the Group is subject to certain regulatory requirements as to how these wells must be retired, typically through a process referred to as plugging. In addition, during periods where there is a high demand for plugging contractors, the costs of plugging wells can rise. As of the date of this Prospectus, the average cost to plug a well is approximately $22,000 per well.

The Group has developed a strategy to safely and systematically retire wells, supported by long-term agreements with the states of Pennsylvania, Ohio, Kentucky and West Virginia, the four states where the majority of the Group's wells are located. The agreements set forth plugging and abandonment schedules and thus provide visibility on asset retirement costs for most of the Group's wells. Under these agreements, the Group can also receive credits for bringing unproductive wells back into production and the credits can be used to reduce the number of wells the Group must plug in a certain state in a given year. The Group is well-equipped to make use of the plugging credit system due to its Smarter Well Management program that allows the Group to extend well-life and reduce decline rates. In 2019, the Group returned approximately 750 non-producing wells to production. The first full year of the Group's plugging programme was 2018 and for the year ended 31 December 2018, the Group plugged 35 wells. For the year ended 31 December 2019, the Group plugged approximately 100 wells and met each of its plugging obligations for each state. Based on its agreements with the four states, the Group's minimum plugging obligations will require the Group to plug 80 wells per year beginning from 2020. The Group has assumed a plugging rate of approximately 85 to 90 wells per year in these four states.

The Group's plugging agreements with the states of Pennsylvania and West Virginia are for 15 years. The agreements with the state of Kentucky and Ohio are for ten years respectively. The Group records a liability for the future cost of decommissioning production facilities and pipelines. The decommissioning liability represents the present value of decommissioning costs relating to gas and oil properties, which the Group expects to incur over the long producing life of its wells, presently estimated through to 2093 when the Group expects the last of its current producing gas and oil properties to reach the end of their economic lives.

The table below summarises the activity for the Group's decommissioning liability. The discount rate and the cost inflation rate used in the calculation of the decommissioning liability was 5.8 per cent. as at each of the periods presented.

	Year Ended 31 December		
(Amounts in thousands $)	2017	2018	2019
Balance at 1 January	**12,265**	**35,448**	**142,725**
Additions	21,497	96,508	252
Accretion	1,764	7,101	12,349
Disposals	(78)	(1,161)	(2,541)
Revisions to estimate[(a)]	—	4,829	46,736
Balance at 31 December	**35,448**	**142,725**	**199,521**
Less: Current decommissioning provision	—	(2,535)	(2,650)
Long-term decommissioning liability	**35,448**	**140,190**	**196,871**

(a) During the year Management revised the plugging program to more closely align with operations. As a result of this revision, cost inputs and assumptions made surrounding the life of certain wells were amended.

These liabilities represent the Directors' best estimates of the future obligation. Such assumptions are based on the current economic environment, and represent what the Directors believe is a reasonable basis upon which to estimate the future liability. The Directors review these estimates regularly and adjust for any identified material changes to the assumptions. However, actual decommissioning costs will ultimately depend upon future market prices at the time the decommissioning services are performed. Furthermore, the timing of decommissioning will vary depending on when the fields ceases to produce economically, which makes the determination dependent upon future gas and oil prices, which are inherently uncertain. As a result of this uncertainty, the Group's future asset retirement obligations may not conform with estimations. See Part III "*Presentation of financial information—Forward-looking statements*" of this Prospectus.

Income Taxes

For US Federal tax purposes, the Group is taxed as one consolidated entity, which includes its parent company, Diversified Gas & Oil plc. In the US, the Group is subject to corporate tax on its taxable profits at the rate of 21 per cent. for US federal tax and approximately 5 per cent. for state taxes. Diversified Gas & Oil plc is also subject to corporate tax in its home jurisdiction of the United Kingdom at the rate of 19 per cent., however, Diversified Gas & Oil plc's taxation in the United Kingdom does not extend to its US operations.

For the year ended 31 December 2019, the Group had federal net operating loss carryforwards of approximately $207 million. The federal net operating loss carryforwards remaining were generated in tax year ended 31 December 2018 primarily as a result of the new 100 per cent. bonus depreciation rules signed into law with the Tax Cuts and Jobs Acts on 22 December 2017. The federal net operating loss carryforward is limited to 80 per cent. of taxable income each year and does not have an expiration date. The Group currently projects the federal net operating losses to be fully utilised in tax year 2022. Additionally, the Group has state net operating loss carryforwards of approximately $37 million, which expire in the year 2038. The Group currently projects the state net operating losses to be fully utilised in tax year 2020.

As of 31 December 2019, the Group had federal marginal well tax credit carryforwards of approximately $20.7 million which expire in years 2037 to 2039. Marginal well credit carryforwards are limited to 75 per cent. of tax due before credits. The Group currently projects the credits to be fully utilised by tax year 2024.

3. CURRENT TRADING AND PROSPECTS

The US gas market continues to be a challenging environment based on the exceptionally low gas prices, abundant supply and wider disruptions in global economic activity as a result of the COVID-19 pandemic. Nevertheless, the Group is successfully navigating the unprecedented market volatility and general economic uncertainty, thus validating its business model that was defined almost 20 years ago. For the three months ended 31 March 2020, the Group's total net daily production was 94,011 boepd, representing a decrease of less than 1.0 per cent. from the Group's 2019 exit production rate of 94,832 boepd and demonstrating the Group's success at meeting energy demand while still responsibly observing social distancing and navigating other operational challenges presented by the COVID-19 pandemic.

The Group was built to ensure resilience in this kind of economic environment, 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 market backdrop. Operating efficiencies will remain the key priority for the Group in 2020 as it seeks to protect and enhance margins across the business.

The Group continues to execute on 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 Well Management to offset natural production declines. The Group's Smarter Well Management programme continues to yield positive results as the Group is succeeding in maintaining production levels on its conventional assets while seeking to minimise the declines from the Group's unconventional assets.

For the three months ended 31 March 2020, the Group's Adjusted EBITDA was approximately $78 million, largely unchanged from an Adjusted EBITDA of approximately $78 million for the three months ended 31 December 2019.

The Group's board declared an interim dividend of 3.5 cents per share for the three months ended 31 March 2020, unchanged from the dividend declared for the three months ended 31 December 2019. The sustainability of the Group's dividend continues to be supported by an expanded hedge portfolio with approximately 90 per cent. of 2020 production and approximately 90 per cent. of 2021 production hedged at $2.73/MMBtu and $2.59/MMBtu, respectively.

Total cash expenses, consisting of Total Lease Operating Expense and Recurring Administrative Expense, were $6.98/boe for the three months ended 31 March 2020, declining by 1.6 per cent. or 11 cents from $7.09/boe for the three months ended 31 December 2019.

In April 2020, the Group completed a second securitised financing arrangement with the addition of its ABS II Facility. The 8.5-year securitised financing of $200 million at a 5.25 per cent. coupon rate further aligns an incremental portion of the Group's capital structure with the underlying long-life nature of its assets. The entire net proceeds of $183.6 million from the financing were used to reduce the Group's utilisation of its revolving credit facility. The Group's borrowing base on its revolving credit facility is currently $425 million, and the Group expects to complete its semi-annual redetermination process during May 2020.

Despite the challenging market backdrop, the Group remains well-positioned to maintain its steady 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 and operational excellence.

4. INTERACTION WITH THE FRC

In August 2019, the Company engaged in a comment letter-review process with the Conduct Committee of the FRC. As a part of its regular review of periodic reports produced by UK reporting companies, the Company received a letter requesting further information in relation to the annual report and accounts for the year ended 31 December 2018 (the "**2018 Annual Report**"). The letter primarily focussed on:

- accounting for business combinations in respect of gains on bargain purchases and valuation of property, plant and equipment;
- asset retirement obligations in respect of the discount rate applied; and
- reconciliation of derivative movements in the balance of derivatives.

The Company responded to the FRC's questions, providing clarifying information and proposing additional disclosures to the Company's annual report and accounts for the year ended 31 December 2019 (the "**2019 Annual Report**"). On this basis, the FRC subsequently confirmed it had closed its enquiries with a satisfactory conclusion. All disclosures that the Company proposed to the FRC have also been reflected in the 2019 Annual Report.

When reviewing the 2018 Annual Report, the FRC noted the limitations of its review as follows:

- Its review is based on the 2018 Annual Report only and does not benefit from a detailed knowledge of the Company's business or an understanding of the underlying transactions entered into.

- Communication from the FRC provides no assurance that the 2018 Annual Report is correct in all material respects, as their role is not to verify the information included therein but rather to consider compliance with reporting requirements and to stimulate improvements in the quality of corporate reporting, and are made on the basis that the FRC (and its officers, employees and agents) accept no liability for reliance on them by the Company or any third party, including but not limited to investors and shareholders.
- The FRC's role is not to verify the information provided but to consider compliance with reporting requirements.

5. DESCRIPTION OF KEY LINE ITEMS

Revenue

In the period under review, the Group generated revenue from sales of natural gas, natural gas liquids and crude oil products. The Group also generated revenue from gathering and transporting third-party gas on its midstream system.

Operating expense

Operating expense includes lease operating expense (daily operating costs incurred to extract natural gas and oil and to maintain the Group's producing properties), production taxes and gathering and transportation expense (daily costs incurred to gather, process and transport natural gas).

Amortisation, depreciation and depletion

Amortisation, depreciation and depletion are non-cash expenses incurred to align capital expenditures with the passage of time.

Administrative expenses

Administrative expenses primarily consist of employee related costs and professional services.

Gain on oil and gas programme and equipment

Gain on oil and gas programme and equipment is related to the sale of oil and gas properties and other equipment.

Gain/(loss) on derivative financial instruments

Gain/(loss) on derivative financial instruments consists of gains or losses from settled hedges and the mark to market valuation of unsettled hedges. Unsettled hedges are marked to market on a monthly basis with any changes in fair value recognised as a gain or loss on the consolidated statements of profit and loss and other comprehensive income. When hedges settle the Group recognises the net settlement as a gain or loss in the consolidated statements of profit and loss and other comprehensive income.

Gain on bargain purchase

Gains on bargain purchase arise when the fair value of an acquisition exceeds the cash consideration paid for the acquisition.

Finance costs

Finance costs are costs incurred to secure financing and consist primarily of interest expense and amortisation of deferred financing costs.

Loss on early retirement of debt

Losses on early retirements of debt are related to early prepayment penalties and accelerated amortisation of deferred financing costs when the Group elects to pay off debt early.

Accretion of asset retirement obligation

Accretion expense is a periodic expense recognised to align the present value of the asset retirement obligation with the passage of time.

Taxation on income

Taxation on income includes corporate income tax for amounts payable in current periods and deferred tax amounts.

6. RESULTS OF OPERATIONS

Consolidated Statement of Comprehensive Income

	Year ended 31 December		
(Amounts in thousands $)	**2017**	**2018**	**2019**
Revenue	41,777	289,769	462,256
Operating expense	(20,908)	(107,793)	(202,385)
Amortisation, depreciation and depletion	(7,536)	(41,988)	(98,139)
Gross profit	**13,333**	**139,988**	**161,732**
Administrative expenses	(8,919)	(40,524)	(56,619)
Gain/(loss) on oil and gas programme and equipment	95	4,079	—
Gain/(loss) on derivative financial instruments	(441)	17,981	73,854
Gain/(loss) on bargain purchase	37,093	173,473	1,540
Operating profit	**41,161**	**294,997**	**180,507**
Finance costs	(5,225)	(17,743)	(36,667)
(Loss)/gain on early retirement of debt	(4,468)	(8,358)	—
Accretion of asset retirement obligation	(1,764)	(7,101)	(12,349)
Income before taxation	**29,704**	**261,795**	**131,491**
Taxation on income	(2,250)	(60,676)	(32,091)
Income after taxation available to ordinary shareholders	27,454	201,119	99,400
Other comprehensive income – gain on foreign currency conversion	355	1	—
Total comprehensive income for the year	**27,809**	**201,120**	**99,400**
Earnings per ordinary share – basic & diluted	**0.23**	**0.52**	**0.15**
Weighted average ordinary shares outstanding – basic	**120,136**	**386,559**	**633,720**
Weighted average ordinary shares outstanding – diluted	**120,269**	**387,925**	**653,192**

Comparison of the years ended 31 December 2019 and 31 December 2018

(Amounts in thousands $)	Year ended 31 December 2018	2019
Revenue	289,769	462,256
Operating Expense	(107,793)	(202,385)
Amortisation, depreciation and depletion	(41,988)	(98,139)
Gross profit/(loss)	**139,988**	**161,732**
Administrative expenses	(40,524)	(56,619)
Gain/(loss) on gas programme and equipment	4,079	—
Gain/(loss) on derivative financial instruments	17,981	73,854
Gain/(loss) on bargain purchase	173,473	1,540
Operating profit	**294,997**	**180,507**
Finance costs	(17,743)	(36,667)
(Loss)/gain on early retirement of debt	(8,358)	—
Accretion of asset retirement obligation	(7,101)	(12,349)
Income before taxation	**261,795**	**131,491**
Taxation on income	(60,676)	(32,091)
Income after taxation available to ordinary shareholders	201,119	99,400
Other comprehensive income – gain on foreign currency conversion	1	—
Total comprehensive income for the year	**201,120**	**99,400**
Earnings per ordinary share – basic & diluted	**0.52**	**0.15**
Weighted average ordinary shares outstanding – basic	**386,559**	**633,720**
Weighted average ordinary shares outstanding – diluted	**387,925**	**653,192**

Revenue

Revenue increased by $172.5 million, or 59.5 per cent., to $462.3 million in the year ended 31 December 2019 from $289.8 million in the year ended 31 December 2018. The increase was due to 107 per cent. higher production and an increase in midstream revenue, both of which were positively impacted by the Group's acquisitive growth strategy. The Group closed 2019 with net MBOE sales of approximately 30,944 as compared to 14,950 for the year ended 31 December 2018. The increase in production was driven by the full integration of the previously acquired EQT and Core asset in 2H18 and the HG Energy and EdgeMarc Energy assets in 2019.

Operating expense

Operating expense increased by $94.6 million, or 87.8 per cent., to $202.4 million in the year ended 31 December 2019 from $107.8 million in the year ended 31 December 2018. The increase was primarily related to acquired assets in 2018 and 2019. The EQT and Core assets acquired in 2H18 had a full year of expenses during 2019 and the HG Energy and Edgemarc Energy assets were acquired in 2019.

Amortisation, depreciation and depletion

Amortisation, depreciation and depletion increased by $56.2 million, or 133.7 per cent., to $98.1 million in the year ended 31 December 2019 from $42.0 million in the year ended 31 December 2018. The increase was due to an increase in production associated with the EQT, Core, and HG Energy acquisitions.

Gross profit

Gross profit increased by $21.7 million, or 15.5 per cent., to $161.7 million in the year ended 31 December 2019 from $140.0 million in the year ended 31 December 2018. The increase was due to 59.5 per cent. increase in revenue offset by a 50.2 per cent. increase in operating expenses and amortisation, depreciation and depletion related to our acquired properties as discussed above.

Administrative expenses

Administrative expenses increased by $16.1 million, or 39.7 per cent., to $56.6 million in the year ended 31 December 2019 from $40.5 million in the year ended 31 December 2018. The increase was due to the Company's acquisition efforts and the investment made in staff and systems to support the Company's growth.

Gains on oil and gas programme equipment

Gains on oil and gas programme equipment decreased by $4.1 million, or 100.0 per cent., to $nil in the year ended 31 December 2019 from $4.1 million in the year ended 31 December 2018. In 2018, there was a one-time sale of certain oil and gas properties.

Gains on derivative financial instruments

Gains on derivative financial instruments increased by $55.9 million, or 310.7 per cent., to $73.9 million in the year ended 31 December 2019 from $18.0 million in the year ended 31 December 2018. The increase was due to an expanded hedge portfolio and underlying commodity prices.

Gains on bargain purchase

Gains on bargain purchase decreased by $172.0 million, or 99.1 per cent., to $1.5 million in the year ended 31 December 2019 from $173.5 million in the year ended 31 December 2018. The gains on bargain purchase arise as a result of fair value acquisitions being greater than the consideration. In particular, this was driven by a large number of acquisitions at attractive prices due to prevailing market conditions in the Appalachian Basin, global gas and oil prices, the financial condition of the sellers and a change in the operational focus of the sellers compelling these sellers to divest of their conventional oil and gas assets. In 2019, the Company recorded gains on bargain purchase related to its EdgeMarc Energy acquisitions. In 2018, the company recorded gains on bargain purchase related to its APC, CNX, EQT and Core acquisitions.

Operating profit

Operating profit decreased by $114.5 million, or 38.8 per cent., to $180.5 million in the year ended 31 December 2019 from $295.0 million in the year ended 31 December 2018. The decrease was primarily due to the 99.1 per cent. decrease in gains on bargain purchase offset by 310.7 per cent. increase in gains on derivative financial instruments as discussed above.

Finance costs

Finance costs increased by $18.9 million, or 106.7 per cent., to $36.7 million in the year ended 31 December 2019 from $17.7 million in the year ended 31 December 2018. The increase was primarily due to the increase in borrowings to fund the Company's acquisition efforts during 2019.

Loss on early retirement of debt

Loss on early retirement of debt decreased by $8.4 million, or 100 per cent., to $nil in the year ended 31 December 2019 from $8.4 million in the year ended 31 December 2018. The 2018 loss on early retirement of debt was related to the early termination fee and accelerated amortisation of deferred financing costs associated with the Company's move from Angelo Gordon to Key Bank. This is a non-recurring item and was not relevant in 2019.

Accretion of asset retirement obligation

Accretion of asset retirement obligation increased by $5.2 million, or 73.9 per cent., to $12.3 million in the year ended 31 December 2019 from $7.1 million in the year ended 31 December 2018. The increase was primarily due to the increase in the asset retirement obligation as a result of adding additional obligations on its acquired assets. The EQT and Core assets acquired in 2H18 had a full year of accretion expneses during 2019 and the HG Energy and Edgemarc Energy assets were acquired in 2019.

Income before taxation

Income before taxation decreased by $130.3 million, or 49.8 per cent., to $131.5 million in the year ended 31 December 2019 from $261.8 million in the year ended 31 December 2018. The decrease was due to the 38.8 per cent. decrease in operating profit, the 106.7 per cent. increase in finance costs and the 73.9 per cent. increase in accretion expense as discussed above.

Taxation on income

Taxation on income decreased by $28.6 million, or 47.1 per cent., to $32.1 million in the year ended 31 December 2019 from $60.7 million in the year ended 31 December 2018. The decrease was due to the decrease to income before taxation as discussed above.

Income after taxation available to ordinary shareholders

Income after taxation available to ordinary shareholders decreased by $101.7 million, or 50.6 per cent., to $99.4 million in the year ended 31 December 2019 from $201.1 million in the year ended 31 December 2018. The decrease was due to the 49.7 per cent. decrease in income before taxation offset by the 46.1 per cent. decrease in taxation as discussed above.

Gains on foreign currency conversion

Gains on foreign currency conversion decreased by $1,000, or 100 per cent., to $nil in the year ended 31 December 2019 from $1,000 in the year ended 31 December 2018. This decrease was due to timing of transactions and year over year changes in the conversion rate.

Total comprehensive income for the year

Total comprehensive income for the year decreased by $101.7 million, or 50.6 per cent., to $99.4 million in the year ended 31 December 2019 from $201.1 million in the year ended 31 December 2018.

Comparison of the years ended 31 December 2018 and 31 December 2017

	Year ended 31 December	
(Amounts in thousands $)	2017	2018
Revenue	41,777	289,769
Operating Expense	(20,908)	(107,793)
Amortisation, depreciation and depletion	(7,536)	(41,988)
Gross profit/(loss)	**13,333**	**139,988**
Administrative expenses	(8,919)	(40,524)
Gain/(loss) on gas programme and equipment	95	4,079
Gain/(loss) on derivative financial instruments	(441)	17,981
Gain/(loss) on bargain purchase	37,093	173,473
Operating profit	**41,161**	**294,997**
Finance costs	(5,225)	(17,743)
(Loss)/gain on early retirement of debt	(4,468)	(8,358)
Accretion of asset retirement obligation	(1,764)	(7,101)
Income before taxation	**29,704**	**261,795**
Taxation on income	(2,250)	(60,676)
Income after taxation available to ordinary shareholders	27,454	201,119
Other comprehensive income – gain on foreign currency conversion	355	1
Total comprehensive income for the year	**27,809**	**201,120**
Earnings per ordinary share – basic & diluted	**0.23**	**0.52**
Weighted average ordinary shares outstanding – basic	**120,136**	**386,559**
Weighted average ordinary shares outstanding – diluted	**120,269**	**387,925**

Revenue

Revenue increased by $248.0 million, or 593.3 per cent., to $289.8 million in the year ended 31 December 2018 from $41.8 million in the year ended 31 December 2017. The increase in revenue was primarily attributable to a 523.0 per cent. increase in produced volumes sold on a barrel of oil equivalent basis compounded by a 13.7 per cent. increase in the average realised sales price. In the year ended 2018, the Group realised net MBOE sales of approximately 14,950 compared to net MBOE sales in the same period in 2017 of approximately 2,400. Production increases, were driven primarily by the acquisition of additional producing wells from Alliance Petroleum and CNX in March 2018, from EQT in July 2018, and Core in October 2018.

Operating expense

Operating expense increased by $86.9 million, or 415.8 per cent., to $107.8 million in the year ended 31 December 2018 from $20.9 million in the year ended 31 December 2017. The increase was due to additional expenses related to newly acquired oil and gas properties from Alliance Petroleum, CNX, EQT and Core during 2018 and from the Titan acquisition in H2 2017. On a per boe basis, operating expense decreased in the same period by 17 per cent. which was attributable to higher production volumes received from an increased number of producing wells from these acquired properties.

Amortisation, depreciation and depletion

Amortisation, depreciation and depletion increased by $34.5 million, or 460.0 per cent., to $42.0 million in the year ended 31 December 2018 from $7.5 million in the year ended 31 December 2017. The increase was due to an increased depreciable base related to oil and gas properties and higher production volumes as a result of the Alliance Petroleum, CNX, EQT, Core and Titan acquisitions.

Gross profit

Gross profit increased by $126.7 million, or 952.6 per cent., to $140.0 million in the year ended 31 December 2018 from $13.3 million in the year ended 31 December 2017. The increase was due to the Group's acquisitions as discussed above and its success in integrating and achieving economies of scale from the acquisitions. The continuing concentration of the Group's assets in the Appalachian Basin has allowed it to run highly efficient operations where employees are able to service a large number of assets in a way that reduces operating expenditures, thus improving profitability.

Administrative expenses

Administrative expenses increased by $31.5 million, or 350.0 per cent., to $40.5 million in the year ended 31 December 2018 from $9.0 million in the year ended 31 December 2017. The increase was due to costs of the Group's acquisitions in 2018 and the investment made in staff and systems to support the Group's growth.

Gains on oil and gas programme equipment

Gains on oil and gas programme equipment increased by $4.0 million, or 4,000.0 per cent., to $4.1 million in the year ended 31 December 2018 from $0.1 million in the year ended 31 December 2017. The increase was due to a one-time sale of certain oil and gas properties.

Gains (losses) on derivative financial instruments

Gains on derivative financial instruments changed to a gain of $18.0 million in the year ended 31 December 2018 from a loss of $0.4 million in the year ended 31 December 2017. The change was due to the enlarged hedging portfolio as a result of the Group's acquisitions further discussed above.

Gains on bargain purchase

Gains on bargain purchase increased by $136.4 million, or 367.7 per cent., to $173.5 million in the year ended 31 December 2018 from $37.1 million in the year ended 31 December 2017, as a result of fair value acquisitions being greater than the consideration. In particular, this was driven by a large number of acquisitions at attractive prices due to prevailing market conditions in the Appalachian Basin, the context of global gas and oil prices, the financial condition of the sellers and a change in the operational focus of the sellers compelling these sellers to divest of their conventional oil and gas assets. In 2018, the Company recorded gains on bargain purchase related to its APC, CNX, EQT and Core acquisitions.

Operating profit

Operating profit increased by $253.8 million, or 616.0 per cent., to $295.0 million in the year ended 31 December 2018 from $41.2 million in the year ended 31 December 2017. The increase was due to the factors discussed above.

Finance costs

Finance costs increased by $12.5 million, or 239.6 per cent., to $17.7 million in the year ended 31 December 2018 from $5.2 million in the year ended 31 December 2017. The increase was primarily due to a $11.7 million rise in interest expense on borrowings, driven by greater borrowing to finance the Group's acquisitions.

Loss on early retirement of debt

Losses on early retirement of debt increased by $3.9 million, or 86.7 per cent., to $8.4 million in the year ended 31 December 2018 from $4.5 million in the year ended 31 December 2017. The increase was due a one-time early payment penalty and acceleration of deferred financing costs related to the retirement of previously outstanding debt.

Accretion of asset retirement obligation

Accretion of asset retirement obligation increased by $5.3 million, or 294.4 per cent., to $7.1 million in the year ended 31 December 2018 from $1.8 million in the year ended 31 December 2017. The increase was due to the corresponding increase in the asset retirement obligation which was driven by the Group's acquisitions discussed in Section 2.2.

Income before taxation

Income before taxation increased by $232.1 million, or 781.5 per cent., to $261.8 million in the year ended 31 December 2018 from $29.7 million in the year ended 31 December 2017. The increase was primarily due to the Group's acquisitions described above.

Taxation on income

Taxation on income increased by $58.4 million, or 2,539.1 per cent., to $60.7 million in the year ended 31 December 2018 from $2.3 million in the year ended 31 December 2017. The increase was primarily due to the Group's increased profits as a result of the acquisitions discussed above. Of this increase, only $2.9 million was related to current taxes with the remainder being deferred into future tax periods.

Income after taxation available to ordinary shareholders

Income after taxation available to ordinary shareholders increased by $173.6 million, or 631.3 per cent., to $201.1 million in the year ended 31 December 2018 from $27.5 million in the year ended 31 December 2017. The increase was primarily due to the Group's acquisitions discussed above.

Gains on foreign currency conversion

Gains on foreign currency conversion decreased by $0.4 million, or 99.7 per cent., to $1,000 in the year ended 31 December 2018 from $0.4 million in the year ended 31 December 2017. The decrease was due to the change in conversion rate between the US dollar and Pound Sterling.

Total comprehensive income for the year

Total comprehensive income for the year increased by $173.3 million, or 623.4 per cent., to $201.1 million in the year ended 31 December 2018 from $27.8 million in the year ended 31 December 2017. The increase was due to the Group's acquisitions discussed above and the gain on bargain purchase discussed above.

7. LIQUIDITY AND CAPITAL RESOURCES

Overview

The Group's principal sources of liquidity have historically been cash generated from operating activities and, to the extent necessary, commitments available under its credit facilities. The Group's principal funding arrangements are described below under the paragraph entitled "*Borrowings*" in this Section 6.

The Group monitors its working capital to ensure that the levels remain adequate to operate the business. In addition to working capital management, the Group has a disciplined approach to allocating capital resources by focusing on flexible assets, capital modification and re-use when and where appropriate and managing its fixed costs, all of which support overall cash flow generation in its business operations.

The Group manages commodity pricing risk through hedging. The Group operates under a board-approved hedging policy. Further, the Group monitors interest rate exposure, but has strategically decided not to lock in its floating rate on the revolving bank facility. The recent ABS securitisation financings eliminated some of this exposure by locking in a 5 per cent. fixed rate on $200 million and a 5.25 per cent. fixed rate on an additional $200 million. The Group's current floating rate on the revolving bank facility is less than 4.5 per cent.

Liquidity/funding is managed through the Group's revolving bank facility. The Group utilises the swing line borrowing option for most day-to-day cash needs (swing line offers on-demand, same-day borrowing with a $25 million limit). The swing line balance is typically paid off on a monthly basis using operating cash flows or, if needed, rolled into a typical LIBOR loan. The Group strategically manages the overall revolver balance to ensure adequate liquidity exists for operations.

Cash Flow

The following table sets forth consolidated cash flow information for the years ended December 31, 2017, 2018 and 2019.

(Amounts in thousands $)	Year ended 31 December 2017	2018	2019
Cash flows from operating activities			
Income after taxation	27,454	201,119	99,400
Cash flow from operations reconciliation:			
Amortisation, depreciation and depletion	7,536	41,988	98,139
Accretion of asset retirement obligation	1,764	7,101	12,349
Income tax charge	2,250	60,676	32,091
Provision for working interest owners receivable	632	—	—
Loss/(gain) on derivative financial instruments	1,965	(32,768)	(20,270)
Asset retirement (plugging)	(78)	(1,171)	(2,541)
Gain on oil and gas program and equipment	(396)	(4,079)	—
Gain on bargain purchase	(37,093)	(173,473)	(1,540)
Finance costs	4,510	17,743	36,677
Loss on early retirement of debt	—	8,358	—
Gain on disposal of property and equipment	95	—	—
Non-cash equity compensation	59	783	3,065
Working capital adjustments:			
Change in trade receivables	(11,464)	(41,225)	4,528
Change in other current assets	798	(6,286)	2,606
Change in other assets	(38)	(1,732)	409
Change in trade and other payables	(2,495)	1,134	7,669
Change in other current and non-current liabilities	11,345	8,396	6,574
Net cash provided by operating activities	**6,844**	**86,564**	**279,156**
Cash flows from investing activities			
Acquisitions	(89,785)	(750,256)	(439,272)
Expenditures on oil and gas properties, intangible assets and property and equipment	(2,935)	(18,515)	(32,313)
Increase in restricted cash	(627)	(986)	(5,302)
Proceeds on disposal of oil and gas properties	334	4,079	10,000
Net cash used in investing activities	**(93,013)**	**(765,678)**	**466,887**
Cash flows from financing activities			
Repayment of borrowings	(42,514)	(280,890)	(618,010)
Proceeds from borrowings	75,000	581,221	765,236
Financing expense	(3,298)	(15,433)	(32,715)
Cost incurred to secure financing	—	(17,176)	(11,574)
Proceeds from capital lease	1,246	4,401	—
Repayment of capital lease	(529)	(1,093)	(1,724)
Proceeds from equity issuance, net	76,984	425,601	221,860
Dividends to shareholders	(5,776)	(31,313)	(82,151)
Repurchase of shares	—	—	(52,902)
Net cash provided by financing activities	**101,113**	**665,318**	**188,020**
Net (decrease) increase in cash and cash equivalents	14,944	(13,796)	289
Cash and cash equivalents – beginning of the period	224	15,168	1,372
Cash and cash equivalents – end of the period	**15,168**	**1,372**	**1,661**

Net cash provided by operating activities

Net cash provided by operating activities increased by $192.6 million, or 222.5 per cent., to $279.2 million in the year ended 31 December 2019 from $86.6 million in the year ended 31 December 2018. This increase was primarily due to the $127 million increase in Adjusted EBITDA (hedged) and a $61.4 million increase to changes in working capital.

Net cash provided by operating activities increased by $79.8 million, or 1,173.5 per cent., to $86.6 million in the year ended 31 December 2018 from $6.8 million in the year ended 31 December 2017. The increase was due to increased production related to the Group's acquisitions discussed above.

Net cash used in investing activities

Net cash used in investing activities decreased by $298.8 million, or 39.0 per cent., to $466.9 million in the year ended 31 December 2019 from $765.7 million in the year ended 31 December 2018. The decrease was a result of less acquisition activity in 2019, during which the Company made only two substantial acquisitions as compared to four in the prior year.

As stated below, the Company made four substantial acquisitions in the prior year and only two in 2019 (HG and EdgeMarc Energy).

Net cash used in investing activities increased by $672.7 million, or 723.3 per cent., to $765.7 million in the year ended 31 December 2018 from $93.0 million in the year ended 31 December 2017. The increase was due to the increased investment in acquisitions discussed above.

Net cash provided by financing activities

Net cash provided by financing activities decreased by $477.3 million, or 71.7 per cent., to $188.0 million in the year ended 31 December 2019 from $665.3 million in the year ended 31 December 2018. The decrease was due to less acquisition activity in 2019.

Net cash provided by financing activities increased by $564.2 million, or 558.1 per cent., to $665.3 million in the year ended 31 December 2018 from $101.1 million in the year ended 31 December 2017. The increase was due to increased borrowing to support the Group's acquisition efforts discussed above.

Capital Resources

Borrowings

	Year ended 31 December		
(Amounts in thousands $)	**2017**	**2018**	**2019**
8.50% unsecured individual and investor bonds due June 2020	81	86	—
Financial institution (2.00% plus LIBOR (2019) and 2.25% plus LIBOR (2018))	73,249	495,284	436,700
ABS Facility (5.00% securitised note)	—	—	200,000
Miscellaneous (real estate, vehicles and equipment)	495	2,537	8,219
Total Borrowings	**73,825**	**497,907**	**644,919**
Less: Current portion of long-term debt	(373)	(286)	(23,510)
Less: Deferred financing costs	(2,833)	(15,093)	(22,631)
Total non-current borrowings, net	**70,619**	**482,527**	**598,778**

Total borrowings increased by $147.0 million or 29.5 per cent., to $644.9 million in the year ended 31 December 2019 from $497.9 million in the year ended 31 December 2018. This was primarily due to the Group entering into its $200.0 million ABS Facility (defined below) and a vehicle fleet financing agreement for $7.7 million with an implied interest rate of 2.0 per cent.

Total borrowings increased by $424.1 million or 574.4 per cent. to $497.9 million for the year ended 31 December 2018 from $73.8 million for the year ended 31 December 2017. The increase in borrowings was primarily to finance the Company's acquisitions in 2018.

The Group's existing $1.5 billion, senior secured credit facility was amended in April 2019 to decrease the borrowing base to $950 million and reduce the one-month LIBOR pricing grid to 2.00 per cent. to 3.00 per cent. plus LIBOR based on utilisation. In November 2019, the $950 million borrowing base was reduced to $650 million following the closing of the Group's asset-backed securitisation financing arrangement. The current facility maintains the July 2023 maturity date.

In November 2019, the Group closed its inaugural BBB- investment grade-rated securitised financing arrangement with a coupon of 5 per cent. (the "**ABS I Facility Notes**"). The ABS I Facility Notes, rated by both Fitch and Morningstar, have a 10-year scheduled maturity, though provide for a longer, 17-year final legal maturity. To facilitate the ABS I Facility, the Group created a wholly-owned and fully consolidated (for accounting purposes) special purpose vehicle, Diversified ABS LLC ("**DABS I**"), to issue $200 million (approximately $190 million net) of non-recourse asset-backed securities, collateralised by a 21.6 per cent. working interest in the Group's existing upstream proved developed producing asset portfolio (the "**DABS I Collateral**").

In April 2020, the Group closed a BBB investment grade-rated securitised financing arrangement with a coupon of 5.25 per cent. (the "**ABS II Facility Notes**" and together with the ABS II Facility Notes, the "**Notes**"). The ABS II Facility Notes, rated by both Fitch and Morningstar, have a 8.5 year scheduled maturity, though provide for a longer, 17-year final legal maturity. Similar to the ABS I Facility, the Group created a wholly-owned and fully consolidated (for accounting purposes) special purpose vehicle, Diversified ABS Phase II LLC ("**DABS II**" and together with DABS I, the "**LLCs**"), to issue $200 million (approximately $190 million net) of non-recourse asset-backed securities, collateralised by a 29.4 per cent. working interest in the Group's existing upstream proved developed producing asset portfolio (the "**DABS II Collateral**") and together with the DABS I Collateral, the "**Collateral**").

The Notes allow the Group to retain 100 per cent. ownership and operational control of the Collateral, and the Collateral excludes the Group's midstream assets and its most recently acquired upstream EdgeMarc Energy assets due to the timing of the closure of the EdgeMarc Energy Acquisition. The financing structure is ideally suited for long-tenor hedges that protect its cash flows from commodity price volatility. The Notes provide a superior present value of estimated future revenues advance rate compared to the Group's existing revolving credit facility. These structures related to the Notes also protect the Group's liquidity with no semi-annual borrowing base redeterminations and provides for flexible and limited financial covenants tied only to the performance of the securitised assets.

After establishing a required reserve account of approximately $7 million for each of the ABS I Facility Notes and the ABS II Facility Notes, the Group used the net proceeds from the ABS I Facility Notes to reduce its borrowings on its KeyBank Facility by approximately $183 million and the net proceeds from the ABS II Facility to reduce its borrowings on its KeyBank Facility by approximately $184 million. Going forward, the Group will use the hedge-protected cash flows generated by the LLCs' working interests to satisfy the payment of principal and interest on the Notes, with any excess cash flows distributed upstream to the parent on a monthly basis and available to further pay down the KeyBank Facility. The Notes structure places no covenants on the parent company and places no restrictions on any cash flow distributed from the LLCs to the parent company so long as the LLCs remain in covenant compliance. The Group has the ability, if desired, to upsize the borrowings under the Notes in the future with the same high-quality, private investor base and at the same attractive fixed rate by increasing the working interest share of upstream assets allocated to the LLCs.

For more information on the Group's borrowings, please see section 12.1 "*Diversified ABS LLC Agreement*" and 12.2 "*Diversified ABS Phase II LLC Agreement*" and 12.3 "*KeyBank Facility and Amended Keybank Facility Agreement*" of Part XVI "*Additional Information*" of this Prospectus.

Capital Expenditure

The Group's primary capital expenditures are related to the acquisitions discussed above. Given the Group's operational focus is to acquire and operate conventional wells with a shallow decline rate, the Group does not incur large capital expenditures associated with drilling that would typically be incurred by other E&P Companies. Further, the Group's capital expenditures are primarily associated with the maintenance of its gas and oil properties and its midstream system.

The table below provides a summary of the Group's capital expenditures:

(Amounts in thousands $)	Year Ended 31 December		
	2017	2018	2019
Acquisitions	$89,785	$750,256	$439,272
Operating capital expenditures	$2,935	$18,515	$32,313
Non-recurring capital expenditures	$—	$ 7	$15,000
Total	**$92,720**	**$768,778**	**$486,585**

In the table above, "Acquisitions" relates to the capital expenditures incurred to acquire the targeted gas and oil assets. "Operating capital expenditures" relates to expenses incurred to maintain and operate the Company's gas and oil properties, midstream system and other business functions. These costs include costs incurred to extend the life of the Company's wells, pipeline and compression repairs and replacements and other costs to operate the business. "Plugging capital expenditures" relates to costs incurred in order to restore a non-producing wellbore back to its original environmental state. "Non-recurring capital expenditures" relates to cost incurred on capital projects that are outside the Company's normal course of business. During 2019 the Company incurred $15 million in non-recurring capital expenditures related to the implementation of a network of accounting, production, land and measurement systems into a single data platform.

8. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS

For a description of the Directors' management of market, interest rate, commodity price, credit, cash and cash equivalents, trade receivables, liquidity, capital and collateral risks, see Note 25 "*Financial risk management*" to the Group Financial Information set out in Section B: "*Historical Financial Information of the Group*" of Part XIV "*Historical Financial Information*" of this Prospectus.

9. CRITICAL ACCOUNTING ESTIMATES AND JUDGMENTS AND RECENT ACCOUNTING PRONOUNCEMENTS

For a full description of the Group's critical accounting estimates and judgments and key sources of estimation uncertainty, see Note 4 "*Significant accounting judgements, estimates and assumptions*" to the Group Financial Information set out in Section B: "*Historical Financial Information of the Group*" of Part XIV "*Historical Financial Information*" of this Prospectus.

PART XII

OPERATING AND FINANCIAL REVIEW OF ALLIANCE PETROLEUM

The following discussion of Alliance Petroleum's financial condition and results of operations should be read in conjunction with the Sections entitled "*Presentation of Information*" and Part XIV "*Historical Financial Information*" of this Prospectus. This discussion contains forward-looking statements that reflect the current view of the Directors and involve risks and uncertainties. Alliance Petroleum's actual results could differ materially from those contained in any forward-looking statements as a result of factors discussed below and elsewhere in this Prospectus, particularly the risk factors discussed in Part II "*Risk Factors*" of this Prospectus. Certain regulatory and industry issues also affect Alliance Petroleum's results of operations and are described in Part VII "*Business*" and Part VII "*Industry Overview*" of this Prospectus.

The financial information in this Part XI "*Operating and Financial Review of Alliance Petroleum*" has been extracted or derived without adjustment from the Alliance Petroleum Financial Information contained in Section D "*Historical Financial Information of Alliance Petroleum*" of Part XIV "*Historical Financial Information*" of this Prospectus, save where otherwise stated.

1. OVERVIEW

In March 2018, the Group acquired a 100 per cent. ownership interest in Alliance Petroleum including approximately 13,000 gas and oil wells and PDP reserves of 49 MMboe in Pennsylvania, West Virginia and Ohio for a purchase price of $95.0 million. At the time of acquisition, Alliance Petroleum's product mix was 98.8 per cent. natural gas and 1.2 per cent. oil. For the year ended 31 December 2018, Alliance Petroleum's total operating expense was $20.2 million and $23.1 million for the year ended 31 December 2019. The acquisition of Alliance Petroleum increased the Group's total production to 19,940 boepd.

2. DESCRIPTION OF KEY LINE ITEMS

Revenue

In the period under review, the Group generated revenue from sales of natural gas, natural gas liquids and crude oil products.

Operating expense

Operating expense includes lease operating expense (daily operating costs incurred to extract natural gas and oil and to maintain the Group's producing properties), production taxes and gathering and transportation expense (daily costs incurred to gather, process and transport natural gas).

Depreciation and depletion

Depreciation and depletion are non-cash expenses incurred to align capital expenditures with the passage of time.

Administrative expenses

Administrative expenses primarily consist of employee related costs and professional services.

Gain/(loss) on derivative financial instruments

Gain/(loss) on derivative financial instruments consists of gains or losses from settled hedges and the mark to market valuation of unsettled hedges. Unsettled hedges are marked to market on a monthly basis with any changes in fair value recognised as a gain or loss on the consolidated statements of profit and loss and other comprehensive income. When hedges settle the Group recognises the net settlement as a gain or loss in the consolidated statements of profit and loss and other comprehensive income.

Gain on bargain purchase

Gain on bargain purchase represents the difference between the fair value of assets acquired and the actual consideration paid.

Finance costs

Finance costs are costs incurred to secure financing and consist primarily of interest expense and amortisation of deferred financing costs.

3. RESULTS OF OPERATIONS

The table below presents the statements of comprehensive income of Alliance Petroleum for the year ended 31 December 2017 and the two-month period ended 28 February 2018.

	Year ended 31 December	2-months ended 28 February
(Amounts in thousands $)	2017	2018
Revenue	45,946	8,516
Cost of sales	(26,928)	(5,136)
Depletion	(2,901)	(754)
Depreciation and depletion	(80)	(19)
Gross profit	**16,037**	**2,607**
Gain on derivative financial instruments	9,201	1,927
Gain on bargain purchase	21,421	-
Gain on disposal of assets	1,522	82
Administrative expenses	(7,009)	(994)
Operating profit	**41,172**	**3,622**
Finance costs	(1,476)	(210)
Income before taxation	**39,696**	**3,412**
Taxation on income	(10,711)	(268)
Total comprehensive income for the year/period	**28,985**	**3,144**
Earnings per ordinary share – basic and diluted	$289,850	$31,440

Revenue

Revenue was $45.9 million in the year ended 31 December 2017, primarily related to oil and gas sales. During 2017, Alliance Petroleum's oil and gas production was 32 Mbbls and 15,983 MMcf, respectively. The average realised price was $2.73 per mcfe.

Revenue was $8.5 million for the two months ended 28 February 2018 and primarily related to oil and gas sales. For the two months ended 28 February 2018, Alliance Petroleum's oil and gas production was 5 Mbbls and 3,032 MMcf, respectively. The average realised price was $2.62 per mcfe.

Cost of sales

Cost of sales was $26.9 million, or $1.45 per mcfe, in the year ended 31 December 2017 and $5.1 million, or $1.26 per mcfe, for the two months ended 28 February 2018. Cost of sales reflect daily operating costs incurred to extract oil and natural gas and to maintain producing properties. Such costs include maintenance cost, repairs, insurance, employee and benefit costs, automobile expenses, transportation expense on oil and gas production, and production taxes.

Depreciation, depletion and accretion

Alliance Petroleum depreciates other property and equipment using the straight-line method over their estimated useful lives. Alliance Petroleum depletes its oil and gas properties on a unit-of-production basis over the proved reserves. Alliance Petroleum records accretion of decommissioning liability on the present value of its estimated decommissioning liability.

Depreciation, depletion and accretion was $4.9 million in the year ended 31 December 2017, of which $1.5 million related to accretion of the decommissioning liability, $2.9 million related to depletion and $0.5 million related to depreciation.

Depreciation, depletion and accretion was $1.0 million for the two months ended 28 February 2018, of which $0.1 million related to accretion of the decommissioning liability, $0.8 million related to depletion and $0.1 million related to depreciation.

Gross profit

Gross profit was $16.0 million in the year ended 31 December 2017 and $2.6 million for the two months ended 28 February 2018.

Gain on derivative financial instruments

Gain on derivative financial instruments was $9.2 million in the year ended 31 December 2017 and $1.9 million for the two months ended 28 February 2018. Alliance Petroleum utilises derivative financial instruments to reduce exposure to fluctuations in commodity prices. This amount represents gains and losses on settlements of derivative contracts for positions that have settled within the period.

Gain on bargain purchase

Gain on bargain purchase was $21.4 million in the year ended 31 December 2017. The gain arose on the purchase of various assets from XTO Energy Inc, which were fair valued at $27.7 million. Consideration paid for the assets was $6.3 million, giving rise to a gain on bargain purchase of $21.4 million.

No gain on bargain purchase was recorded in the two months ended 28 February 2018.

Gain on disposal of oil and gas properties

Gain on disposal of oil and gas properties was $1.5 million in the year ended 31 December 2017. The gain arose on the disposal of 127 non-operating wells to US Energy Inc.

Gain on disposal of property and equipment was $82 thousand for the two months ended 28 February 2018. The gain arose on the disposal of sundry plant and equipment.

Administrative expenses

Administrative expenses were $7.0 million in the year ended 31 December 2017. Administrative expenses include accretion expense of $1.5 million, payroll and benefits for corporate staff, costs of maintaining corporate facilities, costs of managing production, franchise taxes, fees for audit and other professional services, and legal compliance.

Administrative expenses were $1.0 million the two months ended 28 February 2018. Administrative expenses include accretion expense of $0.1 million, payroll and benefits for corporate staff, costs of maintaining corporate facilities, costs of managing production, franchise taxes, fees for audit and other professional services, and legal compliance.

Operating profit

Operating profit was $41.1 million in the year ended 31 December 2017 and $3.6 million for the two months ended 28 February 2018.

Finance costs

Finance costs were $1.5 million in the year ended 31 December 2017 and $0.2 million for the two months ended 28 February 2018. Alliance Petroleum incurred interest expense on its line of credit with Crossfirst Bank with an interest rate at 5.0 per cent.

Income before taxation

Income before taxation was $39.7 million in the year ended 31 December 2017 and $3.4 million for the two months ended 28 February 2018.

Taxation on income

Taxation on income was $10.7 million in the year ended 31 December 2017 and $3.1 million for the two months ended 28 February 2018.

Total comprehensive income for the year/period

Income after taxation was $29.0 million in the year ended 31 December 2017 and $3.1 million for the two months ended 28 February 2018.

4. LIQUIDITY AND CAPITAL RESOURCES

Cash Flow

The table below presents the consolidated statements of cash flows of Alliance Petroleum for the year ended 31 December 2017 and the two-month period ended 28 February 2018.

(Amounts in thousands $)	**Year ended 31 December 2017**	**2-months ended 28 February 2018**
Cash flows from operating activities		
Income after taxation	28,985	3,144
Cash flow from operations reconciliation:		
Depletion of oil and gas properties	2,901	754
Depreciation of property, plant and equipment	523	118
Accretion of asset retirement obligation	1,474	150
Unrealised gain on derivative financial instruments	(3,690)	(1,927)
Gain on bargain purchase	(21,421)	—
Gain on disposal of oil and gas properties	(1,522)	(82)
Finance costs	1,476	210
Working capital adjustments:		
Change in inventories	27	—
Change in trade receivables	(6,089)	(2,392)
Change in other current assets	(127)	179
Change in trade payables	234	2,002
Change in other current liabilities	14,163	(632)
Change in other non-current liabilities	(46)	77
Net cash from operating activities	16,888	1,251
Cash flows from investing activities		
Purchase of property, plant and equipment	(553)	(25)
Proceeds from the sale of property, plant and equipment	—	82
Purchase of oil and gas properties	(5,075)	(39)
Proceeds from the sale of oil and gas properties	1,522	—
Net cash (used in)/from investing activities	**(4,106)**	**18**
Cash flows from financing activities		
Repayment of borrowings	(6,170)	(282)
Dividends to shareholders	(1,049)	—
Interest paid	(1,476)	(210)
Net cash used in financing activities	**(7,219)**	**(282)**
Net increase in cash and cash equivalents	**4,087**	**777**
Cash and cash equivalents – beginning of the period	3,774	7,861
Cash and cash equivalents – end of the period	**7,861**	**8,638**

Net cash from operating activities

Net cash from operating activities was $16.9 million in the year ended 31 December 2017 and $1.3 million for the two months ended 28 February 2018. These cash inflows were due to the profitable nature of Alliance Petroleum's oil and gas business, which focused on the low cost production of oil and gas from its portfolio of producing wells.

Net cash (used in)/from investing activities

Net cash used in investing activities was $4.1 million in the year ended 31 December 2017. During the year, Alliance Petroleum acquired $27.7 million of shallow formation assets from XTO Energy Inc for consideration of $6.3 million, of which $5.2 million was paid in cash during the year.

Additionally, Alliance Petroleum acquired:

- 14 wells in West Virginia from Arsenal Resources LLC;
- 25 wells in Ohio from Carrizo Oil & Gas, Inc;
- 27 wells in West Virginia from CNX Gas Company LLC; and
- 10 wells in Ohio from G&O Resources Limited.

Aggregate consideration for the above acquisitions was $0.5 million, paid in cash.

During the year ended 31 December 2017, Alliance Petroleum sold 127 non-operating wells to US Energy Inc. for cash consideration of $1.5 million.

During the year ended 31 December 2017, Alliance Petroleum purchased $553,000 of property, plant and equipment in cash.

Net cash from investing activities was $18,000 for the two months ended 28 February 2018, comprising $39,000 of oil and gas property purchases, $25,000 of property, plant and equipment purchases and the receipt of $82,000 from the sale of property, plant and equipment.

Net cash used in financing activities

Net cash used in financing activities was $8.7 million in the year ended 31 December 2017. During 2017, Alliance Petroleum made net payments of $7.7 million on its line of credit with Crossfirst Bank and other borrowing facilities. In addition, the Company paid dividends of $1.0 million.

Net cash used in financing activities was $0.5 million for the two months ended 28 February 2018, which primarily reflected net payments of $0.5 million on its line of credit with Crossfirst Bank.

PART XIII

CAPITALISATION AND INDEBTEDNESS

This section should be read in combination with Section B "*Historical financial information of the Group*" of Part XIV "*Historical Financial information*" of this Prospectus.

Capitalisation

The table below sets out the capitalisation of the Group as at 31 December 2019, as extracted from the audited financial information set out in Section B "*Historical financial information of the Group*" of Part XIV "*Historical financial information*" of this Prospectus:

	Audited As at 31 December 2019 $'000
Shareholders' equity[1]	
Share capital	8,800
Share premium	760,543
Merger reserve	(478)
Capital redemption reserve	518
Share-based payment reserve	3,907
Total capitalisation	**773,290**

[1] *Shareholders' equity does not include the retained earnings reserve.*

Save for the proposed further issue of 64,280,500 Ordinary Shares as set out in paragraph 3.3(l) of Part XVI of this Prospectus and the repurchase of 12,957,782 Ordinary Shares in the period since 31 December 2019 to the Last Practicable Date under the Group's existing share buyback programme, there has been no material change in the Group's capitalisation since 31 December 2019 to the date of this Prospectus.

Indebtedness

The table below sets out the gross indebtedness of the Group as at 31 March 2020, as extracted from the unaudited management information of the Group as at that date:

	Unaudited As at 31 March 2020 $'000
Current debt	
Guaranteed	—
Secured[1]	27,405
Unguaranteed/unsecured	—
Total current debt	**27,405**
Non-current debt	
Guaranteed	—
Secured[1]	590,277
Unguaranteed/unsecured	—
Total non-current debt	**590,277**
Total gross indebtedness[2]	**617,682**

Notes:

[1] Secured debt includes borrowings under both the Group's five-year senior secured credit facility and securitised notes.

[2] Total gross indebtedness includes finance leases but excludes deferred financing costs.

The following table sets out the net indebtedness of the Group as at 31 March 2020, as extracted from the unaudited management information of the Group as at that date:

	Unaudited As at 31 March 2020 $'000
Cash	15,036
Cash equivalents	—
Liquidity	**15,036**
Current financial receivable	**—**
Current portion of non-current debt	(26,607)
Other current financial debt	(798)
Current financial debt	**(27,405)**
Net current financial (indebtedness)/cash	**(12,369)**
Non-current bank loans	(590,066)
Bonds issued	—
Other non-current loans	(211)
Non-current financial indebtedness	**(590,277)**
Net financial indebtedness[(1)(2)]	**(602,646)**

Notes:

(1) Excluded from the table above are financial instruments relating to natural gas and oil derivative contracts.

(2) Net financial indebtedness includes finance leases but excludes deferred financing costs.

There has been no material change in the Group's indebtedness since 31 March 2020 to the date of this Prospectus, save for the following:

- as set out in paragraph 12.1 of Part XVI this Prospectus, on 9 April 2020, the Group entered into a $200 million secured note due 28 July 2037. The proceeds have been used to, *inter alia*, repay a portion of the Group's five year credit facility.

PART XIV

HISTORICAL FINANCIAL INFORMATION

SECTION A: ACCOUNTANT'S REPORT ON THE HISTORICAL FINANCIAL INFORMATION OF THE GROUP

The Directors
Diversified Gas & Oil PLC
27-28 Eastcastle Street,
London,
W1W 8DH
United Kingdom

Stifel Nicolaus Europe Limited
150 Cheapside
London
EC2V 6ET

13 May 2020

Dear Ladies and Gentlemen

Diversified Gas & Oil PLC

We report on the financial information for the three years ended 31 December 2019 set out in section B of Part XIV below (the "**Financial Information Table**"). The Financial Information Table has been prepared for inclusion in the prospectus dated 13 May 2020 (the "**Prospectus**" of Diversified Gas & Oil PLC (the "**Company**") on the basis of the accounting policies set out in note 3 to the Financial Information Table. This report is required by item 18.3.1 of Annex 1 to the PR Regulation and is given for the purpose of complying with that item and for no other purpose.

Responsibilities

The Directors of the Company are responsible for preparing the Financial Information Table in accordance with International Financial Reporting Standards as adopted by the European Union.

It is our responsibility to form an opinion as to whether the Financial Information Table gives a true and fair view, for the purposes of the Prospectus and to report our opinion to you.

Save for any responsibility which we may have to those persons to whom this report is expressly addressed and for any responsibility arising under item 5.3.2R(2)(f) of the Prospectus Regulation Rules to any person as and to the extent there provided, to the fullest extent permitted by law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in connection with this report or our statement, required by and given solely for the purposes of complying with item 1.3 of Annex 1 to the PR Regulation, consenting to its inclusion in the Prospectus.

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PricewaterhouseCoopers LLP is a limited liability partnership registered in England with registered number OC303525. The registered office of PricewaterhouseCoopers LLP is 1 Embankment Place, London WC2N 6RH. PricewaterhouseCoopers LLP is authorised and regulated by the Financial Conduct Authority for designated investment business.

Basis of opinion

We conducted our work in accordance with the Standards for Investment Reporting issued by the Auditing Practices Board in the United Kingdom. Our work included an assessment of evidence relevant to the amounts and disclosures in the financial information. It also included an assessment of significant estimates and judgments made by those responsible for the preparation of the financial information and whether the accounting policies are appropriate to the Company's circumstances, consistently applied and adequately disclosed.

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 sufficient evidence to give reasonable assurance that the financial information is free from material misstatement whether caused by fraud or other irregularity or error.

Opinion

In our opinion, the Financial Information Table gives, for the purposes of the Prospectus dated 13 May 2020, a true and fair view of the state of affairs of the Company as at the dates stated and of its profits, cash flows and changes in equity for the periods then ended in accordance with International Financial Reporting Standards as adopted by the European Union.

Declaration

For the purposes of Prospectus Regulation Rules 5.3.2R(2)(f) we are responsible for this report as part of the Prospectus and we declare that to the best of our knowledge, the information contained in this report is in accordance with the facts and makes no omission likely to affect its import. This declaration is included in the Prospectus in compliance with item 1.2 of Annex 1 to the PR Regulation.

Yours faithfully

PricewaterhouseCoopers LLP
Chartered Accountants

SECTION B: HISTORICAL FINANCIAL INFORMATION OF THE GROUP

Consolidated statements of comprehensive income

The audited consolidated statements of comprehensive income of the Group for each of the three years ended 31 December 2017, 2018 and 2019 are set out below:

	Note	*(Restated)* Audited Year ended 31 December 2017 $'000	Audited Year ended 31 December 2018 $'000	Audited Year ended 31 December 2019 $'000
Revenue	6	**41,777**	**289,769**	**462,256**
Cost of sales	7	(20,908)	(107,793)	(202,385)
Amortisation, depreciation and depletion	7	(7,536)	(41,988)	(98,139)
Gross profit		**13,333**	**139,988**	**161,732**
(Loss)/gain on derivative financial instruments	23	(441)	17,981	73,854
Gain on bargain purchase	5	37,093	173,473	1,540
Gain on disposal of property and equipment	7	95	4,079	—
Administrative expenses	7	(8,919)	(40,524)	(56,619)
Operating profit		**41,161**	**294,997**	**180,507**
Accretion of asset retirement obligation	18	(1,764)	(7,101)	(12,349)
Finance costs	20	(5,225)	(17,743)	(36,667)
Loss on debt cancellation	20	(4,468)	(8,358)	—
Income before taxation		**29,704**	**261,795**	**131,491**
Taxation	9	(2,250)	(60,676)	(32,091)
Income after taxation		**27,454**	**201,119**	**99,400**
Other comprehensive income – gain on foreign currency conversion		355	1	—
Total comprehensive income for the year		**27,809**	**201,120**	**99,400**
Earnings per Ordinary Share – basic and diluted	10	$0.23	$0.52	$0.15

Consolidated statements of financial position

The audited consolidated statements of financial position of the Group as at 31 December 2017, 2018 and 2019 are set out below:

	Note	*(Restated)* Audited Year ended 31 December 2017 $'000	*(Restated)* Audited Year ended 31 December 2018 $'000	*(Restated)* Audited Year ended 31 December 2019 $'000
ASSETS				
Oil and gas properties	12	215,325	1,092,951	1,490,905
Intangible assets	13	—	2,563	15,980
Property and equipment	14	6,947	325,186	325,866
Restricted cash	3	—	—	6,505
Other non-current assets	15	1,036	22,543	4,191
Indemnification receivable	5	—	2,133	2,133
Non-current assets		**223,308**	**1,445,376**	**1,845,580**
Trade receivables	16	13,917	78,451	73,924
Other current assets	15	513	30,043	83,568
Cash and cash equivalents		15,168	1,372	1,661
Restricted cash	3	744	1,730	1,207
Current assets		**30,342**	**111,596**	**160,360**
Total assets		**253,650**	**1,556,972**	**2,005,940**
EQUITY AND LIABILITIES				
Share capital	17	1,940	7,346	8,800
Share premium	17	76,026	540,655	760,543
Merger reserve		(478)	(478)	(478)
Capital redemption reserve		—	—	518
Share-based payment reserve		59	842	3,907
Retained earnings		30,691	200,498	164,845
Total equity		**108,238**	**748,863**	**938,135**
Asset retirement obligation	18	35,448	140,190	196,871
Lease	19	836	2,694	1,015
Borrowings	20	70,619	482,528	598,778
Deferred tax liability	9	17,399	95,033	124,112
Other non-current liabilities	21	2,278	1,060	18,041
Uncertain tax position	5	—	2,133	2,133
Total non-current liabilities		**126,580**	**723,638**	**940,950**
Trade and other payables	22	2,132	9,383	17,052
Borrowings	20	373	286	23,723
Lease	19	324	842	798
Other current liabilities	21	16,003	73,960	85,282
Total current liabilities		**18,832**	**84,471**	**126,855**
Total liabilities		**145,412**	**808,109**	**1,067,805**
Total equity and liabilities		**253,650**	**1,556,972**	**2,005,940**

Consolidated statements of changes in shareholders' equity

The audited consolidated statements of changes in shareholders' equity of the Group for each of the three years ended 31 December 2017, 2018 and 2019 are set out below:

	Note	Share capital $'000	Share premium $'000	Merger reserve $'000	Capital Redemption reserve $'000	Share-based payment reserve $'000	Retained earnings $'000	Total equity $'000
Balance at 1 January 2017 *(Restated)*		**669**	**313**	**(478)**	**—**	**—**	**8,658**	**9,162**
Income after taxation		—	—	—	—	—	27,454	27,454
Gain on foreign currency conversion		—	—	—	—	—	355	355
Total comprehensive income		—	—	—	—	—	*27,809*	*27,809*
Issuance of Ordinary Shares, initial offering	17	768	43,550	—	—	—	—	44,318
Issuance of Ordinary Shares, secondary offering	17	503	32,163	—	—	—	—	32,666
Equity compensation		—	—	—	—	59	—	59
Dividends	11	—	—	—	—	—	(5,776)	(5,776)
Transactions with owners		*1,271*	*75,713*	—	—	*59*	*(5,776)*	*71,267*
Balance as at 31 December 2017 *(Restated)*		**1,940**	**76,026**	**(478)**	**—**	**59**	**30,691**	**108,238**
Income after taxation		—	—	—	—	—	201,119	201,119
Gain on foreign currency conversion		—	—	—	—	—	1	1
Total comprehensive income		—	—	—	—	—	*201,120*	*201,120*
Issuance of Ordinary Shares	17	5,406	464,629	—	—	—	—	470,035
Equity compensation		—	—	—	—	783	—	783
Dividends	11	—	—	—	—	—	(31,313)	(31,313)
Transactions with owners		*5,406*	*464,629*	—	—	*783*	*(31,313)*	*(439,505)*
Balance as at 31 December 2018		**7,346**	**540,655**	**(478)**	**—**	**842**	**200,498**	**748,863**
Income after taxation		—	—	—	—	—	99,400	99,400
Total comprehensive income		—	—	—	—	—	*99,400*	*99,400*
Issuance of Ordinary Shares	17	1,972	219,888	—	—	—	—	221,860
Equity compensation		—	—	—	—	3,065	—	3,065
Repurchase of Ordinary Shares	17	(518)	—	—	518	—	(52,902)	(52,902)
Dividends	11	—	—	—	—	—	(82,151)	(82,151)
Transactions with owners		*1,454*	*219,888*	—	*518*	*3,065*	*(135,053)*	*89,872*
Balance as at 31 December 2019		**8,800**	**760,543**	**(478)**	**518**	**3,907**	**164,845**	**938,135**

Consolidated statements of cash flows

The audited consolidated statements of cash flows of the Group for each of the three years ended 31 December 2017, 2018 and 2019 are set out below:

	(Restated) **Audited Year ended 31 December 2017 $'000**	**Audited Year ended 31 December 2018 $'000**	**Audited Year ended 31 December 2019 $'000**
Cash flows from operating activities			
Income after taxation	27,454	201,119	99,400
Cash flow from operations reconciliation:			
Amortisation, depreciation and depletion	7,536	41,988	98,139
Accretion of asset retirement obligation	1,764	7,101	12,349
Income tax charge	2,250	60,676	32,091
Provision for working interest owners receivable	632	—	—
Loss/(gain) on derivative financial instruments	1,965	(32,768)	(20,270)
Asset retirement (plugging)	(78)	(1,171)	(2,541)
Gain on oil and gas program and equipment	(396)	(4,079)	—
Gain on bargain purchase	(37,093)	(173,473)	(1,540)
Finance costs	4,510	17,743	36,677
Loss on early retirement of debt	—	8,358	—
Gain on disposal of property and equipment	95	—	—
Non-cash equity compensation	59	783	3,065
Working capital adjustments:			
Change in trade receivables	(11,464)	(41,225)	4,528
Change in other current assets	798	(6,286)	2,606
Change in other assets	(38)	(1,732)	409
Change in trade and other payables	(2,495)	1,134	7,669
Change in other current and non-current liabilities	11,345	8,396	6,574
Net cash provided by operating activities	**6,844**	**86,564**	**279,156**
Cash flows from investing activities			
Acquisitions	(89,785)	(750,256)	(439,272)
Expenditures on oil and gas properties, intangible assets and property and and equipment	(2,935)	(18,515)	(32,313)
Increase in restricted cash	(627)	(986)	(5,302)
Proceeds on disposal of oil and gas properties	334	4,079	10,000
Net cash used in investing activities	**(93,013)**	**(765,678)**	**(466,887)**
Cash flows from financing activities			
Repayment of borrowings	(42,514)	(280,890)	(618,010)
Proceeds from borrowings	75,000	581,221	765,236
Financing expense	(3,298)	(15,433)	(32,715)
Cost incurred to secure financing	—	(17,176)	(11,574)
Proceeds from lease	1,246	4,401	—
Repayment of lease	(529)	(1,093)	(1,724)
Proceeds from equity issuance, net	76,984	425,601	221,860
Dividends to Shareholders	(5,776)	(31,313)	(82,151)
Repurchase of Ordinary Shares	—	—	(52,902)
Net cash provided by financing activities	**101,113**	**665,318**	**188,020**
Net increase/(decrease) in cash and cash equivalents	**14,944**	**(13,796)**	**289**
Cash and cash equivalents – beginning of the year	*224*	*15,168*	*1,372*
Cash and cash equivalents – end of the year	**15,168**	**1,372**	**1,661**

NOTES TO THE GROUP FINANCIAL INFORMATION

1. GENERAL INFORMATION

The Group is a natural gas and crude oil producer that is focused on acquiring and operating mature producing wells with long lives and slow decline profiles. The Group's assets are exclusively located within the Appalachian Basin of the US. The Group is domiciled in the UK but is headquartered in Birmingham, Alabama, USA with field offices located in the states of Pennsylvania, Ohio, West Virginia and Tennessee.

The Company was incorporated on 31 July 2014 in England and Wales as a private limited company under company number 09156132. The Company's registered office is located at 27/28 Eastcastle Street, London W1W 8DH, United Kingdom.

In February 2017, the Company's Ordinary Shares were admitted to trading on AIM under the ticker "DGOC".

2. BASIS OF PREPARATION AND MEASUREMENT

(a) Basis of preparation

The Group Financial Information has been prepared in accordance with IFRS, issued by the International Accounting Standards Board, including interpretations issued by the International Financial Reporting Interpretations Committee, and the Companies Act 2006 applicable to companies reporting under IFRS.

Unless otherwise stated, the Group Financial Information is presented in $ which is the Company's functional currency and the currency of the primary economic environment in which the Group operates, and all values are rounded to the nearest thousand dollars except per unit amounts and where otherwise indicated.

Transactions in foreign currencies are translated into $ at the rate of exchange on the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated at the exchange ruling at the balance sheet date. This is most applicable for transactions of the Company which has a different functional currency where the resulting gain or loss is reflected within "*Other Comprehensive income – gain on foreign currency conversion*" in the "*Consolidated Statements of Profit or Loss and Other Comprehensive Income*".

The Group Financial Information has been prepared under the historical cost convention.

Going concern basis

The Group Financial Information has been prepared on the going concern basis, which contemplates the continuity of business activity and the realisation of assets and the settlement of liabilities in the normal course of business, taking into account the Directors' assessment of the financial and trading effects of Covid-19. The Directors have reviewed the Group's overall position and outlook and are of the opinion that the Group is sufficiently well funded to be able to operate as a going concern for at least the next twelve months from the date of Admission.

COVID-19

The Directors closely monitor and carefully manage the Group's liquidity risk. Cash flow projections are regularly produced and sensitivities run for different scenarios including, but not limited to, changes in commodity prices and different production rates from the Group's producing assets. The Group's cash flow projections have been updated in light of COVID-19. There remains significant uncertainty over the impact of COVID-19, however to date, the Group's day-to-day operations continue without being materially affected. To consider any impacts of COVID-19, price volatility or other operational issues, the Directors have prepared a downside sensitivity scenario for each of the years ending 31 December 2020 and 31 December 2021. The downside sensitivity scenario includes, but is not limited to, the following assumptions:

- using the lowest 3-month average commodity price from 2010 to February 2020;
- reducing production by approximately 10 per cent.;
- including the financial impact of the Group's current hedging contracts in place, being approximately 81 per cent. of total production volumes hedged for the year ending 31 December 2020 and 85 per cent. for the year ending 31 December 2021;
- excluding discretionary capital expenditure, but including plugging expenditure; and
- including the scheduled principle and interest payments on the Group's current debt arrangements.

Under this downside sensitivity scenario, the Group remains cash flow positive.

(b) Prior period restatement

During the period ended 30 June 2018, the Group finalised the fair value measurement related to the previously reported EnerVest Assets Acquisition and Titan Energy Acquisition discussed in Note 5 "*Acquisitions*" to the Group Financial Information. As a result, the Group retrospectively adjusted previously reported provisional amounts related to the EnerVest Assets Acquisition and the Titan Energy Acquisition in accordance with IFRS 3 "*Business Combinations*". The following tables summarises the impact of these adjustments on the previously reported financial information for the year ended 31 December 2017:

	(Reported) Year ended 31 December 2017 $'000	Revisions $'000	*(Restated)* Year ended 31 December 2017 $'000
Balance sheet accounts impacted			
Oil and gas properties, net	190,358	24,967	215,325
Deferred tax liability	11,011	6,388	17,399
Retained earnings	12,112	18,579	30,691
Income statement accounts impacted			
Amortisation, depreciation and depletion	(7,013)	(523)	(7,536)
Gain on bargain purchase	11,603	25,490	37,093
Income tax benefit/(expense)	4,138	(6,388)	(2,250)

For the year ended 31 December 2017, the cumulative impact of these adjustments resulted in an $18,579,000 increase to the Consolidated Statements of Changes in Equity through retained earnings and did not impact net cash provided by operating activities on the Consolidated Statement of Cash Flow.

(c) Prior period reclassification

As discussed in Note 21 "*Other non-current and current liabilities*" to the Group Financial Information, since the timing of revenue to be distributed that is payable to third-party working interest owners that has not yet been paid due to title, legal, ownership or other issues is unknown, the Group records the balance as non-current liabilities. The Group reclassified prior period amounts of $20,159,000 at 31 December 2018 and $3,486,000 at 31 December 2017 from other non-current liabilities to other current liabilities on the "*Statement of Financial Position*" to conform to current year presentation.

During the year ended 31 December 2019, the Group reclassified its ERP software from property and equipment to intangible fixed assets.

(d) Basis of consolidation

During the year ended 31 December 2019, the Group underwent a restructuring in order to simplify its organisation. Under this restructuring all production entities were merged into Diversified Production, LLC and all midstream entities were merged into Diversified Midstream, LLC. Further, Diversified Energy Marketing, LLC was created to sell the commodities produced by Diversified Production, LLC and certain third parties. There is no financial information impact as a result of the reorganisation.

The Group Financial Information for the year ended 31 December 2019 reflects the following corporate structure of the Group:

- The Company, and its wholly owned subsidiary:
  - o Diversified Gas & Oil Corporation ("DGOC"), as well as its wholly owned subsidiaries;
    - Diversified Production, LLC;
      - Diversified ABS Holdings, LLC;
        - o Diversified ABS, LLC;
      - Diversified Midstream, LLC; and
      - Diversified Energy Marketing, LLC.

The Group Financial Information for the years ended 31 December 2018 and 31 December 2017 reflects the following corporate structure of the Group:

- The Company, and its wholly owned subsidiary:
  - o Diversified Gas & Oil Corporation ("DGOC") as well as its, direct and indirect, wholly owned subsidiaries:
    - Diversified Resources, Inc.;
    - M & R Investments, LLC;
    - M & R Investments Ohio, LLC;
    - Marshall Gas and Oil Corporation;
    - R&K Oil and Gas, Inc.;
    - Fund 1 DR, LLC;
    - Diversified Oil & Gas, LLC;
    - Alliance Petroleum Corporation
    - Diversified Appalachian Group, LLC;
    - Diversified Energy, LLC;
      - Diversified Partnership Holdings, LLC
      - Diversified Partnership Holdings II, LLC
      - Atlas Energy Tennessee, LLC
        - o Atlas Pipeline Tennessee, LLC
    - Diversified Southern Production, LLC;
    - Diversified Southern Midstream, LLC;
    - Diversified Energy Marketing, LLC; and
    - Core Appalachia Holding Co, LLC;
      - Core Appalachia Compression, LLC
      - Core Appalachia Midstream, LLC
      - Core Appalachia Operating, LLC
      - Core Appalachia Production, LLC

(e) New standards and interpretations

Adopted

IFRS 9 "Financial Instruments"

In July 2014, the IASB issued IFRS 9 "*Financial Instruments*" that replaces IAS 39 "*Financial Instruments: Recognition and Measurement*" and all previous versions of IFRS 9 "*Financial Instruments*". IFRS 9 "*Financial Instruments*" incorporates the three aspects of the accounting for financial instruments: classification and measurement; impairment; and hedge accounting. Financial assets are classified as trading activities (assets that are held for collection of contractual trading and are measured at amortised cost) or financial assets held for future sale (assets that are held for collection of contractual cash flows and are measured at fair value through other comprehensive income). The standard should be applied using the retrospective application. This standard was effective on or after 1 January 2018.

The Company applied the simplified approach permitted by IFRS 9 "*Financial Instruments*" for trade receivables, which requires expected lifetime losses to be recognised from initial recognition of the receivables. The Group's financial liabilities are initially measured at fair value and subsequently measured at amortised cost.

The Company adopted the new standard on 1 January 2018. The Group is not a financial institution and does not have any complex financial instruments. The Group does not apply hedge accounting and its customers are considered creditworthy and pay consistently within agreed payments terms. As such, other than disclosures, this standard will not have a material impact on its financial information.

IFRS 15 "Revenue from Contracts with Customers"

In May 2014, the IASB issued IFRS 15 "*Revenue from Contracts with Customers*". The standard requires an entity to recognise revenue in a manner that depicts the transfer of goods or services to customers at an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The new standard will supersede all current revenue recognition requirements under IFRS when it becomes effective. The standard can be applied using either the full retrospective approach or a modified retrospective approach at the date of adoptions. This standard was effective on or after 1 January 2018.

The Company adopted the new standard on 1 January 2018, using the modified retrospective method at the date of adoption. The adoption of IFRS 15 "*Revenue from Contracts with Customers*" is not expected to have a material quantitative impact on the financial results of the Group and no adjustment arose on transition. There were no contractual arrangements with customers giving rise to material deferred revenues at 1 January 2018, 31 December 2018 or 31 December 2019. No amounts have been recognised in relation to assets derived from costs to obtain or fulfil customer contracts and no practical expedients have been applied on transition to IFRS 15 "*Revenue from Contracts with Customers*".

IFRS 16 "Leases"

In January 2016, the IASB issued IFRS 16 "*Leases*". The standard establishes the principles for the recognition, measurement, presentation and disclosure of leases for both the lessee and lessor. The standard requires all lease transactions (with terms in excess of 12 months) to be recognised on the balance sheet as lease assets and lease liabilities, and to depreciate lease assets separately from interest on lease liabilities in the income statement. IFRS 16 "*Leases*" replaces the previous lease standard, IAS 17 "*Leases*", and related interpretations. This standard became effective on 1 January 2019. Early adoption is permitted only if the Company also applies IFRS 15 "*Revenue from Contracts with Customers*". The standard can be applied using either the full retrospective approach or a modified retrospective approach at the date of adoption.

On transition to IFRS 16 "*Leases*", the Directors elected to apply the practical expedient to grandfather the assessment of which transactions are leases. The Directors applied IFRS 16 "*Leases*" only to contracts that were previously identified as leases. Contracts that were not identified as leases under IAS 17 "*Leases*" and IFRIC 4 "*Determining Whether an Arrangement Contains a Lease*" were not assessed. Therefore, the definition of a lease under IFRS 16 "*Leases*" has been applied only to contracts entered into on or after 1 January 2019.

Previously, the Directors determined at contract inception whether an arrangement was or contained a lease under IFRIC 4 "*Determining Whether an Arrangement Contains a Lease*". The Directors now assess whether a contract contains a lease based on the new definition of a lease. Under IFRS 16 "*Leases*", a contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

The Company adopted IFRS 16 "*Leases*" on 1 January 2019 and its adoption did not have a material impact on the Group Financial Information.

3. SIGNIFICANT ACCOUNTING POLICIES

The preparation of the Group Financial Information in compliance with IFRS requires the Directors to exercise judgment in applying the Company's accounting policies. The areas involving a higher degree of judgment or complexity, or areas where assumptions and estimates are significant to the Group Financial Information are disclosed in Note 4 "*Significant judgements, estimates and assumptions*" to the Group Financial Information.

(a) Business combinations

The Group applies the acquisition method of accounting for business combinations. The consideration transferred by the Group to obtain control of a subsidiary is calculated as the sum of the acquisition date fair values of assets transferred, liabilities incurred and equity interests issued by the Group. Acquisition costs are expensed as incurred.

(b) Cash and cash equivalents

Cash on the balance sheet comprises cash at banks. Balances held at banks, at times, exceed federally insured amounts. The Group has not experienced any losses in such accounts and the Directors believe that the Group is not exposed to any significant credit risk on its cash. As at 31 December 2019, the Group's cash balance was $1,661,000 (2018: $1,372,000, 2017: $15,168,000)

(c) Trade receivables

Trade receivables are stated at the historical carrying amount, net of any provisions required. Trade receivables are due from customers throughout the oil and natural gas industry. Although diversified among several companies, collectability is dependent on the financial condition of each individual company as well as the general economic conditions of the industry. The Directors review the financial condition of customers prior to extending credit and generally do not require collateral to support of the Group's trade receivables. Any changes in the Directors' provision for un-collectability of trade receivables during the year is recognised in the "*Statements of Profit or Loss and Other Comprehensive Income*". Trade receivables also include certain receivables from third-party working interest owners. The Directors consistently assess the collectability of these receivables. As at 31 December 2019, the Directors considered a portion of these working interest receivables uncollectable and recorded a provision in the amount of $3,210,000 (2018: $2,200,000 2017: $nil).

(d) Borrowings

Borrowings are recognised initially at fair value, net of any applicable transaction costs incurred. Borrowings are subsequently carried at amortised cost. Any difference between the proceeds (net of transaction costs) and the redemption value is recognised in the income statement over the period of the borrowings using the effective interest method (if applicable).

Interest on borrowings is accrued as applicable to that class of borrowing.

(e) Derivative financial instruments

Derivatives are used as part of the Directors' overall strategy to mitigate risk associated with the unpredictability of cash flows due to volatility in commodity prices. Further details of the Group's exposure to these risks are detailed in Note 22 "*Derivatives*" to the Group Financial Information. The Group has entered into financial instruments which are considered derivative contracts, such as swaps and collars which result in net cash settlement each month and do not result in physical deliveries. The derivative contracts are initially recognised at fair value at the date contract is entered into and re-measured to fair value every balance sheet date. The resulting gain or loss is recognised in the "*Statements of Profit or Loss and Other Comprehensive Income*" in the year incurred.

(f) Restricted cash

Cash held on deposit for bonding purposes is classified as restricted cash and recorded within current and non-current assets. The cash is restricted in use by state governmental agencies to be utilised and drawn upon if the operator should abandon any wells or is being held as collateral by the Group's surety bond providers. As at 31 December 2019, the Group's restricted cash balance was $7,712,000 (2018: $1,730,000 2017: $744,000).

(g) Oil and gas properties

Development and acquisition costs

Expenditures related to the construction, installation or completion of infrastructure facilities, such as platforms and pipelines, and the drilling of development wells, including delineation wells, are capitalised within oil and gas properties. The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of the well asset retirement obligation. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

Depletion

Oil and gas properties are depleted on a unit-of-production basis over the proved reserves of the field concerned, except in the case of assets whose useful life is shorter than the lifetime of the field, in which case the straight- line method is applied. Rights and concessions are depleted on the unit-of-production basis over the total proven reserves of the relevant area. The unit-of-production rate for the depreciation of field development costs considers expenditures incurred to date, together with sanctioned future development expenditure.

(h) Intangible assets

Development and acquisition costs

Development costs that are directly attributable to the design and testing of identifiable and unique software products controlled by the Group are recognised as intangible assets where the following criteria are met:

- it is technically feasible to complete the software so that it will be available for use;
- the Directors intend to complete the software and use or sell it;
- there is an ability to use the software;
- it can be demonstrated how the software will generate probable future economic benefits;
- adequate technical, financial and other resources to complete the development and to use the software are available; and
- the expenditure attributable to the software during its development can be reliably measured.

Directly attributable costs that are capitalised as part of the software include employee costs and an appropriate portion of relevant overheads.

Capitalised development costs are recorded as intangible assets and amortised from the point at which the asset is ready for use.

Costs associated with maintaining software programmes are recognised as an expense as incurred.

Impairment of intangible assets

Intangible assets are tested for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment loss is recognised for the amount by which the asset's carrying amount exceeds its recoverable amount. The recoverable amount is the higher of an asset's fair value less costs of disposal and value in use. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash inflows which are largely independent of the cash inflows from other assets or groups of assets (cash-generating units). Intangible assets that suffered an impairment are reviewed for possible reversal of the impairment at the end of each reporting period.

Amortisation

The Group amortises intangible assets with a limited useful life, using the straight-line method over the following periods:

ERP system	5 years

(i) Property and equipment

Property and equipment are stated at cost less accumulated depreciation and impairment losses, if any. The cost of an item of property, plant and equipment initially recognised includes its purchase price and any cost that is directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by the Directors.

Property, plant and equipment are generally depreciated on a straight-line basis over their estimated useful lives:

Buildings and leasehold improvements	7 – 15 years
Equipment	10 – 39 years
Motor vehicles	5 – 7 years
Compression assets	13 years
Pipeline assets	15 years
Other property and equipment	3 – 5 years

Property and equipment held under leases are depreciated over the shorter of lease term and estimated useful life.

(j) Impairment of financial assets

IFRS 9 "*Financial Instruments*" requires the application of an expected credit loss model in considering the impairment of financial assets. The expected credit loss model requires the Group to account for expected credit losses and changes in those expected credit losses at each reporting date to reflect changes in credit risk since initial recognition of the financial assets. The credit event does not have to occur before credit losses are recognised. IFRS 9"*Financial Instruments*" allows for a simplified approach for measuring the loss allowance at an amount equal to lifetime expected credit losses for trade receivables and contract assets.

The Group applies the expected credit loss model to trade receivables arising from:

- sales of natural gas, NGLs and crude oil;
- sales of gathering and transportation of third party natural gas; and
- the provision of other services.

(k) Impairment of non-financial assets

At each reporting date, the Directors assess whether indications exist that an asset may be impaired. If indications do exists, or when annual impairment testing for an asset is required, the Directors estimate the asset's recoverable amount. An asset's recoverable amount is the higher of an asset's or cash-generating unit's fair value less costs to sell and its value-in-use, and is determined for an individual asset, unless the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets. Where the carrying amount of an asset or cash-generating unit exceeds its recoverable amount, the Directors consider the asset impaired and write the subject asset down to its recoverable amount. In assessing value-in-use, the Directors discount the estimated future cash flows to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. In determining fair value less costs to sell, the Directors consider recent market transactions, if available. If no such transactions can be identified, the Directors utilise an appropriate valuation model.

(l) Leases

The determination of whether an arrangement is, or contains, a lease is based on the substance of the arrangement at inception date: whether fulfilment of the arrangement is dependent on the use of a specific asset or assets or the arrangement conveys a right to use the asset.

(m) Asset retirement obligation

Where a material liability for the removal of production equipment and site restoration at the end of the production life of a well exists, the Group recognises a liability for well asset retirement. The amount recognised is the present value of estimated future net expenditures determined in accordance with local conditions and requirements. The unwinding of the discount on the decommissioning liability is included as accretion of the decommissioning provision. The cost of the relevant property, plant and equipment asset is increased with an amount equivalent to the liability and depreciated on a unit of production basis. The Directors recognise changes in estimates prospectively, with corresponding adjustments to the liability and the associated non-current asset.

The Group currently has no midstream asset retirement obligations.

(n) Taxation

Deferred taxation

Deferred tax is provided in full, using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the Group Financial Information. Deferred tax is determined using tax rates (and laws) that have been enacted or substantially enacted by the balance sheet date and expected to apply when the related deferred tax is realised or the deferred liability is settled.

Deferred tax assets are recognised to the extent that it is probable that the future taxable profit will be available against which the temporary differences can be utilised.

Income taxation

Current income tax assets and liabilities for the years ended 31 December 2019, 31 December 2018 and 31 December 2017 are measured at the amount to be recovered from, or paid to, the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted at the reporting date in the jurisdictions where the Group operates and generates taxable income.

(o) Revenue recognition

Natural gas, NGLs and crude oil

Revenue from sales of natural gas, NGLs and crude oil products is recognised when the customer obtains control of the commodity. This transfer generally occurs when product is physically transferred into a vessel, pipe, sales meter or other delivery mechanism. This also represents the point at which the Group fulfills its single performance obligation to its customer under contracts for the sale of natural gas, NGLs and crude oil.

Revenue from the production of oil in which the Group has an interest with other producers is recognised proportionately based on the Group's working interest and the terms of the relevant production sharing contracts. The portion of revenue that is due to minority working interests is included as a liability in Note 21 "*Other non-current and current liabilities*" to the Group Financial Information.

Third-party gathering revenue

Revenue from gathering and transportation of third-party natural gas is recognised when the customer transfers its gas to the entry point in the Group's midstream network and becomes entitled to withdraw an equivalent volume of gas from the exit point in the Group's midstream network under contracts for the gathering and transportation of natural gas. This transfer generally occurs when product is physically transferred into the Group's vessel, pipe, or sales meter. The customer's entitlement to withdraw an equivalent volume of gas is broadly coterminous with transfer of gas into the Group's midstream network.

Other revenue

Revenue from the operation of third-party wells is recognised as earned in the month work is performed and consistent with the Group's contractual obligations. The Group's contractual obligations in this respect are considered to be its performance obligations for the purposes of IFRS 15 "*Revenue from Contracts with Customers*".

Revenue from the sale of water disposal services to third-parties into the Group's disposal well is recognised as earned in the month the water was physically disposed. Disposal of the water is considered to be the Group's performance obligation under these contracts.

Revenue is stated after deducting sales taxes, excise duties and similar levies.

(p) Functional currency and foreign currency translation

The Group Financial Information is presented in $, which is the Company's functional currency.

The results and financial position of all Group entities that have a functional currency different from the presentation currency are translated into the presentation currency as follows:

- assets and liabilities are translated at the closing rate at the date of the "*Statement of Financial Position*";
- income and expenses are translated at average exchange rates (unless this average is not a reasonable approximation of the cumulative effect of the rates prevailing on the transaction dates, in which case income and expenses are translated at the dates of the transactions); and
- all resulting exchange differences are recognised in other comprehensive income.

On consolidation, the Group recognises in "*other comprehensive income*" the exchange differences arising from the translation of the net investment in foreign entities, and of monetary items receivable from foreign subsidiaries for which settlement is neither planned nor likely to occur in the foreseeable future.

(q) Share-based payments

The Group accounts for share-based payments under IFRS 2 "*Share-based payment*". All of the Company's share-based awards are equity settled. The fair value of the awards are determined at the date of grant. As at each of 31 December 2019, 31 December 2018 and 31 December 2017, the Company had two types of share-based payment awards, Restricted Stock Units ("RSUs") and stock options. The fair value of the grant of the Company's RSUs is determined using the stock price at the grant date and uniformly expensed over the vesting period. The fair value of the Company's stock options are calculated using the Black Scholes model as of the grant date. The inputs to the Black Scholes model included:

- the share price at the date of grant;
- exercise price;
- expected volatility;
- expected dividends;
- risk-free rate of interest; and
- patterns of exercise of the plan participants.

The grant date fair value of stock options, adjusted for market-based performance conditions, are expensed uniformly over the vesting period.

(r) Segmental reporting

The Company complies with IFRS 8 "*Operating Segments*", to determine its operating segments and has identified one reportable segment that produces natural gas and crude oil in the Appalachian Basin of the US.

4. SIGNIFICANT ACCOUNTING JUDGEMENTS, ESTIMATES AND ASSUMPTIONS

The Directors have made the following judgments which may have a significant effect on the amounts recognised in the Group Financial Information:

(a) Estimating the fair value of oil and gas properties

The Directors determine the fair value of the Group's oil and gas assets using the income approach based on expected discounted future cash flows from estimated reserve quantities, costs to produce and develop reserves, and oil and natural gas forward prices. The future net cash flows are discounted using a weighted average cost of capital as well as any additional risk factors. Proved reserves are estimated by reference to available geological and engineering data and only include volumes for which access to market is assured with reasonable certainty. Estimates of proved reserves are inherently imprecise, require the application of judgment and are subject to regular revision, either upward or downward, based on new information such as from the drilling of additional wells, observation of long-term reservoir performance under producing conditions and changes in economic factors, including product prices, contract terms or development plans. Changes in assumptions related to the Group's asset retirement obligation could result in a material change in the carrying value within the next financial year. Sensitivity analysis on the significant inputs to the fair value to assessment is included in Note 5 "*Acquisitions*" to the Group Financial Information.

(b) Impairment of oil and gas properties

In preparing the Group Financial Information, the Directors consider that a key judgment is whether there is any evidence that the oil and gas properties are impaired. Having identified an impairment indicator relating to the market capitalisation of the Group, the Directors undertook an impairment test in line with the Group's accounting policy. The Directors engaged an expert to prepare a value in use calculation of the Group's oil and gas properties. Having performed this assessment no impairment was recognised.

When applicable, the Group recognises impairment losses of continuing operations in the "*Statement of Profit or Loss and Other Comprehensive Income*" in those expense categories consistent with the function of the impaired asset.

(c) Reserve estimates

Reserves are estimates of the amount of natural gas and crude oil product that can be economically and legally extracted from the Group's properties. To calculate the reserves, estimates and assumptions are required about a range of geological, technical and economic factors, including quantities, production techniques, recovery rates, production costs, transport costs, commodity demand, commodity prices and exchange rates.

Estimating the quantity and/or grade of reserves requires the size, shape and depth of fields to be determined by analysing geological data, such as drilling samples. This process may require complex and difficult geological judgments and calculations to interpret the data.

Given the economic assumptions used to estimate reserves change from year-to-year and, because additional geological data is generated during the course of operations, estimates of reserves may change from time-to-time.

(d) Asset retirement obligation costs

The ultimate asset retirement obligation costs are uncertain and cost estimates can vary in response to many factors including changes to relevant legal requirements, the emergence of new restoration techniques or experience at other production sites. The expected timing and amount of expenditure can also change, for example, in response to changes in reserves or changes in laws and regulations or their interpretation. As a result, significant estimates and assumptions are made in determining the provision for asset retirement. These assumptions include costs to plug the wells, the economic life of the wells and the discount rate. Changes in assumptions related to the Group's asset retirement obligation could result in a material change in the carrying value within the next financial year. See Note 18 "*Asset retirement obligation*" to the Group Financial Information for more information and sensitivity analysis.

5. ACQUISITIONS

2019 Acquisitions

HG Energy Assets Acquisition

In April 2019, the Group acquired 107 non-conventional wells in the states of Pennsylvania and West Virginia from HG Energy. The Group paid purchase consideration of $384,020,000, excluding customary purchase price adjustments. The Group funded the cash consideration for the purchase with the proceeds from the Company's equity placing of Ordinary Shares in April 2019, as discussed in Note 17 "*Share capital and share premium*" to the Group Financial Information, and a draw from the credit facility discussed in Note 20 "*Borrowings*" to the Group Financial Information. Associated costs of the acquisition were $4,788,000.

The HG Energy Assets Acquisition increased the Group's total production to 90,940 boepd. In the period from its acquisition to 31 December 2019, the HG Energy Assets Acquisition contributed revenue of approximately $34,400,000. The properties associated with the acquisition have been comingled with the Group's existing properties and it is impractical to provide stand-alone operational results related to these acquired properties.

As stated in Note 4 "*Significant accounting judgements, estimates and assumptions*" to the Group Financial Information, changes in the Directors' assumptions used as inputs for acquisitions could result in a material change of the fair value of the acquired reserves. The Directors consider the discount rate, commodity pricing, production and operating expense assumptions to be the inputs most sensitive to the fair value of the acquired reserves. The table below represents the impact of a +/-100 basis point adjustment to the discount rate, commodity price, production and operating expense would have on the fair value of the acquired reserves:

	+100 basis points $'000	-100 basis points $'000
Discount rate		
Adjusted fair value of oil and gas properties	414,044	358,509
Pricing[(a)]		
Adjusted fair value of oil and gas properties	389,477	378,429
Production		
Adjusted fair value of oil and gas properties	389,352	378,553
Operating expense		
Adjusted fair value of oil and gas properties	385,637	382,269

(a) The Directors used a base realised price of $2.83 for natural gas and $63.27 for oil.

As a result of the valuation, the fair value of the reserves held in the assets acquired was $385,651,000, which was derived using a cumulative discount rate of 8 per cent. The estimated fair values of the assets and liabilities assumed were as follows:

	$'000
Total consideration	384,020
Net assets acquired:	
Oil and gas properties	385,671
Oil and gas properties (asset retirement obligation, asset portion)	236
Suspense[(a)]	(1,651)
Asset retirement obligation	(236)
Net assets acquired	**384,020**

(a) Suspense represents the amounts payable to minority working interest owners.

EdgeMarc Energy Assets Acquisition

In September 2019, the Group acquired 12 non-conventional wells and 3 drilled but uncompleted wells in Ohio from EdgeMarc Energy. The Group paid purchase consideration of $48,107,000, excluding customary purchase price adjustments. The Group funded the cash consideration for the purchase from a draw on the credit facility discussed in Note 20 "*Borrowings*" to the Group Financial Information. Associated costs of the acquisition were $747,000.

The acquisition of the EdgeMarc Energy assets increased the Group's total production to 95,940 boepd. In the period from its acquisition to 31 December 2019, the EdgeMarc Energy assets contributed revenue of approximately $6,600,000. The properties associated with the acquisition have been comingled with the Group's existing properties and it is impractical to provide stand-alone operational results related to these acquired properties.

As stated in Note 4 "*Significant accounting judgements, estimates and assumptions*" to the Group Financial Information, changes in the Directors' assumptions used as inputs for acquisitions could result in a material change of the fair value of the acquired reserves. The Directors consider the discount rate, commodity pricing, production and operating expense assumptions to be the inputs most sensitive to the fair value, operating expense and the fair value of the acquired reserves. The table below represents the impact of a +/-100 basis point adjustment to the discount rate, commodity price, production and operating expense would have on the fair value of the acquired reserves:

	+100 basis points $'000	-100 basis points $'000
Discount rate		
Adjusted fair value of oil and gas properties	42,394	38,838
Pricing[(a)]		
Adjusted fair value of oil and gas properties	41,293	39,720
Production		
Adjusted fair value of oil and gas properties	41,192	39,822
Operating expense		
Adjusted fair value of oil and gas properties	40,854	40,159

(a) The Directors used a base retained price of $2.27 using Henry Hub Strip prices adjusted for differentials.

As a result of the valuation, the fair value of the reserves held in the assets acquired was $40,507,000, which was derived using a cumulative discount rate of 8.5 per cent. The estimated fair values of the assets and liabilities assumed were as follows:

	$'000
Total consideration	48,107
Net assets acquired:	
Oil and gas properties	40,507
Oil and gas properties (asset retirement obligation, asset portion)	15
Drilled but uncompleted	10,000
Fair value of derivatives	2,213
Asset retirement obligation	(15)
Suspense[(a)]	(2,744)
Taxes payable	(329)
Net assets acquired	**49,647**
Gain on bargain purchase	(1,540)
Purchase price	**48,107**

(a) Suspense represents the amounts payable to minority working interest owners.

The Group recorded a $1,540,000 gain on the acquisition of the EdgeMarc Energy assets which the Directors believe is reasonable given the facts and circumstances of acquisition. The Group entered into a "*stalking-horse*" Asset Purchase Agreement with EdgeMarc Energy, debtors-in-possession under title 11 of the United States Code, pursuant to voluntary petitions for relief filed under Chapter 11 of the United States Bankruptcy Code. Given the circumstances of EdgeMarc Energy, the Directors believe that EdgeMarc Energy was in a distressed position to sell the assets under fair market value.

Acquisition of natural gas gathering systems

In September 2019, the Group acquired certain natural gas gathering systems from Dominion and Equitrans, for total cash consideration of $7,700,000, excluding customary purchase price adjustments. The natural gas gathering systems associated with the acquisitions have been comingled with the Group's existing natural gas gathering systems and it is impractical to provide stand-alone operational results related to these acquired assets. The Group funded the cash consideration of the purchase from a draw on the credit facility discussed in Note 20 "*Borrowings*" to the Group Financial Information. The Group accounted for this acquisition as an asset acquisition under IFRS 3 "*Business combinations*". Associated costs of the Dominion and Equitrans acquisitions were $726,000 and $507,000 respectively.

2018 Acquisitions

Acquisition of the stock of Alliance Petroleum

In March 2018, the Group acquired the entire share capital of Alliance Petroleum, including approximately 13,000 conventional natural gas and oil wells in the states of Pennsylvania, West Virginia and Ohio and all other property and equipment. The Group paid consideration of $80,743,000, excluding customary purchase price adjustments. The Group funded the cash consideration for the purchase with the net proceeds from the Company's equity placing of Ordinary Shares in February 2018, as discussed further in Note 17 "*Share capital and share premium*" to the Group Financial Information. Associated costs of the acquisition were $733,000.

The properties associated with the acquisition have been comingled with the Group's existing properties and it is impractical to provide stand-alone operational results related to these acquired properties.

The Directors determined the fair value of the reserves held in the assets acquired to be $129,125,000 which was approximately 9 per cent. cumulative discount reserve valuation derived from a third party engineer at the time of purchase. The estimated fair values of the assets and liabilities assumed were as follows:

	$'000
Total cash consideration	80,743
Less cash received	(8,638)
Cash consideration, net of cash received	72,105
Net assets acquired:	
Current assets	13,403
Oil and gas properties, net	129,125
Property and equipment, net	2,444
Other assets[(a)]	2,133
Current liabilities	(7,576)
Deferred tax liability	(19,852)
Uncertain tax position[(a)]	(2,133)
Debt[(b)]	(25,000)
Other liabilities	(119)
Asset retirement obligation	(20,153)
Net assets acquired	72,272
Gain on bargain purchase	(167)
Purchase price	**72,105**

(a) *At the date of acquisition, the Directors determined that Alliance Petroleum had taken uncertain tax positions, and as a result, an indemnification agreement was executed. The Group recorded an indemnification receivable in the amount of $2,133,000. In accordance with IFRS 3 "Business combinations", the Group assigned acquisition date fair value to the indemnification asset using the same valuation techniques used to determine the acquisition date fair value of the related liability.*

(b) *On the date of acquisition, the Group repaid the debt in full using proceeds from the February 2018 equity placing.*

CNX Assets Acquisition

In March 2018, the Group acquired approximately 11,000 conventional natural gas and oil wells principally in the states of Pennsylvania and West Virginia and other equipment from CNX. The Group paid purchase consideration of $89,296,000 excluding customary purchase price adjustments. The Group funded the cash consideration for the purchase with the proceeds from the Company's equity placing of Ordinary Shares in February 2018, as discussed further in Note 17 "*Share capital and share premium*" to the Group Financial Information. Subsequent to the purchase of these assets, CNX agreed to retain a monthly tariff obligation applicable to the Appalachian assets that requires monthly cash payments to a pipeline transmission company through a portion of calendar year 2022. Tariff payments from the effective date of the purchase through their expiration in 2022 totalled $27,000,000. In exchange for CNX retaining this $27,000,000 pipeline tariff obligation, the Group paid CNX $17,000,000. This one-time payment allowed the Group to retain complete and uninterrupted access to the applicable pipeline system and eliminates the $27,000,000 tariffs the Group would have paid over the remaining term. Associated costs of the acquisition were $1,590,000, of which $14,000 were recognised in the year ended 31 December 2019 and $1,576,000 in the year ended 31 December 2018.

The properties associated with the acquisition have been comingled with the Group's existing properties and it is impractical to provide stand-alone operational results related to these acquired properties.

The Directors determined the fair value of the reserves held in the assets acquired to be $130,500,000 which was approximately 9 per cent. cumulative cash flow discount reserve derived from a third-party engineer at the time of purchase. The fair values of the assets and liabilities assumed were as follows:

	$'000
Oil and gas properties	130,500
Oil and gas properties (asset retirement obligation, asset portion)	14,332
Asset retirement obligation	(14,332)
Other liabilities	(4,790)
Gain on bargain purchase	(36,414)
Purchase price	**89,296**

The Group recorded a $36,414,000 gain on the CNX Assets Acquisition which the Directors believe is reasonable given the facts and circumstances of CNX Assets Acquisition. The Directors believe that CNX was motivated to divest of assets it considered as being non-core to their operations and was willing to sell the assets at under fair market value.

EQT Assets Acquisition

In July 2018, the Group acquired approximately 11,250 conventional natural gas wells and a wholly-owned midstream gathering and a compression system with approximately 6,400 miles of pipeline and 59 compressor stations in the states of Kentucky, West Virginia and Virginia and other equipment from EQT. The Group paid purchase consideration of $527,158,000 excluding customary purchase price adjustments. The Group funded the cash consideration for the purchase with the proceeds from a placing of the Company's Ordinary Shares in July 2018, discussed in Note 17 "*Share capital and share premium*" to the Group Financial Information, and a draw of $336,200,000 from the debt facility discussed in Note 20 "*Borrowings*" to the Group Financial Information. Associated costs of the acquisition were $13,949,000, of which $785,000 were recognised in the year ended 31 December 2019 and $13,164,000 in the year ended 31 December 2018.

The properties associated with the acquisition have been comingled with the Group's existing properties and it is impractical to provide stand-alone operational results related to these acquired properties.

At the time of acquisition, the Group engaged a third party valuation firm to further substantiate the Directors' valuation assumptions. As a result of this valuation, the fair value of the reserves held in the assets acquired was $363,300,000 which was derived using a cumulative discount rate of 10.5 per cent. The tangible assets acquired were determined to have a fair value of $272,343,000 which was derived using a cumulative discount rate of 9.5 per cent. The fair values of the assets and liabilities assumed were as follows:

	$'000
Oil and gas properties	363,300
Oil and gas properties (asset retirement obligation, asset portion)	26,257
Pipelines	205,810
Compressors	46,634
Mobile equipment	8,562
Rights of way	3,250
Buildings	620
Land	2,420
Inventory	5,047
Asset retirement obligation	(26,257)
Suspense[(a)]	(4,764)
Other	(3,428)
Gain on bargain purchase	(100,293)
Purchase price	**527,158**

(a) *Suspense represents the amounts payable to minority working interest owners.*

The Group recorded a $100,293,000 gain on the EQT Assets Acquisition which the Directors believe is reasonable given the facts and circumstances of the EQT Assets Acquisition. The Directors believe that EQT was motivated to divest of assets it considered as being non-core to its operations and was willing to sell the assets at under fair market value.

Acquisition of the stock of Core

In October 2018, the Group acquired Core, which included approximately 5,000 conventional natural gas wells and a wholly-owned midstream gathering and compression system with approximately 4,100 miles of pipeline and 47,000 horsepower of compression in the states of Kentucky, West Virginia and Virginia. The Group funded the acquisition with approximately $46,000,000 of cash and the issue of 35,000,000 Ordinary Shares (at an assumed offering price of $1.41 per Ordinary Share (1.07 pence), which was the last reported sale price of the Ordinary Shares on the acquisition date) discussed further in Note 17 "*Share capital and share premium*" to the Group Financial Information. Associated costs of the acquisition were $5,536,000, of which $1,644,000 were recognised in the year ended 31 December 2019 and $3,892,000 in the year ended 31 December 2018.

The properties associated with the acquisition have been comingled with the Group's existing properties and it is impractical to provide stand-alone operational results related to these acquired properties.

At the time of acquisition, the Group engaged a third party valuation firm to further substantiate management's valuation assumptions. As a result of this valuation, the fair value of the reserves held in the assets acquired was $176,860,000 which was derived using a cumulative discount rate of 10.5 per cent. The tangible assets acquired were determined to have a fair value of $48,812,000 which was derived using a cumulative discount rate of 9 per cent. The fair values of the assets and liabilities assumed were as follows:

	$'000
Cash consideration	45,938
Less cash received	(4,454)
Fair value of stock consideration	49,159
Total consideration	90,643
Net assets acquired:	
Oil and gas properties	176,860
Oil and gas properties (asset retirement obligation, asset portion)	19,214
Pipelines	27,797
Compressors	6,401
Mobile equipment	4,206
Buildings	3,880
Land	6,440
Other	88
Accounts receivable	11,506
Other current assets	3,754
Other long-term assets	6,617
Asset retirement obligation	(19,214)
Accounts payable	(5,586)
Taxes payable	(7,020)
Notes payable assumed	(93,246)
Other current liabilities	(12,259)
Other long-term liabilities	(1,898)
Net assets acquired	**127,540**
Gain on bargain purchase	(36,897)
Purchase price	**90,643**

The Group recorded a $36,897,000 gain on the Core Acquisition which the Directors believe is reasonable given the facts and circumstances of the Core Acquisition. The Directors believe that the owners of Core were interested in purchasing the EQT assets discussed above. The Directors believe that Core recognised that they lost the opportunity to increase in scale in the region after losing the bid and, therefore, Core was willing to divest of its assets at under fair market value.

Other acquisitions

In July 2018, the Group purchased for $20,212,000 additional working interests in certain wells it already operated. These assets were previously held in seven limited partnerships with working interest ranges from 54 per cent. to 82 per cent. to which the Group served as the managing general partner. The Group funded the cash consideration for the purchase with a draw on its debt facility. The working interests associated with the acquisitions have been comingled with the Group's existing properties and it is impractical to provide stand-alone operational results related to these acquired working interests.

2017 Acquisitions

EnerVest Assets Acquisition

In April 2017, the Group acquired approximately 1,300 conventional natural gas and oil wells in Ohio and equipment from EnerVest. The Group paid in cash the consideration totalling $1,750,000. Associated costs of the acquisition were immaterial.

The properties associated with the acquisition have been comingled with the Group's existing properties and it is impractical to provide stand-alone operational results related to these acquired properties.

The Directors considered the fair value of the reserves held in the assets acquired to be $8,500,000, which was the 30 per cent. cumulative cash flow discount reserve valuation derived from a third-party engineer at the time of purchase. During 2018, the Group finalised the fair value measurement of the EnerVest Assets Acquisition. As a result, Group retrospectively adjusted previously reported amounts related to the acquisition in accordance with IFRS 3 "*Business combinations*". The fair values of the assets and liabilities assumed were as follows:

	$'000
Oil and gas properties	8,500
Oil and gas properties (decommissioning provision, asset portion)	2,406
Decommissioning liability	(2,406)
Gain on bargain purchase	(6,750)
Purchase price	**1,750**

Acquisition of assets from Titan Energy

In June 2017, the Group acquired approximately 8,380 producing conventional natural gas and oil wells in the states of Pennsylvania, Ohio, and Tennessee (including approximately 1,140 non-operated wells) and equipment from Titan Energy. The Group paid total consideration of $77,343,000 excluding customary purchase price adjustments. The cash consideration for the purchase was funded by a new $110,000,000 senior secured loan facility, of which, $64,000,000 was drawn at closing on 30 June 2017, and an equity placing of Ordinary Shares. The Company placed 39,300,000 Ordinary Shares at $0.89 per Ordinary Share with certain existing and new institutional investors to raise $35,020,000. The equity placing occurred in two tranches of 11,400,000 Ordinary Shares which raised $10,158,000 and 27,900,000 Ordinary Shares were placed with the second tranche, which raised $24,862,000. Associated costs of the acquisition were $3,621,000, of which $272,000 were recognised in the year ended 31 December 2018 and $3,349,000 in the year ended 31 December 2017.

The properties associated with the acquisition have been comingled with the Group's existing properties and it is impractical to provide stand-alone operational results related to these acquired properties.

The Directors determined the fair value of the reserves held in the assets acquired on 30 June 2017 to be $108,011,000. The fair values of the assets and liabilities assumed were as follows:

	$'000
Oil and gas properties	108,011
Oil and gas properties (decommissioning provision, asset portion)	16,366
Other PPE	1,752
Asset retirement obligation	(16,366)
Other liabilities	(2,279)
Gain on bargain purchase	(30,141)
Purchase price	**77,343**

Acquisition of assets from NGO

In November 2017, the Group acquired approximately 550 wells in Central Ohio from NGO. The Group paid cash consideration totalling $3,114,000. Associated costs of the acquisition were immaterial.

The properties associated with the acquisition have been comingled with the Group's existing properties and it is impractical to provide stand-alone operational results related to these acquired properties.

The Directors determined the fair value of the reserves held in the assets acquired to be $3,003,000, which was approximately 25 per cent. cumulative cash flow discount reserve valuation derived from a third-party engineer at the time of purchase. The fair values of the assets and liabilities assumed were as follows:

	$'000
Oil and gas properties	3,003
Oil and gas properties (decommissioning provision, asset portion)	818
Other PPE	352
Decommissioning liability	(818)
Other liabilities	(39)
Gain on bargain purchase	(202)
Purchase price	**3,114**

6. REVENUE

The Group extracts and sells natural gas, NGLs and crude oil to various customers in addition to operating a majority of these oil and natural gas wells for customers and other working interest owners. In addition, the Group provides gathering and transportation services to third parties. All revenue was generated in the United States. The following table reconciles the Group's revenue for the periods presented:

	Year ended 31 December 2017 $'000	Year ended 31 December 2018 $'000	Year ended 31 December 2019 $'000
Natural gas	30,463	219,189	384,121
NGL	1,043	41,854	33,685
Oil	8,047	19,117	20,474
Total natural gas, NGL and oil	39,553	280,160	438,280
Midstream revenue	—	7,315	22,166
Other	2,224	2,294	1,810
Total revenue	**41,777**	**289,769**	**462,256**

A significant portion of the Group's trade receivables represent receivables related to either sales of natural gas, NGL and oil or operational services, all of which are generally un-collateralised, and collected within 30 to 60 days depending on the commodity, location and well-type.

During the year ended 31 December 2019, one customer individually totalled more than 10 per cent. of total revenues, totalling 13 per cent. (2018: two customers totalling 24 per cent. and 18 per cent., 2017: two customers totalling 25 per cent. and 17 per cent.).

7. EXPENSES BY NATURE

	Year ended 31 December 2017 $'000	Year ended 31 December 2018 $'000	Year ended 31 December 2019 $'000
Employees and benefits (operations)	8,539	35,061	55,947
Well operating expenses, net	6,380	25,315	29,643
Automobile	1,441	5,569	10,504
Insurance	491	4,698	6,208
Production taxes (severance, property and other)	1,345	11,978	16,427
Gathering, compression and transportation	2,712	25,172	83,656
Total operating expense[(a)]	**20,908**	**107,793**	**202,385**
Amortisation	—	212	1,629
Depreciation	862	10,981	21,939
Depletion	6,674	30,795	74,571
Total amortisation, depreciation and depletion	**7,536**	**41,988**	**98,139**
Employees and benefits	2,655	12,653	20,914
Other administrative[(b)]	1,611	1,834	7,383
Professional fees[(c)]	360	5,070	5,212
Auditors' remuneration			
Fees payable to the Company's auditor for the audit of the Group and the Company's annual accounts	55	95	350
Fees payable to the Company's auditor and its associates for other services:			
Audit of accounts of subsidiaries	125	310	1,092
Other assurance services	73	142	225
Total auditors' remuneration	253	547	1,667
Rent	—	—	896
Recurring administrative expenses	**4,879**	**20,104**	**36,072**
Non-recurring costs associated with acquisitions[(d)]	3,349	19,637	9,210
Other non-recurring costs[(e)]	—	—	7,542
Provision for working interest owners receivable[(f)]	632	—	730
Non-cash equity compensation[(g)]	59	783	3,065
Non-recurring administrative expenses	**4,040**	**20,420**	**20,547**
Total administrative expenses	**8,919**	**40,524**	**56,619**
Total expenses	**37,363**	**190,305**	**357,143**

Staff costs

	Year ended 31 December 2017 $'000	Year ended 31 December 2018 $'000	Year ended 31 December 2019 $'000
Aggregate remuneration (including Directors):			
Wages and salaries	8,272	30,238	68,226
Payroll taxes	729	1,972	2,869
Benefits	2,252	4,323	5,766
Total employees and benefits expense	**11,253**	**36,533**	**76,861**

The average monthly number of employees was as follows:

	Year ended 31 December 2017 #	Year ended 31 December 2018 #	Year ended 31 December 2019 #
Field operations	229	488	790
Administration *(including Directors)*	260	112	128
Total employees	**489**	**600**	**918**

The Directors consider that the Group's key management personnel comprise the Directors. Directors' remuneration was as follows:

	Year ended 31 December 2017 #	Year ended 31 December 2018 #	Year ended 31 December 2019 #
Executive Directors			
Salary	767	682	775
Taxable benefits	—	8	11
Bonus	393	205	1,124
	1,160	**895**	**1,910**
Non-Executive Directors			
Salary	485	208	374
	485	**208**	**374**
Total remuneration	**1,645**	**1,103**	**2,284**

(a) Total operating expense increased due to a full year of operating expenses related to the EQT Assets Acquisition and the Core Acquisition. In addition, the year ended 31 December 2019 includes eight months of costs related to the HG Energy Assets Acquisition and three months of costs related to the EdgeMarc Energy assets acquired. See Note 5 "Business acquisitions" to the Group Financial Information for additional information.

(b) Other administrative expense includes general liability insurance, information technology services, other office expenses and travel.

(c) Professional fees include legal fees, marketing fees, payroll fees, consultation fees and costs associated with being a public company.

(d) Non-recurring costs associated with acquisitions primarily relate to legal and consulting costs directly related to the acquisitions.

(e) Other non-recurring costs include costs associated with early buyouts of long-term firm transportation agreements, severance packages, temporary service agreements for onboarding of acquired assets and consolidation of the Group's corporate structure.

(f) Provision for working interest owners' receivable reflects a portion of receivables from working interest owners that the Directors consider uncollectable.

(g) Non-cash equity issuances in each of the years ended 31 December 2019, 31 December 2018 and 31 December 2017 reflect the expense recognition related to stock compensation provided to certain key managers.

8. ADJUSTED EBITDA

Adjusted EBITDA (hedged) and Adjusted EBITDA (unhedged) are a non-IFRS financial measure that is defined as operating profit plus or minus items detailed in the table below, which is of particular interest to the industry and the Directors, as it is essentially the cash generated from operations that the Group has free for interest payments capital investments, and dividend payments. Adjusted EBITDA (hedged) and Adjusted EBITDA (unhedged) should not be considered as an alternative to operating profit/(loss), comprehensive income, cash flow from operating activities or any other financial performance or liquidity measure presented in accordance with IFRS.

The Directors believe Adjusted EBITDA (hedged) and Adjusted EBITDA (unhedged) are a useful measure because it enables a more effective way to evaluate operating performance and compare the results of operations from period-to-period and against its peers without regard to the Company's financing methods or capital structure. The Directors exclude the items listed in the table below from operating profit in arriving at Adjusted EBITDA (hedged) and Adjusted EBITDA (unhedged) for the following reasons:

- certain amounts are non-recurring from the operation of the business such as:
  - o the gain on foreign currency hedge;
  - o costs associated with acquisitions or other one-time events; or
  - o costs associated with gains on oil & gas properties or equipment.

- certain amounts are non-cash such as:
  - o amortisation, depreciation and depletion; and
  - o gains or losses on the valuation of derivative instruments; and
  - o equity issuance costs included in administrative expenses.

The following table reconciles operating profit to Adjusted EBITDA (hedged) and Adjusted EBITDA (unhedged):

	Year ended 31 December 2017 $'000	Year ended 31 December 2018 $'000	Year ended 31 December 2019 $'000
Operating profit	41,161	294,997	180,507
Amortisation, depreciation and depletion	7,536	41,988	98,139
Gain on bargain purchase	(37,093)	(173,473)	(1,540)
Gain on oil and gas programme and equipment	(95)	(4,079)	—
Loss/(gain) on derivative financial instruments	1,965	(33,636)	(20,270)
Non-recurring costs associated with acquisitions	3,349	19,637	9,210
Provision for working interest owners receivable	632	—	730
Other non-recurring costs	—	—	7,542
Non-cash equity issuance included in administrative expenses	59	783	3,065
Gain on foreign currency hedge	—	—	(4,117)
Total adjustments	**(23,647)**	**(148,780)**	**92,579**
Adjusted EBITDA (hedged)	**17,514**	**146,217**	**273,266**
Cash portion of settled hedges	(1,524)	15,655	(53,584)
Adjusted EBITDA (unhedged)	**15,990**	**161,872**	**219,682**
Weighted average Ordinary Shares – basic	120,136	386,559	641,666
Weighted average Ordinary Shares – diluted	120,269	387,925	644,782
Adjusted EBITDA (hedged) per Ordinary Share – basic	**$0.15**	**$0.38**	**$0.43**
Adjusted EBITDA (hedged) per Ordinary Share – diluted	**$0.15**	**$0.38**	**$0.42**

9. TAXATION

The Group files a consolidated US federal tax return, multiple state tax returns, and a separate UK tax return for the Company. Income taxes are provided for the tax effects of transactions reported in the Group Financial Information and consist of taxes currently due, plus deferred taxes related to differences between the basis of assets and liabilities for financial and income tax reporting.

For the taxable year ending 31 December 2019, the Group had a tax expense of $32,091,000 (2018: tax expenses of $60,676,000, 2017: $2,250,000). The effective tax rate was 24.4 per cent. (2018: 23.2 per cent., 2017: 7.5 per cent.) for the same periods. The effective tax rate was primarily impacted by recognition of federal tax credits, capital loss carryovers for which no deferred tax asset was recognised, state taxes, other deferred tax and permanent differences, such as meals and entertainment.

The components of the provision for taxation on income included in the "*Statements of Profit or Loss and Other Comprehensive Income*" for the periods presented are summarised below:

	Year ended 31 December 2017 $'000	Year ended 31 December 2018 $'000	Year ended 31 December 2019 $'000
Current income tax expense			
Federal	—	—	654
State	—	2,894	2,217
Foreign – UK	—	—	142
Total current income tax expense	**—**	**2,894**	**3,013**
Deferred income tax expense			
Federal	883	47,554	22,252
State	1,367	10,228	6,825
Total deferred income tax expense	**2,250**	**57,782**	**29,079**
Total income tax expense	**2,250**	**60,676**	**32,091**

The differences between the statutory federal income tax rate and the effective tax rates are summarised as follows:

	2019	
	$'000	
Expected tax at statutory US federal income tax rate	27,613	21.0%
Increase/(decrease) in tax resulting from:		
State income taxes, net of federal tax benefit	7,946	6.0%
Federal credits	(7,000)	(5.3%)
Other – net	3,532	2.7%
	32,091	**24.4%**

	2018	
	$'000	
Expected tax at statutory US federal income tax rate	54,954	21.0%
Increase/(decrease) in tax resulting from:		
State income taxes, net of federal tax benefit	12,515	4.8%
Federal credits	(7,084)	(2.7%)
Other – net	291	0.1%
	60,676	**23.2%**

	2017	
	$'000	
Expected tax at statutory US federal income tax rate	10,212	34.0%
Increase/(decrease) in tax resulting from:		
State income taxes, net of federal tax benefit	862	2.9%
Federal and state rate changes due to TCJA	(8,526)	(28.4%)
Federal credits	(250)	(0.8%)
Other – net	(48)	(0.2%)
	2,250	7.5%

The Group's effective tax rate was higher for the year ended 31 December 2019 compared to 31 December 2018 primarily due to the Group acquiring assets (through various 2019 asset acquisitions) in higher US state tax rate jurisdictions, including Pennsylvania, and for capital loss carryovers for which no deferred tax asset was recognised.

The Group had a net deferred tax liability of $124,112,000 at 31 December 2019 (2018: $95,033,000, 2017: $17,399,000). The deferred tax liability increased by $29,079,000, primarily due to acquisitions during the year ended 31 December 2019, whereby immediate expensing of the fair value of oil and gas properties acquired subsequent to purchase for federal tax purposes. Additionally, the net deferred tax liability increased due to unrealised gains for unsettled derivatives and due to an increase of US federal and state net operating losses utilised.

The components of the net deferred income tax liability included in noncurrent liabilities are as follows:

	Year ended 31 December 2017 $'000	Year ended 31 December 2018 $'000	Year ended 31 December 2019 $'000
Deferred tax assets			
Decommissioning provision, asset	9,133	46,893	52,254
Derivative adjustment	742	—	—
Allowance for doubtful accounts	166	577	841
Net operating loss carryforward	1,056	53,904	41,199
State net operating loss	216	3,177	2,063
Federal tax credits carryover	250	14,365	19,502
Capital loss carryover	—	1,988	4,610
Valuation allowance	—	(1,988)	(4,610)
Other	83	1,334	2,344
Total deferred tax assets	**11,646**	**120,250**	**118,203**
Deferred tax liabilities			
Amortisation and depreciation	(29,045)	(206,795)	(228,004)
Foreign currency translation adjustment	—	(8,488)	(14,311)
Total deferred tax liabilities	**(29,045)**	**(215,283)**	**(242,315)**
Net deferred tax liabilities	**(17,399)**	**(95,033)**	**(124,112)**

The Group reported the effects of deferred tax expense as follows for the year ended 31 December 2019:

	Opening balance $'000	Income statement $'000	Closing balance $'000
Decommissioning provision, liability	46,893	5,361	52,254
Allowance for doubtful accounts	577	264	841
Net operating loss carryforward	53,904	(12,704)	41,200
State net operating loss	3,177	(1,114)	2,063
Federal tax credits carryover	14,365	5,138	19,503
Premises, equipment and oil and gas properties	(206,795)	(21,210)	(228,005)
Derivative adjustment	(8,488)	(5,823)	(14,311)
Other	1,334	1,009	2,343
Total deferred tax liabilities	**(95,033)**	**(29,079)**	**(124,112)**

The Group reported the effects of deferred tax expense as follows for the year ended 31 December 2018:

	Opening balance $'000	Income statement $'000	Acquisitons $'000	Closing balance $'000
Decommissioning provision, liability	9,133	29,607	8,153	46,893
Allowance for doubtful accounts	166	411	—	577
Net operating loss carryforward	1,056	52,848	—	53,904
State net operating loss	216	2,961	—	3,177
Federal tax credits carryover	250	7,085	7,030	14,365
Premises, equipment and oil and gas properties	(29,045)	(142,599)	(35,151)	(206,795)
Derivative adjustment	742	(9,230)	—	(8,488)
Other	83	1,135	116	1,334
Total deferred tax liabilities	**(17,399)**	**(57,782)**	**(19,852)**	**(95,033)**

The Group reported the effects of deferred tax expense as follows for the year ended 31 December 2017:

	Opening balance $'000	Income statement $'000	Closing balance $'000
Decommissioning provision, liability	4,696	4,437	9,133
Allowance for doubtful accounts	—	166	166
Net operating loss carryforward	1,677	(621)	1,056
State net operating loss	—	216	216
Federal tax credits carryover	—	250	250
Premises, equipment and oil and gas properties	(21,563)	(7,482)	(29,045)
Derivative adjustment	360	382	742
Foreign currency translation adjustment	(319)	319	—
Other	—	83	83
Total deferred tax liabilities	**(15,149)**	**(2,250)**	**(17,399)**

The Group's deferred tax assets and liabilities all arise in the US.

For US federal tax purposes, the Group is taxed as one consolidated entity, which includes the Company. The Company is subject to additional taxes in its home jurisdiction of the UK. For the year ended 31 December 2019, the Company incurred $100,000 of income tax liability in the UK (2018: $nil, 2017: $nil).

On 22 December 2017, the President of the United States signed into law the TCJA tax reform legislation. This legislation makes significant change in US tax law including a reduction in the corporate tax rates, changes to net operating loss carryforwards and carrybacks, and a repeal of the corporate AMT. The legislation reduced the US corporate tax rate from the current rate of 34 per cent. to 21 per cent. for the year ended 31 December 2018.

As at 31 December 2019, the Group continued to maintain the $2,100,000 uncertain tax position liability related to uncertain tax positions that Alliance Petroleum had taken in years prior to the Group acquiring Alliance Petroleum. The Group recorded an indemnification receivable in the same amount of $2,100,000 because the purchase agreement between the Group and Alliance Petroleum's former owners provided a specific indemnification for these uncertain tax positions. The Group does not have any other uncertain tax positions as of 31 December 2019.

As at 31 December 2019, the Group had US federal net operating loss carryforwards of approximately $196,200,000. The remaining US federal net operating loss carryforward of $196,200,000 generated in the year ended 31 December 2018 does not have an expiration date. Additionally, the Group has US state net operating loss carryforwards of approximately $40,600,000, which expire in the years 2036 through 2038.

As at 31 December 2019, the Group had US federal marginal well tax credit carryforwards of approximately $19,500,000, which expire in the years 2036 through 2039.

At 31 December 2019, the Group had US federal capital loss carryovers of $17,600,000, which expire in the years 2020 through 2023. The Group does not expect to utilise these carryovers, and therefore, a deferred tax asset for these carryovers has not been recorded.

The Group completed a Section 382 study through 31 December 2019 in accordance with the Internal Revenue Code of 1986, as amended. The study concluded that the Group has experienced ownership changes as defined by Section 382 on 3 February 2017 and on 6 March 2018. This causes the Group's utilisation of its US federal and state net operating loss and US federal tax credit carryforwards to be subject to annual limitations. The Directors expect the Group's net operating loss carryforwards to be fully available for utilisation by 31 December 2019 and tax credit carryforwards to be fully available for utilisation by 2024. The Group's ability to utilise its US federal and state net operating loss and US federal tax credit carryforwards may be further limited as a result of subsequent ownership changes. All such limitations could result in the expiration of carryforwards before they are utilised.

10. EARNINGS PER ORDINARY SHARE

The calculation of basic earnings per Ordinary Share is based on the income after taxation available to Shareholders and on the weighted average number of Ordinary Shares outstanding during the period. The calculation of diluted earnings per Ordinary Share is based on the income after taxation available to Shareholders and the weighted average number of Ordinary Shares outstanding plus the weighted average number of Ordinary Shares that would be issued if dilutive options and warrants were converted into Ordinary Shares on the last day of the reporting period. Basic and diluted earnings per Ordinary Share is calculated as follows:

	Year ended 31 December 2017 $'000	**Year ended 31 December 2018 $'000**	**Year ended 31 December 2019 $'000**
Income after taxation *(a)*	27,454	201,119	99,400
Weighted average number of Ordinary Shares – basic (#'000) *(b)*	120,316	386,559	641,666
Weighted average number of Ordinary Shares – diluted (#'000) *(c)*	120,269	387,925	644,782
Earnings per Ordinary Share basic *(=a/b)*	**$0.23**	**$0.52**	**$0.15**
Earnings per Ordinary Share diluted *(=a/c)*	**$0.23**	**$0.52**	**$0.15**
Adjusted EBITDA per Ordinary Share basic (Note 10 "Earnings per Ordinary Share" to the Group Financial Information)	**$0.15**	**$0.38**	**$0.43**
Adjusted EBITDA per Ordinary Share diluted (Note 10 "Earnings per Ordinary Share" to the Group Financial Information)	**$0.15**	**$0.38**	**$0.42**

11. DIVIDENDS

The following table summarises the Company's dividends paid and declared:

Date declared	$	£	Record date	Pay date	Ordinary Shares outstanding	Gross dividend paid $'000
Dividend declared 15 June 2017	0.0199	0.0155	07 July 2017	31 July 2017	145,076	2,888
Dividend declared 11 September 2017	0.0199	0.0149	17 November 2017	20 December 2017	145,076	2,888
Dividends paid during the year ended 31 December 2017						**5,776**
Dividend declared 30 April 2018	0.0345	0.0251	11 May 2018	25 May 2018	311,476	10,746
Dividend declared 29 June 2018	0.0173	0.0131	13 July 2018	24 September 2018	311,476	5,373
Dividend declared 11 September 2018	0.0280	0.0223	30 November 2018	19 December 2018	542,633	15,194
Dividends paid during the year ended 31 December 2018						**31,313**
Dividend declared 14 December 2018	0.0330	0.0253	8 March 2019	29 March 2019	542,654	17,908
Dividend declared 28 February 2019	0.0340	0.0239	12 April 2019	28 June 2019	542,654	18,450
Dividend declared 13 June 2019	0.0342	0.0278	6 September 2019	27 September 2019	663,636	22,696
Dividend declared 8 August 2019	0.0350	0.0269	29 November 2019	20 December 2019	659,903	23,097
Dividends paid during the year ended 31 December 2019						**82,151**

On 10 December 2019, the Company announced a dividend of $0.035 per Ordinary Share. The dividend will be paid on 27 March 2020 to Shareholders on the register as at 6 March 2020. No liability is recorded in the Group Financial Information in respect of this dividend as it was not approved by the Shareholders as at 31 December 2019.

12. OIL AND GAS PROPERTIES

The following table summarises the Group's oil and gas properties for each of the periods presented:

	$'000
Cost as at 1 January 2017	94,608
Additions[(a)]	145,527
Disposals	(321)
Cost as at 31 December 2017	**239,814**
Additions[(a)]	908,514
Disposals	(93)
Cost as at 31 December 2018	**1,148,235**
Additions[(a)]	482,525
Disposals[(b)]	(10,000)
Cost as at 31 December 2019	**1,620,760**
Accumulated depletion and impairment at 1 January 2017	(17,815)
Charge for the year	(6,674)
Disposals	—
Accumulated depletion and impairment at 31 December 2017	**(24,489)**
Charge for the year	(30,795)
Disposals	—
Accumulated depletion and impairment at 31 December 2018	**(55,284)**
Charge for the year	(74,571)
Disposals	—
Accumulated depletion and impairment at 31 December 2019	**(129,855)**
Net book value as at 31 December 2017	**215,325**
Net book value as at 31 December 2018	**1,092,951**
Net book value as at 31 December 2019	**1,490,905**

(a) See Note 5 "Business acquisitions" to the Group Financial Information for more information about the Group's acquisitions.

(b) In November 2019, the Group sold the 3 drilled but uncompleted wells that were acquired in the EdgeMarc Energy Acquisition set out in Note 5 "Business acquisitions" to the Group Financial Information. The carrying value of the 3 drilled but uncompleted wells at the time of sale was $10,000,000.

The Directors have reviewed the carrying value of the Group's oil and gas properties as at 31 December 2019. Based on this review, the carrying value oil and gas properties is not impaired.

13. INTANGIBLE ASSETS

	Total $'000
Cost as at 1 January 2017	**—**
Additions	—
Cost as at 31 December 2017	**—**
Additions	2,775
Cost as at 31 December 2018	**2,775**
Additions	15,046
Cost as at 31 December 2019	**17,821**
Accumulated amortisation at 1 January 2017	**—**
Charge for the year	—
Accumulated amortisation at 31 December 2017	**—**
Charge for the year	(212)
Accumulated amortisation at 31 December 2018	**(212)**
Charge for the year	(1,629)
Accumulated amortisation at 31 December 2019	**(1,841)**
Net book value as at 31 December 2017	**—**
Net book value as at 31 December 2018	**2,563**
Net book value as at 31 December 2019	**15,980**

Additions during the period under review relate to costs associated with the Group's ERP project.

14. PROPERTY AND EQUIPMENT

	Total $'000
Cost as at 1 January 2017	5,223
Additions	4,595
Disposals	(142)
Cost as at 31 December 2017	**9,676**
Additions[(a)]	328,084
Disposals	(142)
Cost as at 31 December 2018	**337,618**
Additions[(b)]	22,619
Disposals	—
Cost as at 31 December 2019	**360,237**
Accumulated depreciation at 1 January 2017	(1,875)
Charge for the year	(862)
Disposals	8
Accumulated depreciation at 31 December 2017	**(2,729)**
Charge for the year	(10,981)
Disposals	1,278
Accumulated depreciation at 31 December 2018	**(12,432)**
Charge for the year	(21,939)
Disposals	—
Accumulated depreciation at 31 December 2019	**(34,371)**
Net book value as at 31 December 2017	**6,947**
Net book value as at 31 December 2018	**325,186**
Net book value as at 31 December 2019	**325,866**

(a) Of the $328,084,000 in additions, $318,848,000 relates to equipment purchased through acquisitions discussed further in Note 5 "Business acquisitions" to the Group Financial Information.

(b) Of the $22,619,000 in additions, $7,700,000 relates to equipment purchased through the Dominion and Equitrans acquisitions discussed further in Note 5 "Business acquisitions" to the Group Financial Information.

Additions relate to routine capital projects on the Group's compressor and gathering systems, vehicle and equipment additions.

15. OTHER NON-CURRENT AND CURRENT ASSETS

The following table includes a detail of other assets as at the periods presented:

	Year ended 31 December 2017 $'000	Year ended 31 December 2018 $'000	Year ended 31 December 2019 $'000
Other non-current assets			
Derivative financial instruments	—	21,745	3,803
Other non-current assets	1,036	798	388
Total other non-current assets	**1,036**	**22,543**	**4,191**
Other current assets			
Prepaid expenses	513	2,996	4,317
Derivative financial instruments	—	17,573	73,705
Other current assets	—	4,171	383
Inventory	—	5,303	5,163
Total other current assets	**513**	**30,043**	**83,568**

16. TRADE RECEIVABLES

The majority of trade receivables are current and the Directors believe these receivables are collectible. Trade receivables also include certain receivables from third-party working interest owners. The Directors consistently assess the collectability of these receivables. As at 31 December 2019, the Directors considered a portion of these working interests receivables uncollectable and recorded a provision in the amount of $3,210,000 (2018: $2,200,000, 2017: $nil).

	Year ended 31 December 2017 $'000	**Year ended 31 December 2018 $'000**	**Year ended 31 December 2019 $'000**
Trade receivables	13,917	78,451	73,924

17. SHARE CAPITAL AND SHARE PREMIUM

In February 2017, the Company placed 61,000,000 Ordinary Shares at 65 pence per Ordinary Share to raise gross proceeds of $49,589,000 (approximately £39,650,000). The Company used the funds raised for the repurchase of bonds, repayment of existing debt facilities, costs of admission to AIM and working capital requirements of the Group. Following this initial placing, in June 2017, the Company issued an additional 39,300,000 Ordinary Shares at 70 pence per Ordinary Share to raise additional gross proceeds of $35,020,000 (approximately £27,510,000) to fund part of the purchase price for the Titan acquisition.

In February 2018, the Company placed 166,400,000 Ordinary Shares at $1.13 per Ordinary Share (80 pence) to raise gross proceeds of $188,775,000 (approximately £133,120,000). Associated costs of the placing were $8,241,000. The Company used the net proceeds to fund the Alliance Petroleum Acquisition and the CNX Assets Acquisition discussed in Note 5 "*Business acquisitions*" to the Group Financial Information.

In July 2018, the Company placed 195,330,000 Ordinary Shares at $1.28 per Ordinary Share (97 pence) to raise gross proceeds of $250,005,000 (approximately £189,470,000). Associated costs of the placing were $10,171,000. The Company used the net proceeds to partially fund the EQT Assets Acquisition discussed in Note 5 "*Business acquisitions*" to the Group Financial Information.

In October 2018, the Company placed 35,000,000 Ordinary Shares at an assumed offering issue price of $1.41 per Ordinary Share (£1.07) (which was the last reported sale price on the acquisition date) for an assumed value of $49,159,000 to partially fund the Core Acquisition. See further discussion surrounding the acquisition in Note 5 "*Business acquisitions*" to the Group Financial Information.

In April 2019, the Company placed 151,515,000 Ordinary Shares at $1.52 per Ordinary Share (£1.17) to raise gross proceeds of $230,676,000 (approximately £177,278,000). Associated costs of the placing were $8,817,000. The Company used the net proceeds to fund the HG Energy Assets Acquisition set out in Note 5 "*Business acquisitions*" to the Group Financial Information.

In April 2019, the Company announced the terms of a share buyback program. During the year ended 31 December 2019, the Company repurchased 38,662,000 Ordinary Shares at an average price of $1.36 per Ordinary Share, totalling $52,902,000. The Company has accounted for the repurchase of these Ordinary Shares as a direct reduction to retained earnings. All repurchased shares will be cancelled.

The following table summarises the Company's share capital for the periods presented:

	Note	Number of Ordinary Shares '000	Total share capital $'000	Total share premium $'000
Balance as of 1 January 2017		44,210	669	313
Issuance – initial offering		61,381	768	43,550
Issuance – secondary offering		39,485	503	32,163
Balance as at 31 December 2017		**145,076**	**1,940**	**76,026**
Issuance		166,400	2,359	178,301
Issuance	*(a)*	195,330	2,575	236,621
Issuance		35,000	463	49,159
Other issues		848	9	548
Balance as at 31 December 2018		**542,654**	**7,346**	**540,655**
Issuance of Ordinary Shares		151,515	1,972	219,888
Repurchase of Ordinary Shares		(38,662)	(518)	—
Other issues	*(b)*	223	—	—
Balance as at 31 December 2019		**655,730**	**8,800**	**760,543**

(a) In November 2018, the Company issued 162,619 restricted stock units to certain members of management and 685,231 Ordinary Shares upon conversion of stock warrants granted to Smith and Williamson relating to the initial public offering. The restricted stock units had no impact on share capital or share premium. The conversion of the warrants resulted in a $9,000 increase to share capital and a $548,000 increase to share premium.

(b) During the year ended 31 December 2019, the Company issued 223,000 restricted stock units to certain members of management. The issuance of these Ordinary Shares had no impact on share capital or share premium for the year ended 31 December 2019. See further information regarding DGO's share-based compensation in Note 7 "Expenses by nature".

18. ASSET RETIREMENT OBLIGATION

The Group records a liability for future cost of decommissioning its oil and gas properties, which it expects to incur over the long producing life of its wells (the Group presently expects all of its existing wells to have reached the end of their economic lives by 2093). The Group also records a liability for the future cost of decommissioning its production facilities and pipelines if required by contract or statute. The decommissioning liability represents the present value of estimated future decommissioning costs.

In estimating the present value of future decommissioning costs of the Group's oil and gas properties, the Directors take into account the number and state jurisdictions of wells, current costs to decommission by state and the average well life across its portfolio. The Directors' assumptions are based on the current economic environment and represent what they believe is a reasonable basis upon which to estimate the Group's future liability. However, actual decommissioning costs will ultimately depend upon future market prices at the time the decommissioning services are performed. Furthermore, the timing of decommissioning will vary depending on when the fields cease to produce economically, which makes the determination dependent upon future oil and gas prices, which are inherently uncertain.

The Directors apply a contingency allowance for annual cost increases and discounts the resulting cash flows using a credit adjusted risk free discount rate. The Directors consider the Bloomberg 15-year US Energy BB bond to most closely align with the underlying long-term and unsecured liability and have derived their risk adjusted rate by reference to that. The risk discount rate used in the calculation of the Group's decommissioning liability for the year ended 31 December 2019 was 7.3 per cent. (2018: 8.0 per cent., 2017: 8.0 per cent.) and the allowance for annual cost increases 2.3 per cent. (2018: 2.2 per cent., 2017: 2.2 per cent.) resulting in a net rate of 5.0 per cent. (2018: 5.8 per cent., 2017: 5.8 per cent.).

The composition of the provision for asset retirement obligations at each reporting date was as follows:

	Year ended 31 December 2017 $'000	Year ended 31 December 2018 $'000	Year ended 31 December 2019 $'000
Total provision brought forward	*12,265*	*35,448*	*142,725*
Additions	21,497	96,508	252
Accretion	1,764	7,101	12,349
Disposals	(78)	(1,161)	(2,541)
Revisions to estimate[(a)]	—	4,829	46,736
Total provision carried forward	**35,448**	**142,725**	**199,521**
Less: Current decommissioning provision	—	(2,535)	(2,650)
Non-current decommissioning provision	**35,448**	**140,190**	**196,871**

(a) *During the year ended 31 December 2019, the Directors revised the Group's asset retirement obligation to more closely align estimated plugging costs with historical costs incurred to plug and abandon wells, which resulted in a $4,086,000 increase to the liability. Additionally, as at 31 December 2019, the Directors revised the applicable discount rate from 8.0 per cent. as at 31 December 2018 to 7.3 per cent. as at 31 December 2019 and the allowance for annual cost increases from 2.2 per cent. as at 31 December 2018 to 2.3 per cent. as at 31 December 2019, resulting in a net decrease in the rate from 5.8 per cent. as at 31 December 2018 to 5.0 per cent. as at 31 December 2019. This revision resulted in a $46,736,000 increase to the liability. The remaining increase was related to a revision in the costs associated with plugging wells. With respect to the year ended 31 December 2018, the Directors retained the applicable discount rate at 8.0 per cent. as used for the year ended 31 December 2017. The increase of $4,829,000 was a result of a revision in the costs associated with plugging wells.*

Changes to the Directors' assumptions used as inputs for the estimation of the Group's asset retirement obligation could result in a material change in the carrying value of the liability. A one hundred basis point increase in the gross discount rate could have an approximately $74,000,000 impact on the Group's asset retirement obligation as at 31 December 2019.

19. LEASES

The Group leased automobiles, equipment and real estate under leases as at 31 December 2019, 31 December 2018 and 31 December 2017. Future minimum lease payments for the periods under review were as follows:

	Year ended 31 December 2017 $'000	Year ended 31 December 2018 $'000	Year ended 31 December 2019 $'000
Not later than one year	324	842	798
Later than one year and not later than five years	971	2,694	1,015
Later than five years	—	—	—
Total minimum lease payments	**1,295**	**3,536**	**1,813**
Less amount representing interest	(135)	(351)	—
Present value of minimum lease payments	**1,160**	**3,185**	**1,813**

Reconciliation of leases arising from financing activities:

	Total present value of minimum lease payments $'000
As at 1 January 2017	443
Net cash flows	717
As at 31 December 2017	**1,160**
Net cash flows	2,025
As at 31 December 2018	**3,185**
Net cash flows	(1,372)
As at 31 December 2019	**1,813**

20. BORROWINGS

The Group's borrowings consist of the following amounts for the periods presented:

	Year ended 31 December 2017 $'000	Year ended 31 December 2018 $'000	Year ended 31 December 2019 $'000
Individuals and institutional investor bonds, interest rate of 8.50%, maturing June 2020, unsecured	81	86	—
Financial institution, interest rate of 2.00% plus LIBOR (2019), 2.25% plus LIBOR (2018) and 8.25% plus LIBOR (2017), secured by oil and gas properties	73,249	495,284	436,700
Securitised note, interest rate of 5.00%, secured by 21.60% of Diversified Production LLC's working interest	—	—	200,000
Miscellaneous, primarily for real estate, vehicles and equipment	495	2,537	8,219
Total borrowings	**73,825**	**497,907**	**644,919**
Less current portion of long-term debt	(373)	(286)	(23,510)
Less deferred financing costs	(2,833)	(15,093)	(22,631)
Total non-current borrowings, net	**70,619**	**482,528**	**598,778**

In March 2018, the Group closed a $500,000,000 five-year credit facility, initially subject to a borrowing limit of $140,000,000. Following the closing of the CNX Assets Acquisition in March 2018, as discussed in Note 5 "*Business acquisitions*" to the Group Financial Information, the borrowing limit increased to $200,000,000.

In July 2018, in conjunction with the EQT Assets Acquisition, the Group closed on an enlarged $1 billion, five-year secured revolving credit facility with an initial borrowing base of $600,000,000 which replaced the existing $200,000,000 facility.

In November 2018, following the October 2018 acquisition of Core, the Group closed on a further-enlarged $1.5 billion, five-year senior secured credit facility. The enlarged facility consolidated the Group's previous $1 billion facility with Core's facility and has an initial borrowing base of $725,000,000. The facility maintains the maturity date of the previous $1 billion facility of July 2023. In December 2018, the Group extinguished $93,000,000 of debt assumed with the Core Acquisition. The facility has an initial interest rate of 2.75 per cent. plus the one-month LIBOR and is subject to a grid that fluctuates from 2.25 per cent. to 3.25 per cent. plus LIBOR based on utilisation.

In April 2019, the Group increased its borrowing base on the $1.5 billion five-year senior secured credit facility from $725,000,000 to $950,000,000. The April 2019, the HG Energy Assets Acquisition, as set out in Note 5 "*Business acquisitions*", was funded partially by a $152,000,000 draw on the upsized credit facility. The facility has an initial interest rate of 2.50 per cent. plus the one-month LIBOR and is subject to a pricing grid that fluctuates from 2.00 per cent. to 3.00 per cent. plus LIBOR based on utilisation.

In June 2019, the Group entered into a fleet financing agreement for $7,700,000, with an implied interest rate of 2 per cent.

On 13 November 2019, the Group formed Diversified ABS, LLC, a limited-purpose, bankruptcy-remote, wholly-owned subsidiary of the Company to enter into a securitised financing agreement for $200,000,000 which was issued through a BBB-rated bond. The Group used the net proceeds of $191,000,000 to pay down its revolving credit facility. The note is secured by 21.6 per cent. of the Group's producing assets, excluding the acquired EdgeMarc Energy assets set out in Note 5 "*Business acquisitions*". Natural gas production associated with the 21.6 per cent. working interest was hedged at 85 per cent. at the close of the agreement, using a 10-year swap and rolling two-year basis hedge. Interest and principal payments on the note are payable on a monthly basis beginning 28 February 2020. During the year ended 31 December 2019, the Group accrued $1,600,000 of interest related to the notes. The legal final maturity date is January 2037, with an amortising maturity of December 2029. The note accrues interest at a stated 5 per cent. rate per annum. In the event that Diversified ABS, LLC has cash flow in excess of the required payments, 25 per cent. to 100 per cent. of the excess cash, contingent on certain performance metrics, is required to pay down additional principal with the remaining proceeds remaining with the Group. The note is subject to a series of covenants and restrictions customary for transactions of this type, including:

- that the Issuer maintains specified reserve accounts to be used to make required interest payments in respect of the note;
- provisions relating to optional and mandatory prepayments and the related payment of specified amounts, including specified make-whole payments in the case of the note under certain circumstances;
- certain indemnification payments in the event, among other things, that the assets pledged as collateral for the note is used in stated ways defective of ineffective; and
- covenants related to recordkeeping, access to information and similar matters.

The note is also subject to customary rapid amortisation events provided for in the indenture, including events tied to failure to maintain stated debt service coverage ratios, failure to maintain certain production metrics, certain change of control and manager termination events, and event of default and the failure to repay of refinance the note on the applicable scheduled maturity date. The note is also subject to certain customary events of default, including events relating to non-payment of required interest, principal or other amounts due on or with respect to the note, failure to comply with covenants within certain time frames, certain bankruptcy events, breaches of specified representations and warranties, failure of security interests to be effective and certain judgments. As at 31 December 2019, the Group was in compliance with all financial covenants.

The following table provides a reconciliation of the Group's future maturities of its total borrowings for each of the periods presented:

	Year ended 31 December 2017 $'000	Year ended 31 December 2018 $'000	Year ended 31 December 2019 $'000
Not later than one year	373	286	23,510
Later than one year and not later than five years	73,452	497,621	515,620
Later than five years	—	—	105,789
Total borrowings	**73,825**	**497,907**	**644,919**

The following table represents the Group's finance costs for each of the periods presented:

	Year ended 31 December 2017 $'000	Year ended 31 December 2018 $'000	Year ended 31 December 2019 $'000
Interest	3,298	15,433	32,662
Amortisation of deferred finance cost	1,212	2,230	3,875
Other	715	80	130
Total finance costs	**5,225**	**17,743**	**36,667**
Loss on retirement of debt	**4,468**	**8,358**	**—**

Reconciliation of borrowings arising from financing activities:

	Year ended 31 December 2017 $'000	Year ended 31 December 2018 $'000	Year ended 31 December 2019 $'000
At the beginning of the year	37,294	70,992	482,814
Acquired as part of business combination	—	118,223	—
Proceeds from new borrowings	75,000	581,221	765,236
Repayments of borrowings	(42,514)	(275,115)	(618,010)
Financing fees paid	—	(17,176)	(11,574)
Amortisation of financing fees	1,212	4,812	3,875
Interest paid in cash	(3,298)	(15,433)	(32,715)
Finance cost	3,298	15,290	32,662
At the end of the year	**70,992**	**482,814**	**622,288**

21. OTHER NON-CURRENT AND CURRENT LIABILITIES

The following table includes a detail of other liabilities as at the periods presented:

	Year ended 31 December 2017 $'000	Year ended 31 December 2018 $'000	Year ended 31 December 2019 $'000
Other non-current liabilities			
Customer deposits	52	—	—
Derivative financial instruments	1,943	—	15,706
Other non-current liabilities	283	1,060	2,335
Total other non-current liabilities	**2,278**	**1,060**	**18,041**
Other current liabilities			
Accrued expenses	2,300	21,852	23,645
Revenue to be distributed[(a)]	3,486	20,159	30,321
Taxes payable	—	13,854	19,379
Net revenue clearing[(b)]	6,472	9,299	9,287
Asset retirement obligation	—	2,535	2,650
Derivative financial instruments	961	—	—
Other current liabilities	2,784	6,261	—
Total other current liabilities	**16,003**	**73,960**	**85,282**

(a) *Revenue to be distributed is revenue that is payable to third-party working interest owners, but has yet to be paid due to title, legal, ownership or other issues. The Group releases the underlying liability as the aforementioned issues become resolved. As the timing of resolution is unknown, the Group records the balance as a current liability. Prior year amounts have been reclassified to current liabilities to conform to current year presentation.*

(b) *Net revenue clearing is estimated revenue that is a payable to third-party working interest owners.*

22. TRADE AND OTHER PAYABLES

The following table includes a detail of trade and other payables as at the periods presented:

	Year ended 31 December 2017 $'000	Year ended 31 December 2018 $'000	Year ended 31 December 2019 $'000
Trade payables	1,811	9,360	16,700
Other payables	321	23	352
Total trade and other payables	**2,132**	**9,383**	**17,052**

23. DERIVATIVES

The following table summarises the Group's calculated fair value of derivative financial instruments:

(Liabilities)/assets	Year ended 31 December 2017 $'000	Year ended 31 December 2018 $'000	Year ended 31 December 2019 $'000
Natural gas			
Swaps	28	4,053	69,242
Collars	311	131	3,882
Basis swaps	(965)	(1,720)	(2,455)
Put options	—	7,292	(24,783)
Total natural gas financial derivative contracts	**(626)**	**9,756**	**45,886**
NGLs			
Swaps	—	26,208	15,859
Total NGLs financial derivative contracts	**—**	**26,208**	**15,859**
Oil			
Swaps	(56)	676	(323)
Collars	(2,222)	2,929	380
Total oil financial derivative contracts	**(2,278)**	**3,605**	**57**
Total financial derivative contracts	**(2,904)**	**39,569**	**61,802**

Netting the fair values of derivative assets and liabilities for financial reporting purposes is permitted if such assets and liabilities are with the same counterparty and a legal right of set-off exists, subject to a master netting arrangement. The Directors have elected to present derivative assets and liabilities net when these conditions are met. The following table outlines the Group's net derivatives for the periods presented:

Derivative financial instruments	Statement of Financial Position line item	Year ended 31 December 2017 $'000	Year ended 31 December 2018 $'000	Year ended 31 December 2019 $'000
Non-current assets	*Other non-current assets*	—	21,745	3,803
Current assets	*Other current assets*	—	17,573	73,705
Total assets		**—**	**39,318**	**77,508**
Non-current liabilities	*Other non-current liabilities*	(1,943)	—	(15,706)
Current liabilities	*Other current liabilities*	(961)	—	—
Total liabilities		**(2,904)**	**—**	**(15,706)**
Net (liabilities)/assets – non-current		(1,943)	21,745	(11,903)
Net (liabilities)/assets – current		(961)	17,573	73,705
Net (liabilities)/assets		**(2,904)**	**39,318**	**61,802**

The Group recorded the following gain/(loss) on derivative financial instruments in the "*Statements of Profit or Loss and Other Comprehensive Income*" for the periods presented:

	Year ended 31 December 2017 $'000	Year ended 31 December 2018 $'000	Year ended 31 December 2019 $'000
Net gain/(loss) on settlements[(a)]	1,524	(15,655)	49,467
Gain on foreign currency hedge	—	—	4,117
Total gain/(loss) on settled derivative instruments	**1,524**	**(15,655)**	**53,584**
Net (loss)/gain on fair value adjustments on unsettled financial instruments[(b)]	(1,965)	33,636	20,270
Total (loss)/gain on derivative financial instruments	**(441)**	**17,981**	**73,854**

(a) Represents the cash settlement of hedges that settled during the year.

(b) Represents the change in fair value of financial instruments net of removing the carrying value of hedges that settled during the period.

All derivatives are defined as Level 2 instruments as they are valued using inputs and outputs other than quoted prices that are observable for the assets and liabilities.

24. FAIR VALUE AND FINANCIAL INSTRUMENTS

(a) Fair value

The fair value of an asset or liability is the price that would be received to sell that asset or paid to transfer that liability in an orderly transaction occurring in the principal marked (or most advantageous market in the absence of a principal market) for such asset or liability. In estimating fair value, the Directors utilise valuation techniques that are consistent with the market approach, the income approach and/or the cost approach. Such valuation techniques are consistently applied. Inputs to valuation techniques include the assumptions that market participants would use in pricing an asset or liability. IFRS 13 "*Fair Value Measurement*" establishes a fair value hierarchy for valuation inputs that gives the highest priority to quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs. The fair value hierarchy is defined as follows:

Level 1: Inputs are unadjusted, quoted prices in active markets for identical assets at the measurement date.

Level 2: Inputs (other than quoted prices included in Level 1) can include the following:

- observable prices in active markets for similar assets;
- prices for identical assets in markets that are not active;
- directly observable market inputs for substantially the full term of the asset; and
- market inputs that are not directly observable but are derived from or corroborated by observable market data.

Level 3: Unobservable inputs which reflect the Director's best estimates of what market participants would use in pricing the asset at the measurement date.

The Group does not hold derivatives for speculative or trading purposes and the derivative contracts held by the Group do not contain any credit-risk related contingent features. The Directors have not elected to apply hedge accounting to derivative contracts.

Netting the fair values of derivative assets and liabilities for financial reporting purposes is permitted if such assets and liabilities are with the same counterparty and a legal right of set-off exists, subject to a master netting arrangement. The Directors have elected to present derivative assets and liabilities net when these conditions are met. When derivative assets and liabilities are presented net, the fair value of the right to reclaim collateral assets (receivable) or the obligation to return cash collateral (payable) is also offset against the net fair value of the corresponding derivative. As at each of 31 December 2019, there were no collateral assets or liabilities associated with derivative assets and liabilities 2018: $nil, 2017: $nil).

Derivatives expose the Group to counterparty credit risk. The derivative contracts have been executed under master netting arrangements which allow the Group, in the event of default by its counterparties, to elect early termination. The Directors monitor the creditworthiness of the Group's counterparties but are not able to predict sudden changes and hence may be limited in their ability to mitigate an increase in credit risk.

Possible actions would be to transfer the Group's positions to another counterparty or request a voluntary termination of the derivative contracts, resulting in a cash settlement in the event of non-performance by the counterparty. For each of the fiscal years ended 31 December 2019, 31 December 2018 and 31 December 2017, the counterparties for all of the Group's derivative financial instruments were lenders under formal credit agreements.

The derivative instruments consist of non-financial instruments considered normal purchases and normal sales.

For recurring and non-recurring fair value measurements categorised within Level 2 and Level 3 of the fair value hierarchy, a description of the valuation technique(s) and the inputs used in the fair value measurement. If there has been a change in valuation technique (ex: changing from a market approach to an income approach or the use of an additional valuation technique), the entity shall disclose that change and the reason(s) for making it.

All financial instruments measured at fair value use Level 2 valuation techniques for the each of the years ended 31 December 2019, 31 December 2018 and 31 December 2017.

Level 2 fair value measurements are those including inputs other than quoted prices included within Level 1 that are observable for the asset or liability directly or indirectly. The fair value of the swap commodity derivatives is calculated using a discounted cash flow model and the fair value of the option commodity derivatives are calculated using a relevant option pricing model, which are calculated from relevant market prices and yield curves at the balance sheet date and are therefore based solely on observable price information. These instruments are not directly quoted in active markets and are accordingly classified as Level 2 in the fair value hierarchy.

There were no transfers between fair value levels during the year ended 31 December 2019 (2018: $nil, 2017: $nil).

(b) Financial instruments

For trade receivables, the Group applies the simplified approach permitted by IFRS 9 "*Financial Instruments*", which requires expected lifetime losses to be recognised from initial recognition of the receivables.

Financial liabilities are initially measured at fair value and subsequently measured at amortised cost.

The Group is not a financial institution. The Group does not apply hedge accounting and its customers are considered creditworthy and pay consistently within agreed payments terms.

A classification of the Group's financial instruments for the periods presented is included in the table below:

At	**Year ended 31 December 2017 $'000**	**Year ended 31 December 2018 $'000**	**Year ended 31 December 2019 $'000**
Cash and cash equivalents held at amortised cost	15,168	1,372	1,661
Trade receivables and accrued income held at amortised cost	13,917	78,451	73,924
Financial assets at amortised cost	1,036	7,952	771
Financial liabilities at amortised cost	(15,377)	(56,328)	(35,267)
Fair value through profit or loss	(2,904)	39,319	61,802
Borrowings, net of deferred financing costs	(70,990)	(482,613)	(622,288)
Total	**(59,150)**	**(411,847)**	**(519,397)**

25. FINANCIAL RISK MANAGEMENT

The Group's financial steering framework is built upon the principles of operational efficiency, capital efficiency, financing efficiency and sustainable portfolio management with a focus on strengthening The Group's balance sheet, delivering positive free cash flow and growing its profitability to create value for Shareholders.

The Directors manage the Group's capital structure to safeguard the Group's capital base in order to preserve investor, creditor and market confidence, as well as to provide a sustainable financial foundation for the future operational development of the Group. The Directors' financing strategy focuses on cash flow and financial stability. Principal targets are positive free cash flow after dividends, a strong leverage ratio and a healthy balance sheet.

The Group's principal financial liabilities comprise of borrowings and trade and other payables, which it uses primarily to finance and financially guarantee its operations.

The Group's principal financial assets include cash and cash equivalents and trade and other receivables derived from its operations.

The Group also enters into derivative transactions, which depending on market dynamics are recorded as assets or liabilities. To assist with its hedging program design and composition, the Directors engage a specialist firm with the appropriate skills and experience to manage the Group's risk management derivative-related activities.

(a) Market risk

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises of two types of risk: interest rate risk and commodity price risk. Financial instruments affected by market risk include borrowings and derivative financial instruments. Derivative and non-derivative instruments are used to manage market price risks resulting from changes in commodity prices and foreign exchange rates which could have a negative effect on assets, liabilities or future expected cash flows.

(b) Interest rate risk

Interest rate risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market interest rates. The Group is subject to this risk exposure as it relates to changes in interest rates on its variable rate borrowings. As discussed in Note 20 "*Borrowings*" to the Group Financial Information, the Group had $437,000,000 of total debt outstanding as at 31 December 2019 (2018; $495,000,000, 2017: $73,249,000) on its senior secured credit facility with interest rate of 2.00 per cent. plus LIBOR. In April 2019, the Group increased its borrowing base on the $1,500,000,000, five-year senior secured credit facility from $725,000,000 to $950,000,000. The facility has an initial interest rate of 2.50 per cent. plus the one-month LIBOR and is subject to a pricing grid that fluctuates from 2.00 per cent. to 3.00 per cent. plus LIBOR based on utilisation. The securitised note discussed further in Note 20 "*Borrowings*", has a stated 5 per cent. interest rate and is not subject to interest rate risk.

As at 31 December 2019, the Directors had elected not to enter an interest rate swap (2018: none, 2017: none).

(c) Commodity price risk

The prices for natural gas and crude oil can be volatile and sometimes experience fluctuations as a result of relatively small changes in supply, weather condition, economic conditions and government actions. The Group's revenues are primarily derived from the sale of its natural gas, NGLs and crude oil production and, as such, the Group is subject to this commodity price risk. During the year ended 31 December 2019, the Group's revenue was $384,121,000, $33,685,000 and $20,474,000 in relation to the sale of natural gas, NGLs and crude oil respectively (2018: $219,189,000, $41,854,000 and $19,117,000, 2017: $30,463,000, $1,043,000 and $8,047,000).

To help manage natural gas and oil price risk, the Group has entered into various direct/physical purchase contracts with gas purchasers and entered into various gas and oil financial contracts with BP Energy Company and Cargill. In March 2018, and concurrent with establishing the revolving credit facility with KeyBank (see Note 20 "*Borrowings*" to the Group Financial Information), the Group novated its existing financial hedge contracts from BP Energy Company and Cargill to KeyBank and Huntington Bank. Further, during the year ended 31 December 2019, the Group worked with other financial institutions to broaden its network of financially stable financial hedge counterparties. See Note 20 "*Borrowings*" to the Group Financial Information for more information on the Group's financial hedge contracts.

The Group's normal policy is to sell its products under contract at prices determined by reference to prevailing market prices on petroleum exchanges and keep options and swaps in place for approximately 36 months on approximately 50 per cent. to 75 per cent. of its anticipated production volumes to minimise commodity risk and create stabilised and predictable cash flow important to funding its operation and stated dividend for Shareholders.

(d) Credit risk

Credit risk is the risk that a customer or counterparty to a financial instrument will not meet its obligations under a contract and arises primarily from the Group's cash in banks and trade receivables.

(e) Cash and cash equivalents

The credit risk from its cash and cash equivalents is limited because the counter parties are banks with high credit ratings and have not experienced any losses in such accounts.

(f) Trade receivables

Trade receivables are due from customers throughout the oil and natural gas industry and collectability is dependent on the financial condition of each individual company as well as the general economic conditions of the industry. The Directors review the financial condition of customers prior to extending credit and generally does not require collateral in support of the Group's trade receivables. The majority of trade receivables are current and the Directors believe these receivables are collectible. As at 31 December 2019, the Group had three customers that individually accounted for more than 10 per cent. of total receivables, totalling 41 per cent. of total trade receivables (2018: two customers that individually accounted for more than 10 per cent. of total receivables, totalling 35 per cent., 2017: two customers that individually accounted for more than 10 per cent. of total receivables, totalling 35 per cent.).

Receivables from joint interest owners, classified in other non-current assets, are generally with other oil and natural gas companies that own a working interest in the properties operated by the Group. The Directors have the ability to withhold future revenue payments to recover any non-payment of joint interest receivables.

(g) Liquidity risk

Liquidity risk is the risk that the Group will not be able to meet its financial obligations as they are due. The Directors manage this risk by:

- maintaining adequate cash reserves through the use of the Group's cash from operations and bank borrowings; and
- continuously monitoring projected and actual cash flows to ensure the Group maintains an appropriate amount of liquidity.

For the year ended 31 December 2019:

	Less than 3 months	3 to 12 months	1 to 5 years	> 5 years	Total
	$'000	$'000	$'000	$'000	$'000
Trade and other payables	17,052	—	—	—	17,052
Borrowings[(a)]	684	23,039	469,453	105,602	598,778
Lease	226	656	931	—	1,813
Other liabilities	13,078	39,233	18,041	—	70,352
Asset retirement obligation	663	1,988	6,401	190,469	199,521
Total	**31,703**	**64,916**	**494,826**	**296,071**	**887,516**

For the year ended 31 December 2018:

	Less than 3 months	3 to 12 months	1 to 5 years	> 5 years	Total
	$'000	$'000	$'000	$'000	$'000
Trade and other payables	9,383	—	—	—	9,383
Borrowings[(a)]	32	254	495,709	1,711	497,706
Lease	123	719	2,694	—	3,536
Other liabilities	21,852	29,646	21,219	—	72,717
Asset retirement obligation	211	2,324	12,675	124,980	140,190
Total	**31,601**	**32,943**	**532,297**	**126,691**	**723,532**

For the year ended 31 December 2017:

	Less than 3 months	3 to 12 months	1 to 5 years	> 5 years	Total
	$'000	$'000	$'000	$'000	$'000
Trade and other payables	2,130	2	—	—	2,132
Borrowings[(a)]	266	107	70,619	—	70,992
Lease	54	270	971	—	1,295
Other liabilities	7,978	3,578	3,821	—	15,377
Total	**10,428**	**3,957**	**75,411**	**—**	**89,796**

(a) *Future borrowings represented in the tables above do not include future interest payments.*

(h) Capital risk

The Directors' objectives when managing capital are to provide returns for Shareholders and safeguard the ability to continue as a going concern while pursuing opportunities for growth through identifying and evaluating potential acquisitions and constructing new infrastructure on existing proved leaseholds. The Directors do not establish a quantitative return on capital criteria, but rather promotes year-on-year growth. The Directors use the Group's Net Debt/Adjusted EBITDA to monitor its capital risk and maintain a target of below 2.5x. See Note 8 "*Adjusted EBITDA*" to the Group Financial Information for more information on Adjusted EBITDA.

(i) Collateral risk

The Group has pledged its oil and gas properties to fulfil the collateral requirements for borrowing credit facilities with its senior secured lenders 21.6 per cent. of the Group's oil and gas properties, excluding the EdgeMarc Energy Acquisition set out in Note 5 "*Business acquisitions*" to the Group Financial Information, are pledged as collateral for the asset backed securitisation discussed in Note 20 "*Borrowings*" to the Group Financial Information. The fair value is based on a third-party engineering reserve calculation using a 10 per cent. cumulative discount cash flow and a commodities futures price schedule.

26. CONTINGENCIES AND PROVISIONS

The Group is involved in various pending legal issues that have arisen in the normal course of business. The Group may be subject to a withholding tax of a maximum of $8,800,000 payable to the US tax authorities in relation to its share buyback programme discussed in Note 17 "*Share capital and share premium*" to the Group Financial Information. At the date of of approval of the Group Financial Information, there is no formal tax assessment or audit from the US tax authorities in relation to this and the Directors are assessing the interpretation of the relevant tax rule to identify if the Group is subject to it. As the share buyback transactions are recognised outside profit or loss, should the outcome of the determination process be that the Group is found to be liable to pay an amount of withholding tax, any necessary adjustment would be recognised through equity. The Company has no other contingent liabilities that would have any material impact on the Group's financial position or results of operations.

The Group's operations are subject to environmental regulation in all the jurisdictions in which it operates. The Directors are unable to predict the effect of additional environmental laws and regulations which may be adopted in the future, including whether any such laws or regulations would adversely affect the Group's operations. The Directors can offer no assurance regarding the significance or cost of compliance associated with any such new environmental legislation once implemented.

27. RELATED PARTY TRANSACTIONS

(a) UK legal counsel

During the year ended 31 December 2019, Martin Thomas was a partner at Wedlake Bell LLP, the UK legal advisor to the Group. The total billings from Wedlake Bell LLP to the Group totalled $195,000 (approximately £150,000) for the year ended 31 December 2019 (2018: Watson Farley & Williams LLP fees of $423,000 (approximately £324,000), 2017: Watson Farley & Williams LLP fees of $834,000 (approximately £661,000)).

(b) Office space lease

During each of the years ended 31 December 2018 and 31 December 2017, the Group leased its corporate headquarters in Birmingham, Alabama (US) from Diversified Real Estate Holdings, LLC, a company owned by Rusty Hutson, Jr., a Director of the Company, and by Robert Post, a Director of the Company at that time. During the year ended 31 December 2018, the Group terminated the lease to purchase a new corporate headquarters. During the year ended 3 December 2018, the Group incurred related party costs in relation to this lease of $106,000 (2017: $86,000). The Directors believe the terms of this lease were reasonable and reflected market rates for a facility of this type.

(c) Dividend payments

For each of the years ended 31 December 2019, 31 December 2018 and 31 December 2017, the Directors became aware that aggregate dividends totalling £94.5m paid during this period had been made otherwise than in accordance with the Companies Act 2006, as unaudited interim accounts had not been filed at Companies House prior to the dividend payments. At a General Meeting of Shareholders held on 15 April 2020, a resolution was passed which authorised the appropriation of distributable profits to the payment of the relevant dividends and removed any right for the Company to pursue Shareholders or Directors for repayment. This constituted a related party transaction under IAS 24 "*Related Party Disclosures*". The overall effect of the resolution being passed was to return all parties so far as possible to the position they would have been in had the relevant dividends been made in full compliance with the Companies Act 2006.

28. SUBSEQUENT EVENTS

Dividends

On 10 December 2019, the Company announced a dividend of $0.035 per Ordinary Share. The dividend was paid on 27 March 2020 to Shareholders on the register as at 6 March 2020. No liability is recorded in the Group Financial Information in respect of this dividend as it was not approved by the Shareholders as at 31 December 2019.

Covid-19

Whilst the Group cannot predict the effect of COVID-19 in the US or elsewhere, it does not believe that COVID-19 will impact the working capital requirements of the Group. It is possible that if the outbreak of COVID-19 in the US increases further, then this may lead to the disruption of the Group's operations in the US. An increase in the number of confirmed COVID-19 cases in the US may lead to the US government imposing travel restrictions and other similar restrictions on economic activities within the US. Such restrictions have the potential to impact the Group's operations until such time as such restrictions are lifted and, as such, the Group's operating results may be affected adversely. As part of the Directors' review over going concern, the Group's cash flow projections have been updated in light of COVID-19. Refer to Note 2.

Acquisitions

On 7 April 2020, Diversified Gas & Oil Corporation, a subsidiary of the Company, executed a conditional Carbon PSA with Carbon in connection with the possible acquisition of the Carbon Assets. If the acquisition were to complete, the Company currently estimates that the consideration payable would comprise: (i) approximately $110,000,000, payable in cash at closing; and (ii) a further payment of up to $15,000,000, subject to the achievement of certain conditions with respect to future gas prices, payable over a period of up to three years after closing. However, the final consideration payable may be less than currently estimated and will be determined post completion of due diligence by the Company and satisfaction of the other conditions under the Carbon PSA.

The potential acquisition of the Carbon Assets is subject to a significant number of conditions. The satisfaction of certain of these conditions are within the sole control of the Group such as completion of due diligence (including all title, environmental, contractual, credit, litigation, and regulatory diligence) to the Company's satisfaction and the Company's right to not complete the acquisition if there is a material change in the conditions, assets, or operational matters of the Carbon Assets prior to completion of the acquisition. In addition, the acquisition is also conditional upon satisfaction of various other conditions, including receipt of all necessary shareholder consents, approvals, authorisations and permits (including any authorisations required from the Federal Energy Regulatory Commission and various State Public Service Commissions).

Carbon has provided customary commercial representations and warranties on the Carbon Assets, which are also conditional upon satisfaction of the conditions under the Carbon PSA and completion of the acquisition.

Under the terms of the Carbon PSA, the Company has a right to exclusivity pursuant to which Carbon has agreed to not enter into any negotiations or discussions with any third party in connection with the disposal of the Carbon Assets for a period ending on 30 June 2020 to enable the Company to complete its due diligence and for the satisfaction of all the conditions under the Carbon PSA. If completed, the Carbon PSA will have an effective date of 1 January 2020.

On 11 May 2020, the Company executed a conditional purchase and sale agreement with certain subsidiaries of EQT in connection with the possible acquisition of the EQT Corporation Assets. If the acquisition were to complete, the Company currently estimates that the consideration payable would comprise: (i) approximately $125,000,000, payable in cash at closing; and (ii) a further payment of up to $20,000,000, subject to the achievement of certain conditions with respect to future gas prices, payable over a period of up to three years after closing. However, the final consideration payable may be less than currently estimated and will be determined post completion of due diligence by the Company and satisfaction of the other conditions under the EQT PSA.

The potential acquisition of the EQT Corporation Assets is subject to a significant number of conditions. The satisfaction of certain of these conditions are within the sole control of the Group such as completion of due diligence (including all title, environmental, contractual, credit, litigation, and regulatory diligence) to the Company's satisfaction and the Company's right to not complete the acquisition if there is a material change in the conditions, assets, or operational matters of the EQT Corporation Assets prior to completion of the acquisition. In addition, the acquisition is also conditional upon satisfaction of various other conditions, including receipt of all necessary shareholder consents, approvals, authorisations and permits.

EQT has provided customary commercial representations and warranties on the EQT Corporation Assets, which are also conditional upon satisfaction of the conditions under the EQT PSA and completion of the acquisition.

Under the terms of the EQT PSA, the Company has a right to exclusivity pursuant to which EQT has agreed to not enter into any negotiations or discussions with any third party in connection with the disposal of the EQT Corporation Assets for a period ending on 28 May 2020 to enable the Company to complete its due diligence and for the satisfaction of all the conditions under the EQT PSA. If completed, the EQT PSA will have an effective date of 1 January 2020.

Equity Placing

On 11 May 2020, the Company and the Banks entered into a placing agreement for the conditional placing of 61,813,500 Ordinary Shares at a price of 108 pence per Ordinary Share pursuant to which the Banks agreed, subject to certain conditions, to use their reasonable endeavours to procure subscribers for the placing shares pursuant to the Placing. The Placing Agreement is conditional upon certain conditions that are typical for an agreement of this nature, including Admission of the placing shares having become effective by not later than 8.00 a.m. on 18 May 2020.

29. ULTIMATE CONTROLLING PARTY

As at 31 December 2019, the Company did not have any one identifiable controlling party.

30. NATURE OF THE GROUP FINANCIAL INFORMATION

The Group Financial Information presented above does not constitute statutory financial statements for the periods under review.

SECTION C: ACCOUNTANT'S REPORT ON THE HISTORICAL FINANCIAL INFORMATION OF ALLIANCE PETROLEUM

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Diversified Gas & Oil PLC
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35242
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Stifel Nicolaus Europe Limited
150 Cheapside
London EC2V 6ET

13 May 2020

Dear Ladies and Gentlemen,

Diversified Gas & Oil PLC

We report on the audited historical financial information of Alliance Petroleum Corporation ("**Alliance Petroleum**") for the year ended 31 December 2017 and the two-month period ended 28 February 2018 (together, the "**Alliance Petroleum Financial Information**"). The Alliance Petroleum Financial Information has been prepared for inclusion in Section D "*Historical Financial Information of Alliance Petroleum" of Part XIV* "*Historical Financial Information*" of Diversified Gas & Oil Plc's prospectus dated 13 May 2020 (the "**Prospectus**"), on the basis of the accounting policies set out in note 3 to the Alliance Petroleum Financial Information. This report is given for the purpose of complying with item 18.3.1 of Annex 1 to the Commission Delegated Regulation (EU) 2019/980 (the "**Commission Regulation**") and is given for the purpose of complying with that item and for no other purpose.

Responsibilities

The directors of the Company (the "**Directors**") are responsible for preparing the Alliance Petroleum Financial Information in accordance with International Financial Reporting Standards, as adopted by the European Union ("**IFRS**").

It is our responsibility to form an opinion on the Alliance Petroleum Financial Information, and to report our opinion to you.

Basis of opinion

We conducted our work in accordance with the Standards for Investment Reporting issued by the Auditing Practices Board in the United Kingdom. Our work included an assessment of evidence relevant to the amounts and disclosures in the Alliance Petroleum Financial Information. It also included an assessment of significant estimates and judgments made by those responsible for the preparation of the Alliance Petroleum Financial Information and whether the accounting policies are appropriate to Alliance Petroleum's circumstances consistently applied and adequately disclosed.

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 sufficient evidence to give reasonable assurance that the Alliance Petroleum Financial Information is free from material misstatement whether caused by fraud or other irregularity or error.

Opinion

In our opinion, the Alliance Petroleum Financial Information gives, for the purpose of the Prospectus, a true and fair view of the state of affairs of Alliance Petroleum as at 31 December 2017 and 28 February 2018 and of its results, cash flows and changes in equity for each of the periods then ended in accordance with IFRS.

Declaration

For the purposes of PR 5.3.2R(2)(F), we declare that, to the best of our knowledge, the information contained in this report, for which we are responsible, is in accordance with the facts and that this report makes no omission likely to affect its import. This declaration is included in the Prospectus in compliance with item 1.2 of Annex 1 to the Commission Delegated Regulation (EU) 2019/980.

Yours faithfully,

Crowe U.K. LLP
Chartered Accountants

SECTION D: HISTORICAL FINANCIAL INFORMATION OF ALLIANCE PETROLEUM

Statements of comprehensive income

The audited statements of comprehensive income of Alliance Petroleum for the year ended 31 December 2017 and the two-month period ended 28 February 2018 are set out below:

	Note	Audited Year ended 31 December 2017 $'000	Audited 2 months ended 28 February 2018 $'000
Revenue	6	45,946	8,516
Cost of sales	7	(26,928)	(5,136)
Depletion	7/11	(2,901)	(754)
Depreciation	7/12	(80)	(19)
Gross profit		**16,037**	**2,607**
Gain on derivative financial instruments	19	9,201	1,927
Gain on bargain purchase	5	21,421	—
Gain on disposal of oil and gas properties		1,522	82
Administrative expenses	7	(7,009)	(994)
Operating profit		**41,172**	**3,622**
Finance costs	17	(1,476)	(210)
Income before taxation		**39,696**	**3,412**
Taxation	8	(10,711)	(268)
Total comprehensive income for the year/period		**28,985**	**3,144**
Earnings per ordinary share – basic and diluted	9	$289,850	$31,440

Statements of financial position

The audited statements of financial position of Alliance Petroleum as at 31 December 2017 and 28 February 2018 are set out below:

	Note	Audited As at 31 December 2017 $'000	Audited As at 28 February 2018 $'000
ASSETS			
Non-current assets			
Oil and gas properties	11	90,001	89,286
Property and equipment	12	2,172	2,079
		92,173	**91,365**
Current assets			
Inventories	13	248	248
Other current assets	14	964	785
Trade receivables	15	13,683	16,075
Derivative financial instruments	19	—	1,851
Cash and cash equivalents		7,861	8,638
		22,756	**27,597**
Total assets		**114,929**	**118,962**
EQUITY AND LIABILITIES			
Shareholders' equity			
Share capital	16	—	—
Retained earnings		27,439	30,583
Total equity		**27,439**	**30,583**
Non-current liabilities			
Borrowings	17	37,209	37,215
Asset retirement obligation	18	20,459	20,609
Deferred tax liability	8	7,500	7,672
Derivative financial instruments	19	—	109
Other non-current liabilities	20	105	10
Total non-current liabilities		**65,273**	**65,615**
Current liabilities			
Trade payables	21	3,819	5,821
Borrowings	17	434	146
Derivative financial instruments	19	535	—
Other current liabilities	20	17,429	16,797
		22,217	**22,764**
Total liabilities		**87,490**	**88,379**
Total liabilities and equity		**114,929**	**118,962**

Statements of changes in shareholders' equity

The audited statements of changes in shareholders' equity of Alliance Petroleum for the year ended 31 December 2017 and the two-month period ended 28 February 2018 are set out below:

	Note	Share capital $'000	Retained earnings $'000	Total equity $'000
Balance at 1 January 2017		**—**	**(497)**	**(497)**
Income after taxation		—	28,985	28,985
Total comprehensive income for the year		—	*28,985*	*28,985*
Dividends authorised and declared	10	—	(1,049)	(1,049)
Transactions with owners		—	*(1,049)*	*(1,049)*
Balance as at 31 December 2017		**—**	**27,439**	**27,439**
Profit after taxation		—	3,144	3,144
Total comprehensive profit for the period		—	*3,144*	*3,144*
Balance as at 28 February 2018		**—**	**30,583**	**30,583**

Statements of cash flows

The audited statements of cash flows of Alliance Petroleum for the year ended 31 December 2017 and the two-month period ended 28 February 2018 are set out below:

	Audited Year ended 31 December 2017 $'000	Audited 2 months ended 28 February 2018 $'000
Cash flows from operating activities		
Income after taxation	28,985	3,144
Cash flow from operations reconciliation:		
Depletion of oil and gas properties	2,901	754
Depreciation of property, plant and equipment	523	118
Accretion of asset retirement obligation	1,474	150
Unrealised gain on derivative financial instruments	(3,690)	(2,277)
Gain on bargain purchase	(21,421)	—
Gain on disposal of oil and gas properties	(1,522)	(82)
Finance costs	1,476	210
Working capital adjustments:		
Change in inventories	27	—
Change in trade receivables	(6,089)	(2,392)
Change in other current assets	(127)	179
Change in trade payables	234	2,002
Change in other current liabilities	14,163	(632)
Change in other non-current liabilities	(46)	77
Net cash from operating activities	**16,888**	**1,251**
Cash flows from investing activities		
Purchase of property, plant and equipment	(553)	(25)
Proceeds from the sale of property, plant and equipment	—	82
Purchase of oil and gas properties	(5,075)	(39)
Proceeds from the sale of oil and gas properties	1,522	—
Net cash (used in)/from investing activities	**(4,106)**	**18**
Cash flows from financing activities		
Repayment of borrowings	(6,170)	(282)
Dividends to shareholders	(1,049)	—
Interest paid	(1,476)	(210)
Net cash used in financing activities	**(8,695)**	**(492)**
Net increase in cash and cash equivalents	**4,087**	**777**
Cash and cash equivalents – beginning of the period	*3,774*	*7,861*
Cash and cash equivalents – end of the period	**7,861**	**8,638**

NOTES TO THE ALLIANCE PETROLEUM FINANCIAL INFORMATION

1. GENERAL INFORMATION

Alliance Petroleum is a natural gas and crude oil producer that is focused on acquiring and operating mature producing wells with long lives and slow decline profiles. Alliance Petroleum's assets are exclusively located within Pennsylvania, West Virginia and Ohio in the Appalachian Basin of the US. Alliance Petroleum is headquartered in Birmingham, Alabama, USA with field offices located in the states of Pennsylvania, West Virginia and Ohio.

Alliance Petroleum was incorporated on 29 April 1985 in Georgia, US, as a private limited company under company number 8604701 and the name Petroleum Management Corporation. Petroleum Management Corporation changed its name to Alliance Petroleum on 12 March 1987.

2. BASIS OF PREPARATION AND MEASUREMENT

The Alliance Petroleum Financial Information has been prepared in accordance with IFRS, issued by the International Accounting Standards Board, including interpretations issued by the International Financial Reporting Interpretations Committee.

Unless otherwise stated, the Alliance Petroleum Financial Information is presented in $ which is the currency of the primary economic environment in which Alliance Petroleum operates, and all values are rounded to the nearest thousand dollars except per unit amounts and where otherwise indicated.

Transactions in foreign currencies are translated into $ at the rate of exchange on the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated at the exchange ruling at the balance sheet date. The resulting gain or loss is reflected in the "*Statements of Profit or Loss and Other Comprehensive Income*" within "*Other comprehensive income – gain on foreign currency conversion*".

The Alliance Petroleum Financial Information has been prepared under the historical cost convention, except for derivative financial instruments that have been measured at fair value.

The Alliance Petroleum Financial Information has been prepared on the going concern basis, which contemplates the continuity of normal business activity and the realisation of assets and the settlement of liabilities in the normal course of business. The Directors have reviewed Alliance Petroleum's overall position and outlook and are of the opinion that Alliance Petroleum is sufficiently well funded to be able to operate as a going concern for at least the next twelve months from the date of Admission.

The Alliance Petroleum Financial Information has been prepared using accounting policies consistent with those used in the preparation of the Group Financial Information set out in Section B "*Historical Financial Information of the Group*" of Part XIV "*Historical Financial Information*".

3. SIGNIFICANT ACCOUNTING POLICIES

The preparation of the Alliance Petroleum Financial Information in compliance with IFRS requires the Directors to exercise judgment in applying Alliance Petroleum's accounting policies. The areas involving a higher degree of judgment or complexity, or areas where assumptions and estimates are significant to the Alliance Petroleum Financial Information are disclosed in Note 4 "*Significant judgements, estimates and assumptions*" to the Alliance Petroleum Financial Information.

(a) Cash

Cash on the balance sheet comprises cash at banks. As at 28 February 2018, Alliance Petroleum's cash balance was $8,638,000 (2017: $7,861,000).

For the purpose of the "*Statements of Cash Flows*", cash and cash equivalents consist of cash and cash equivalents as defined above.

(b) Trade receivables

Trade receivables are stated at the historical carrying amount, net of any provisions required.

(c) Derivative financial instruments

Derivatives are used as part of the Directors' overall strategy to mitigate risk associated with the unpredictability of cash flows due to volatility in commodity prices. Further details of Alliance Petroleum's exposure to these risks are detailed in Note 19 "*Derivative financial instruments*" to the Alliance Petroleum Financial Information. Alliance Petroleum has entered into financial instruments which are considered derivative contracts, such as swaps and collars which result in net cash settlement each month and do not result in physical deliveries. The derivative contracts are initially recognised at fair value at the date contract is entered into and re-measured to fair value every balance sheet date. The resulting gain or loss is recognised in the "*Statements of Profit or Loss and Other Comprehensive Income*" in the year incurred.

(d) Oil and gas properties

Development and acquisition costs

Expenditures related to the construction, installation or completion of infrastructure facilities, such as platforms and pipelines, and the drilling of development wells, including delineation wells, are capitalised within oil and gas properties. The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of the decommissioning obligation, for qualifying assets, and borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

Exploration and evaluation costs

Alliance Petroleum follows IFRS 6 "*Exploration for and Evaluation of Mineral Resources*" in accounting for oil and gas assets. Costs incurred prior to obtaining the legal rights to explore an area are expensed immediately to the "*Statements of Profit or Loss and Other Comprehensive Income*". Only material expenditures incurred after the acquisition of a license interest are capitalised. Historically, the expenditures related to exploration and evaluation have not been material, as Alliance Petroleum drills in active areas where there are minimal and immaterial exploration and evaluation costs and therefore the cost has been expensed.

Depletion

Oil and gas properties are depleted on a unit-of-production basis over the proved reserves of the field concerned, except in the case of assets whose useful life is shorter than the lifetime of the field, in which case the straight- line method is applied. Rights and concessions are depleted on the unit-of-production basis over the total proven reserves of the relevant area. The unit-of-production rate for the depreciation of field development costs considers expenditures incurred to date, together with sanctioned future development expenditure.

(e) Property and equipment

Property and equipment are stated at cost less accumulated depreciation and impairment losses, if any. The cost of an item of property, plant and equipment initially recognised includes its purchase price and any cost that is directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

Property, plant and equipment are generally depreciated on a straight-line basis over their estimated useful lives:

Buildings	27.5 years
Leasehold improvements	7 – 15 years
Drilling costs and equipment	10 – 39 years
Motor vehicles	5 – 7 years
Other property and equipment	3 – 5 years

Property and equipment held under finance leases are depreciated over the shorter of lease term and estimated useful life.

(f) Impairment of financial assets

IFRS 9 "*Financial Instruments*" requires an expected credit loss model as opposed to an incurred credit loss model under IAS 39 "*Financial Instruments: Recognition and Measurement*". The expected credit loss model requires Alliance Petroleum to account for expected credit losses and changes in those expected credit losses at each reporting date to reflect changes in credit risk since initial recognition of the financial assets. The credit event does not have to occur before credit losses are recognised. IFRS 9 "*Financial Instruments*" allows for a simplified approach for measuring the loss allowance at an amount equal to lifetime expected credit losses for trade receivables and contract assets.

Alliance Petroleum applies the expected credit loss model to trade receivables arising from:

- the sales of inventory;
- the provision of R&D services; and
- the provision of other services.

(g) Impairment of non-financial assets

At each reporting date, the Directors assess whether indications exist that an asset may be impaired. If indications do exists, or when annual impairment testing for an asset is required, the Directors estimate the asset's recoverable amount. An asset's recoverable amount is the higher of an asset's or cash-generating unit's fair value less costs to sell and its value-in-use, and is determined for an individual asset, unless the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets. Where the carrying amount of an asset or cash-generating unit exceeds its recoverable amount, the Directors consider the asset impaired and write the subject asset down to its recoverable amount. In assessing value-in-use, the Directors discount the estimated future cash flows to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. In determining fair value less costs to sell, the Directors consider recent market transactions, if available. If no such transactions can be identified, the Directors utilise an appropriate valuation model.

When applicable, the Directors recognise impairment losses of continuing operations in the "*Statements of Profit or Loss and Other Comprehensive Income*" in those expense categories consistent with the function of the impaired asset.

(h) Leases

The determination of whether an arrangement is, or contains, a lease is based on the substance of the arrangement at inception date: whether fulfilment of the arrangement is dependent on the use of a specific asset or assets or the arrangement conveys a right to use the asset.

(i) Asset retirement obligation

Where a material liability for the removal of production equipment and site restoration at the end of the production life of a well exists, a liability for decommissioning is recognised. The amount recognised is the present value of estimated future net expenditures determined in accordance with local conditions and requirements. The unwinding of the discount on the decommissioning liability is included as accretion of the decommissioning provision. The cost of the relevant property, plant and equipment asset is increased with an amount equivalent to the liability and depreciated on a unit of production basis. The Directors recognise changes in estimates prospectively, with corresponding adjustments to the liability and the associated non-current asset.

(j) Taxation

Deferred taxation

Deferred tax is provided in full, using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the financial statements. Deferred tax is determined using tax rates (and laws) that have been enacted or substantially enacted by the balance sheet date and expected to apply when the related deferred tax is realised or the deferred liability is settled.

Deferred tax assets are recognised to the extent that it is probable that the future taxable profit will be available against which the temporary differences can be utilised.

Income taxation

Current income tax assets and liabilities for the year ended 31 December 2017 and the two-month period ended 28 February 2018 are measured at the amount to be recovered from, or paid to, the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted at the reporting date in the jurisdictions where Alliance Petroleum operates and generates taxable income.

(k) Revenue recognition

Natural gas, NGLs and crude oil

Revenue from sales of natural gas, NGLs and crude oil products is recognised when the customer obtains control of the commodity. This transfer generally occurs when product is physically transferred into a vessel, pipe, sales meter or other delivery mechanism. This also represents the point at which the Group fulfils its single performance obligation to its customer under contracts for the sale of natural gas, NGLs and crude oil.

Revenue from the production of oil in which Alliance Petroleum has an interest with other producers is recognised based on Alliance Petroleum's working interest and the terms of the relevant production sharing contracts.

Other revenue

Revenue from the operation of third-party wells is recognised as earned in the month work is performed and consistent with Alliance Petroleum's contractual obligations. Alliance Petroleum's contractual obligations in this respect are considered to be its performance obligations for the purposes of IFRS 15 "*Revenue from Contracts with Customers*".

Revenue from the sale of water disposal services to third-parties into Alliance Petroleum's disposal well is recognised as earned in the month the water was physically disposed. Disposal of the water is considered to be Alliance Petroleum's performance obligation under these contracts.

Revenue is stated after deducting sales taxes, production taxes, excise duties and similar levies.

(l) Functional currency and foreign currency translation

The Alliance Petroleum Financial Information is presented in \$, which is Alliance Petroleum's functional currency. Transactions in currencies other than \$ are recorded at the rates of exchange prevailing on the dates of the transactions. At each balance sheet date, monetary assets and liabilities that are denominated in foreign currencies are retranslated at the rates prevailing on the year-end date. Gains and losses arising on retranslation are included in the statement of comprehensive income for the period.

(m) Segmental reporting

Alliance Petroleum complies with IFRS 8 "*Operating Segments*", to determine its operating segments and has identified one reportable segment that produces natural gas and crude oil in the Appalachian Basin of the US.

4. SIGNIFICANT JUDGEMENTS, ESTIMATES AND ASSUMPTIONS

The Directors have made the following judgments which may have a significant effect on the amounts recognised in the Alliance Petroleum Financial Information:

(a) Impairment indicators for oil and gas properties

Following a review by the Directors of ongoing operational performance of Alliance Petroleum's natural gas and crude oil properties for the two-month period ending 28 February 2018, the Directors are of the opinion that no impairment indicators are apparent for these assets.

(b) Reserve estimates

Reserves are estimates of the amount of natural gas and crude oil product that can be economically and legally extracted from Alliance Petroleum's properties. To calculate the reserves, estimates and assumptions are required about a range of geological, technical and economic factors, including quantities, production techniques, recovery rates, production costs, transport costs, commodity demand, commodity prices and exchange rates.

Estimating the quantity and/or grade of reserves requires the size, shape and depth of fields to be determined by analysing geological data, such as drilling samples. This process may require complex and difficult geological judgments and calculations to interpret the data. The Directors have engaged third-party engineers who are considered experts and have extensive experience in oil and gas engineering, with focus in the Appalachian Basin in the US.

Given the economic assumptions used to estimate reserves change from year-to-year and, because additional geological data is generated during the course of operations, estimates of reserves may change from time-to-time.

(c) Asset retirement obligation costs

The ultimate decommissioning costs are uncertain and cost estimates can vary in response to many factors including changes to relevant legal requirements, the emergence of new restoration techniques or experience at other production sites. The expected timing and amount of expenditure can also change, for example, in response to changes in reserves or changes in laws and regulations or their interpretation. As a result, significant estimates and assumptions are made in determining the provision for decommissioning. See Note 18 "*Asset retirement obligation*" to the Alliance Petroleum Financial Information for more information.

5. ACQUISITIONS

2018 Acquisitions

There were no acquisitions during the two-month period ended 28 February 2018.

2017 Acquisitions

Acquisition of assets from XTO Energy Inc

On 1 January 2017, Alliance Petroleum acquired shallow formation assets from XTO Energy Inc. The net purchase price consideration of $6,305,000. The Alliance Petroleum directors determined the fair value of the reserves held in the assets acquired to be $27,725,000, which was approximately 9 per cent. cumulative discount reserve valuation derived from a third party engineer at the time of purchase. The estimated fair values of the assets and liabilities assumed were as follows:

	$'000
Total cash consideration	**6,305**
<u>*Net assets acquired:*</u>	
Oil and gas properties	28,288
Oil and gas properties (asset retirement obligation, asset portion)	7,708
Inventory	550
Trade payables	(812)
Debt	(300)
Asset retirement obligation	(7,708)
Net assets acquired	**27,726**
Gain on bargain purchase	(21,421)
Purchase Price	**6,305**

Other asset acquisitions

During the year ended 31 December 2017, Alliance Petroleum acquired 14 wells in West Virginia from Arsenal Resources LLC, 25 wells in Ohio from Carrizo Oil & Gas, Inc, 27 wells in West Virginia from CNX Gas Company LLC and 10 wells in Ohio from G&O Resources Limited. Aggregate consideration for the above acquisitions was $495,000, paid in cash. No bargain purchase was recognised in respect of these asset acquisitions.

6. REVENUE

Alliance Petroleum extracts and sells natural gas, NGLs and crude oil to various customers in addition to operating a majority of these oil and natural gas wells for customers and other working interest owners. The following table reconciles Alliance Petroleum's revenue for the periods presented:

	Audited Year ended 31 December 2017 $'000	Audited 2 months ended 28 February 2018 $'000
Oil and gas production	39,260	7,467
Field operations	6,686	1,049
Total revenue	**45,946**	**8, 516**

During the two-month period ended 28 February 2018, no customer individually totaled more than 10 per cent. of total revenues (2017: none).

7. EXPENSES BY NATURE

	Audited Year ended 31 December 2017 $'000	Audited 2 months ended 28 February 2018 $'000
Lease operating expenses	9,476	1,946
Field operating expenses	14,347	2,627
Service department expenses	236	37
Other expenses	2,869	526
Total cost of sales	**26,928**	**5,136**
Depletion of oil and gas properties *(cost of sales)*	2,901	754
Depreciation of property and equipment *(cost of sales)*	80	19
Depreciation of property and equipment *(administrative expenses)*	443	99
Accretion of decommissioning liability *(administrative expenses)*	1,474	150
Total depreciation, depletion and accretion	**4,898**	**1,022**
Employees and benefits	3,608	608
Other administrative	919	45
Professional fees	256	33
Auditors' remuneration		
Fees payable to Alliance Petroleum's auditor for the audit of the annual accounts	309	59
Total administrative expenses	**5,092**	**745**
Total expenses	**36,918**	**6,903**

Staff costs

	Audited Year ended 31 December 2017 $'000	Audited 2 months ended 28 February 2018 $'000
Aggregate remuneration (including Directors):		
Wages and salaries	3,003	482
Payroll taxes	174	38
Benefits	431	88
Total employees and benefits expense	**3,608**	**608**

8. TAXATION

The components of the provision for taxation on income included in the "*Statements of Profit or Loss and Other Comprehensive Income*" for the periods presented are summarised below:

	Audited Year ended 31 December 2017 $'000	Audited 2 months ended 28 February 2018 $'000
Current income tax expense		
Federal	8,123	(37)
State	1,706	133
Total current income tax expense	**9,829**	**96**
Deferred income tax expense		
Federal	882	172
State	—	—
Total deferred income tax expense	**882**	**172**
Total income tax expense	**10,711**	**268**

As at 28 February 2018, Alliance Petroleum had a net deferred tax liability of $7,672,000 (2017: $7,500,000). The deferred tax liability comprises temporary timing differences arising from depletion of oil and gas properties, depreciation of property and equipment and accretion of the asset retirement obligation.

The income tax expense for the periods under review can be reconciled to the income per the statement of comprehensive income as follows:

	Audited Year ended 31 December 2017 $'000	Audited 2 months ended 28 February 2018 $'000
Income before tax for the year/period	**39,696**	**3,412**
Effective statutory US federal income tax rate	*35%*	*21%*
Expected tax charge based on the effective tax rate	13,894	717
Decrease in tax resulting from:		
Federal credits	(3,183)	(449)
Total tax charge for the year/period	**10,711**	**268**

9. EARNINGS PER ORDINARY SHARE

The calculation of basic earnings per ordinary share is based on the income after taxation available to shareholders of Alliance Petroleum and on the weighted average number of ordinary shares outstanding during the period. The calculation of diluted earnings per ordinary share is based on the income after taxation available to shareholders of Alliance Petroleum and the weighted average number of ordinary shares outstanding plus the weighted average number of ordinary shares that would be issued if dilutive options and warrants were converted into ordinary shares on the last day of the reporting period.

Basic and diluted earnings per ordinary share is calculated as follows:

	Audited Year ended 31 December 2017	Audited 2 months ended 28 February 2018
Income after taxation	$28,985,000	$3,144,000
Weighted average number of ordinary shares – basic and diluted	100	100
Earnings per ordinary share – basic and diluted	**$289,850**	**$31,440**

10. DIVIDENDS

During the two-month period ended 28 February 2018, no dividends were declared or paid (2017: $1,049,000).

11. OIL AND GAS PROPERTIES

The following table summarises Alliance Petroleum's oil and gas properties for each of the periods presented:

	$'000
Cost as at 1 January 2017	164,441
Additions	43,381
Disposals	(7,853)
Cost as at 31 December 2017	**199,969**
Additions	39
Disposals	(4)
Cost as at 28 February 2018	**200,004**
Accumulated depletion and impairment as at 1 January 2017	(114,920)
Charge for the year	(2,901)
Eliminated on disposal	7,853
Accumulated depletion and impairment as at 31 December 2017	**(109,968)**
Charge for the period	(754)
Eliminated on disposal	4
Accumulated depletion and impairment as at 28 February 2018	**(110,718)**
Net book value as at 31 December 2017	**90,001**
Net book value as at 28 February 2018	**89,286**

As at 28 February 2018, Alliance Petroleum's borrowings were secured against the $89,286,000 oil and gas properties (2017: $90,001,000).

12. PROPERTY AND EQUIPMENT

	Land and buildings $'000	Pipelines and compressors $'000	Furniture, fixtures and equipment $'000	Vehicles $'000	Total $'000
Cost					
As at 1 January 2017	1,060	358	3,975	8	5,401
Additions	172	351	217	—	740
Disposals	—	(3)	—	—	(3)
As at 31 December 2017	**1,232**	**706**	**4,192**	**8**	**6,138**
Additions	—	—	25	—	25
Disposals	—	—	(98)	—	(98)
As at 28 February 2018	**1,232**	**706**	**4,119**	**8**	**6,065**
Depreciation					
As at 1 January 2017	(135)	(226)	(3,081)	(4)	(3,446)
Charge for the year	(42)	(80)	(399)	(2)	(523)
Disposals	—	3	—	—	3
As at 31 December 2017	**(177)**	**(303)**	**(3,480)**	**(6)**	**(3,966)**
Charge for the period	(7)	(19)	(91)	(1)	(118)
Disposals	—	—	98	—	98
As at 28 February 2018	**(184)**	**(322)**	**(3,473)**	**(7)**	**(3,986)**
Net book value					
As at 31 December 2017	**1,055**	**403**	**712**	**2**	**2,172**
As at 28 February 2018	**1,048**	**384**	**646**	**1**	**2,079**

13. INVENTORIES

	Audited As at 31 December 2017 $'000	Audited As at 28 February 2018 $'000
Crude oil	139	139
Material, pipe and supplies	109	109
Inventories	**248**	**248**

14. OTHER CURRENT ASSETS

	Audited As at 31 December 2017 $'000	Audited As at 28 February 2018 $'000
Prepaid expenses	964	785
Other current assets	**964**	**785**

15. TRADE RECEIVABLES

The majority of trade receivables are current and the Directors believe these receivables are collectible. Trade receivables also include certain receivables from third-party working interest owners. The Directors consistently assesses the collectability of these receivables. As at 28 February 2018, the Directors considered a portion of these working interest receivables uncollectable and recorded a provision in the amount of $1,242,000 (2017: $1,260,000).

	Audited As at 31 December 2017 $'000	Audited As at 28 February 2018 $'000
Trade receivables	13,683	16,075

A significant portion of Alliance Petroleum's trade receivables represent receivables related to either sales of oil and natural gas or field operational services. Oil and natural gas trade receivables are generally uncollateralised, and collected within 30 to 60 days depending on the commodity, location and well-type.

16. SHARE CAPITAL

	Ordinary shares of $1 each #	Total share capital $'000
Balance as of 1 January 2017	100	—
Balance as at 31 December 2017	**100**	**—**
Balance as at 28 February 2018	**100**	**—**

17. BORROWINGS

Alliance Petroleum's borrowings consist of the following amounts for the periods presented:

	Audited As at 31 December 2017 $'000	Audited As at 28 February 2018 $'000
Crossfirst Bank[(a)]	24,909	24,915
Gateway obligation	12,000	12,000
Syrews Well[(b)]	300	300
Premium Assignment Corporation[(c)]	430	143
A+ Rental Sales and Service Inc.[(d)]	4	3
Total borrowings	**37,643**	**37,361**
Less current portion of long-term debt	(434)	(146)
Total non-current borrowings, net	**37,209**	**37,215**

(a) Alliance Petroleum had a $32,500,000 line of credit with Crossfirst Bank with a termination date of 31 March 2020. The facility bore interest at the Crossfirst Bank base rate plus 0.5 per cent. and was secured Alliance Petroleum's oil and gas reserves.

(b) As part of the acquisition of assets from XTO Energy Inc. during the year ended 31 January 2017, Alliance Petroleum assumed the requirement to lodge a performance bond of $300,000.

(c) On 17 May 2017, Alliance Petroleum signed a note payable to Premium Assignment Corporation for an amount of $1,435,000 for the purchase of its liability insurance policy with Wells Fargo. The note matured on 11 March 2018 and bore interest at 4.1 per cent. per annum payable monthly. The note was payable in full, or in part, at any time without notice or penalty.

(d) On 19 October 2016, Alliance Petroleum signed a note payable to A+ Rental Sales and Service Inc. for an amount of $14,000 for the purchase of various equipment. The note was payable in monthly instalments of $823 through to 1 May 2018 with total interest calculated at rate of 2.3 per cent.

The following table provides a reconciliation of Alliance Petroleum's future maturities of its total borrowings for each of the periods presented:

	Audited As at 31 December 2017 $'000	Audited As at 28 February 2018 $'000
Not later than one year	434	146
Later than one year and not later than five years	37,209	37,215
Total borrowings	**37,643**	**37,361**

18. ASSET RETIREMENT OBLIGATION

Alliance Petroleum records a liability for future cost of decommissioning production facilities and pipelines. The decommissioning liability represents the present value of decommissioning costs relating to oil and gas properties, which the Directors expect to incur over the long producing life of Alliance Petroleum's wells, presently estimated through to 2092 when the Directors expect Alliance Petroleum's producing oil and gas properties to reach the end of their economic lives.

As discussed more fully in Note 2 "*Basis of preparation and measurement*" to the Alliance Petroleum Financial Information, these liabilities represent the Directors' best estimates of the future obligation. The Directors' assumptions are based on the current economic environment, and represent what they believe is a reasonable basis upon which to estimate the future liability. The Directors review these estimates regularly and adjust for any identified material changes to the assumptions. However, actual decommissioning costs will ultimately depend upon future market prices at the time the decommissioning services are performed. Furthermore, the timing of decommissioning will vary depending on when the fields ceases to produce economically, which makes the determination dependent upon future oil and gas prices, which are inherently uncertain.

The discount rate and the cost inflation rate used in the calculation of the decommissioning liability was 8.0 per cent. (2017: 8.0 per cent.).

	$'000
Liability at 1 January 2017	11,456
Additions	7,708
Accretion	1,474
Disposals	(179)
Liability as at 31 December 2017	**20,459**
Accretion	150
Liability as at 28 February 2018	**20,609**

19. DERIVATIVE FINANCIAL INSTRUMENTS

The following tables summarise Alliance Petroleum's derivative financial instruments:

As at 28 February 2018:

Term	Volume	Fixed price/ basis/NYMEX
Natural gas swaps		
1 February 2018 to 31 March 2018	1,250,500 MMBTU/mth	$2.35 fixed price
1 April 2018 to 31 December 2018	1,015,500 MMBTU/mth	$2.35 fixed price
1 January 2019 to 31 March 2019	1,000,000 MMBTU/mth	$2.35 fixed price
Oil collars		
1 January 2018 to 30 June 2018	2,500 Bbls/mth	$45.00 floor/$53.95 cap
Oil swaps		
1 July 2018 to 31 December 2018	2,500 Bbls/mth	$54.10 cap

As at 31 December 2017:

Term	Volume	Fixed price/ basis/NYMEX
Natural gas swaps		
1 January 2018 to 31 March 2018	1,025,500 MMBTU/mth	NYMEX minus $0.584
1 April 2018 to 31 December 2018	1,030,000 MMBTU/mth	NYMEX minus $0.584
1 January 2018 to 28 February 2018	285,000 MMBTU/mth	$3.07 NYMEX
1 January 2018 to 31 March 2018	725,500 MMBTU/mth	$3.282 NYMEX
Oil collars		
1 January 2018 to 30 June 2018	2,500 Bbls/mth	$45.00 floor/$53.95 cap
Oil swaps		
1 July 2018 to 31 December 2018	2,500 Bbls/mth	$54.10 cap

Alliance Petroleum reports derivative financial instrument assets and liabilities net on its balance sheet. The following table reconciles Alliance Petroleum's derivative financial instrument gross assets and gross liabilities for the periods presented:

Derivative financial instruments	Statement of Financial Position line item	Audited As at 31 December 2017 $'000	Audited As at 28 February 2018 $'000
Non-current assets		—	—
Current assets		—	1,851
Total assets		**—**	**1,851**
Non-current liabilities		—	(109)
Current liabilities		(535)	—
Total liabilities		**(535)**	**(109)**
Net liabilities – non-current	*Other non-current liabilities*	—	(109)
Net (liabilities)/assets –current	*Other current (liabilities)/assets*	(535)	1,851
Net (liabilities)/assets		**(535)**	**1,742**

Alliance Petroleum recorded the following gain/(loss) on derivative financial instruments in the "*Statements of Profit or Loss and Other Comprehensive Income*" for the periods presented:

	Audited Year ended 31 December 2017 $'000	Audited 2 months ended 28 February 2018 $'000
Net gain/(loss) on settlements	5,511	(350)
Net gain on fair value adjustments on unsettled financial instruments	3,690	2,277
Total gain on derivative financial instruments	**9,201**	**1,927**

20. OTHER NON-CURRENT AND CURRENT LIABILITIES

The following table includes a detail of other non-current and current liabilities as at the periods presented:

	Audited As at 31 December 2017 $'000	Audited As at 28 February 2018 $'000
Other non-current liabilities		
Revenue to be distributed	105	10
Total other non-current liabilities	**105**	**10**
Other current liabilities		
Accruals	301	414
Accrued income tax	11,029	9,415
Deferred income	1,020	945
Distributions payable	5,079	6,023
Total other current liabilities	**17,429**	**16,797**

21. TRADE PAYABLES

	Audited As at 31 December 2017 $'000	Audited As at 28 February 2018 $'000
Trade payables	3,819	5,821
	3,819	**5,821**

22. FAIR VALUE AND FINANCIAL INSTRUMENTS

(a) Fair value

The fair value of an asset or liability is the price that would be received to sell that asset or paid to transfer that liability in an orderly transaction occurring in the principal marked (or most advantageous market in the absence of a principal market) for such asset or liability. In estimating fair value, the Directors utilise valuation techniques that are consistent with the market approach, the income approach and/or the cost approach. Such valuation techniques are consistently applied. Inputs to valuation techniques include the assumptions that market participants would use in pricing an asset or liability. IFRS 13 "*Fair Value Measurement*" establishes a fair value hierarchy for valuation inputs that gives the highest priority to quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs. The fair value hierarchy is defined as follows:

Level 1: Inputs are unadjusted, quoted prices in active markets for identical assets at the measurement date.

Level 2: Inputs (other than quoted prices included in Level 1) can include the following:

- observable prices in active markets for similar assets;
- prices for identical assets in markets that are not active;
- directly observable market inputs for substantially the full term of the asset; and
- market inputs that are not directly observable but are derived from or corroborated by observable market data.

Level 3: Unobservable inputs which reflect the Director's best estimates of what market participants would use in pricing the asset at the measurement date.

The Group does not hold derivatives for speculative or trading purposes and the derivative contracts held by Alliance Petroleum do not contain any credit-risk related contingent features. The Directors have not elected to apply hedge accounting to derivative contracts.

Netting the fair values of derivative assets and liabilities for financial reporting purposes is permitted if such assets and liabilities are with the same counterparty and a legal right of set-off exists, subject to a master netting arrangement. The Directors have elected to present derivative assets and liabilities net when these conditions are met. When derivative assets and liabilities are presented net, the fair value of the right to reclaim collateral assets (receivable) or the obligation to return cash collateral (payable) is also offset against the net fair value of the corresponding derivative. As at 28 February 2018, there were no collateral assets or liabilities associated with derivative assets and liabilities (2017: $nil).

Derivatives expose Alliance Petroleum to counterparty credit risk. The derivative contracts have been executed under master netting arrangements which allow Alliance Petroleum, in the event of default by its counterparties, to elect early termination. The Directors monitor the creditworthiness of Alliance Petroleum's counterparties but are not able to predict sudden changes and hence may be limited in their ability to mitigate an increase in credit risk.

Possible actions would be to transfer Alliance Petroleum's positions to another counterparty or request a voluntary termination of the derivative contracts, resulting in a cash settlement in the event of non-performance by the counterparty. For the two-month period ended 28 February 2018 and the year ended 31 December 2017, the counterparties for all of Alliance Petroleum's derivative financial instruments were lenders under formal credit agreements.

The derivative instruments consist of non-financial instruments considered normal purchases and normal sales.

All financial instruments measured at fair value use Level 2 valuation techniques for the two-month period ended 28 February 2018 and the year ended 31 December 2017.

Level 2 fair value measurements are those including inputs other than quoted prices included within Level 1 that are observable for the asset or liability directly or indirectly. The fair value of the swap commodity derivatives is calculated using a discounted cash flow model and the fair value of the option commodity derivatives are calculated using a relevant option pricing model, which are calculated from relevant market prices and yield curves at the balance sheet date and are therefore based solely on observable price information. These instruments are not directly quoted in active markets and are accordingly classified as Level 2 in the fair value hierarchy.

There were no transfers between fair value levels during the two-month period ended 28 February 2018 (2017: $nil).

(b) Financial instruments

Financial liabilities are initially measured at fair value and subsequently measured at amortised cost.

Alliance Petroleum is not a financial institution. Alliance Petroleum does not apply hedge accounting and its customers are considered creditworthy and pay consistently within agreed payments terms.

Classification of financial instruments:

	Audited As at 31 December 2017 $'000	**Audited As at 28 February 2018 $'000**
Cash and cash equivalents held at amortised cost	7,861	8,638
Trade receivables and accrued income held at amortised cost	13,683	16,075
Derivatives at fair value through profit or loss	—	1,851
Borrowings, net of deferred financing costs, at amortised cost	(37,643)	(37,360)
Derivatives at fair value through profit or loss	535	109
Total	**(15,564)**	**(10,687)**

23. FINANCIAL RISK MANAGEMENT

Alliance Petroleum's financial steering framework is built upon the principles of operational efficiency, capital efficiency, financing efficiency and sustainable portfolio management with a focus on strengthening Alliance Petroleum's balance sheet, delivering positive free cash flow and growing its profitability to create value for Shareholders.

The Directors manage Alliance Petroleum's capital structure to safeguard Alliance Petroleum's capital base in order to preserve investor, creditor and market confidence, as well as to provide a sustainable financial foundation for the future operational development of Alliance Petroleum. The Directors' financing strategy focuses on cash flow and financial stability. Principal targets are positive free cash flow after dividends, a strong leverage ratio and a healthy balance sheet.

Alliance Petroleum's principal financial liabilities comprise of borrowings and trade and other payables, which it uses primarily to finance and financially guarantee its operations.

Alliance Petroleum's principal financial assets include cash and cash equivalents and trade and other receivables derived from its operations.

Alliance Petroleum also enters into derivative transactions, which depending on market dynamics are recorded as assets or liabilities. To assist with its hedging program design and composition, the Directors engage a specialist firm with the appropriate skills and experience to manage Alliance Petroleum's risk management derivative-related activities.

(a) Market risk

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises of two types of risk: interest rate risk and commodity price risk. Financial instruments affected by market risk include borrowings and derivative financial instruments. Derivative and non-derivative instruments are used to manage market price risks resulting from changes in commodity prices and foreign exchange rates which could have a negative effect on assets, liabilities or future expected cash flows.

(b) Interest rate risk

Interest rate risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market interest rates. Alliance Petroleum is subject to this risk exposure as it relates to changes in interest rates on its variable rate borrowings. As discussed in Note 17 "*Borrowings*" to the Alliance Petroleum Financial Information, Alliance Petroleum had $24,915,000 of total debt outstanding as at 28 February 2018 (2017: $24,909,000) on its senior secured credit facility with interest rate of 5.00 per cent. plus LIBOR. Based on a notional amount of $10,000 outstanding under the senior secured credit facility, an increase or decrease of 1 per cent. in the interest rate would have a corresponding increase or decrease in our annual net income of approximately $100.

(c) Commodity price risk

The prices for natural gas, NGLs and crude oil can be volatile and sometimes experience fluctuations as a result of relatively small changes in supply, weather condition, economic conditions and government actions. Alliance Petroleum's revenues are primarily derived from the sale of its natural gas, NGLs and crude oil production and, as such, Alliance Petroleum is subject to this commodity price risk. During the two-month period ended 28 February 2018, Alliance Petroleum's revenue was $6,253,000 and $267,000 in relation to the sale of natural gas and crude oil (2017: $34,252,000 and $1,502,000).

To help manage natural gas and oil price risk, Alliance Petroleum entered into various direct/physical purchase contracts with oil and gas purchasers.

Alliance Petroleum's normal policy is to sell its products under contract at prices determined by reference to prevailing market prices on petroleum exchanges and keep options and swaps in place on a proportion of its anticipated production volumes to minimise commodity risk and create stabilised and predictable cash flow important to funding its operation and stated dividend for shareholders.

The mark-to-market amount associated with the unsettled natural gas and oil collars and swaps was $1,742,000 (2017: $(535,000)). The key variable which affects the fair value of Alliance Petroleum's hedging instruments is the market's expectations about future commodity prices. An increase of 10 per cent. in the forward natural gas and oil prices would decrease the mark-to-market gain of these instruments, and hence profit before tax, by $369,000. A consequential decrease of 10 per cent. in forward natural gas an oil prices would increase the mark-to-market gain by $369,000.

(d) Credit risk

Credit risk is the risk that a customer or counterparty to a financial instrument will not meet its obligations under a contract and arises primarily from Alliance Petroleum's cash in banks and trade receivables.

Balances held at banks, at times, exceed federally insured amounts. Alliance Petroleum has not experienced any losses in such accounts and the Directors believe that Alliance Petroleum is not exposed to any significant credit risk on its cash.

For trade receivables, Alliance Petroleum applies the simplified approach permitted by IFRS 9 "*Financial Instruments*", which requires expected lifetime losses to be recognised from initial recognition of the receivables.

Trade receivables are due from customers throughout the oil and natural gas industry. Although diversified among several companies, collectability is dependent on the financial condition of each individual company as well as the general economic conditions of the industry. The Directors review the financial condition of customers prior to extending credit and generally do not require collateral to support of Alliance Petroleum's trade receivables. Any changes in the Directors' provision for un-collectability of trade receivables during the year is recognised in the "*Statements of Profit or Loss and Other Comprehensive Income*". Trade receivables also include certain receivables from third-party working interest owners. The Directors consistently assess the collectability of these receivables. As at 28 February 2018, the Directors considered a portion of these working interest receivables uncollectable and recorded a provision in the amount of $1,242,000 (2017: $1,260,000).

(e) Cash and cash equivalents

The credit risk from its cash and cash equivalents is limited because the counter parties are banks with high credit ratings and have not experienced any losses in such accounts.

(f) Trade receivables

Trade receivables are due from customers throughout the oil and natural gas industry and collectability is dependent on the financial condition of each individual company as well as the general economic conditions of the industry. The Directors review the financial condition of customers prior to extending credit and generally does not require collateral in support of Alliance Petroleum's trade receivables. The majority of trade receivables are current and the Directors believe these receivables are collectible.

Receivables from joint interest owners, classified in other non-current assets, are generally with other oil and natural gas companies that own a working interest in the properties operated by Alliance Petroleum. The Directors have the ability to withhold future revenue payments to recover any non-payment of joint interest receivables.

(g) Liquidity risk

Liquidity risk is the risk that Alliance Petroleum will not be able to meet its financial obligations as they are due. The Directors manage this risk by:

- maintaining adequate cash reserves through the use of Alliance Petroleum's cash from operations and bank borrowings; and
- continuously monitoring projected and actual cash flows to ensure Alliance Petroleum maintains an appropriate amount of liquidity.

(j) Capital risk

The Directors' objectives when managing capital are to safeguard the ability to continue as a going concern while pursuing opportunities for growth through identifying and evaluating potential acquisitions and constructing new infrastructure on existing proved leaseholds. The Directors do not establish a quantitative return on capital criteria, but rather promotes year-over-year growth.

(k) Collateral risk

Alliance Petroleum has pledged its oil and gas properties to fulfill the collateral requirements for borrowing credit facilities with its senior secured lenders. The fair value is based on a third-party engineering reserve calculation using an 8.0 per cent. cumulative discount cash flow and a commodities futures price schedule.

24. CONTINGENCIES AND PROVISIONS

Alliance Petroleum is involved in various pending legal issues that have arisen in the normal course of business, none which are expected to have any material impact on Alliance Petroleum's financial position or results of operations.

Alliance Petroleum's operations are subject to environmental regulation in all the jurisdictions in which it operates. The Directors are unable to predict the effect of additional environmental laws and regulations which may be adopted in the future, including whether any such laws or regulations would adversely affect Alliance Petroleum's operations. The Directors can offer no assurance regarding the significance or cost of compliance associated with any such new environmental legislation once implemented.

25. SUBSEQUENT EVENTS

On 28 February 2018, the entire share capital of Alliance Petroleum was acquired by the Group.

26. ULTIMATE CONTROLLING PARTY

As at 28 February 2018, Alliance Petroleum's ultimate controlling party was Lake Fork Resources Acquisition Corporation.

27. NATURE OF THE ALLIANCE PETROLEUM FINANCIAL INFORMATION

The Alliance Petroleum Financial Information presented above does not constitute statutory financial statements for the periods under review.

PART XV

COMPETENT PERSON'S REPORT

COMPETENT PERSON'S REPORT (CPR)

TO THE INTERESTS OF DIVERSIFIED GAS & OIL PLC

Prepared For:

BOARD OF DIRECTORS
DIVERSIFIED GAS & OIL PLC
1800 CORPORATE DRIVE
BIRMINGHAM, AL 35242, UNITED STATES

And

SPONSOR FOR DIVERSIFIED GAS & OIL PLC
STIFEL NICOLAUS EUROPE LIMITED
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LONDON, EC2V 6ET, UNITED KINGDOM

11 May, 2020

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Attn: Board of Directors
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Stifel Nicolaus Europe Limited
150 Cheapside
London, EC2V 6ET, United Kingdom

INTRODUCTION

Ladies and Gentlemen:

At the request of the Board of Directors of Diversified Gas & Oil PLC (DGO) and Stifel Nicolaus Europe Limited (Stifel), as Sponsor for DGO, Wright & Company, Inc. (Wright) has prepared this Competent Person's Report (CPR) to present our independent estimates of the proved (1P) developed reserves and associated economics based on specified technical and economic parameters effective January 1, 2020 (Effective Date). Wright's estimates of future production and income are attributable to certain working and net revenue interests of DGO as of the Effective Date. The subject properties are located in the United States (US) and primarily in the region referred to as the Appalachian Basin. According to DGO, the properties evaluated by Wright represent 100 percent of the total 1P developed net liquid and natural gas reserves owned by them at the Effective Date.

This CPR was prepared in accordance with the requirements of the Prospectus Regulation Rules, Prospectus Regulations (EU 2017/1129), Prospectus Delegated Regulation (EU 1019/980), and the European Securities and Markets Authority (ESMA) update of the Committee of European Securities Regulators (CESR) Recommendation 2013. The estimates of reserves contained in this CPR were determined by accepted industry methods as determined by the Guidelines for Application of the Petroleum Resources Management System (PRMS) updated and approved by the Society of Petroleum Engineers (SPE) in 2018, and in accordance with the SPE Petroleum Reserves Definitions. At the request of DGO, only the 1P developed properties were included in Wright's evaluation. The estimates of reserves and economics were based on annual averages of the five-year New York Mercantile Exchange (NYMEX) Futures Settlements prices as published by the Chicago Mercantile Exchange (CME) Group on December 31, 2019 for years 2020 through 2024. Settle prices for January are not included in the December 31, 2019 NYMEX Futures Settlements. Base prices used are the January closing price for oil published by CME Group December 19, 2019, and the January closing price for gas published by CME Group December 27, 2019. The 2024 product prices were escalated at five percent per annum for years 2025 through 2029, and then held constant thereafter at the 2029 prices in accordance with the instructions of DGO (Base Case). At the request of DGO, Wright also included two (2) price sensitivity cases in this CPR. These sensitivities are described in detail in the *PRODUCT PRICE SENSITIVITIES (+/- 10%)* section of this CPR.

After the Effective Date, but prior to the completion of this CPR, there have been significant changes in product prices due to the impacts of COVID-19 and the OPEC+ and Russia price confrontation for crude oil (Subsequent Events). The base product prices used as of the Effective Date have been negatively impacted. In order to reflect the impact of the subsequent decline in commodity prices for crude oil and natural gas resulting from the Subsequent Events, Wright provided a third price sensitivity case to reflect the potential impact on DGO's reserves value. For this additional price sensitivity case, Wright utilized commodity prices based on NYMEX Futures Settlements prices as published by the CME on April 13, 2020. This sensitivity is described in detail in the *PRODUCT PRICE SENSITIVITY (SUBSEQUENT EVENTS)* section of this CPR.

The purpose of this evaluation is to meet relevant regulatory requirements in DGO's transition from an AIM Market listed company to a Main Market listed company on the London Stock Exchange. Wright is confident that this CPR provides a fair and reasonable representation of the aggregate reserves based on specified economic parameters and associated results of the DGO assets. Wright consents to the inclusion of the CPR, and/or extracts therefrom, in the Prospectus and the reference thereto, and to its name in the form and context in which they are included in the Prospectus. Wright also accepts responsibility, for the purposes of the paragraph 5.3.2(R)(2)(f) of the Prospectus Regulation Rules, for the CPR set out in Part XV of the Prospectus and for any information sourced from the CPR in the Prospectus. In accordance with Item 1.2 of Annex 1 and Item 1.2 of Annex 11 to Commission Delegated Regulation (DU) 2019/980, Wright confirms, to the best of its knowledge, the information contained therein is in accordance with the facts and contains no material omission likely to affect the import of such information.

This CPR is intended to be used in its entirety and should not be used for any purpose other than that outlined herein without the prior knowledge of and express written authorization by an officer of Wright. All related data will be retained in our files and are available for your review.

Very truly yours,

Wright & Company, Inc.
TX Reg. No. F-12302

By: ____________________________

D. Randall Wright
President

DRW/ADN/MCB/SLM/ts

EXECUTIVE SUMMARY

At the request of the Board of Directors of Diversified Gas & Oil PLC (DGO) and Stifel Nicolaus Europe Limited (Stifel), as Sponsor for DGO, Wright & Company, Inc. (Wright) has prepared this Competent Person's Report (CPR) to present our independent estimates of the proved (1P) developed reserves and associated economics based on specified technical and economic parameters effective January 1, 2020 (Effective Date). Wright's estimates of future production and income are attributable to certain working and net revenue interests of DGO as of the Effective Date. The subject properties are located in the US and primarily in the region referred to as the Appalachian Basin. According to DGO, the properties evaluated by Wright represent 100 percent of the total 1P developed net liquid and natural gas reserves owned by them at the Effective Date.

This CPR was prepared in accordance with the requirements of the Prospectus Regulation Rules, Prospectus Regulations (EU 2017/1129), Prospectus Delegated Regulation (EU 1019/980), and the European Securities and Markets Authority (ESMA) update of the Committee of European Securities Regulators (CESR) Recommendation 2013. The estimates of reserves contained in this CPR were determined by accepted industry methods as determined by the Guidelines for Application of the Petroleum Resources Management System (PRMS), in particular section 4.1.4.3, as related to reserves estimation in mature reservoirs, and updated and approved by the Society of Petroleum Engineers (SPE) in 2018, and in accordance with the SPE Petroleum Reserves Definitions. An abbreviated form of the PRMS is presented in **Exhibit A**.

The estimates of reserves and economics were based on annual averages of the five-year New York Mercantile Exchange (NYMEX) Futures Settlements prices as published by the Chicago Mercantile Exchange (CME) Group on December 31, 2019 for years 2020 through 2024. Settle prices for January are not included in the December 31, 2019 NYMEX Futures Settlements. Base prices used are the January closing price for oil published by CME Group December 19, 2019, and the January closing price for gas published by CME Group December 27, 2019. The 2024 product prices were escalated at five percent per annum for years 2025 through 2029, and then held constant thereafter at the 2029 prices in accordance with the instructions of DGO (Base Case). At the request of DGO, Wright also included two (2) price sensitivity cases in this CPR by adjusting the base case with a +10 and -10 percent base price at the Effective Date. These sensitivities are described in further detail in the *PRODUCT PRICE SENSITIVITIES (+/- 10%)* section of this CPR.

After the Effective Date, but prior to the completion of this CPR, there have been significant changes in product prices due to the impacts of COVID-19 and the OPEC+ and Russia price confrontation for crude oil (Subsequent Events). The base product prices used as of the Effective Date have been negatively impacted. In order to reflect the impact of the subsequent decline in commodity prices for crude oil and natural gas resulting from the Subsequent Events, Wright provided a third price sensitivity case to reflect the potential impact on DGO's reserves value. For this additional price sensitivity case, Wright utilized commodity prices based on NYMEX Futures Settlements prices as published by the CME on April 13, 2020. This sensitivity is described in further detail in the *PRODUCT PRICE SENSITIVITY (SUBSEQUENT EVENTS)* section of this CPR. **Exhibit B** shows the Base Case prices used in this CPR. NYMEX is a commodity futures exchange owned and operated by CME Group of Chicago and is located in lower Manhattan, New York, New York, US.

This CPR details the geological and technical descriptions of methods in estimating reserves quantities and deliverability, product prices, expenses, and other criteria utilized by Wright in the evaluation process. It should be noted that this CPR is not a complete financial statement for DGO and should not be utilized as the sole basis for any transaction concerning DGO or the evaluated properties. Wright is confident that this CPR provides a fair and reasonable representation of the aggregate reserves and associated results of the DGO assets. The evaluation is based on two ARIES® databases, which represent the Northern (Northern Division) and Southern (Southern Division) Divisions. The following table is a summary of the results of the Northern Division and Southern Division evaluations as of the Effective Date. The corresponding cash flow summaries can be found in **Exhibit C**. It should be noted that there are no grand total cash flow summaries; therefore, the following table is presented as a summary of the combined results of the Northern and Southern Divisions evaluations as of the Effective Date.

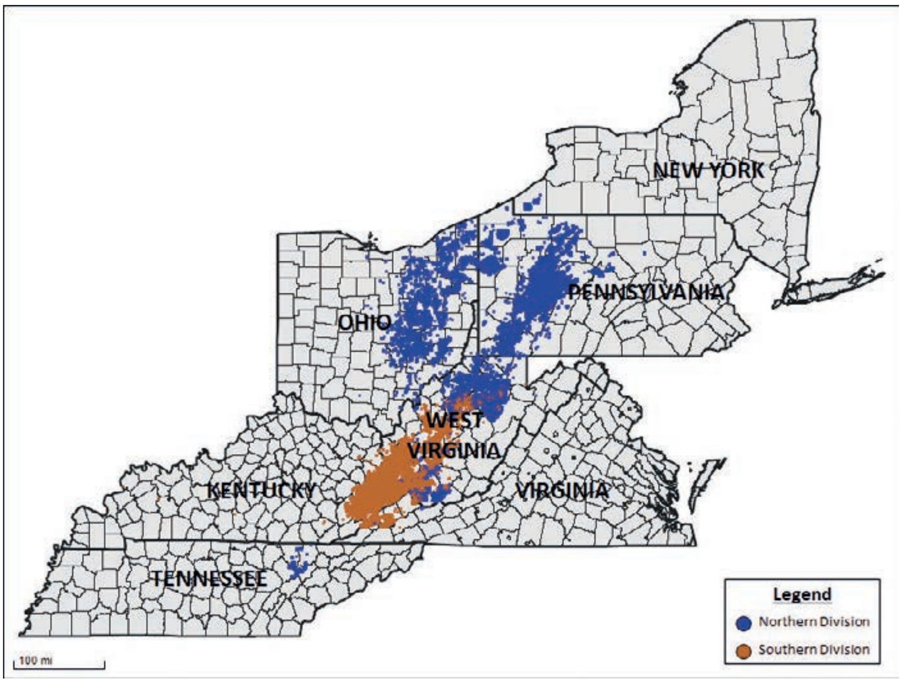
Evaluation of DGO Assets Utilizing Specified Economics Northern and Southern Divisions	Total Proved Developed Northern Division	Total Proved Developed Southern Division	Total Proved Developed
Net 1P Developed Reserves to the Evaluated Interests			
Oil, Mbbl:	3,387	1,404	4,791
Gas, MMcf:	1,309,953	1,632,645	2,942,598
NGL, Mbbl:	493	67,716	68,209
Oil Equivalent, MBOE:			
(6 Mcf = 1 BOE)*	222,205	341,227	563,432
Number of Wells:	42,445	17,373	59,818
Cash Flow Before Tax (BTAX), M$ (US)**			
Undiscounted:	1,052,147	2,928,289	3,980,436
Discounted at 10% per Annum:	743,290	1,120,936	1,864,226
Cash Flow After Tax (ATAX), M$ (US)**			
Undiscounted:	778,311	2,166,934	2,945,245
Discounted at 10% per Annum:	549,477	828,633	1,378,110

* *For purposes of this CPR, quantities of natural gas are converted into equivalent quantities of oil at the ratio of 6,000 standard cubic feet of gas equal 1 barrel of oil equivalent (BOE). For additional information see the GENERAL INFORMATION section of this CPR.*

** *Includes summary cases for asset retirement obligations, corporate expenses, and non-hydrocarbon revenue sources.*

The individual projections of lease reserves and economics were generated using certain data that describe the production forecasts and all associated evaluation parameters such as interests, severance and *ad valorem* taxes, product prices, operating expenses, investments, and net asset retirement obligation (ARO) costs, as applicable. DGO is an Appalachian Basin-focused gas and oil company with headquarters in Birmingham, Alabama. DGO was founded in 2001 and now owns interests in approximately 58,298 conventional wells and 1,520 unconventional wells in multiple states and focuses on acquiring developed areas with stable and reasonably predictable production. A map of the DGO assets located in the Appalachian Basin is shown in **Figure 1**.

Figure 1



DGO has grown rapidly through the acquisition of conventional and unconventional wells. DGO began growing its investment in oil and gas producing properties through acquisitions beginning in 2010 with the purchase of approximately 1,124 wells from AB Resources and others. In 2014, DGO acquired approximately 334 wells from Fund 1 DR LLC, and continued acquisitions in 2015 with approximately 792 wells from Broadstreet Energy and another 2,001 wells from Texas Keystone Inc. In 2016, DGO acquired approximately 3,810 properties from Eclipse Resources and Seneca Resources. All of these wells are almost entirely conventional and relatively shallow vertical wells producing from multiple horizons.

Prior to 2017, DGO had interests in approximately 8,061 wells. In February 2017, DGO successfully completed an acquisition of 1,717 wells from EnerVest, Ltd., increasing the number of wells to approximately 9,778. These wells are referred to as the "DGO Legacy" properties. DGO made an acquisition in 2017 from Titan Energy, LLC (Titan), which included approximately 8,260 wells. Additionally, DGO obtained another 544 wells from NGO Development Corporation (NGO). For purposes of this CPR, the Titan and NGO wells are referred to as the "DGO Energy" wells.

Entering 2018, DGO owned interests in approximately 18,582 wells. During the first half of 2018, DGO gained approximately 23,744 wells through the acquisition of Alliance Petroleum Corporation (APC) and certain wells from CNX Gas Company (CNX). DGO acquired an additional 17,373 wells from EQT Corporation (EQT) and Core Appalachia Holding Co LLC (Core) during the second half of 2018. With each of these acquisitions in 2017 and 2018, DGO inherited multiple databases and various accounting systems. Certain acquisitions of this magnitude have an extensive transition period, especially for the consolidation of economic parameters and operations. For purposes of this CPR, DGO utilized the latest available monthly averages for lease operating expenses, pricing contracts and differentials, and plant products for natural gas liquids (NGLs).

In the first half of 2019, DGO acquired 107 horizontal Marcellus Shale (Marcellus) wells from HG Energy II Appalachia, LLC (HG), of which 51 wells are located in West Virginia and 56 wells are in Pennsylvania. This acquisition included wells that were drilled and completed between 2009 and 2015. Most recently, in September of 2019, DGO acquired 12 producing horizontal wells in the Utica/Point Pleasant (Utica) from EdgeMarc Energy Holdings, LLC (EdgeMarc). The following table shows the number of wells acquired by company and year. The well counts in this table have been populated as of the Effective Date and are subject to change, largely due to DGO's ongoing asset retirement and divestiture activities.

Year	Company	Database Location	Number of Wells*
2010	AB Resources & Others	Northern Division	1,124
2014	Fund 1 DR LLC	Northern Division	334
2015	Broadstreet Energy	Northern Division	792
2015	Texas Keystone Inc.	Northern Division	2,001
2016	Eclipse Resources	Northern Division	1,523
2016	Seneca Resources	Northern Division	2,287
2017	EnerVest, Ltd.	Northern Division	1,717
2017	Titan Energy, LLC	Northern Division	8,260
2017	NGO Development Corporation	Northern Division	544
2018	Alliance Petroleum Corporation	Northern Division	13,395
2018	CNX Gas Company	Northern Division	10,349
2018	EQT Corporation	Southern Division	12,128
2018	Core Appalachia Holding Co LLC	Southern Division	5,245
2019	HG Energy II Appalachia, LLC	Northern Division	107
2019	EdgeMarc Energy Holdings, LLC	Northern Division	12
TOTAL			**59,818**

* *The well counts in this table have been populated as of the Effective Date and may, therefore, differ from well counts reflected elsewhere in this Prospectus. These figures are subject to change, largely due to DGO's ongoing asset retirement and divestiture activities.*

DGO's asset base includes both conventional and unconventional wells producing natural gas and oil, and with processing also includes the sale of NGLs. For reporting purposes, DGO requested Wright to evaluate and report based upon conventional and unconventional wells in the Northern and Southern Divisions as presented in their appropriate sections of this CPR.

It should be noted that DGO's strategic plan has been to acquire 1P developed wells that were already drilled and put into production by preceding operators. This CPR is an evaluation of these existing wells, so no consideration was given to prior drilling and completion techniques. Based on the instructions of DGO, no future development of conventional or unconventional hydrocarbon resources was considered by Wright and none are included in the assets evaluated.

GENERAL INFORMATION

The majority of the properties evaluated in this CPR are located in the northeastern US in the Appalachian Basin. Primarily, the wells are located in the states of Kentucky, New York, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia. Additionally, there are miscellaneous and immaterial non-operated interests in several other states. A map showing the states and counties in which the operated properties are located was previously shown in **Figure 1**.

For this CPR, projections of the reserves and associated cash flow and economics to the evaluated interests were based on specified economic parameters, operating conditions, and government regulations considered to be applicable at the Effective Date. Net income to the evaluated interests is the cash flow after consideration of royalty revenue payable to others, standard state and county taxes, operating expenses, investments, salvage values, and asset retirement costs, as applicable. The cash flow in US dollars, is before federal income tax (BTAX) and excludes consideration of any encumbrances against the properties if such exist. At the request of DGO, Wright has also tabulated a summary of cash flow values after federal income tax (ATAX). These summaries can be found in **Exhibit C**. It was assumed there would be no significant delay between the date of oil and gas production and the receipt of the associated revenue for this production.

Wright used the ARIES® Version 5000.2.3.0 petroleum software program of Landmark Graphics Corporation, a Halliburton business line, in the evaluation of the properties. Certain data such as product prices, operating expenses, *ad valorem* tax rate, and interests were provided by DGO, the accuracy of which was not independently verified by Wright. Wright did not review individual gas and oil purchase contracts. A review of the price terms and adjustments is contained in the *PRODUCT PRICES (BASE CASE)* and *PRICE ADJUSTMENTS* sections of this CPR.

Unless specifically identified and documented by DGO as being curtailed, gas production or sales trends have been assumed to be a function of well productivity and not of market conditions. In the opinion of Wright, for properties in which current rates of production are limited due to operating conditions, projections represent the operating status at the Effective Date.

Oil and other liquid hydrocarbon volumes are expressed in thousands of US barrels (Mbbl) of 42 US gallons per barrel. Gas volumes are expressed in millions of standard cubic feet (MMcf) at 60 degrees Fahrenheit and at the legal pressure base that prevails in the state in which the reserves are located. For purposes of this CPR, quantities of natural gas are converted into equivalent quantities of oil at the ratio of 6,000 standard cubic feet of gas equal 1 barrel of oil equivalent (BOE). BOE is a way of standardizing natural gas and other energy resources to a barrel of oil's energy. One barrel of crude oil generally has approximately the same energy content as 6,000 standard cubic feet of natural gas. This ratio does not apply to the economic values of the commodities and meets PRMS guidelines set out in Section 3.0. No adjustment of the individual gas volumes to a common pressure base has been made.

No investigation was made of potential gas volume and/or value imbalances that may have resulted from over/under delivery to the evaluated interests. Therefore, the estimates of reserves and cash flow do not include adjustments for the settlement of any such imbalances.

The Cash Flow (BTAX) and Cash Flow (ATAX) were discounted monthly at an annual rate of 10.0 percent as requested by DGO. Future cash flow was also discounted at several secondary rates as indicated on each reserves and economics page. These additional discounted amounts are displayed as totals only. It should be noted that no opinion is expressed by Wright as to the fair market value of the evaluated properties. In the determination of the Cash Flow (ATAX), DGO represented to Wright that their combined effective federal and state corporate tax rate was 26 percent, which was used in accordance with their instructions.

It should be noted that there could exist other revenues, overhead costs, or other costs associated with DGO that are not included in this CPR. Such additional costs and revenues are outside the scope of this CPR. This CPR is not a financial statement for DGO and should not be used as the sole basis for any transaction concerning DGO or the evaluated properties.

Wright is an independent petroleum consulting firm founded in 1988 and owns no interests in the properties covered by this CPR. No employee, officer, or director of Wright is an employee, officer, or director of DGO, nor does Wright or any of its employees have direct financial interest in DGO. Neither the employment of nor the compensation received by Wright is contingent upon the values assigned or the opinions rendered regarding the properties covered by this CPR.

DATA SOURCES

All data utilized in the preparation of this CPR with respect to ownership interests, product prices, gas contract terms, operating expenses, investments, salvage values, asset retirement costs, well information, and current operating conditions, as applicable, were provided by DGO. Data obtained after the Effective Date, but prior to the completion of this CPR, were used only if such data were applied consistently. If such data were used, the reserves category assignments reflect the status of the wells as of the Effective Date. Production or sales data were provided by DGO or obtained by Wright through publicly available sources. All data have been reviewed for reasonableness and, unless obvious errors were detected, have been accepted as correct. Wright requested and received detailed information allowing Wright to check and confirm any calculations provided by DGO with regard to product pricing, appropriate adjustments, lease operating expenses, and capital investments for asset retirement obligations. Furthermore, if in the course of Wright's examination something came to our attention that brought into question the validity or sufficiency of any information or data, Wright did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or independently verified such information or data. It should be emphasized that revisions to the projections of reserves and economics included in this CPR may be required if the provided data are revised for any reason.

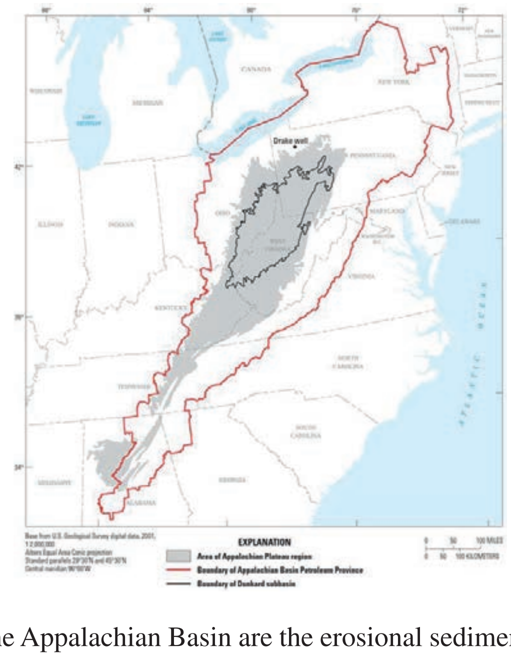
For many years Wright has evaluated a large number of the wells currently owned and operated by DGO for the previous owners. Wright has evaluated DGO's reserves since 2011. Based on the long history of evaluating the wells, Wright has not inspected the properties and believes it is neither necessary nor customary for the purposes and scope of this CPR.

GEOLOGY

The Appalachian Basin is an area located in the northeastern US encompassing 11 states including, but not limited to, Alabama, Georgia, Kentucky, Maryland, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia. The Appalachian Basin covers an area of approximately 185,500 square miles. It stretches approximately 1,075 miles from the northeast, where it may be over 300 miles wide, toward the southwest, where it may be less than 20 miles wide.

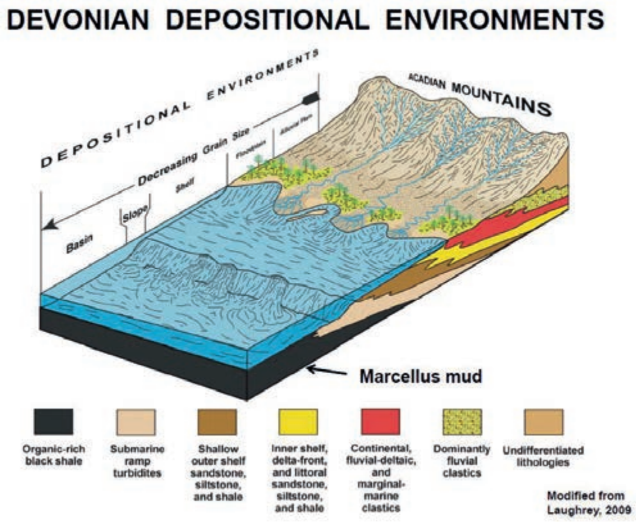
The areal extent of the Appalachian Basin is depicted in **Figure 2**. The Appalachian Basin has a long history of oil and gas production, although much of it has not been systematically recorded due to limited record-keeping in the early days of its development. Despite the incomplete production history, the US Geological Survey (USGS) has estimated that the basin has produced over 3.5 billion barrels of oil and 44 trillion cubic feet (Tcf) of gas. This estimate was calculated based on vertical conventional production and was derived before any horizontal or unconventional development was initiated.

Figure 2



The deposition materials for the Appalachian Basin are the erosional sediments from the Acadian Mountains situated to the southeast of the basin. The basin was confined to the western side by the Cincinnati Arch. As the Acadian Mountains eroded over time, the sediment was deposited in the basin with various and alternating layers of carbonate, limestone, sandstone, siltstone, and shale intervals as shown in **Figure 3**.

Figure 3



Hydrocarbon production from the Appalachian Basin has been significant since the early 1800s. The initial production for commercial use was in the early 1820s from Devonian shale near Fredonia, New York. This gave rise to the development of a series of shallow shale-gas fields that were situated along the Lake Erie shoreline in the 1860s. These shallow gas fields supplied gas for domestic and light industrial use.

Despite the aforementioned ventures, history marks the beginning of the oil and gas industry in 1859 with the discovery of oil in the Edwin Drake well located in northwestern Pennsylvania. Oil in this well was produced from the Upper Devonian at a depth of approximately 70 feet. This discovery well opened a trend of oil and gas fields producing from the Upper Devonian, Mississippian, and Pennsylvanian aged formations across parts of Kentucky, New York, Ohio, Pennsylvania, and West Virginia.

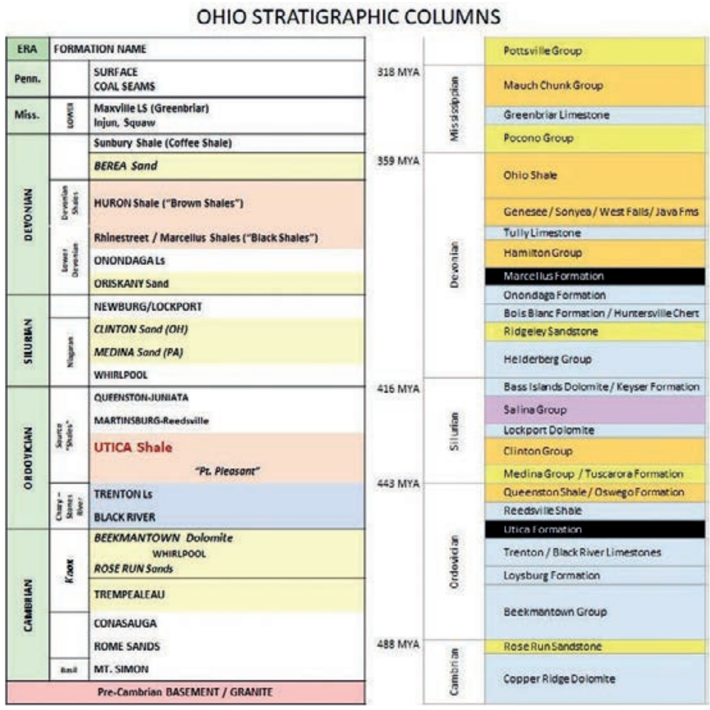
Across much of the Appalachian Basin, there are many prolific and commercially viable hydrocarbon producing zones ranging in depth from less than 2,000 feet in portions of Kentucky and Virginia to more than 13,000 feet in Pennsylvania and West Virginia. Additionally, the types of producing reservoirs vary greatly ranging from extremely shallow, low pressure coal bed methane wells; to normally pressured, shallow, tight sandstone/shale wells; to deep, over-pressured, unconventional shale wells in the Marcellus and Utica.

Northern Division – Conventional

DGO's conventional assets in the Northern Division are primarily located in New York, Ohio, Pennsylvania, Tennessee, and West Virginia. DGO has 41,942 conventional wells in the Northern Division. In Ohio, the conventional producing formations include the Berea Sand, Bradford Sand, Clinton Sand, Gantz Sand, Gordon Sand, Knox Group, and several others as noted in the Ohio stratigraphic column shown in **Figure 4**. The majority of DGO's Ohio production comes from the Clinton Sand. The Clinton Sand is a Silurian Age formation and has been the most actively drilled zone in Ohio since the 1950s.

The Clinton Sand was discovered in 1885 in Knox County, Ohio. It is believed to have been formed as a nearshore deposit during the Silurian period and was deposited as a blanket of sand throughout eastern Ohio and western Pennsylvania, where it is called the Medina Sand. The average depth is approximately 5,200 feet, with depths ranging from 3,500 to 6,000 feet. The entire Clinton/Medina Sand interval is generally 150 to 200 feet in thickness with net productive pay ranging from 10 to 100 feet.

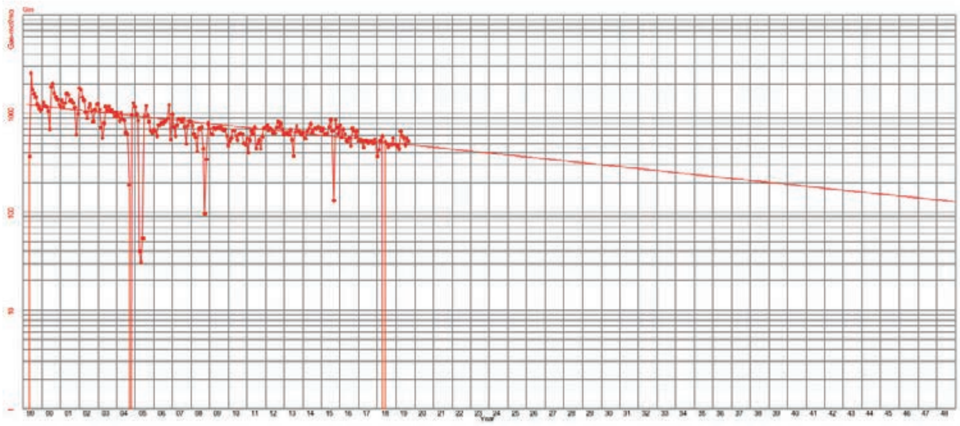
Figure 4



The Cambrian Ordovician Age Knox Group in the Appalachian Basin extends from northern Tennessee to southcentral Kentucky, through eastern Ohio and occurs in localized areas of northwestern Pennsylvania and western New York. The Knox Unconformity is a major erosional angular unconformity that truncates progressively younger beds of rock from southeastern Ohio in the northwestern direction. The truncation of these gently dipping Lower Ordovician to Cambrian aged carbonates and sandstones provides an excellent trap and seal for hydrocarbon accumulation. The Knox Group is usually subdivided into units, listed in descending stratigraphic order: Beekmantown Dolomite, Rose Run Sandstone, and the Upper Copper Ridge Dolomite (Trempealeau).

The majority of the production from DGO's conventional assets located in Pennsylvania and West Virginia is from Silurian, Devonian, and Mississippian aged formations. DGO has 33,336 conventional wells in Pennsylvania and West Virginia. For DGO's assets, the primary productive formations in Pennsylvania include the Balltown, Bayard, Bradford, Elk, Fifth, Medina, Sheffield, Speechley, Tiona, and Warren. Similarly, in West Virginia, the primary productive formations include the Alexander, Balltown, Benson, Big Injun, Big Lime, Elk, Fifth, Gordon, Riley, and Warren. The conventional wells produce from these various formations, and production is commonly commingled in a single wellbore. In general, formation thickness for these reservoirs ranges from 5 to 25 feet for any individual zone with cumulative net pay thickness ranging from 40 to 100 feet. Many of the aforementioned formations have low permeability and require stimulations in order to obtain commercially viable production rates. The uniform deposition of the formations along with the high number of wells producing from those formations yields highly predictable results. An example production profile from a conventional well located in West Virginia is shown in **Figure 5**.

Figure 5



Example Conventional Well from DGO's Northern Division in West Virginia (50-year time-frame)

Northern Division – Unconventional

DGO's unconventional assets in the Northern Division are primarily located in Kentucky, Ohio, Pennsylvania, Tennessee, and West Virginia. DGO has 503 unconventional wells in the Northern Division. Of the 503 unconventional wells, 449 produce from the Marcellus, 13 produce from the Utica, and 41 produce from a Devonian shale in Tennessee. Collectively, approximately 26.4 percent of the 10.0 percent cumulative discounted (Cum. Disc.) cash flow (BTAX) value of DGO is located in the Northern Division unconventional assets. Since 2004, more than 20,000 horizontal wells have been drilled and completed with hydraulic stimulation in the Appalachian Basin, which is now considered to be one of the largest gas fields in the world. Much of the gas currently produced in the Appalachian Basin is extracted from the Marcellus.

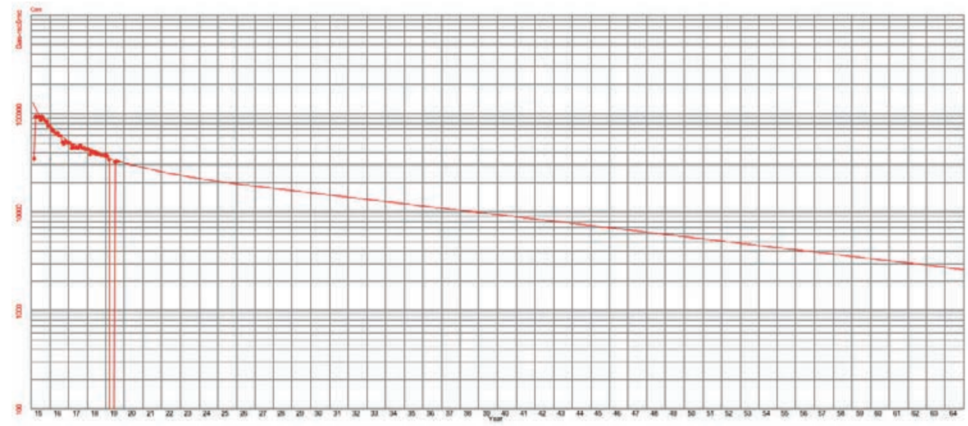
The Marcellus is a Devonian aged formation, located in portions of New York, Ohio, Pennsylvania, and West Virginia. The Marcellus has been known to be a gas producing source rock since the early 1800s. Until recently, the organic-rich Marcellus was not a significant hydrocarbon producer in the Appalachian Basin. Unlike the various Devonian shales, such as the Huron and Rhinestreet in the Big Sandy Field, the Marcellus was not considered a primary target for development before 2007. Although the Marcellus had been identified as an exploration target in the central and northern Appalachian Basin in the 1970s, successful attempts to achieve commercial production were localized and inconsistent. Characteristically, vertical Marcellus wells produce low volumes over a long productive life.

This has changed significantly over the last 10 to 15 years. The modern era of Marcellus production in the Appalachian Basin began in October 2004 when Range Resources drilled and tested the #1 Renz well in Washington County, Pennsylvania where DGO owns or owns interests in 64 Marcellus wells. Current development of the Marcellus includes horizontal drilling to reach targets beneath adjacent acreage, reduce the footprint of field development, and increase the length of the pay zone in a well. Horizontal drilling was designed to intersect natural fractures and install surface facilities where access to the resources may be impossible or extremely expensive. There are several reasons for drilling non-vertical wells, of which some are listed below:

- Target areas that cannot be reached by vertical drilling
- Drain a larger area from a single drilling pad, thus reducing the surface footprint
- Increase the length of the pay zone within the target rock unit
- When combined with hydraulic fracturing, realize commercial production from formerly unproductive source rock
- Improve the productivity of wells in a fractured reservoir
- Increase the productivity of wells where permeability is very low and fluids move very slowly through the rock

Most horizontal wells begin at the surface as a vertical well until the drill bit is several hundred feet above the target rock unit. As the drilling progresses, the bit follows a path that steers the wellbore from vertical to horizontal over a distance of several hundred feet. Once steered into the target formation, the well follows within the target rock unit. Horizontal drilling is relatively expensive, and when it is combined with hydraulic fracturing, the well can cost many times more per foot than drilling a vertical well. The extra cost is usually offset by the increased productivity and ultimate recovery of the well. An example of a production profile from a horizontal Marcellus well located in West Virginia is shown in **Figure 6**.

Figure 6



Example Unconventional, Horizontal, Marcellus Well from DGO's Northern Division in West Virginia (50-year time-frame)

The Silurian-aged Utica and Point Pleasant, which is stratigraphically situated 2,000 to 6,000 feet below the Marcellus, is a massive formation that lies beneath portions of Kentucky, Maryland, New York, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and a part of Canada. Junex Inc., an exploration and production company located in Quebec, Canada, developed the concept and leased acreage to test the equivalent rocks of the Utica and Point Pleasant. Together with Forest Oil they drilled the first test well in 2006. Despite this discovery, both geologic and regulatory considerations have shifted much of the development focus of the play to Ohio and, to a lesser degree, Pennsylvania and West Virginia. Within Ohio and Pennsylvania, depths to the base of the Point Pleasant (top of Trenton Limestone) for the main play area range from about 5,000 to 10,000 feet. In Ohio, development of the play started in Belmont, Carroll, Guernsey, and Harrison Counties.

Stratigraphically, the Point Pleasant Formation lies directly above the Trenton Limestone and is, at least in part, equivalent with the thick deposits of the Trenton carbonate platform of northwestern Ohio. This formation is famous for the Lima-Indiana Oil-And-Gas Trend, which was the first true giant field produced in North America starting in 1884. The Point Pleasant is a hybrid fine-grained reservoir system composed of organic-rich carbonates interlayered with organic-rich shale. The overlying Utica Shale is mostly light gray to black shale with few limestone layers and is, in general, more massive and denser than the Point Pleasant. The combined thickness of the Point Pleasant Formation and Utica Shale varies from less than 150 feet to over 300 feet.

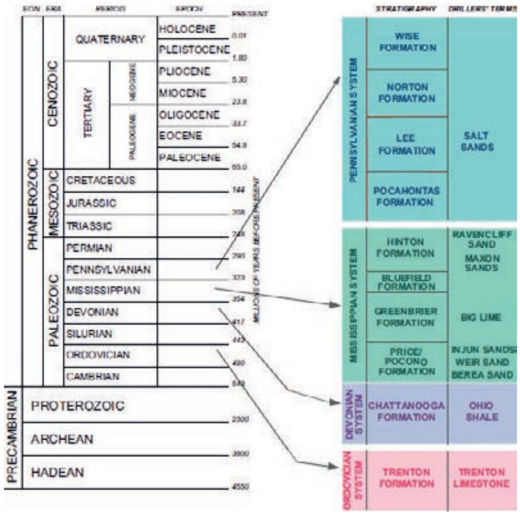
Like other low-permeability plays, key geologic criteria that control play boundaries and high productivity areas include thermal maturity, total organic carbon (TOC) content, formation thickness, porosity, depth, pressure, and the ability of the formation to be hydraulically fractured. However, there are operational challenges that face developers of this prolific play. In some areas of the Utica, certain drilling tools such as rotary steerables and azimuthal gamma-ray directional tools are required to ensure proper wellbore positioning and placement in the target zone. Additionally, high strength proppants may be required in certain areas of the play where pressure gradients (pressure/footage of vertical depth) may exceed the compressive strength of conventional propping agents such as sand (silica).

Both of these factors contribute to increased cost and operational complexity when drilling and completing wells. However, the combinations of deeper total vertical depth, higher formation reservoir pressure, low water saturations in the reservoir, and a high reservoir quality enable the Utica to produce high rate initial gas volumes.

Southern Division – Conventional

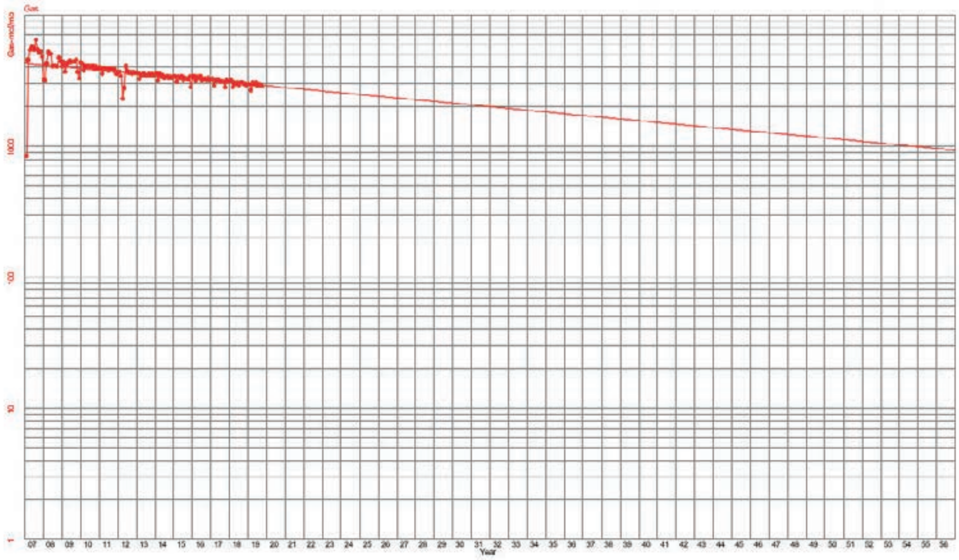
The majority of DGO's assets in the Southern Division are located in Kentucky, Virginia, and West Virginia and are conventional vertical wells. These wells typically produce from intervals that span geologic time from the Upper Cambrian to the Lower Mississippian as shown in **Figure 7**. Productive formations include, but are not limited to, the Alexander, Balltown, Berea, Big Injun, Big Lime, Bradley, Cleveland Shale, Gordon, Lower Huron Shale, Maxton, and the Rosedale. Formation thickness for these reservoirs range from 5 to 25 feet for any individual zone with cumulative net pay thickness ranging from 40 to 100 feet.

Figure 7



As previously mentioned, the majority of the production from DGO's conventional assets located in Pennsylvania and West Virginia is from Silurian, Devonian, and Mississippian aged formations. Many of the aforementioned formations have low permeability and require stimulations in order to obtain commercially viable production rates. The uniform deposition of the formations along with the high number of wells producing from those formations yields highly predictable results. An example of a conventional well located in West Virginia with comingled production from various reservoirs that have been stimulated is presented in **Figure 8**.

Figure 8

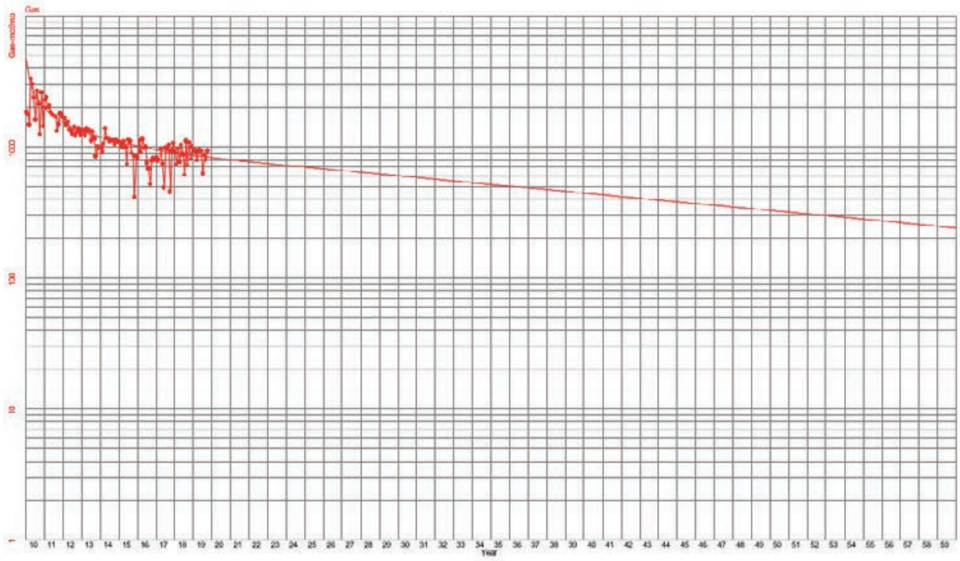


Example Conventional Well from DGO's Southern Division (50-year time-frame)

Southern Division – Unconventional

DGO'S unconventional assets in the Southern Division are primarily located in Kentucky, Virginia, and West Virginia and are primarily shallow, horizontal, Lower Huron Shale wells located in the Big Sandy Field. DGO has approximately 1,017 unconventional, horizontal wells in the Southern Division. An example well production decline profile is shown in **Figure 9**.

Figure 9



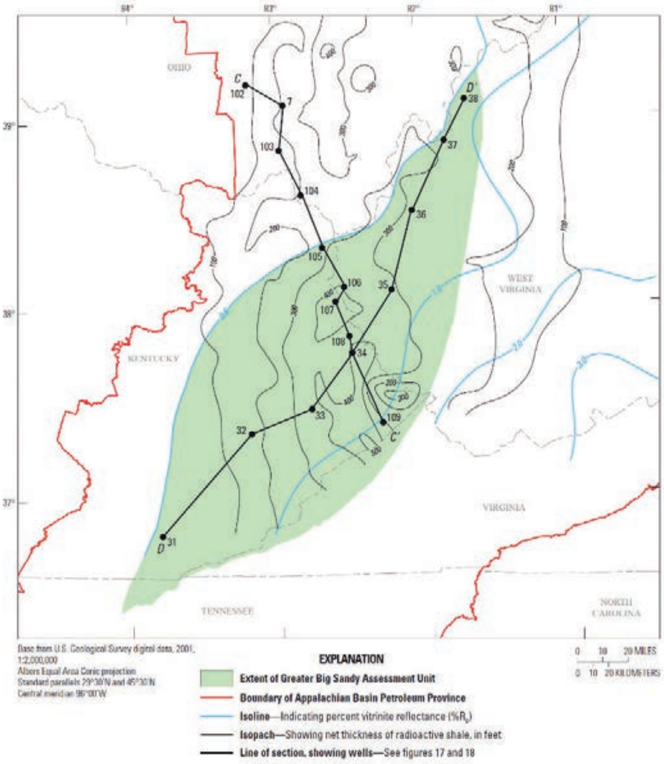
Example Unconventional Well from DGO's Southern Division (50-year time-frame)

The first significant shale discovery in the Appalachian Basin occurred in 1921 in northeastern Kentucky, which was the basis for establishing the Big Sandy Gas Field. The primary target in the Big Sandy Field is the Huron Shale of the Devonian period, which is characterized by a shallow total vertical depth, a sub-normal pressure profile, and a well-established open natural fracture network. As the Big Sandy Field continued to be developed, oil and gas production came from other formations of the Upper Devonian, Mississippian, and Pennsylvanian age. Since inception, more than 21,000 wells have been drilled in the Greater Big Sandy ranging from eastern Kentucky, southern West Virginia, southern Ohio, and southwestern Virginia.

The thickness of the Greater Big Sandy (**Figure 10**) decreases from about 2,500 feet in the northeastern part of the area to about 100 feet in the southwestern part. The thickness of confining and underlying intervals generally increases relative to the total thickness of black shale and is also concurrent with the overall increase in thickness of strata to the northeast. The depositional strike is generally north to south and follows the general thickness trends of the Big Sandy unit.

The reservoirs are generally under-pressured and have very low matrix permeability values of less than 0.0001 millidarcies. Log-derived porosity values in the Big Sandy Field range from 1.5 percent to 11 percent, with an average of 4.3 percent. The most productive gas shale reservoirs within the field contain gas-filled micro-pores that have well developed natural fracture networks, which drive the commercial viability of the production.

Figure 10



CONVENTIONAL AND UNCONVENTIONAL RESERVOIRS

DGO's asset base includes both conventional and unconventional wells producing natural gas and oil, and with processing also includes the sale of NGLs. The 58,298 conventional wells are relatively shallow depth and the approximately 1,520 unconventional wells produce from low permeability reservoirs. For purposes of this CPR, Wright recognizes the technical difference in various formations such as coalbed methane (CBM), tight gas sands, and Upper Devonian, and Ordovician shale members. For simplicity and ease of descriptions, Wright has broadly divided the DGO wells into conventional and unconventional categories. The unconventional wells are all wells that are drilled horizontally. Additionally, vertical Marcellus wells will be considered unconventional in this CPR. All other vertical wells included in this CPR are considered conventional wells. A summary of the conventional and unconventional wells, by division, is provided in the following table for reference. It should be noted that numbers in the following table do not correspond to the numbers found in the table on page 6 or the cash flow summaries found in **Exhibit C** due to certain summary level corporate cases.

	Conventional	Unconventional	TOTALS*
Northern Division			
Number of Wells	41,942	503	**42,445**
Net Oil Equivalent, MBOE:	102,148	120,058	**222,206**
Cash Flow Before Tax (BTAX), M$			
Undiscounted:	770,806	1,321,758	**2,092,564**
Discounted at 10% per Annum:	305,828	492,353	**798,181**
Southern Division			
Number of Wells	16,356	1,017	**17,373**
Net Oil Equivalent, MBOE:	245,401	95,827	**341,228**
Cash Flow Before Tax (BTAX), M$			
Undiscounted:	2,420,175	1,375,224	**3,795,399**
Discounted at 10% per Annum:	738,575	398,979	**1,137,554**
Percent of Discounted 10% Combined Total, %**	**53.95**	**46.05**	**100.00**

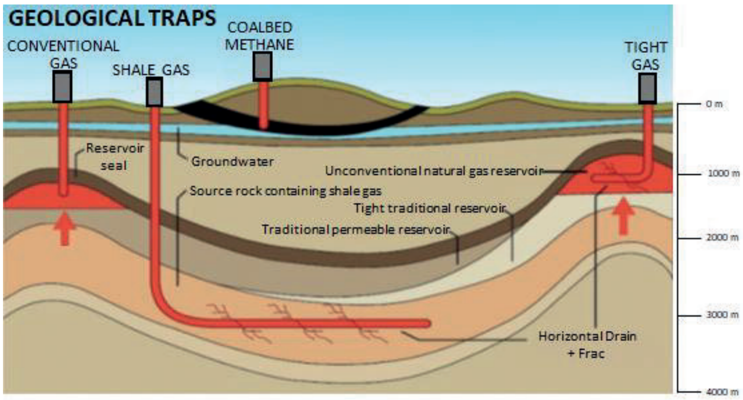
* *Certain values for asset retirement obligations, firm transportation, and maintenance capital, etc. are excluded.*

** *Certain values for asset retirement obligations, corporate expense cases, and non-hydrocarbon revenue sources are included.*

By definition, conventional wells are so named because they are drilled into and produce from conventional reservoirs. Conventional reservoirs typically consist of sandstone or limestone with enough porosity to store oil and natural gas with sufficient permeability. Porosity is the measure of the void spaces in a given rock or material. Permeability is a measure of how easily fluid flows through the rock. Porosity and permeability are related properties of any rock or loose sediment, quantifying the number, size, and connectivity in the rock. A rock may be extremely porous, but if the pores are not connected, it will have no permeability. Likewise, a rock may have a few continuous cracks that allow fluid to flow, but may not be very porous. While a number of such gas wells can produce sufficient quantities of gas without stimulation by hydraulic fracturing, some conventional wells require this stimulation technique due to the reservoir characteristics. Stimulation of conventional wells, however, generally does not require the volume of fluids required for modern day unconventional wells.

The following **Figure 11** shows a depiction of wells drilled in conventional and unconventional formations, which generally may be referred to as conventional and unconventional wells. Both are described in further detail in the following paragraphs.

Figure 11



Schematic cross-section showing the general setting of basin centered/low permeability regional gas accumulations. Taken from 'Gas Fact Sheet – Gas Resource Types.' Government of Western Australia www.dmp.wa.gov.au/onshoregas

The following table generally describes a comparison of conventional and unconventional reservoirs. DGO has wells that are producing from most of the types of reservoirs listed below, with the exception of Tar Sands and Methane Hydrates.

Conventional Reservoir vs. Unconventional Reservoir

Conventional Reservoir	*Unconventional Reservoir*
Contained gas and oil can flow naturally and easily	Low permeability constricts the flow of gas and oil
Gas and oil migrate from the source rock	Gas and oil remain in the source rock
Reservoir rock examples: – Sandstones – Fractured Limestones – Fractured Dolomites	Reservoir rock is the source itself and has many types: – Shale – Tight Sand – Coal Bed Methane (CBM) – Tar Sands – Methane Hydrates
Easily produced by direct (vertical drilling) method	To produce from unconventional, the reservoir is stimulated, creating a higher permeability

Conventional Operations

Although exploration and development drilling operations are currently outside the regular operational activities for DGO, it is important for the discussions contained within this CPR to include a brief description of typical conventional operations. The full operational cycle of a conventional well as discussed below can be briefly summarized into four main phases: site or pad clearing and construction, drilling and completion of the well, production operations, and asset retirement. DGO's current operations are exclusive to production operations and asset retirement. A discussion of DGO's operations can be found in the *OPERATIONS* section of this CPR.

A typical well pad cleared for a conventional oil or natural gas well is suited to the needs of the small conventional operations. Conventional well sites are flexible and can be more easily adapted to existing site terrain.

Once a pad site has been prepared, drilling operations can commence. First, a hole of generally 13 to 15 inches in diameter is drilled vertically to a depth of 50 to 1,500 feet, depending on the properties of the area being drilled. Next, a steel pipe called a surface casing string is lowered into this hole and cemented into place. Then, vertical drilling can proceed using a smaller bit of seven to nine inches in diameter. This bit may be used to drill into the reservoir. Once the desired depth is reached, another piece of string, called the production casing string, can be lowered into the hole and cemented in place. Once the production string is in place, a perforating gun is used to puncture the casing to allow oil and gas to flow into the wellbore, to the surface, and into production processing equipment. It should be noted that this is a generalized and simplified overview of the drilling and completion process for conventional wells. Actual processes and designs may vary from well to well.

Wellhead pressures of new conventional wells are relatively low, beginning at several hundred pounds per square inch of pressure (psi) or less and quickly reducing to lower pressures. Once drilling and completion operations are completed and the associated equipment is removed, a conventional oil or gas well has a relatively small surface footprint in the production phase. As pressure and production rates decrease over time, field operations often use artificial means such as pumping to help maintain production. In some cases, well productivity can be increased by a workover or modifying surface or downhole equipment as further discussed in the *OPERATIONS* section of this CPR.

Unconventional Operations

Although exploration and development drilling operations are currently outside the regular operational activities for DGO, it is important that the discussions in this CPR contain a brief description of typical unconventional operations. The full operational cycle of an unconventional well can briefly be summarized as site or pad clearing and construction, drilling and completion of the well, hydraulic stimulation, production operations, and asset retirement. DGO's current operations are exclusive to production operations and asset retirement. A discussion of DGO's operations can be found in the *OPERATIONS* section of this CPR.

A typical well pad cleared for unconventional oil or natural gas wells is suited to the greater needs of the initial drilling, completion, and stimulation operations. Predominantly, unconventional well pads are larger due to the large amount of equipment required for the hydraulic stimulation of the well(s). In addition, most unconventional well sites accommodate multiple wellheads. In an effort to minimize surface disturbances and maximize facility utilization, unconventional well pads may be designed for anywhere from 4 to 40 wellheads depending on various factors. These factors include considerations such as lease unit configuration, topography, site access, and the number of productive zones being targeted.

An unconventional well is different from a conventional well in that it is generally drilled into an organic rock that is the source of the oil and gas. An unconventional well usually employs sophisticated operating practices including horizontal drilling and hydraulic stimulation. These methods are required because the unconventional reservoirs typically have low permeability, and reservoir fluids do not easily flow through the rock.

The initial steps to drilling and completing an unconventional well may in some cases be very similar to conventional wells. Unconventional wells may be vertical, or may be drilled vertically to the reservoir, then turn horizontally using directional drilling equipment. Drilling horizontally and adding more perforations to the pipe are ways to provide more area for the oil and gas to flow into the well. In contrast to a vertical well where exposure to the productive zone is limited by the thickness of the zone, the exposure to the zone in a horizontal well is limited only by the length of the lateral section of the well. Perforating the lateral section provides much more exposure to the reservoir, which leads to greater connectivity for the oil and gas to flow into the well.

Modern hydraulic stimulating techniques take this concept one step further. In order to provide an even better pathway from the reservoir to the wellbore, hydraulic pumps send large volumes of water mixed with certain additives into the well and out into the rock to create fractures through which the oil and gas can flow. Once sufficient water has been pumped to initiate the fracture, additional water is pumped with sand or some other type of proppant. The purpose of the proppant is to fill the fractures in order to keep them from closing once the hydraulic pressure is no longer being applied by the pumps. The proppant also provides a permeable channel for the oil and gas to flow through in order to reach the wellbore.

Wellhead pressures of new unconventional wells are high relative to conventional pressures, beginning at thousands of psi and reducing to hundreds of psi over the course of months or years. An unconventional oil or gas well has a smaller surface footprint in the production phase than in the drilling, completion, and stimulation phases. However, surface facility design must consider very large capacities of production due to the high initial rates and the number of producing wells on the pad. As previously described, pressure and production rates decrease over time, and field operations often use artificial means such as pumping to help maintain well productivity. In some cases, well productivity can be increased by a workover or modifying surface or downhole equipment. At some point, the commodity price for the volume of production is not enough to cover the operating expenses, and the well becomes uneconomic as further described in the *OPERATIONS* section of this CPR.

It should be noted that DGO's strategic plan has been to acquire 1P developed wells that were already drilled and put into production by preceding operators. This CPR is an evaluation of these existing wells, so no consideration was given to prior drilling and completion techniques. Based on the instructions of DGO, no future development of conventional or unconventional hydrocarbon resources was considered by Wright and none are included in the assets evaluated.

METHODS OF RESERVES DETERMINATION

Decline curve analysis (DCA) is a form of production performance analysis used to assign reserves quantities and timing to the wells included in this CPR. In the opinion of Wright, DCA is an appropriate production performance analysis forecasting method for the wells included in this CPR. According to the PRMS section 4.1.4.3, for mature reservoirs, the future production forecast may be sufficiently well defined that the remaining uncertainty in the technical profile is not significant. DCA is a common method used to assign reserves by extrapolating historical production trends to forecast future production volumes. There are several types of declines under the umbrella of DCA. Two of the most common types of DCA are exponential decline and hyperbolic decline, one of which was applied to each of the forecasted wells included in this CPR.

Exponential decline uses an exponential equation to calculate the forecasted production. When using exponential DCA, production rate is plotted on the vertical axis using a log scale, and time is plotted on the horizontal axis using a linear scale. This semi-log graph is used because exponentially declining production plotted on this type of graph forms a straight line. By visually reviewing both the production profile and forecast as straight lines, the fitting exercise is conducted relatively simply. Fitting the forecast to the production data in the reserves and economics software determines the critical parameters required to generate an exponential production forecast, which are the decline rate (De) and initial production rate (IP). The IP is generally considered as the rate at the beginning of the well life, and the De is the percentage that the production rate declines each year. Wright may assign exponential decline forecasts with a decline rate of 3 to 5 percent, or even as low as 1.5 percent to wells that have demonstrated low decline rates for a substantial period of time. This method applies to the majority of DGO wells, which have long producing histories that can be approximated as a straight line on a semi-log scale. The forecasts are a simple fit to historical production trends for the DGO wells, which are then used to project volumes in the future based on the same straight-line model.

Many reservoirs demonstrate a decline profile that does not match the 'straight-line' decline of an exponential forecast. These wells demonstrate a very high initial decline rate that decreases to a lower exponential terminal decline rate over time. This transient decline rate generates a curved production profile that describes a hyperbolic slope. For example, wells that demonstrate this production profile may have De values that range from 35 percent to more than 90 percent in the first year. However, the De decreases each year that the well produces until the decline reaches its terminal (Dmin). This exponential terminal decline rate depends on reservoir and operational conditions, which may produce a range of values.

A hyperbolic forecast is created by matching the forecast line visually to historical production data to determine three critical parameters: IP, initial decline rate, and hyperbolic b-factor (b-factor). The IP and initial decline rate are similar to exponential decline forecasts. The b-factor determines the intensity of 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 pre-determined value, the curved hyperbolic forecast transitions to a terminal exponential decline. If a terminal exponential decline is not used, the decline rate would continue to decrease until it becomes flat at a constant production rate, which is not how oil and gas wells typically behave. Wright assigns terminal exponential decline rates of no less than three percent to wells demonstrating a hyperbolic decline trend.

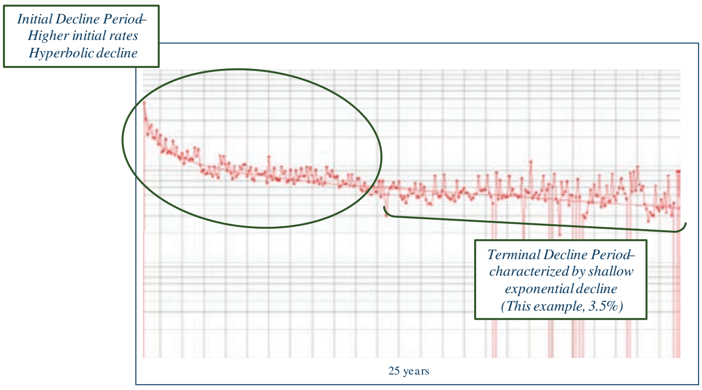
This method is suited to forecast certain DGO wells that have historically demonstrated a hyperbolic production decline profile and not yet reached a terminal exponential decline rate. These wells are typically newer wells that have been producing for less than approximately 10 to 15 years. This method may have also been applied to wells that were previously on a terminal exponential decline, were shut in, and have now been returned to production. Such wells often demonstrate a short-term hyperbolic production profile that is commonly seen when shut-in wells are returned to production. Fitting these curves to the production history can be more involved as the decline rate and b-factor should be matched to the production profile. Once this match is completed and the critical parameters determined, the curve can be extrapolated to forecast future production. The length of the forecast period in conjunction with the critical parameters for each type of forecast determine the quantity of remaining reserves assigned.

Wright typically assigns 50 years of projected reserves life unless the well becomes uneconomic. A large number of the wells should have the ability to produce at least 50 years, with some lasting in excess of 80 years. As an example, Wright has performed an extensive study of the Big Sandy Field located throughout Kentucky in the Appalachian Basin. This study reviewed approximately 900 wells completed in the Big Sandy in which the original completion date was known. The data showed that approximately 67 percent of these wells had a well life in excess of 50 years with three wells having produced more than 90 years. Again, forecast parameters for wells in conventional reservoirs have been applied according to each well's specific production profile as warranted. It should be noted that many of the conventional wells acquired by DGO had already produced for several decades prior to the acquisition date.

Wright evaluated all of DGO's 1P developed reserves. Due to the number of properties, wells were split into different value groups based on values of previous reserves evaluations. These value groups were confirmed based on updated reserves forecasts and values at the end of the process. The two major review groups consisted of all wells that cumulatively made up 90 percent of the present value discounted at a rate of 10 percent (PV10) hereinafter referred to as "Top 90" and all wells that fall outside of that group hereinafter referred to as "Bottom 10." Historical production trends were reviewed and forecasted on an individual basis for all wells included in the "Top 90" group. The "Bottom 10" group constituted a much larger well set, each well of which represents a much smaller fraction of total company value than the average well in the "Top 90" well group. For reasons of practicality, these "Bottom 10" wells were forecasted by DGO and the reserves forecasts were graphically reviewed by Wright in summary plots as appropriate. For any of the summary groups that appeared to warrant additional review, Wright may have broken the group down into smaller summary sets or reviewed wells individually in order to assign reserves. At the end of the process, Wright verified that the "Top 90" and "Bottom 10" groupings of wells still represented approximately their proportionate share of total value as defined. This methodology was confirmed to be consistent with the aggregation resource assessment methods outlined in section 4.2.5 of the PRMS.

There are many examples of wells in this CPR that have produced over 30 years with potential for another 40 years or more of productive life remaining. **Figure 12** is an example of the demonstrated longevity of these wells. These production profiles indicate long life wells with very predictable future production rates.

Figure 12



Example: Clinton Reservoir, Columbiana County, OH

There is an exception to the general rule for minimum terminal decline rate. If a well has demonstrated a straight-line (exponential) decline for several years, generally three or more, a final decline rate of less than three percent may have been used based on demonstrated performance. See **Figure 13** and **Figure 14** in the following pages for a distribution of wells projected using hyperbolic and exponential DCA.

Figure 13

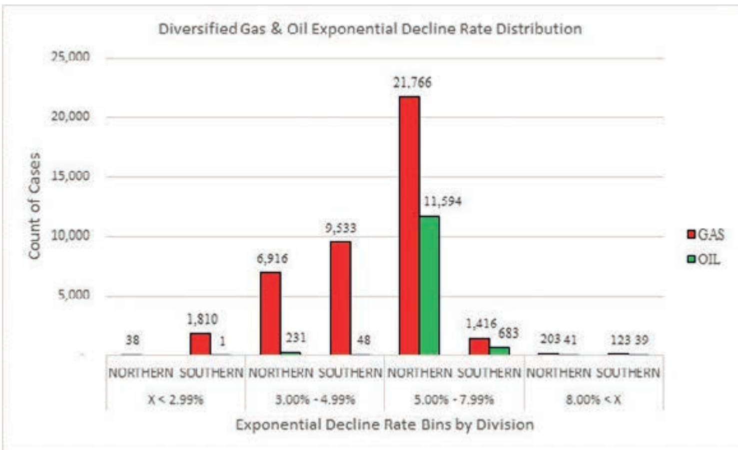
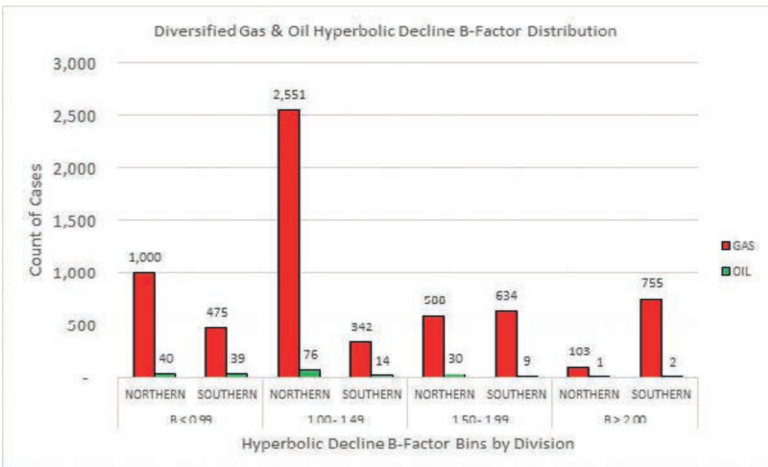


Figure 14



The estimates of reserves contained in this CPR were determined by accepted industry methods as promulgated by the PRMS and approved by the SPE in 2018, and in accordance with the SPE Petroleum Reserves Definitions. Methods utilized in this CPR include extrapolation of historical production or sales trends and analogy to similar producing properties. It should be noted that subsequent production performance trends may cause the need for significant revisions to the estimates of reserves.

There are significant uncertainties inherent in estimating reserves, future rates of production, and the timing and amount of future costs. The estimation of reserves must be recognized as a subjective process that cannot be measured in an exact way, and estimates of others might differ materially from those of Wright. The accuracy of any reserves estimate is a function of the quantity and quality of available data and of subjective interpretations and judgments. It should be emphasized that production data subsequent to the date of these estimates may warrant revisions of such estimates. Accordingly, reserves estimates are often different from the quantities of reserves that are ultimately recovered.

INTERESTS

The overall average working interest (WI) owned by DGO for properties included in this CPR calculates to be approximately 89 percent, and the overall average net revenue interest (NRI) calculates to be approximately 78 percent. The average royalty rate is approximately 13 percent.

In the US, minerals are developed on both private and public lands. Development on private lands takes place pursuant to either ownership rights (i.e. the operator owns the minerals that are being produced) or lease rights (i.e. the operator leases the minerals that are being produced from the actual owner). Often, the owner of the minerals is not the owner of the surface of the property, but the lease rights or mineral ownership rights of the operator permit them to utilize the surface of the property. On publicly owned properties, the minerals are developed by the operator pursuant to a license or permit from the government or owner. The vast majority of DGO's wells are operated on private land pursuant to DGO's mineral ownership or lease rights. Both private leases and government licenses provide that the operator will pay a royalty to the mineral owner as compensation for oil and natural gas that has been produced. Typically, the royalty amount is a percentage of the sales revenue, but sometimes it is a flat monetary amount per produced unit or producing well.

Leases generally have two components to the duration of the lease: the primary term and the secondary term. The primary term is a set number of years or months, and the secondary term exists as long as oil and gas are produced from the leased premises, which is known as the "held by production" concept. In addition to the primary term, this concept allows the operator time to develop multiple wells on the leased premises. Previously, courts have held that the "held by production" concept will hold leased premises for future well development for many decades. DGO has estimated that more than 90 percent of their undeveloped land is "held by production." DGO has production, drilling, exploration, ingress and egress access, and gathering/transportation rights on all licenses and leases.

PRODUCT PRICES (BASE CASE)

The estimates of reserves and economics were based on annual averages of the five-year NYMEX Futures Settlements prices as published by the Chicago Mercantile Exchange (CME) Group on December 31, 2019 for years 2020 through 2024. Settle prices for January are not included in the December 31, 2019 NYMEX Futures Settlements. Base prices used are the January closing price for oil published by CME Group December 19, 2019, and the January closing price for gas published by CME Group December 27, 2019. The 2024 product prices were escalated at five percent per annum for years 2025 through 2029, and then held constant thereafter at the 2029 prices in accordance with the instructions of DGO (Base Case). A table of the product prices can be found in **Exhibit B**. At the request of DGO, the NGL product prices were calculated to be a certain percent of the base oil prices, as appropriate by area. The prices were adjusted for energy content, quality, and basis differential. It should be emphasized that with the current economic uncertainties, fluctuations in market conditions could significantly change the economics in this CPR.

PRODUCT PRICE SENSITIVITIES (+/- 10%)

In order to fulfil the ESMA guidelines on the valuation of reserves ESMA Appendix III, iv. (3), information to demonstrate sensitivity changes in the Base Case assumptions will be done utilizing product price sensitivities. As requested by DGO, the product price sensitivities were conducted for two scenarios, +10% and -10% relative to the Base Case product price scenario described in the *PRODUCT PRICES* section of this CPR.

DGO Base Case prices for gas and oil were adjusted by +/- 10 percent for years 2020 through 2024. Beginning with the 2024 price, the adjusted gas and oil prices were escalated at five percent per annum for years 2025 through 2029, then held constant at the 2029 price for the life of the properties. At the request of DGO, the NGL product prices were calculated to be a certain percent of the base oil prices, as appropriate by area. This percentage of the base oil price, was applied to the sensitivity product prices.

A table showing the product prices used in the sensitivities can be found in **Exhibit B**. These sensitivity prices were adjusted for energy content, quality, and basis differential as outlined in the *PRICE ADJUSTMENTS* section of this CPR. It should be emphasized that price adjustments, operating expenses, tax rates, impact fees, investments, and any other corporate cases were not changed or escalated from the Base Case scenario.

For reference, the two price sensitivities are depicted in the following tables.

Price Sensitivity 1 – Base Case +10%

Evaluation of DGO Assets Utilizing Specified Economics Northern and Southern Divisions	**Total Proved Developed Northern Division**	**Total Proved Developed Southern Division**	**Total Proved Developed**
Net 1P Developed Reserves to the Evaluated Interests			
Oil, Mbbl:	3,492	1,415	4,907
Gas, MMcf:	1,344,427	1,662,252	3,006,679
NGL, Mbbl:	1,557	68,091	69,648
Oil Equivalent, MBOE:	229,121	346,549	575,670
Number of Wells:	42,445	17,373	59,818
Cash Flow Before Tax (BTAX), M$			
Undiscounted:	1,462,991	3,677,454	5,140,445
Discounted at 10% per Annum:	897,877	1,346,064	2,243,941

Certain values for asset retirement obligations, corporate expense cases, and non-hydrocarbon revenue sources are included.

Price Sensitivity 2 – Base Case -10%

Evaluation of DGO Assets Utilizing Specified Economics Northern and Southern Divisions	**Total Proved Developed Northern Division**	**Total Proved Developed Southern Division**	**Total Proved Developed**
Net 1P Developed Reserves to the Evaluated Interests			
Oil, Mbbl:	3,252	1,388	4,640
Gas, MMcf:	1,267,957	1,589,918	2,857,875
NGL, Mbbl:	453	67,108	67,561
Oil Equivalent, MBOE:	215,031	333,482	548,513
Number of Wells:	42,445	17,373	59,818
Cash Flow Before Tax (BTAX), M$			
Undiscounted:	653,632	2,193,274	2,846,906
Discounted at 10% per Annum:	592,136	899,101	1,491,237

Certain values for asset retirement obligations, corporate expense cases, and non-hydrocarbon revenue sources are included.

PRODUCT PRICE SENSITIVITY (SUBSEQUENT EVENTS)

Due to the impacts of COVID-19 and the OPEC+ and Russia price confrontation for crude oil, subsequent to the Effective Date, commodity prices were negatively impacted. In order to reflect the potential impact of the recent decline in commodity prices for crude oil and natural gas, Wright has provided a price sensitivity case in the following table to reflect the potential impact on DGO's reserves value. For this additional price sensitivity case, the estimates of reserves and economics were based on annual averages of the five-year NYMEX Futures Settlements prices as published by the CME Group on April 13, 2020 for years 2020 through 2024. Prices for January through April of 2020 are based on monthly averages of the daily settled spot prices, which were not included in the April 13, 2020 NYMEX Futures Settlements. Base prices used are the May closing prices for oil and gas published by CME Group on April 13, 2020. The 2024 product prices were escalated at five percent per annum for years 2025 through 2029, and then held constant thereafter at the 2029 prices in accordance with the instructions of DGO.

Price Sensitivity 3 – Subsequent Events

Evaluation of DGO Assets Utilizing Specified Economics Northern and Southern Divisions	Total Proved Developed Northern Division	Total Proved Developed Southern Division	Total Proved Developed
Net 1P Developed Reserves to the Evaluated Interests			
Oil, Mbbl:	3,187	1,389	4,576
Gas, MMcf:	1,305,239	1,622,751	2,927,990
NGL, Mbbl:	474	67,250	67,724
Oil Equivalent, MBOE:	221,201	339,098	560,299
Number of Wells:	42,445	17,373	59,818
Cash Flow Before Tax (BTAX), M$			
Undiscounted:	966,152	2,472,114	3,438,266
Discounted at 10% per Annum:	709,071	965,419	1,674,490

Certain values for asset retirement obligations, corporate expense cases, and non-hydrocarbon revenue sources are included.

In addition to the value of the individual wells being influenced by the product price, so too is the economic life. DGO operates and owns interest in both high rate and high decline rate assets such as the Marcellus and Utica wells in Ohio, Pennsylvania, and West Virginia along with many low rate and low decline rate wells throughout the entirety of the company's regional footprint. These low rate assets are extremely sensitive to product price fluctuations, and the duration of their economic life relative to the Effective Date of this CPR can demonstrate such sensitivity.

Economic well life varies by well throughout the DGO asset. Economic well life may vary through time based on changes in productivity and to input parameters such as operating expenses, workover expenses, and realized pricing. The economic life of any well may be extended if conditions exist that allow for increased production rates that may be achieved via workover, compression, or other improvements. In section 3.1.2 of the PRMS both net present value (NPV) and economic limit are considered when evaluating the economic viability of a given assessment. Economic is defined as "a project with a positive undiscounted cumulative net cash flow," which would mean that a project with a negative undiscounted cumulative net cash flow would be considered uneconomic, both terms being based on the reference point/Effective Date. Conversely, if operating costs increase and product prices decline, the individual well-life could be shortened, and more wells could become uneconomic. Furthermore, a reduction in product prices could lead to producing fields or areas to be shut down and could be entered into the decommissioning schedule earlier than anticipated. Although a well may become uneconomic due to pricing and costs, production may continue, and decommissioning the well is not necessarily imminent.

As stated in section 3.1.3.5 of the PRMS, "in some situations, entities may choose to initiate production below or continue production past the economic limit. Production must be economic to be considered as reserves, and the intent to or act of producing sub-economic resources does not confer reserves status to those quantities. In these instances, the production represents a movement from Contingent Resources to production. However, once produced such quantities can be shown in the reconciliation process for production and revenue accounting as a positive technical revision to reserves. No future sub-economic production can be Reserves."

PRICE ADJUSTMENTS

Gas price basis differentials represent the relative difference between gas prices realized at local or regional delivery points and the gas prices realized at Henry Hub pipeline, located in Erath, Louisiana, which serves as the official delivery location for all NYMEX futures gas contracts. Oil price basis differentials represent the relative difference between 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 oil on the NYMEX.

For the purposes of this CPR, DGO has provided pricing differentials for both the Northern and Southern Divisions, which can be found in **Exhibit D**. Within each division, the price differentials were prescribed by acquisition set, and then further specified by well district. These price adjustments were not verified, validated, or reviewed for accuracy aside from affirming that they were prescribed in a consistent and effective manner. DGO provided supporting information to validate their assumptions based on 12-month rolling averages, which meet the requirements of PRMS section 3.1.2 on guidelines for evaluation and reporting as it pertains to economic criteria.

According to DGO, there are multiple hedge structures in place for natural gas, oil and NGL products. These various mechanisms are utilized by DGO to protect cash flow in down markets but were not accounted for in any of the pricing adjustments or basis differential calculations. These hedge structures are considered to be financial strategies executed at the corporate level and are not considered to be within the scope of this CPR.

OPERATING EXPENSES

Operating expenses were provided by DGO and are described in **Exhibit E**. These expenses were used in accordance with the instructions provided by DGO and were ascertained based upon the 12-month or latest available average of actual costs (PRMS Section 3.1.2). These costs included, but were not limited to, all direct operating expenses, miscellaneous proved developed producing (PDP) maintenance and field level overhead costs. Expenses for workovers, well stimulations, and other maintenance were included in the operating expenses for the Northern Division. Details on maintenance and workover expenses in the Southern Division are outlined in the *OPERATIONS* section of this CPR. Judgments for the exclusion of the nonrecurring expenses were made by DGO. Any internal indirect overhead costs (general and administrative), which are not billable to the working interest owners, were not included. Based on the economics in this CPR, the operating expenses for the PDP properties are expected to average approximately $5.29 per barrel of oil equivalent (BOE) through year 2023. For properties where data were unavailable, operating expenses were estimated by DGO based on analogy to similar properties. After the Effective Date, the operating expenses were held constant for the life of the properties.

SEVERANCE AND AD VALOREM TAXES

Standard state severance taxes and average county *ad valorem* taxes have been deducted as appropriate. All taxes were provided by DGO and were used in accordance with their instructions. According to DGO, any *ad valorem* taxes not deducted separately were included in the operating expenses. For the purposes of this CPR, the following table shows the various rates for each state.

State	Ad Valorem Tax Rates	Severance Tax Rates	
		Oil	Gas
Kentucky	Ranged from 0% to 7.83% of Revenue, depending on area	Ranged from 2.63% to 5.23% of Revenue	Ranged from 2.63% to 7.25% of Revenue
Ohio	0% of Revenue	$0.20/bbl	$0.03/Mcf
Pennsylvania*	N/A	N/A	N/A
Tennessee	0% of Revenue	3% of Revenue	3% of Revenue
Virginia	Ranged from 0% to 10% of Revenue, depending on area	Ranged from 0.5% to 3.67% of Revenue	Ranged from 1% to 3.67% of Revenue
West Virginia	Ranged from 0% to 9.45% of Revenue, depending on area	Ranged from 0% to 5% of Revenue	Ranged from 0% to 5.5% of Revenue

* *There are no applicable severance taxes in Pennsylvania.*

PENNSYLVANIA IMPACT FEES

Wright has included certain fees for unconventional gas wells in this CPR based on the Act Amending Title 58 (Oil and Gas) of the Pennsylvania Consolidated Statutes (Act 13 of 2012). Act 13 of 2012 imposes a fee on every producer and applies to all unconventional (horizontal and vertical) gas wells spud in the Commonwealth (Impact Fee). The Impact Fees are based on the date a well is spud and the average price of natural gas in the year the fee is imposed. The spud date is defined as the year the actual drilling of the unconventional well began. Horizontal wells are assessed fees for 15 years while vertical wells are assessed at 20 percent of the horizontal well fee for 10 years. Payment for these fees is due on April 1 of the following year.

Under Act 13 of 2012, beginning January 1, 2013, the Pennsylvania Public Utility Commission (PUC) may annually adjust the fee to reflect any upward changes in the Consumer Price Index for all urban consumers for the Delaware, Maryland, New Jersey, and Pennsylvania area in the preceding 12 months. The adjustment may only occur if the total number of unconventional wells spud in a given year exceeds the number of unconventional wells spud in the prior year.

CORPORATE DIVISIONS

DGO's operational units are separated into two areas referred to as the Northern and Southern Divisions. As previously stated, DGO submitted two ARIES® databases for the divisions. According to DGO, some wells may not be specific to the individual database and the internal operations may be assigned to the other operating group to capture better efficiencies and synergies.

In accordance with the ESMA guidelines on historical production (ESMA Appendix III, vi.), the following table depicts DGO's historical net production by division of the acquired assets for the previous three years. The volumes were provided by DGO and were not independently verified by Wright.

Corporate Division	2016 Net Production (MBOE)	2017 Net Production (MBOE)	2018 Net Production (MBOE)	YTD 2019 Net Production (MBOE) (01/2019 – 08-2019)
Northern Division	23,872	21,815	20,883	13,295
Southern Division	17,799	17,168	16,196	10,529
TOTALS	**41,671**	**38,983**	**37,079**	**23,824**

DGO has interests in approximately 59,818 1P developed wells of which approximately 49,015 are assigned to the PDP reserves category, and approximately 10,803 are assigned to the proved developed nonproducing shut-in (PDNP-SI) reserves category. DGO is evaluating all inactive wells to determine if smarter well management and operational restoration efforts are economically viable for restoring production. Additional information regarding these efforts can be found in the *OPERATIONS* section of this CPR. Some of these inactive wells may be turned to production intermittently and may contribute to sales volumes. This activity is part of an ongoing program to maintain well productivity. All reserves values assigned in this CPR are from active PDP wells only.

Northern Division

The Northern Division database contains DGO Legacy, DGO Energy, APC, and CNX designated properties. The wells acquired from HG in April 2019 and EdgeMarc in September 2019 are also included in the Northern Division database. There are approximately 42,445 gross wells in the Northern Division that combine to a total 10.0 percent Cum. Disc. cash flow (BTAX) value of 798,181 M$, which is approximately 43 percent of the total 10.0 percent Cum. Disc. cash flow (BTAX) value of the company. More specifically, the assets acquired from HG and EdgeMarc account for 432,518 M$, which is approximately 23 percent of the total 10.0 percent Cum. Disc. (BTAX) value of the company. The following table shows the number of wells, net reserves, and value by state for the Northern Division.

Northern Division Properties Net Reserves and Discounted Cash Flow by State

	Ohio	Pennsylvania	Tennessee	Virginia	West Virginia	Misc. Non-Op.	TOTALS*
Number of 1P Developed Wells:	8,051	24,183	487	13	9,601	110	**42,445**
Net Oil, Mbbl:	2,349	285	77	0	674	3	**3,387**
Net Gas, MMcf:	105,659	789,230	9,712	109	404,599	644	**1,309,953**
Net NGL, Mbbl:	196	292	0	0	5	0	**493**
10.0 % Cum. Disc. (BTAX) Value, M$:	110,241	451,914	8,386	50	227,240	350	**798,181**
Percent of Northern Division Total Proved 10% Cum. Disc. (BTAX) Value, %:	13.81	56.62	1.05	0.01	28.47	0.04	**100.00**
Percent of DGO Total Proved 10.0 % Cum. Disc. (BTAX) Value, %: **	5.91	24.24	0.45	0.00	12.19	0.02	**42.82**

* *Certain values for asset retirement obligations and firm transportation are excluded.*

** *Certain values for asset retirement obligations, corporate expense cases, and non-hydrocarbon revenue sources are included.*

Recent Acquisitions – HG and EdgeMarc

In April 2019, DGO acquired certain gas and oil properties from HG, comprising 107 1P developed wells drilled into the Marcellus. The wells are located in Pennsylvania (56) and West Virginia (51) and were sold as 'wellbore only' properties in the transaction. This addition further solidified DGO's position in the Appalachian Basin. There is significant value in the wells acquired from HG, which represent a 10.0 percent Cum. Disc. (BTAX) value of 377,220 M$, or approximately 20 percent of the total 10.0 percent Cum. Disc. (BTAX) value of the company. Approximately 82 of the top 100 value properties for all of DGO are within HG.

The wells acquired from HG included 100 percent working interests with net revenue interests of approximately 87 percent. Prior to 2013, 18 wells were PDP and located in West Virginia. Eighty-seven wells were turned-in-line between 2013 and 2015 and an additional two wells in 2019. The average lateral length for all 107 wells is approximately 6,600 feet.

In September 2019, DGO acquired certain gas and oil properties from EdgeMarc, which included 12 horizontal wells located in southeastern Ohio where the Utica typically produces a dry gas. This dry gas has minimal shrink and requires little to no processing expense to make the product pipeline quality. The quality of the gas, rapid decline in water production, and proximity to major interstate gas transportation lines are all factors that result in relatively low operating costs. These wells began production between 2015 and 2019 and have an average producing life of 27 months to date. As is the case with most unconventional wells, the hyperbolic portion of the well's production profile can last 10 to 15 years or longer from the date of first production. As a note, the average decline rate for these wells as of the Effective Date was 38.2 percent. The following table shows the number of wells, net reserves, and value by state for the HG and EdgeMarc acquisitions.

HG and EdgeMarc Acquisition Properties Net Reserves and Discounted Cash Flow by State

	Ohio	Pennsylvania	West Virginia	TOTALS*
Number of 1P Developed Wells	12	56	51	**119**
Net Oil, Mbbl	7	10	16	**32**
Net Gas, MMcf	73,663	348,574	187,384	**609,620**
Net NGL, Mbbl	180	0	0	**180**
10.0 % Cum. Disc. (BTAX) Value, M$	55,298	249,715	127,504	**432,518**
Percent of Acquisition Properties Total Proved 10% Cum. Disc. (BTAX) Value, %	12.79	57.74	29.48	**100.00**
Percent of DGO Total Proved 10.0 % Cum. Disc. (BTAX) Value, %**	2.97	13.40	6.84	**23.20**

* *Certain values for asset retirement obligations, firm transportation, and maintenance capital cases are excluded.*

** *Certain values for asset retirement obligations, corporate expense cases, and non-hydrocarbon revenue sources are included.*

Southern Division

The Southern Division is comprised of assets acquired from Core and EQT that combine to a total 10.0 percent Cum. Disc. (BTAX) value of 1,137,554 M$, which is approximately 61 percent of the total 10.0 percent Cum. Disc. (BTAX) value of the company. More specifically, the EQT properties account for 923,682 M$, which is approximately 50 percent of the total 10.0 percent Cum. Disc. (BTAX) value of the company. The following table shows the number of wells, net reserves, and value by state for the Southern Division.

Southern Division Properties Net Reserves and Discounted Cash Flow by State

	Kentucky	Virginia	West Virginia	TOTALS*
Number of 1P Developed Wells:	8,902	825	7,646	**17,373**
Net Oil, Mbbl:	1,009	27	368	**1,404**
Net Gas, MMcf:	954,838	80,185	597,621	**1,632,644**
Net NGL, Mbbl:	66,983	20	713	**67,716**
10.0 % Cum. Disc. (BTAX) Value, M$:	850,296	53,213	234,045	**1,137,554**
Percent of Southern Division Total Proved 10% Cum. Disc. (BTAX) Value, %:	74.75	4.68	20.57	**100.00**
Percent of DGO Total Proved 10.0 % Cum. Disc. (BTAX) Value, %: **	45.61	2.85	12.55	**61.02**

* *Certain values for asset retirement obligations and maintenance capital are excluded.*

** *Certain values for asset retirement obligations, corporate expense cases, and non-hydrocarbon revenue sources are included.*

In July 2018, DGO acquired certain gas and oil properties from EQT, comprising approximately 12,128 1P developed wells. The wells are located in Kentucky, Virginia, and West Virginia and expanded DGO's footprint in the Appalachian Basin southward from prior holdings. As noted previously, gas production is commingled and includes Berea Sand, Big Lime, Big Injun, Cleveland, Lower Huron, and the Weir. All are considered tight sands with low permeability.

Acquisition of the wells from Core closed in the fourth quarter of 2018 and included approximately 5,245 1P developed wells that are located in southwestern and southcentral West Virginia. The Core wells are largely adjacent and contiguous to the EQT wells. According to DGO, the synergies between the EQT and Core wells have streamlined field operations and processing and marketing arrangements.

OPERATIONS

DGO reports that 'Smarter Well Management' is one of the key differentiators between their operations and those of their peers. Most operators in the Appalachian Basin are focused on capital-intensive projects such as developing unconventional resources in the Marcellus and Utica. According to DGO, their strategy is to forego the capitally intensive investment of drilling and completing new wells for more manageable expenses by continuing to acquire and operate producing wells.

DGO has focused on improving production on active producing wells and returning previously inactive or shut-in wells to a producing status. In instances where the well cannot be restored to production using the natural pressure that is in the well, certain activities are being continually employed to restore and, in some instances, boost production rates. These activities include installing pumpjacks, swabbing, installing plunger lifts, well treatments with water or chemicals, and installing wellhead compression. Each of these activities are routine oilfield techniques that have been employed by operators throughout the history of the Appalachian Basin.

Based on information provided by DGO, there have been over 1,000 individual well restoration efforts since 2018. This activity is ongoing and fluctuates seasonally with higher activity in the warmer months. The overwhelming majority of restoration activities are related to replacing equipment such as tubulars or artificial lift components, installing new artificial lift systems, and general well interventions as described above.

Pulling tubing is an operation that is often conducted in response to a significant reduction in production rates. These reduced rates could be due to a leak in the tubing string caused by routine stresses, abrasion on the tubing from downhole equipment, or routine wear from production operations. In this operation, the production tubulars are retrieved from the well and inspected for integrity. If damaged sections of pipe are observed, they are replaced, and the tubulars are run back into the hole to restore production.

Another common well intervention operation is swabbing. Swabbing is the removal of water or liquid hydrocarbons from a well so that the oil and gas can flow freely into the wellbore. This operation is conducted with a truck-mounted swabbing unit that has a short mast used to lower a swab tool into the well or tubing string on a wireline. The swab tool itself is generally a steel rod with rubber cups or rings around the steel to create a seal against the inside of the production tubulars. When the swab tool is lowered to the fluid level of the well and pulled towards the surface, a vacuum is created between the swab tool and the fluid, effectively lifting the fluid out of the well.

The efforts previously described are managed by considering a variety of factors that include the candidate selection (with preference given to oil), probability of success, and the quickest return on investment. Based on these criteria, the distribution of restoration activity favors the oil-weighted Legacy assets in the Northern Division over the predominantly dry gas assets in the Southern Division. However, DGO reports that the results from each area consistently demonstrate that well intervention and restoration activities can effectively arrest the decline rate of the well, restore deferred production, and either increase or accelerate reserves.

In most PDP wells, little or no capital investment is expected to be incurred to maintain the profile for anticipated future production. Wright did not evaluate any behind pipe zones for potential recompletion or undeveloped locations, if such exist; therefore, there is no capital investment included in this CPR for potential future development. All Northern Division expenses related to miscellaneous PDP maintenance are included in the lease operating expenses that were previously referenced and are shown in **Exhibit E**. As a part of the Southern Division, well work and gathering maintenance capital investments were prescribed in summary at the division level. According to DGO these figures are consistent with internal accounting figures for well work and maintenance associated with the assets in the Southern Division.

For the evaluation of wells acquired from EQT, DGO requested Wright to include annual capital investments of 7,780 M$ for gathering system maintenance and 2,972 M$ for miscellaneous well maintenance expenses. These annual expenses are applied at the summary level and are relevant to the subset of operated wells acquired from EQT. The annual capital applied equally across the total gross wells would be approximately $245 per well for well maintenance and $640 per well for gathering system maintenance.

For the evaluation of wells acquired from Core, DGO requested that Wright include capital investments for miscellaneous PDP maintenance expenses starting at $4,500 per month and reduced by three percent per year after the first year. These capital costs were applied at the summary level and are relevant to the operated wells through the life of the properties. For the total gross wells acquired from Core, the average monthly burden is approximately $0.86 per well.

It should be noted that DGO's strategic plan has been to acquire 1P developed wells that were already drilled and put into production by preceding operators. This CPR is an evaluation of these existing wells, so no consideration was given to prior drilling and completion techniques. Based on the instructions of DGO, no future development of conventional or unconventional hydrocarbon resources was considered by Wright and none are included in the assets evaluated. According to DGO, they hold leases across approximately 7.8 million acres in various states. These leases are "held by production" from the 1P developed reserves evaluated in this CPR.

MIDSTREAM ASSETS

DGO owns and operates an extensive gathering and compression system that includes approximately 10,500 miles of pipeline and 61 compressor stations that were part of the EQT acquisition. This gathering system transports gas volumes from the DGO wells and other third-party wells and delivers the gas to larger pipelines. At the request of DGO, Wright included a non-hydrocarbon revenue source for the third-party gathering and compression fees as stand-alone cases included at the summary level in the Southern Division.

DGO acquired complementary midstream assets from EdgeMarc in 2019. These assets added 1,700 miles of low-pressure pipeline to DGO's portfolio of nearly 10,500 miles of midstream assets. According to DGO, this acquisition increased the third-party corporate midstream revenues, expanded DGO's midstream synergies to the Northern Division, and secured DGO's flow assurance by adding certainty to capacity and realized pricing.

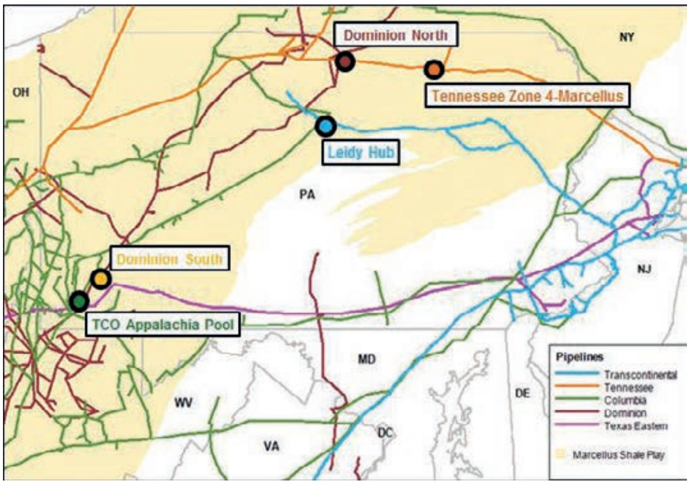
The midstream gathering case associated with assets acquired from Core contains fixed forecasted monthly cash flow revenue figures that have been projected in accordance with DGO's instructions. This 10.0 percent Cum. Disc. cash flow (BTAX) value is in excess of 52,000 M$ for a 20-year schedule and is summarized in the Southern Division total. The forecasted cash flows were generated from historical data that considered volumes gathered from DGO and volumes gathered from third-party operators. Based on the information provided by DGO, the projection of a three percent annual decline in gas production rates and flat operating expenses appear to be reasonable for the purposes of this CPR.

The third-party revenue case that is associated with the EQT asset generates a 10.0 percent Cum. Disc. cash flow (BTAX) value in excess of 62,000 M$ over a 50-year schedule and is summarized in the Southern Division total. Similar to the case described above, the revenues were generated from historical data that considers volumes gathered from third-party operators. Unlike the previous case, the revenues associated with this case are received directly from transportation charges. These revenues are scheduled to decline at a 3.75 percent annual rate. A separate case contains annual capital investments of 7,780 M$ for gathering system maintenance and is summarized in the Southern Division total.

GAS MARKETING AND TRANSPORTATION

Henry Hub is a natural gas pipeline located in Erath, Louisiana, that serves as the official delivery location for futures contracts on the NYMEX. 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. The Appalachian Basin is home to several other regional trading hubs that are indexed relative to Henry Hub. These hubs include Dominion South Point, Columbia Gas Transmission (TCO) Pool, and the Leidy Hub and are depicted in **Figure 15** (regional map from EIA). The Leidy Hub reflects gas prices that are delivered to TCO in northcentral Pennsylvania and Texas Eastern Transmission (Tetco) M-2 (western region) and M-3 (eastern region). The TCO Pool reflects the price for natural gas that is delivered north of the KY-OH-WV juncture. Finally, Dominion South (and North) represent prices delivered on the Dominion Transmission Inc. (DTI) pipeline in their respective regions.

Figure 15



According to DGO, it markets and sells natural gas through its wholly-owned subsidiary, Diversified Energy Marketing LLC (DEM). DEM purchases produced natural gas from the group's production company, Diversified Production LLC (DP).

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. DEM natural gas sales are on ten different pipeline systems and are tied primarily to three Standard & Poors (S&P) Global Platts published price index points; TCO, Dominion South, and Tetco M-2 with total sales volumes being distributed at 45, 22, and 27 percent, respectively. The remainder of the gas sales are at various smaller sales points. Wright has not independently verified these reported sales volume percentages applicable to the various index points.

According to DGO, 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 DGO'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.

According to DGO, 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.

ASSET RETIREMENT OBLIGATION

The ARO is generally described as asset retirement of uneconomic wells. As discussed in the *OPERATIONS* section of this CPR, many wells acquired by DGO from various operators may have been shut-in or are not actively producing for a variety of reasons. Costs to plug a well can vary significantly due to a number of reasons such as region, depth of producing formation, type of well (vertical or horizontal), the presence of coal, the regulations and requirements of the state in which the well is located, and the overall mechanical condition of the well. The costs to retire a well include permitting and design, access to the physical site of the well, the actual cost of decommissioning the well, the removal and disposal of unsalvageable well and facility equipment, and environmental expenses including surface site reclamation.

DGO's decision process for selecting a well to decommission considers four primary criteria. These selection criteria address the following questions: 1) does the well pose a safety concern, 2) does the well pose an environmental concern, 3) is the well included in an agreement with a state agency to be decommissioned, or

4) are there other factors such as changes to areas around the well, like economic development? Prior to retiring any well, DGO completes a thorough assessment to determine the capability of future production. If future production is not possible, DGO will schedule the well for decommissioning.

The state regulatory agency typically requires a permit prior to the commencement of operation to retire a well. Once a well is selected, DGO will apply for the proper permit, typically 30-60 days in advance of the planned operation. In preparation for the operation, well records and the well site are examined to prepare a work plan, wellbore diagram, and budget for the project. A service rig and other necessary equipment and services are then procured and scheduled. Contact with the regional regulatory inspector may also be required prior to commencement of the project.

Once a permit is obtained, the necessary equipment, typically a service rig, is moved to the well site. Preparation is made to extract all tubulars and artificial lift components from the well. Once the wellbore equipment is removed, the cementing operations begin. A "bottom hole" cement plug of specified length is first set by being pumped in a cement slurry from a pump truck, through the work string, to the bottom of the well. This cement plug is located inside the production casing. Typically, the top of cement depth between the open-hole and the production casing is determined by examination of a cement bond log. The production casing is then severed above the annular top of cement and the remaining production casing is extracted. After the production casing is removed there is an "open-hole" section.

The integrity of the bottom-hole plug is then verified. Upon verification, additional cement plugs are spotted above the formations bearing or having borne, natural gas, crude oil, or brine water. Some states may require a cement plug over certain regionally prolific productive zones, coal seams, storage zones, and/or depleted intervals as identified.

High viscosity spacers can be used between plugs, if necessary, as a filler. Once the final spacers have been pumped, the top cement plug is then spotted per the retirement program. Once the last plug is in place and the cement has set, the hole is generally filled to the surface with some type of porous aggregate. Typically, the state will require that all surface casing remain in place.

Once the well has been retired, the operator submits the required documentation and records to the state regulatory inspector. The inspector then completes the required documents such as an "asset retirement/plugging" certificate and retains those records with the regulatory agency. The site is cleaned and returned to its natural condition as per the state requirements, leaving a safe and accessible environment. Any equipment, such as pipe, separators, tanks, etc., is removed and salvaged when possible. A permanent marker is placed on the well location designating it as decommissioned. In some instances, an alternate method of plugging is approved by the local regulatory inspector. For these cases, there is a special form that accompanies a restoration report in order to document that the site was restored. All forms and final permits are approved and finalized by the state inspectors, providing the company with the appropriate records for the completion of the project.

As with any operation in the oil and gas industry, the processes, procedures, and regulatory requirements outlined here are specific to the state and region of operations. The explanations outlined above describe a relatively standard process of asset retirement projects and this process is applicable to a large majority of DGO's wells. There are various situations and instances where additional work and process is required. Although these situations are not typical, they can result in additional time and cost for the asset retirement project. Reference to applicable state regulations and their specific requirements as it relates to asset retirement should be reviewed when considering general plugging process requirements.

DGO reports that it has proactively engaged in discussions with the appropriate regulatory agencies to address its asset retirement obligations. As part of these discussions, DGO has negotiated agreements to establish a definitive schedule of wells to retire over multi-year periods. The following table is a summary of DGO's agreements by each state and approved commitment to properly plug and retire each well.

Plugging Agreement Detail	PA	OH	KY	WV
Date of Agreement Execution	3/7/19	4/25/18	2/18/19	11/19/18
Term of Agreement (yrs.)	15	5	10	15
Agreement Termination Date	3/7/34	4/25/23	12/31/28	12/31/34
Initial Wells (2019)	20	14	25	30
Annual Minimum	20	18	20	20

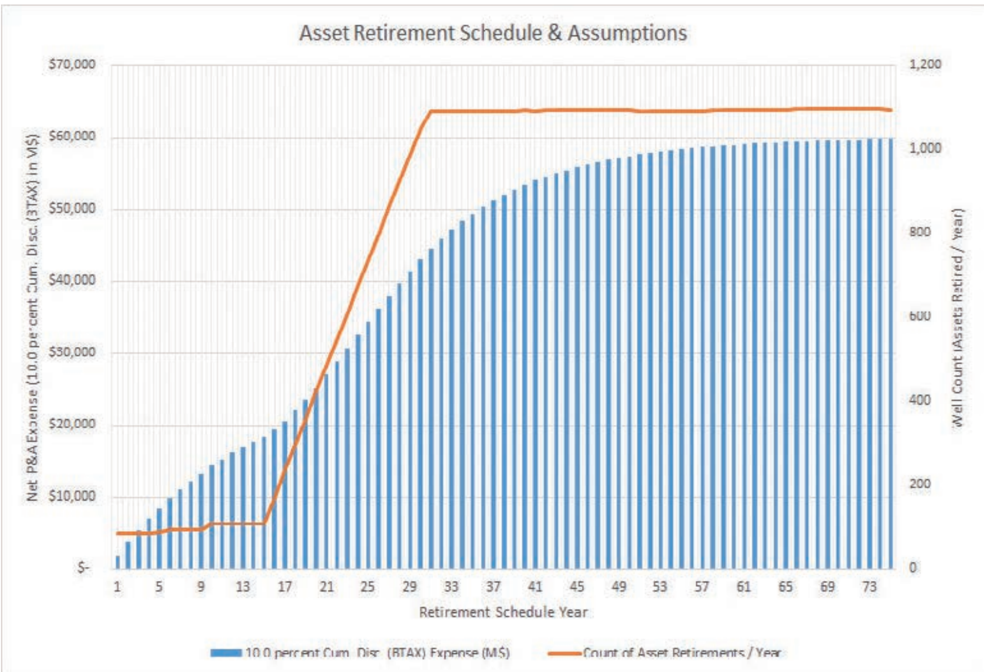
Wright requested and received information on the actual amount paid by well type for the wells that have been plugged or retired to date. An average cost was determined and applied to the remaining wells. According to DGO, these wells were accessible and plugged without issues. In the future, some of the wells may require more involvement based on location, depth, and complexity. Where DGO had not plugged wells, assumptions of investment were based on analogy to other operators and/or areas.

Asset Retirement Group	Gross Well Count	Weighted Average Gross Retirement Expense Per Well, M$	Total Net Undiscounted Retirement Expense, M$	10.0 % Cum. Disc. (BTAX) Value, M$
Kentucky	8,938	25.000	195,843	8,039.070
Ohio	8,039	22.652	154,514	6,342.574
Pennsylvania	23,856	26.428	574,010	23,562.274
West Virginia	17,145	30.000	467,259	19,180.301
Marcellus/Utica	429	90.000	34,419	1,412.850
Miscellaneous....................	1,399	25.220	29,286	1,202.148
TOTALS	**59,806**	**27.190**	**1,454,931**	**59,739.220**

* *Plugging assumptions for 12 Utica properties in Ohio that were recently acquired from EdgeMarc are excluded from the table. These excluded properties model 90 M$ asset retirement capital within the individual well case that is applied at the end of the property's economic life.*

These assumptions were applied using four corporate summary cases that were assigned based on relevant subsets of the two operating divisions. The following graphic (**Figure 16**) demonstrates the modelled 75-year plugging schedule that meets the aforementioned state agreements for the first 15 years and then escalates to a schedule of approximately 1,100 asset retirements per year by the year 2050. The schedule then levels off for the remaining term. The asset retirement by year is depicted with the orange line, while the total 10.0 percent Cum. Disc. (BTAX) expense is represented by the blue bars. Wright offers no opinion to the schedule that has been presented by DGO.

Figure 16



Wright is not aware of any potential environmental liabilities that may exist concerning the properties evaluated. There are no costs included in this CPR for potential property environmental restoration, liability, or clean-up of damages, if any beyond typical ARO activities that may be necessary due to past or future operating practices. DGO has represented to Wright that to the best of their knowledge, they have acquired and maintain all material permits, licenses, rights, and interests necessary to operate the business and assets, including production, plugging, and environmental activities.

CONCLUSIONS

Based on data and information provided by DGO, and the specified economic parameters, operating conditions, and government regulations considered applicable at the Effective Date, it is Wright's opinion that this CPR provides a fair and reasonable representation of the aggregate reserves to the interests of DGO in those certain properties included in this CPR.

Wright considers that the scope of the CPR is appropriate and was prepared in accordance with the requirements of the Financial Conduct Authority (FCA) including its Prospectus Regulation Rules, Regulations (EU) 2017/1129 and 2019/980 and the ESMA update of the CESR Recommendations (ESMA/2013/319). It is Wright's opinion that the methodologies employed, the adequacy and quality of the data relied upon, the depth and thoroughness of the reserves estimation process, the classification of reserves based on the relevant definitions used, and the reasonableness of the estimated reserves quantities are appropriate for the purpose served by the CPR and are in accordance with the guidelines set forth by the FCA.

Wright was founded in 1988 by D. Randall Wright. In preparing this CPR, Mr. Wright had the direct oversight and management of the evaluation methods and procedures and is a professionally qualified Competent Person (CP). Wright has evaluated tens of thousands of wells similar to the ones included in this CPR for many clients. Wright routinely prepares CPRs, or similar reports, for clients of their oil and gas reserves and economics pursuant to the financial reporting requirements of the US Securities and Exchange Commission (SEC) for various publicly traded companies.

Wright maintains extensive knowledge and utilizes its proprietary internal database of analogous information, in conjunction with data and information from various clients, for evaluations of oil and gas reserves and economics throughout the US and particularly the Appalachian Basin.

Exhibit A

Abbreviated Form of the Petroleum Resources Management System

As Revised June 2018

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 World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE).

PREAMBLE

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total 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 development projects, and presenting results within a comprehensive classification framework.

The PRMS definitions and the related classification system are now in common use internationally to support petroleum project and portfolio management requirements. They provide a measure of comparability, reduce the subjective nature of resources estimation, and are intended to improve clarity in global communications regarding petroleum resources.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. 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

1.0.0.2 The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. Quantities of petroleum and associated products can be reported in terms of volumes (e.g., barrels or cubic meters), mass (e.g., metric tonnes) or energy (e.g., Btu or Joule). These quantities are associated with exploration, appraisal, and development projects at various stages of design and implementation. The commercial aspects considered will relate the project's maturity status (e.g., technical, economical, regulatory, and legal) to the chance of project implementation.

1.0.0.3 The use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios. The application of PRMS must consider both technical and commercial factors that impact the project's feasibility, its productive life, and its related cash flows.

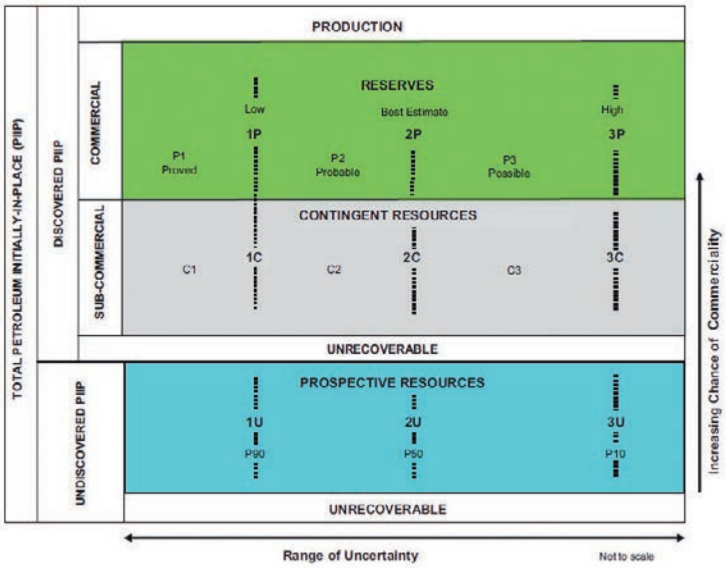
1.1 Petroleum Resources Classification Framework

1.1.0.1 Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid state. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulphide, and sulphur. In rare cases, non-hydrocarbon content can be greater than 50 percent.

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 A1 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 Petroleum.

Figure A1—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, Pc, which is the chance that a project will be committed for development and reach commercial producing status.

1.1.1.5 The following definitions apply to the major subdivisions within the resources classification:

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.

A. Discovered PIIP is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production.

B. 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 (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.

1.1.0.8 Other terms used in resource assessments include the following:

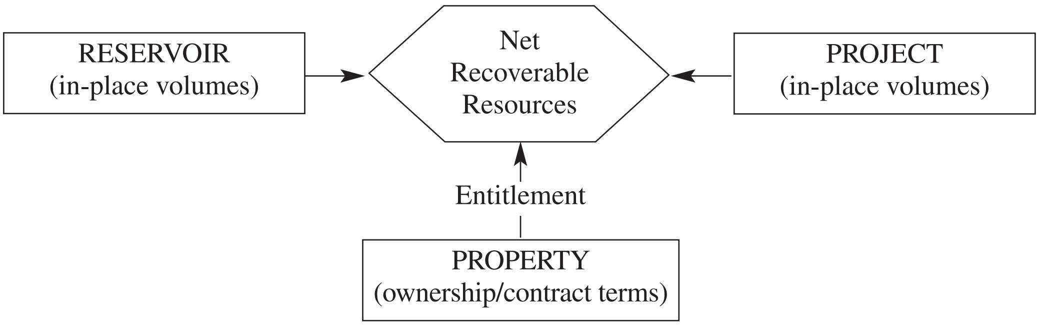
A. Estimated Ultimate Recovery (EUR) is not a resources category or class, but a term that can be applied to an accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities 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.

1.2 Project-Based Resource 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 below).

Figure A2—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.

1.2.0.10 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.

1.2.0.12 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

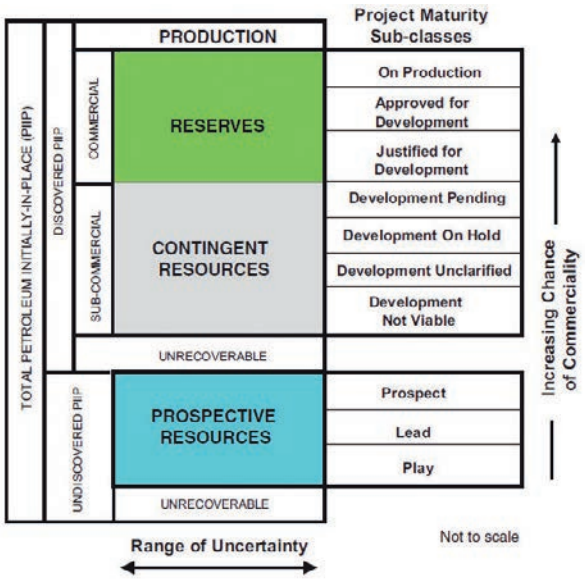
2.1 Resources Classification

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.

2.1.3.5 Project Maturity Sub-Classes

2.1.3.5.1 As Figure 2.1 illustrates, development projects and associated recoverable quantities may be sub-classified according to project maturity levels and the associated actions (i.e., business decisions) required to move a project toward commercial production.

Figure A3—Sub-Classes based on Project Maturity



2.1.3.5.2 Maturity terminology and definitions for each project maturity class and sub-class are provided in Table 1. This approach supports the management of portfolios of opportunities at various stages of exploration, appraisal, and development. Reserve sub-classes must achieve commerciality while

Contingent and Prospective Resources sub-classes may be supplemented by associated quantitative estimates of chance of commerciality to mature.

2.1.3.5.4 Projects that are classified as Reserves must meet the criteria as listed in Section 2.1.2, Determination of Commerciality. Projects sub-classified as Justified for Development are agreed upon by the managing entity and partners as commercially viable and have support to advance the project, which includes a firm intent to proceed with development. All participating entities have agreed to the project and there are no known contingencies to the project from any official entity that will have to formally approve the project.

2.1.3.5.7 Where commercial factors change and there is a significant risk that a project with Reserves will no longer proceed, the project shall be reclassified as Contingent Resources.

2.2 Resources Categorization

2.2.0.1 The horizontal axis in the resources classification in Figure A1 defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project or group of projects. These estimates include the uncertainty components as follows:

A. The total petroleum remaining within the accumulation (in-place resources).

B. The technical uncertainty in the portion of the total petroleum that can be recovered by applying a defined development project or projects (i.e., the technology applied).

C. Known variations in the commercial terms that may impact the quantities recovered and sold (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) are part of project's scope and are included in the horizontal axis, while the chance of satisfying the commercial terms is reflected in the classification (vertical axis).

2.2.0.2 The uncertainty in a project's recoverable quantities is reflected by the 1P, 2P, 3P, Proved (P1), Probable (P2), Possible (P3), 1C, 2C, 3C, C1, C2, and C3; or 1U, 2U, and 3U resources categories. The commercial chance of success 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.

2.2.1.4 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).

2.2.2 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 A-1 and A-3) 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.

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.

2.2.2.8 Tables 1, 2, and 3 present category definitions and provide guidelines designed to promote consistency in resources assessments. The following summarize the definitions for each Reserves category in terms of both the deterministic incremental method and the deterministic scenario method, and also provides the criteria if probabilistic methods are applied. For all methods (incremental, scenario, or probabilistic), low, best and high estimate technical forecasts are prepared at an effective date (unless justified otherwise), then tested to validate the commercial criteria, and truncated as applicable for determination of Reserves quantities.

2.2.2.9 One, but not the sole, criterion for qualifying discovered resources and to categorize the project's range of its low/best/high or P90/P50/P10 estimates to either 1C/2C/3C or 1P/2P/3P is the distance away from known productive area(s) defined by the geoscience confidence in the subsurface.

2.2.2.10 A conservative (low-case) estimate may be required to support financing. However, for project justification, it is generally the best-estimate Reserves or Resources quantity that passes qualification because it is considered the most realistic assessment of a project's recoverable quantities. The best estimate is generally considered to represent the sum of Proved and Probable estimates (2P) for Reserves, or 2C when Contingent Resources are cited, when aggregating a field, multiple fields, or an entity's resources.

2.2.2.11 It should be noted that under the deterministic incremental method, discrete estimates are made for each category and should not be aggregated without due consideration of associated confidence. Results from the deterministic scenario, deterministic incremental, geostatistical and probabilistic methods applied to the same project should give comparable results (see Section 4.2, Resources Assessment Methods). If material differences exist between the results of different methods, the evaluator should be prepared to explain these differences.

2.3 Incremental Projects

2.3.0.2 An incremental project must have a defined development plan. A development plan may include projects targeting the entire field (or even multiple, linked fields), reservoirs, or single wells. Each incremental project will have its own planned timing for execution and resource quantities attributed to the project. Development plans may also include appraisal projects that will lead to subsequent project decisions based on appraisal outcomes.

2.3.1 Workovers, Treatments, and Changes of Equipment

2.3.1.1 Incremental recovery associated with a future workover, treatment (including hydraulic fracturing stimulation), re-treatment, changes to existing equipment, or other mechanical procedures where such projects have routinely been successful in analogous reservoirs may be classified as Developed Reserves, Undeveloped Reserves, or Contingent Resources, depending on the associated costs required (see Section 2.1.3.2, Reserves Status) and the status of the project's commercial maturity elements.

2.3.2 Compression

2.3.2.1 Reduction in the backpressure through compression can increase the portion of in-place gas that can be commercially produced and thus included in resources estimates. If the eventual installation of compression meets commercial maturity requirements, the incremental recovery is included in either Undeveloped Reserves or Developed Reserves, depending on the investment on meeting the Developed or Undeveloped classification criteria. However, if the cost to implement compression is not significant, relative to the cost of one new well in the field, or there is reasonable expectation that compression will be implemented by a third party in a common sales line beyond the reference point, the incremental quantities may be classified as Developed Reserves. If compression facilities were not part of the original approved development plan and such costs are significant, it should be treated as a separate project subject to normal project maturity criteria.

2.3.3 Infill Drilling

2.3.3.1 Technical and commercial analyses may support drilling additional producing wells to reduce the well spacing of the initial development plan, subject to government regulations. Infill drilling may have the combined effect of increasing recovery and accelerating production. Only the incremental recovery (i.e. recovery from infill wells less the recovery difference in earlier wells) can be considered as additional Reserves for the project; this incremental recovery may need to be reallocated.

2.3.4 Improved Recovery

2.3.4.1 Improved recovery is the additional petroleum obtained, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural reservoir energy. It includes secondary recovery (e.g., waterflooding and pressure maintenance), tertiary recovery processes (thermal, miscible gas injection, chemical injection, and other types), and any other means of supplementing natural reservoir recovery processes.

2.4 Unconventional Resources

2.4.0.1 The types of in-place petroleum resources defined as conventional and unconventional may require different evaluation approaches and/or extraction methods. However, the PRMS resources definitions, together with the classification system, apply to all types of petroleum accumulations regardless of the in- place characteristics, extraction method applied, or degree of processing required.

A. Conventional resources exist in porous and permeable rock with pressure equilibrium. The PIIP is trapped in discrete accumulations related to a local geological structure feature and/or stratigraphic condition. Each conventional accumulation is typically bounded by a down dip contact with an aquifer, as its position is controlled by hydrodynamic interactions between buoyancy of petroleum in water versus capillary force. The petroleum is recovered through wellbores and typically requires minimal processing before sale.

B. Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and are not significantly affected by hydrodynamic influences (also called "continuous-type deposit"). Usually there is not an obvious structural or stratigraphic trap. Examples include coalbed methane (CBM), basin-centered gas (low permeability), tight gas and tight oil (low permeability), gas hydrates, natural bitumen (very high viscosity oil), and oil shale (kerogen) deposits. Note that shale gas and shale oil are sub-types of tight gas and tight oil where the lithologies are predominantly shales or siltstones. These accumulations lack the porosity and permeability of conventional reservoirs required to flow without stimulation at economic rates. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, hydraulic fracturing stimulation for tight gas and tight oil, steam and/or solvents to mobilize natural bitumen for in-situ recovery, and in some cases, surface mining of oil sands). Moreover, the extracted petroleum may require significant processing before sale (e.g., bitumen upgraders).

3.0 EVALUATION AND REPORTING GUIDELINES

3.0.0.1 The following guidelines are provided to promote consistency in project evaluations and reporting. "Reporting" in this document refers to the presentation of evaluation results within the entity conducting the evaluation and should not be construed as replacing requirements for public disclosures established by regulatory and/or other government agencies or any current or future associated accounting standards.

3.1 Assessment of Commerciality

3.1.0.1 Commercial assessments are conducted on a project basis and are based on the entity's view of future conditions. The forecast commercial conditions, technical feasibility, and the entity's decision to commit to the project are several of the key elements that underpin the project's resources classification. Commercial conditions include, but are not limited to, assumptions of an entity's investment hurdle criteria; financial conditions (e.g., costs, prices, fiscal terms, taxes); partners' investment decision(s); organization capabilities; and marketing, legal, environmental, social, and governmental factors. Project value may be assessed in several ways (e.g., cash flow analysis, historical costs, comparative market values, key economic parameters) (see Section 2.1.2, Determination of Commerciality). The guidelines herein apply only to assessments based on cash-flow analysis. Moreover, modifying factors that may additionally influence investment decisions, such as contractual or political risks, should be recognized so the entity may address these factors if they are not included in the project analysis.

3.1.1 Net Cash-Flow Evaluation

3.1.1.1 Project-based resource economic evaluations are based on estimates of future production and the associated net cash-flow schedules for each project as of an effective date. These net cash flows should be discounted using a defined discount rate, and the sum of the future discounted cash flows is termed the net present value (NPV) of the project. The calculation shall be based upon an appropriately defined reference point (see Section 3.2.1, Reference Point) and should reflect the following:

A. The forecast production quantities over identified time periods.

B. The estimated costs and schedule associated with the project to develop, recover, and produce the quantities to the reference point, including abandonment, decommissioning, and restoration (ADR) costs, based on the entity's view of the expected future costs.

C. The estimated revenues from the quantities of production based on the evaluator's view of the prices expected to apply to the respective commodities in future periods, taking into account any sales contracts or price hedges specific to a property, including that portion of the costs and revenues accruing to the entity.

D. Future projected production- and revenue-related taxes and royalties expected to be paid by the entity.

E. A project life that is limited to the period of economic interest or a reasonably certain estimate of the life expectancy of the project, which is typically truncated by the earliest occurrence of either technical, license, or economic limit.

F. The application of an appropriate discount applicable to the entity at the time of the evaluation.

3.1.2 Economic Criteria

3.1.2.1 Economic determination of a project is tested assuming a zero percent discount rate (i.e., undiscounted). A project with a positive undiscounted cumulative net cash flow is considered economic. Production from the project is economic when the revenue attributable to the entity interest from production exceeds the cost of operation. A project's production is economically producible when the net revenue from an ongoing producing project exceeds the net expenses attributable to a certain entity's interest. The ADR costs are excluded from the economically producibility determination. A project is commercial when it is economic and it meets the criteria discussed in Section 2.1.2.

3.1.2.2 Economic viability is tested by applying a forecast case that evaluates cash-flow estimates based on an entity's forecasted economic scenario conditions (including costs and product price schedules, inflation indexes, and market factors). The forecast made by the evaluator should reflect and document assumptions the entity assesses as reasonable to exist throughout the life of the project. Inflation, deflation, or market adjustments may be made to forecast costs and revenues.

3.1.2.3 Forecasts based solely on current economic conditions are estimated using an average of those conditions (including historical prices and costs) during a specified period. The default period for averaging prices and costs is one year. However, if a step change has occurred within the previous 12-month period, the use of a shorter period reflecting the step change must be justified. In developments with high well counts and a continuous program of activity, the use of a learning curve within a resources evaluation may be justified to predict improvements in either time taken to carry out the activity, the cost to do so, or both, if confirmed by operational evidence and documented by the evaluator. The confidence in the ability to deliver such savings must be considered in developing the range of uncertainty in production and NPV estimates.

3.1.2.4 All costs, including future ADR liabilities, are included in the project economic analysis unless specifically excluded by contractual terms. ADR is not included in determining the economic producibility or for determining the point the project reaches the economic limit (see Section 3.1.3, Economic Limit). ADR costs are included for project economics but are not included in judging economic producibility or determining the economic limit (see Section 3.1.3, Economic Limit). ADR costs may also be reported for other purposes, such as for a property sale/acquisition evaluation, future field planning, accounting report of future obligations, or as appropriate to the circumstances for which the resource evaluation is conducted. The entity is responsible for providing the evaluator with documentation to ensure that funds are available to cover forecast costs and ADR liabilities in line with the contractual obligations.

3.1.2.6 Alternative economic scenarios may also be considered in the decision process and, in some cases, may supplement reporting requirements. Evaluators may examine a constant case in which current economic conditions are held constant without inflation or deflation throughout the project life.

3.1.2.7 Evaluations may also be modified to accommodate criteria regarding external disclosures imposed by regulatory agencies. For example, these criteria may include a specific requirement that, if the recovery were confined to the Proved Reserves estimate, the constant case should still generate a positive cash flow. External reporting requirements may also specify alternative guidance on the definition of current conditions or defined criteria with which to evaluate Reserves.

3.1.2.8 There may be circumstances in which the project meets criteria to be classified as Reserves using the best estimate (2P) forecast but the low case is not economic and fails to qualify for Proved Reserves. In this circumstance, the entity may record 2P and 3P estimates and no Proved Reserves. As costs are incurred in future years (i.e. become sunk costs) and development proceeds, the low estimate may eventually become economic and be reported as Proved Reserves. Some entities, according to internal policy or to satisfy regulatory reporting requirements, will defer reclassifying projects from Contingent Resources to Reserves until the low estimate case is economic.

3.1.3 Economic Limit

3.1.3.1 The economic limit is defined as the production rate at the time when the maximum cumulative net cash flow occurs for a project. The entity's entitlement production share, and thus net entitlement resources, includes those produced quantities up to the earliest truncation occurrence of either technical, license, or economic limit.

3.1.3.2 In this evaluation, operating costs should include only those costs that are incremental to the project for which the economic limit is being calculated (i.e., only those cash costs that will actually be eliminated if project production ceases). Operating costs should include fixed property-specific overhead charges if these are actual incremental costs attributable to the project and any production and property taxes, but for purposes of calculating the economic limit, should exclude depreciation, ADR costs, and income tax as well as any overhead that is not required to operate the subject property. Operating costs may be reduced, and thus project life extended, by various cost-reduction and revenue-enhancement approaches, such as sharing of production facilities, pooling maintenance contracts, or marketing of associated non- hydrocarbons (see Section 3.2.4, Associated Non-Hydrocarbon Components).

3.1.3.3 For a given project, no future development costs can exist beyond the economic limit date. ADR costs are not included in the economic limit calculations, even though they may be reported for other purposes.

3.1.3.4 Interim negative project net cash flows may be accommodated in periods of development capital spending, low product prices, or major operational problems provided that the longer-term cumulative net- cash-flow forecast determined from the effective date becomes positive. These periods of negative cash flow will qualify as Reserves if the following positive periods more than offset the negative.

3.1.3.5 In some situations, entities may choose to initiate production below or continue production past the economic limit. Production must be economic to be considered as Reserves, and the intent to or act of producing sub-economic resources does not confer Reserves status to those quantities. In these instances, the production represents a movement from Contingent Resources to Production. However, once produced such quantities can be shown in the reconciliation process for production and revenue accounting as a positive technical revision to Reserves. No future sub-economic production can be Reserves.

3.2 Production Measurement

3.2.0.1 In general, all petroleum production from the well or mine is measured to allow for the evaluation of the extracted quantities' recovery efficiency in relation to the PIIP. The marketable product, as measured according to delivery specifications at a defined reference point, provides the basis for sales production quantities. Other quantities that are not sales may not be as rigorously measured at the reference point(s) but are as important to take into account.

3.2.0.2 The operational issues in this section should be considered in defining and measuring production. While referenced specifically to Reserves, the same logic would be applied to projects forecast to develop Contingent and Prospective Resources conditional on discovery and development.

3.2.3 Wet or Dry Natural Gas

3.2.3.1 The Reserves for wet or dry natural gas should be considered in the context of the specifications of the gas at the agreed reference point. Thus, for gas that is sold as wet gas, the quantity of the wet gas would be reported, and there would be no reporting of any associated hydrocarbon liquids extracted downstream of the reference point. It would be expected that the corresponding enhanced value of the wet gas would be reflected in the sales price achieved for such gas.

3.2.3.2 When liquids are extracted from the gas before sale and the gas is sold in dry condition, then the dry gas quantity and the extracted liquid quantities, whether condensate and/or natural gas liquids (NGLs), must be accounted for separately in resources assessments at the agreed reference point(s).

3.2.4 Associated Non-Hydrocarbon Components

3.2.4.1 In the event that non-hydrocarbon components are associated with production, the reported quantities should reflect the agreed specifications of the petroleum product at the reference point. Correspondingly, the accounts will reflect the value of the petroleum product at the reference point. If it is required to remove all or a portion of non-hydrocarbons before delivery, the Reserves and Production should reflect only the marketable product recognized at the reference point.

3.2.4.2 Even if an associated non-hydrocarbon component, such as helium or sulphur, removed before the reference point is subsequently separately marketed, these quantities are included in the voidage extraction quantities (e.g., raw production) from the reservoir but are not included in Reserves. The revenue generated by the sale of non-hydrocarbon products may be included in the project's economic evaluation.

3.2.9 Equivalent Hydrocarbon Conversion

3.2.9.1 The industry sometimes simplifies communication of Reserves, Resources, and Production quantities with the term "barrel of oil equivalent" (BOE). The term allows for consolidation of multiple product types into a single equivalent product. In instances where natural gas is the predominate product, liquids may be converted to gas equivalence (i.e. one thousand cubic feet (MCF) volume equal 1 McfGE (MCF gas equivalent)).

3.2.9.2 Oil, condensate, bitumen and synthetic crude oil can be summed together without conversion (i.e., 1 bbl volume equals 1 BOE). NGLs may need to be converted, depending on the actual composition. Natural gas must be converted to report on a BOE basis.

3.2.9.3 The presentation of Reserve or Resources quantities should be made in the appropriate units for each individual product type reported (e.g. barrels, cubic meters, metric tonnes, joules, etc.). If BOE's or McfGE's are presented, they must be provided as supplementary information to the actual liquid or gas quantities with the conversion factor(s) clearly stated.

3.3 Resources Entitlement and Recognition

3.3.0.1 While assessments are conducted to establish estimates of the total PIIP and that portion recovered by defined projects, the allocation of sales quantities, costs, and revenues impacts the project economics and commerciality. This allocation is governed by the applicable contracts between the mineral lease owners (lessors) and contractors (lessees) and is generally referred to as entitlement.

3.3.0.2 Evaluators must ensure that, to their knowledge, the recoverable resource entitlements from all participating entities sum to the total recoverable resources.

3.3.0.3 The ability for an entity to recognize Reserves and Resources is subject to satisfying certain key elements. These include (a) having an economic interest through the mineral lease or concession agreement (i.e., right to proceeds from sales); (b) exposure to market and technical risk; and (c) the opportunity for reward through participation in exploration, appraisal, and development activities. Given the complexities of some agreements, there may be additional elements that must be considered in determining entitlement and the recognition of Reserves and Resources.

3.3.0.4 For publicly traded companies, securities regulators may set criteria regarding the classes and categories that can be "recognized" in external disclosures. For national interests, the reporting of 100% quantities without concession agreement constraints is typically specified.

3.3.1 Royalty

3.3.1.1 Royalty refers to a type of entitlement interest in a resources project that is free and clear of the costs and expenses of development and production to the royalty interest owner as opposed to a working interest where an entity has cost exposure. A royalty is commonly retained by a resources owner (lessor/host) when granting rights to a producer (lessee/contractor) to develop and produce the resources. Depending on the specific terms defining the royalty, the payment obligation may be expressed in monetary terms as a portion of the proceeds of production in-cash or as a right to take a portion of production in-kind. The royalty terms may also provide the option to switch between forms of payment at the discretion of the royalty owner. In either case, royalty quantities must be deducted from the lessee's entitlement to resources so that only net revenue interest quantities are recognized.

4.0 ESTIMATING RECOVERABLE QUANTITIES

4.0.0.1 Assuming that projects have been classified according to project maturity, estimation of associated recoverable quantities under a defined project and assignment to uncertainty categories may be based on one or a combination of analytical procedures. Such procedures may be applied using an incremental and/or scenario approach; moreover, the method of assessing relative uncertainty in these estimates of recoverable quantities may employ both deterministic and probabilistic methods.

4.1 Analytical Procedures

4.1.0.1 The analytical procedures for estimating recoverable quantities fall into three broad categories: (a) analogy, (b) volumetric estimates, and (c) performance-based estimates (e.g., material balance, history- matched simulation, decline-curve analysis, and rate-transient analysis. Reservoir simulation may be used in either volumetric or performance-based analyses. Pre- and early post-discovery assessments typically are made with analog field/project data and volumetric estimation. After production commences and production rates and pressure information become available, performance-based methods can be applied. Generally, the range of EUR estimates is expected to decrease as more information (pressure, performance, and PIIP) becomes available, but this is not always the case.

4.1.0.2 In each procedure evaluated under either the deterministic scenario, deterministic incremental, geostatistical, or probabilistic methods, the results are not a single quantity of remaining recoverable petroleum, but rather a range that reflects the underlying uncertainties in both the in-place quantities and the recovery efficiency of the applied development project. By applying consistent guidelines (see Section 2.2, Resources Categorization), evaluators can define remaining recoverable quantities using the approaches listed above. The confidence in assessment results generally increases when the estimates are supported by more than one analytical procedure.

4.1.4 Production Performance Analysis

4.1.4.1 Analysis of the change in production rate and production fluid ratios versus time and versus cumulative production as reservoir fluids are withdrawn provides useful information to predict ultimate recoverable quantities. In some cases, before production decline rates become apparent, trends in performance indicators such as gas/oil ratio, water/oil ratio, condensate/gas ratio, and bottomhole or flowing pressures can be extrapolated to economic limit conditions to estimate Reserves.

4.1.4.3 For mature reservoirs, the future production forecast may be sufficiently well defined that the remaining uncertainty in the technical profile is not significant; in such cases, the best estimate 2P scenario may be justifiable to also use for the 1P and 3P production forecasts. Other uncertainties (e.g., operational, regulatory, contractual) that will impact the abandonment rate may still exist, however, and these should be accommodated in the reserves categorization uncertainty range.

4.1.4.4 In very low-permeability reservoirs (e.g., unconventional reservoirs), care should be taken in the production performance analyses because the lengthy period of transient flow and complex production physics can make analyses very difficult.

4.2 Resources Assessment Methods

4.2.0.1 Regardless of the analytical procedures used, the goal is to communicate the range of uncertainty in the recoverable resources. An underlying principle is that the reliability of the estimates depends on the quantity and quality of the source data.

4.2.0.3 Assessment methods may be broadly characterized as deterministic, geostatistical, and probabilistic and may be applied in combination for integrated uncertainty analysis.

4.2.1 Deterministic Method

4.2.1.1 In the deterministic method, quantities are estimated by taking a discrete value or array of values for each input parameter to produce a discrete result. For the low-, best- and high-case estimates, the internally consistent deterministic inputs are selected to reflect the resultant confidence of the project scenario and the constraints applied for the resources category and resources class. A single outcome of recoverable quantities is derived for each deterministic increment or scenario. Two approaches are included in the deterministic method—the scenario (or cumulative) method and the incremental method—and should yield similar results.

4.2.1.2 In the deterministic scenario method, the evaluator provides three estimates of the quantities to be recovered from the project being applied to the accumulation. Estimates consider the full range of values for each input parameter based on available engineering and geoscience data, but one set is selected that is most appropriate for the corresponding resources confidence category. A single outcome of recoverable quantities is derived for each category. Thus, low, best and high estimates for the total project reflect uncertainty and consider confidence constraints of the categories. The low case should take into account specific choices for some variables (e.g., contact assumptions).

4.2.1.4 While deterministic estimates may have broadly inferred confidence levels, these estimates do not have associated quantitatively defined probabilities. Nevertheless, the ranges of the probability guidelines established for the probabilistic method (see Section 2.2.1, Range of Uncertainty) influence the amount of uncertainty generally inferred in the estimate derived from the deterministic method.

4.2.4 Integrated Methods

4.2.4.1 Resources assessments typically employ different methods as appropriate at each stage of exploration, appraisal, and development and often integrate several methods to better define the uncertainty.

4.2.4.3 Deterministic, geostatistical, and probabilistic methods may be used in combination to ensure that results of the methods are reasonable.

4.2.5 Aggregation Methods

4.2.5.1 Oil and gas quantities are generally estimated and categorized according to certainty of recovery within individual reservoirs or portions of reservoirs; this is referred to as a "reservoir level" assessment. These estimates are summed to arrive at estimates for fields, properties, and projects. Further summation is applied to yield totals for geographic areas, countries, and companies; these are generally referred to as "resources reporting levels." The uncertainty distribution of the individual estimates at each of these levels may differ widely, depending on the geological settings and the maturity of the resources. This cumulative summation process is generally referred to as aggregation.

4.2.5.3 In practice, there may be a large degree of dependence between reservoirs in the same field, and such dependencies must be incorporated in the probabilistic calculation. When dependency is present and not accounted for, aggregation will overestimate the low estimate and underestimate the high estimate.

4.2.5.4 The aggregation method used depends on the purpose. It is recommended that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level.

4.2.5.5 Various techniques are available to aggregate deterministic and/or probabilistic field, property, or project assessment results for the purposes of detailed business unit or corporate portfolio analyses where the results incorporate the benefits of portfolio size and diversification. Again, aggregation should incorporate the degree of dependency. Where the underlying analyses are available, comparison of arithmetic and statistical aggregation results may be valuable in assessing the impact of the portfolio effect. Whether deterministic, geostatistical, or probabilistic methods are used, care should be taken to avoid systematic bias in the estimation process.

4.2.5.6 It is recognized that the monetary value associated with petroleum recovery is dependent on the production and cash flow schedules for each Project; thus, aggregate distributions of recoverable quantities may not be a direct indication of corresponding uncertainty distributions of aggregate value.

Exhibit B
Product Prices

Year	10-Year Annual Average Original NYMEX Prices		Base Case*		Sensitivity 1 (Base Case +10%)		Sensitivity 2 (Base Case -10%)		Sensitivity 3 (Subsequent Events)	
	Oil, $/bbl	Gas, $/MMBtu	Oil, $/bbl	Gas, $/MMBtu	Oil, $/bbl	Gas, $/MMBtu	Oil, $/bbl	Gas, $/MMBtu	Oil, $/bbl	Gas, $/MMBtu
2020......	59.03	2.283	59.03	2.283	64.93	2.511	53.13	2.055	35.54	2.072
2021......	54.38	2.424	54.38	2.424	59.82	2.666	48.94	2.182	37.43	2.628
2022......	52.09	2.420	52.09	2.420	57.30	2.662	46.88	2.178	39.10	2.482
2023......	51.31	2.455	51.31	2.455	56.44	2.701	46.18	2.210	40.90	2.454
2024......	51.44	2.492	51.44	2.492	56.58	2.741	46.30	2.243	42.79	2.455
2025......	52.07	2.528	54.01	2.617	59.41	2.878	48.61	2.355	44.93	2.578
2026......	52.57	2.554	56.71	2.747	62.38	3.022	51.04	2.473	47.18	2.707
2027......	52.84	2.601	59.55	2.885	65.50	3.173	53.59	2.597	49.53	2.842
2028......	52.84	2.645	62.53	3.029	68.78	3.332	56.27	2.726	52.01	2.984
2029......	52.84	2.689	65.66	3.180	72.22	3.498	59.09	2.862	54.62	3.133
2030......	52.84	2.751	65.66	3.180	72.22	3.498	59.09	2.862	54.62	3.133
2031......	52.84	2.856	65.66	3.180	72.22	3.498	59.09	2.862	54.62	3.133
2032 and thereafter	52.84	2.961	65.66	3.180	72.22	3.498	59.09	2.862	54.62	3.133

* *The Base Case prices are annual averages of the five-year New York Mercantile Exchange (NYMEX) Futures Settlements prices as published by the Chicago Mercantile Exchange (CME) Group on December 31, 2019 for years 2020 through 2024. Settle prices for January are not included in the December 31, 2019 NYMEX Futures Settlements. Base prices used are the January closing price for oil published by CME Group December 19, 2019, and the January closing price for gas published by CME Group December 27, 2019. The 2024 product prices were escalated at five percent per annum for years 2025 through 2029, and then held constant thereafter at the 2029 prices in accordance with the instructions of DGO.*

Exhibit C

Northern Division Summaries – Before Federal Income Tax (BTAX)

CONVENTIONAL & UNCONVENTIONAL PROPERTIES & CORPORATE SUMMARY CASES
NORTHERN DIVISION
TOTAL PROVED (1P) DEVELOPED
DIVERSIFIED GAS & OIL PLC

DATE : 02/26/2020
TIME : 09:21:28
DBS FILE : DGO
SCENARIO : WRIYE19

R E S E R V E S   A N D   E C O N O M I C S

UTILIZING SPECIFIED ECONOMICS

JOB 19.2077

EFFECTIVE DATE: 01/2020

--END-- MO-YEAR	GROSS PRODUCTION OIL, MBBL	GROSS PRODUCTION GAS, MMCF	GROSS PRODUCTION NGL, MBBL	NET PRODUCTION OIL, MBBL	NET PRODUCTION GAS, MMCF	NET PRODUCTION NGL, MBBL	PRICES OIL $/B	PRICES GAS $/M	PRICES NGL $/B	M$ TOTAL REVENUE
12-2020	339.583	111793.792	64.403	239.359	89583.152	37.587	55.13	1.864	17.12	180827.424
12-2021	315.058	98248.704	58.009	221.846	78710.688	33.796	50.49	2.001	15.79	169256.512
12-2022	292.916	89016.848	51.973	206.194	71316.056	30.040	48.21	1.990	15.14	152315.104
12-2023	272.848	82093.080	47.935	192.023	65762.244	27.688	47.43	2.022	14.91	142462.416
12-2024	256.084	76510.848	44.658	180.182	61285.592	25.799	47.56	2.057	14.96	134990.016
12-2025	241.502	71826.520	41.855	169.925	57532.060	24.180	50.13	2.184	15.72	134541.664
12-2026	227.470	67753.096	39.372	160.037	54270.488	22.739	52.84	2.318	16.51	134647.888
12-2027	214.719	64120.492	37.148	151.079	51364.032	21.449	55.67	2.460	17.35	135138.928
12-2028	202.915	60831.312	35.134	142.790	48733.976	20.281	58.65	2.609	18.22	135898.784
12-2029	190.679	57592.760	32.928	134.133	46148.684	18.925	61.78	2.766	19.11	136295.056
12-2030	178.097	54318.316	30.852	125.207	43536.240	17.655	61.78	2.766	19.06	128506.496
12-2031	165.570	51238.732	28.870	116.252	41087.276	16.444	61.78	2.767	18.99	121172.288
12-2032	154.175	48314.536	27.156	108.158	38756.956	15.416	61.78	2.767	18.96	114231.416
12-2033	143.245	45574.688	25.560	100.308	36569.160	14.459	61.78	2.768	18.93	107693.808
12-2034	133.425	42984.984	24.044	93.311	34498.640	13.557	61.77	2.769	18.90	101531.960
S TOT	3328.285	1022218.752	589.895	2340.803	819155.200	340.015	54.52	2.315	16.94	2029509.504
AFTER	1512.495	608628.032	298.551	1046.057	490797.920	153.011	61.73	2.784	18.72	1433659.392
TOTAL	4840.780	1630846.720	888.446	3386.860	1309953.152	493.026	56.75	2.490	17.49	3463169.024

--END-- MO-YEAR	OPERATIONS, M$ SEV & ADV TAXES	OPERATIONS, M$ NET OPER EXPENSES	OPERATIONS, M$ T&C EXPENSES	OPERATIONS, M$ ACTIVE WELLS	CAPITAL COSTS, M$ TANGIBLE INVEST.	CAPITAL COSTS, M$ INTANG. INVEST.	CAPITAL COSTS, M$ TOTAL INVEST.	CAPITAL COSTS, M$ SALVAGE VALUE	CASH FLOW BTAX, M$	10.0% CUM. DISC BTAX, M$
12-2020	4622.310	41455.444	28952.124	17031.000	0.000	1234.895	1234.895	0.000	104562.432	99863.688
12-2021	4411.379	39929.904	24949.088	16946.000	0.000	1234.895	1234.895	0.000	98731.320	185546.400
12-2022	3190.044	38604.552	22250.696	16620.000	0.000	1324.895	1324.895	0.000	86945.200	254140.576
12-2023	3022.366	36260.000	20316.470	16428.000	0.000	1324.895	1324.895	0.000	81538.496	312580.256
12-2024	2892.565	32722.062	18806.006	16318.000	0.000	1363.336	1363.336	0.000	79206.336	364211.712
12-2025	2878.222	32321.772	17646.120	16300.000	0.000	1463.115	1463.115	0.000	80232.272	411754.752
12-2026	2875.083	31950.576	16675.000	16284.000	0.000	1463.115	1463.115	0.000	81683.848	455755.840
12-2027	2418.648	31614.654	15836.690	16262.000	0.000	1463.115	1463.115	0.000	83805.928	496799.008
12-2028	2426.404	31330.516	15094.219	16241.000	0.000	1463.115	1463.115	0.000	85584.592	534902.048
12-2029	2433.936	30620.122	14388.934	16232.000	0.000	1559.218	1559.218	0.000	87292.960	570232.128
12-2030	2311.584	29384.062	13591.282	15645.000	0.000	1469.218	1469.218	0.000	81750.432	600310.848
12-2031	2195.065	28159.738	12844.498	15037.000	0.000	1469.218	1469.218	0.000	76503.512	625900.160
12-2032	2085.748	26938.878	12136.474	14442.000	0.000	1469.218	1469.218	0.000	71601.168	647672.512
12-2033	1982.045	25758.132	11472.576	13821.000	0.000	1469.218	1469.218	0.000	67011.960	666196.928
12-2034	1883.338	24618.340	10850.900	13233.000	0.000	1469.218	1469.218	0.000	62710.144	681956.288
S TOT	41628.736	481668.768	255811.072		0.000	21240.684	21240.684	0.000	1229160.576	681956.288
AFTER	28708.228	417126.976	160872.128		1066.801	1002898.880	1003965.696	0.000	-177013.312	743289.984
TOTAL	70336.960	898795.776	416683.200		1066.801	1024139.584	1025206.400	0.000	1052147.264	743289.984

	OIL	GAS
GROSS WELLS	1542.0	40903.0
GROSS ULT., MB & MMF	17795.554	6393930.752
GROSS CUM., MB & MMF	12954.773	4763083.776
GROSS RES., MB & MMF	4840.781	1630846.720
NET RES., MB & MMF	3386.861	1309953.152
NET REVENUE, M$	192192.848	3262352.384
INITIAL N.I., PCT.	70.530	80.721
FINAL N.I., PCT.	67.303	81.626

LIFE, YRS.	50.00
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	0.01
DISCOUNTED PAYOUT, YRS.	0.01
RATE-OF-RETURN, PCT.	0.00
DISCOUNTED NET/INVEST.	0.02
INITIAL W.I., PCT.	95.306
FINAL W.I., PCT.	94.568

P.W. %	P.W., M$
5.00	998455.808
8.00	835365.312
9.00	787370.496
10.00	743291.200
12.00	666300.672
15.00	574559.424
20.00	466603.840
25.00	393861.792
30.00	342171.584
40.00	274220.384

WRIGHT & COMPANY, INC.
BRENTWOOD, TENNESSEE
D.RANDALL WRIGHT / PRESIDENT
MATTHEW BOOTHE / PETROLEUM CONSULTANT
STEPHANIE MATLOCK / SENIOR TECHNICAL ANALYST

Northern Division Cash Flow Summaries – After Federal Income Tax (ATAX)

CONVENTIONAL & UNCONVENTIONAL PROPERTIES & CORPORATE SUMMARY CASES
NORTHERN DIVISION
TOTAL PROVED (1P) DEVELOPED
DIVERSIFIED GAS & OIL PLC
UTILIZING SPECIFIED ECONOMICS
JOB 19.2077

DATE : 02/26/2020
TIME : 19:23:50
DBS : DGO
SETTINGS : WRIYE19
SCENARIO : WRIYE19

A F T E R   T A X   E C O N O M I C S

EFFECTIVE DATE: 01/2020

--END-- MO-YEAR	TAXABLE CASH FLOW M$	DEPRECIA- TION M$	DEPLETION M$	INTANG. EXPENSED M$	INTEREST PAID & CAP M$	TAXABLE INCOME M$	TAX CREDIT M$	TAXES PAYABLE M$	CASH FLOW ATAX M$	10.0% CUM. DISC ATAX M$
12-2020	105797.328	0.000	0.000	1234.895	0.000	104562.432	0.000	27186.266	77376.320	73775.368
12-2021	99966.216	0.000	0.000	1234.895	0.000	98731.320	0.000	25670.120	73061.208	137103.648
12-2022	88270.096	0.000	0.000	1324.895	0.000	86945.200	0.000	22605.726	64339.312	187802.240
12-2023	82863.392	0.000	0.000	1324.895	0.000	81538.496	0.000	21199.990	60338.320	231025.760
12-2024	80569.672	0.000	0.000	1363.336	0.000	79206.336	0.000	20593.600	58612.636	269195.936
12-2025	81695.384	0.000	0.000	1463.115	0.000	80232.272	0.000	20860.382	59371.892	304345.632
12-2026	83146.960	0.000	0.000	1463.115	0.000	81683.848	0.000	21237.814	60446.120	336878.016
12-2027	85269.040	0.000	0.000	1463.115	0.000	83805.928	0.000	21789.510	62016.316	367221.216
12-2028	87047.704	0.000	0.000	1463.115	0.000	85584.592	0.000	22251.990	63332.576	395391.424
12-2029	88852.176	0.000	0.000	1559.218	0.000	87292.960	0.000	22696.160	64596.812	421511.904
12-2030	83219.648	0.000	0.000	1469.218	0.000	81750.432	0.000	21255.108	60495.356	443750.048
12-2031	77972.728	0.000	0.000	1469.218	0.000	76503.512	0.000	19890.896	56612.596	462669.024
12-2032	73070.384	0.000	0.000	1469.218	0.000	71601.168	0.000	18616.306	52984.996	478765.984
12-2033	68481.176	0.000	0.000	1469.218	0.000	67011.960	0.000	17423.120	49588.788	492461.632
12-2034	64179.360	0.000	0.000	1469.218	0.000	62710.144	0.000	16304.619	46405.532	504112.960
12-2035	60140.520	0.000	0.000	2712.144	0.000	57428.376	0.000	14931.341	42496.952	513812.960
12-2036	56344.216	0.000	0.000	3840.204	0.000	52504.012	0.000	13651.050	38852.944	521875.008
12-2037	52773.080	0.000	0.000	4968.264	0.000	47804.816	0.000	12429.231	35375.604	528548.160
12-2038	49414.588	0.000	0.000	6096.324	0.000	43318.264	0.000	11262.745	32055.496	534045.312
12-2039	46261.500	0.000	0.000	7224.384	0.000	39037.116	0.000	10149.640	28887.432	538548.864
S TOT	1515335.040	0.000	0.000	46082.004	0.000	1469253.120	0.000	382005.568	1087247.232	538548.864
AFTER	562018.432	0.000	0.000	978057.600	0.000	-416039.168	0.000	-108170.160	-308935.968	549477.184
TOTAL	2077353.472	0.000	0.000	1024139.584	0.000	1053213.952	0.000	273835.392	778311.296	549477.184

BTAX RATE OF RETURN (PCT)	40.00	ATAX RATE OF RETURN (PCT)	40.00
BTAX PAYOUT YEARS	0.01	ATAX PAY OUT YEARS	0.02
BTAX PAYOUT YEARS (DISC)	0.01	ATAX PAY OUT YEARS (DISC)	0.02
BTAX NET INCOME/INVEST	2.03	ATAX NET INCOME/INVEST	1.76
BTAX NET INCOME/INVEST(DISC)	19.05	ATAX NET INCOME/INVEST(DISC)	14.35
PRODUCTION START DATE	01/2010	PROJECT LIFE (YEARS)	50.00
		DISCOUNT - RATE (PCT)	10.00
INITIAL OIL PRICE ($/B)	55.150	INITIAL GAS PRICE ($/M)	1.848
MAXIMUM OIL PRICE ($/B)	61.711	MAXIMUM GAS PRICE ($/M)	2.787
GROSS OIL WELLS	****	GROSS GAS WELLS	****
CUMULATIVE OIL (MBBL)	12954.773	CUMULATIVE GAS (MMF)	4763083.776
REMAINING OIL (MBBL)	4840.781	REMAINING GAS (MMCF)	1630846.720
ULTIMATE OIL (MBBL)	17795.554	ULTIMATE GAS (MMCF)	6393930.752
INITIAL WI (PCT)	95.306	FINAL WI (PCT)	94.568
INITIAL NET OIL (PCT)	70.530	FINAL NET OIL (PCT)	67.303
INITIAL NET GAS (PCT)	80.721	FINAL NET GAS (PCT)	81.626

PRESENT WORTH PROFILE AND
---- RATE-OF-RETURN VS. BONUS TABLE ---

P.W. FACTOR %	B.F.I.T. WORTH M$	A.F.I.T. WORTH M$	A.F.I.T. BONUS M$
0.00	1052147.3	778310.9	1322279.4
5.00	998455.8	738694.4	891170.1
8.00	835365.3	617740.2	709676.0
9.00	787370.5	582156.9	661860.4
10.00	743291.2	549477.1	619286.2
12.00	666300.7	492401.6	547365.2
15.00	574559.4	424384.2	464824.1
17.00	525830.7	388248.8	422109.2
20.00	466603.8	344314.6	371085.8
22.00	434270.2	320320.2	343606.5
25.00	393861.8	290320.9	309609.8
27.00	371193.5	273484.5	290697.8
30.00	342171.6	251918.1	266644.6
35.00	303778.4	223362.7	235086.4
40.00	274220.4	201352.1	210983.3

WRIGHT & COMPANY, INC.
BRENTWOOD, TENNESSEE
D. RANDALL WRIGHT / PRESIDENT
MATTHEW BOOTHE / PETROLEUM CONSULTANT
STEPHANIE MATLOCK / SENIOR TECHNICAL ANALYST

Southern Division Cash Flow Summaries – Before Federal Income Tax (BTAX)

CONVENTIONAL & UNCONVENTIONAL PROPERTIES & CORPORATE SUMMARY CASES
SOUTHERN DIVISION
TOTAL PROVED (1P) DEVELOPED
DIVERSIFIED GAS & OIL PLC

DATE : 02/26/2020
TIME : 13:02:32
DBS FILE : DGO
SCENARIO : WRIYE19

R E S E R V E S   A N D   E C O N O M I C S

UTILIZING SPECIFIED ECONOMICS

JOB 19.2077

EFFECTIVE DATE: 01/2020

--END-- MO-YEAR	GROSS PRODUCTION OIL, MBBL	GROSS PRODUCTION GAS, MMCF	GROSS PRODUCTION NGL, MBBL	NET PRODUCTION OIL, MBBL	NET PRODUCTION GAS, MMCF	NET PRODUCTION NGL, MBBL	PRICES OIL $/B	PRICES GAS $/M	PRICES NGL $/B	M$ TOTAL REVENUE
12-2020	127.022	96040.432	3143.004	98.770	71114.880	2839.604	53.52	1.964	16.53	236774.720
12-2021	108.680	91655.032	2998.604	83.532	67877.304	2708.386	48.97	2.126	14.20	230312.304
12-2022	100.190	87756.872	2870.749	76.789	65016.056	2592.708	46.71	2.119	13.05	217262.496
12-2023	93.148	84226.800	2755.648	71.289	62433.560	2488.903	45.94	2.158	12.66	210249.056
12-2024	87.180	80978.000	2650.412	66.657	60061.460	2394.219	46.08	2.199	12.73	205094.832
12-2025	81.823	77959.792	2553.171	62.520	57860.836	2306.938	48.66	2.344	14.02	209209.136
12-2026	76.938	75130.560	2462.482	58.760	55799.352	2225.687	51.36	2.496	15.38	213510.960
12-2027	72.444	72466.720	2377.348	55.310	53858.976	2149.510	54.20	2.656	16.80	217984.352
12-2028	68.285	69943.648	2296.910	52.123	52021.572	2077.605	57.19	2.824	18.30	222602.704
12-2029	64.409	67459.952	2220.063	49.156	50215.376	2008.926	60.32	3.001	19.87	227151.936
12-2030	60.728	64993.528	2145.567	46.337	48421.304	1942.480	60.33	3.000	19.87	219216.528
12-2031	57.281	62635.672	2074.728	43.698	46710.200	1879.312	60.33	3.000	19.87	211629.472
12-2032	53.987	60363.200	2005.626	41.178	45053.168	1817.802	60.33	3.000	19.88	204280.912
12-2033	50.774	58180.388	1939.668	38.723	43462.756	1759.075	60.34	2.999	19.88	197220.576
12-2034	47.867	56083.844	1876.307	36.500	41934.840	1702.547	60.34	2.999	19.88	190454.768
S TOT	1150.756	1105874.432	36370.292	881.343	821841.728	32893.698	53.07	2.532	16.50	3212954.880
AFTER	684.497	1072102.400	38019.336	522.172	810802.816	34822.540	60.37	2.996	19.90	3748628.992
TOTAL	1835.253	2177976.832	74389.632	1403.514	1632644.608	67716.240	55.79	2.763	18.25	6961584.128

--END-- MO-YEAR	OPERATIONS, M$ SEV & ADV TAXES	OPERATIONS, M$ NET OPER EXPENSES	OPERATIONS, M$ T&C EXPENSES	OPERATIONS, M$ ACTIVE WELLS	CAPITAL COSTS, M$ TANGIBLE INVEST.	CAPITAL COSTS, M$ INTANG. INVEST.	CAPITAL COSTS, M$ TOTAL INVEST.	SALVAGE VALUE	CASH FLOW BTAX, M$	10.0% CUM. DISC BTAX, M$
12-2020	9791.936	52156.348	28989.716	12075.000	0.000	12736.987	12736.987	0.000	133099.808	127026.128
12-2021	9722.582	51797.936	27362.816	12052.000	0.000	12736.987	12736.987	0.000	128692.000	238620.336
12-2022	9181.701	51459.108	25981.132	12030.000	0.000	12736.987	12736.987	0.000	117903.608	331559.808
12-2023	8955.934	51153.528	24772.582	12019.000	0.000	12736.987	12736.987	0.000	112630.448	412268.512
12-2024	8809.410	50871.600	23690.408	12011.000	0.000	12736.987	12736.987	0.000	108986.168	483264.192
12-2025	9182.004	50608.336	22705.880	12009.000	0.000	12758.195	12758.195	0.000	113955.056	550748.416
12-2026	9559.961	50352.392	21798.714	12008.000	0.000	12758.195	12758.195	0.000	119042.328	614837.120
12-2027	9942.806	50108.936	20957.440	12006.000	0.000	12758.195	12758.195	0.000	124216.848	675632.640
12-2028	10329.943	49873.620	20170.668	12006.000	0.000	12758.195	12758.195	0.000	129470.112	733239.040
12-2029	10708.894	49513.408	19403.054	12005.000	0.000	12977.020	12977.020	0.000	134549.888	787663.552
12-2030	10347.734	48985.936	18642.888	11886.000	0.000	12977.020	12977.020	0.000	128262.816	834827.648
12-2031	10002.045	48489.484	17920.360	11757.000	0.000	12977.020	12977.020	0.000	122240.656	875690.112
12-2032	9665.056	47941.276	17229.284	11634.000	0.000	12977.020	12977.020	0.000	116468.000	911082.944
12-2033	9341.930	47405.640	16567.218	11463.000	0.000	12977.020	12977.020	0.000	110928.784	941727.296
12-2034	9031.219	46898.792	15941.392	11336.000	0.000	12977.020	12977.020	0.000	105606.240	968248.448
S TOT	144573.152	747616.320	322133.568		0.000	192579.840	192579.840	0.000	1806052.736	968248.448
AFTER	180330.976	1324643.584	294691.168		0.000	826726.592	826726.592	0.000	1122236.160	1120935.552
TOTAL	324904.128	2072259.840	616824.704		0.000	1019306.432	1019306.432	0.000	2928288.768	1120935.552

	OIL	GAS
GROSS WELLS	104.0	17269.0
GROSS ULT., MB & MMF	2205.406	2225817.600
GROSS CUM., MB & MMF	370.152	47840.732
GROSS RES., MB & MMF	1835.254	2177976.832
NET RES., MB & MMF	1403.514	1632644.608
NET REVENUE, M$	78295.120	4510231.552
INITIAL N.I., PCT.	78.807	87.522
FINAL N.I., PCT.	77.490	91.277

LIFE, YRS.	50.00
DISCOUNT %	10.00
UNDISCOUNTED PAYOUT, YRS.	0.09
DISCOUNTED PAYOUT, YRS.	0.09
RATE-OF-RETURN, PCT.	0.00
DISCOUNTED NET/INVEST.	0.01
INITIAL W.I., PCT.	94.584
FINAL W.I., PCT.	97.620

P.W. %	P.W., M$
5.00	1688914.944
8.00	1300983.936
9.00	1204876.288
10.00	1120935.936
12.00	982124.544
15.00	826656.000
20.00	654095.488
25.00	542879.360
30.00	466013.888
40.00	367535.232

WRIGHT & COMPANY, INC.
BRENTWOOD, TENNESSEE
D. RANDALL WRIGHT / PRESIDENT
MATTHEW BOOTHE / PETROLEUM CONSULTANT
STEPHANIE MATLOCK / SENIOR TECHNICAL ANALYST

Southern Division Cash Flow Summaries – After Federal Income Tax (ATAX)

CONVENTIONAL & UNCONVENTIONAL PROPERTIES & CORPORATE SUMMARY CASES	DATE : 02/26/2020
SOUTHERN DIVISION	TIME : 14:38:46
TOTAL PROVED (1P) DEVELOPED	DBS : DGO
DIVERSIFIED GAS & OIL PLC	SETTINGS : WRIYE19
UTILIZING SPECIFIED ECONOMICS	SCENARIO : WRIYE19
JOB 19.2077	

A F T E R   T A X   E C O N O M I C S

EFFECTIVE DATE: 01/2020

--END-- MO-YEAR	TAXABLE CASH FLOW M$	DEPRECIA-TION M$	DEPLETION M$	INTANG. EXPENSED M$	INTEREST PAID & CAP M$	TAXABLE INCOME M$	TAX CREDIT M$	TAXES PAYABLE M$	CASH FLOW ATAX M$	10.0% CUM. DISC ATAX M$
12-2020	145836.784	0.000	0.000	12736.987	0.000	133099.808	0.000	34605.928	98493.920	93904.960
12-2021	141428.992	0.000	0.000	12736.987	0.000	128692.000	0.000	33459.842	95232.048	176396.672
12-2022	130640.592	0.000	0.000	12736.987	0.000	117903.608	0.000	30654.906	87248.752	245098.352
12-2023	125367.440	0.000	0.000	12736.987	0.000	112630.448	0.000	29283.912	83346.464	304759.168
12-2024	121723.160	0.000	0.000	12736.987	0.000	108986.168	0.000	28336.376	80649.736	357240.128
12-2025	126713.248	0.000	0.000	12758.195	0.000	113955.056	0.000	29628.324	84326.576	407126.816
12-2026	131800.520	0.000	0.000	12758.195	0.000	119042.328	0.000	30950.948	88091.248	454504.512
12-2027	136975.056	0.000	0.000	12758.195	0.000	124216.848	0.000	32296.436	91920.576	499448.768
12-2028	142228.304	0.000	0.000	12758.195	0.000	129470.112	0.000	33662.184	95807.760	542036.224
12-2029	147526.912	0.000	0.000	12977.020	0.000	134549.888	0.000	34982.892	99566.816	582272.064
12-2030	141239.840	0.000	0.000	12977.020	0.000	128262.816	0.000	33348.386	94914.600	617139.968
12-2031	135217.680	0.000	0.000	12977.020	0.000	122240.656	0.000	31782.586	90458.056	647348.736
12-2032	129445.024	0.000	0.000	12977.020	0.000	116468.000	0.000	30281.776	86186.432	673513.600
12-2033	123905.808	0.000	0.000	12977.020	0.000	110928.784	0.000	28841.528	82087.488	696167.680
12-2034	118583.264	0.000	0.000	12977.020	0.000	105606.240	0.000	27457.656	78148.712	715773.376
12-2035	113466.456	0.000	0.000	13423.275	0.000	100043.184	0.000	26011.244	74031.680	732657.088
12-2036	108541.736	0.000	0.000	13819.432	0.000	94722.304	0.000	24627.788	70094.432	747188.864
12-2037	103801.800	0.000	0.000	14215.589	0.000	89586.208	0.000	23292.440	66293.860	759682.624
12-2038	99238.312	0.000	0.000	14611.746	0.000	84626.568	0.000	22002.850	62623.544	770411.200
12-2039	94845.576	0.000	0.000	15007.902	0.000	79837.672	0.000	20757.804	59079.976	779611.968
S TOT	2518526.720	0.000	0.000	263657.792	0.000	2254868.736	0.000	586265.856	1668602.624	779611.968
AFTER	1429069.056	0.000	0.000	755648.704	0.000	673420.480	0.000	175089.264	498331.072	828633.472
TOTAL	3947595.776	0.000	0.000	1019306.496	0.000	2928289.280	0.000	761355.136	2166933.760	828633.472

BTAX RATE OF RETURN (PCT)	40.00	ATAX RATE OF RETURN (PCT)	40.00
BTAX PAYOUT YEARS	0.09	ATAX PAY OUT YEARS	0.11
BTAX PAYOUT YEARS (DISC)	0.09	ATAX PAY OUT YEARS (DISC)	0.11
BTAX NET INCOME/INVEST	3.87	ATAX NET INCOME/INVEST	3.13
BTAX NET INCOME/INVEST(DISC)	8.78	ATAX NET INCOME/INVEST(DISC)	6.75
PRODUCTION START DATE	01/2010	PROJECT LIFE (YEARS)	50.00
		DISCOUNT - RATE (PCT)	10.00
INITIAL OIL PRICE ($/B)	53.454	INITIAL GAS PRICE ($/M)	1.973
MAXIMUM OIL PRICE ($/B)	60.321	MAXIMUM GAS PRICE ($/M)	2.982
GROSS OIL WELLS	104.	GROSS GAS WELLS	****
CUMULATIVE OIL (MBBL)	370.152	CUMULATIVE GAS (MMF)	47840.732
REMAINING OIL (MBBL)	1835.254	REMAINING GAS (MMCF)	2177976.832
ULTIMATE OIL (MBBL)	2205.406	ULTIMATE GAS (MMCF)	2225817.600
INITIAL WI (PCT)	94.584	FINAL WI (PCT)	97.620
INITIAL NET OIL (PCT)	78.807	FINAL NET OIL (PCT)	77.490
INITIAL NET GAS (PCT)	87.522	FINAL NET GAS (PCT)	91.277

PRESENT WORTH PROFILE AND
---- RATE-OF-RETURN VS. BONUS TABLE ---

P.W. FACTOR %	B.F.I.T. WORTH M$	A.F.I.T. WORTH M$	A.F.I.T. BONUS M$
0.00	2928286.2	2166936.1	3128831.0
5.00	1688914.9	1249311.0	1453779.7
8.00	1300983.9	961994.6	1074048.3
9.00	1204876.3	890808.4	985561.1
10.00	1120935.9	828635.0	909784.3
12.00	982124.5	725807.6	787290.0
15.00	826656.0	610621.4	653828.9
17.00	747548.4	551995.8	587285.5
20.00	654095.5	482719.4	509763.8
22.00	604201.0	445722.3	468832.6
25.00	542879.4	400231.9	418942.8
27.00	508958.7	375058.6	391535.0
30.00	466013.9	343175.2	357024.7
35.00	410020.6	301573.0	312330.0
40.00	367535.2	269973.7	278636.4

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Exhibit D
Price Adjustments

Price Adjustments

Division	Acquisition	Well District	PAJ/GAS*, $/MMBtu	PAJ/NGL*, FRAC	PAJ/OIL*, $/B or FRAC
Northern	DGO Energy & Legacy	Cambridge	0.180	0.41	(3.06)
Northern	DGO Energy & Legacy	Deerfield	(0.170)	0.20	(3.54)
Northern	DGO Energy & Legacy	Indiana PA	(0.931)	0.29	(2.77)
Northern	DGO Energy & Legacy	Jackson Center	(0.292)	0.20	(6.60)
Northern	DGO Energy & Legacy	Lycoming	(0.760)	0.20	(3.52)
Northern	DGO Energy & Legacy	Marietta	0.176	0.41	(3.06)
Northern	DGO Energy & Legacy	Mckean	(0.191)	0.48	(2.73)
Northern	DGO Energy & Legacy	Millersburg	0.149	0.20	(3.11)
Northern	DGO Energy & Legacy	New Philadelphia	0.149	0.20	(3.06)
Northern	DGO Energy & Legacy	Tennessee	0.295	0.14	(6.74)
Northern	DGO Energy & Legacy	Waynesburg	(0.617)	0.20	(2.80)
Northern	DGO Energy & Legacy	West Virginia	(0.724)	0.63	(5.24)
Northern	APC	APC/CNX, Misc.	(0.620)	0.00	(8.90)
Northern	APC	Buckhannon	(1.236)	0.00	(6.61)
Northern	APC	Indiana	(0.680)	0.00	(7.02)
Northern	APC	Indiana Airport	(0.615)	0.00	(9.67)
Northern	APC	Jefferson	(0.512)	0.00	(1.64)
Northern	APC	Magnolia	(0.431)	0.00	(4.96)
Northern	APC	Marietta	(0.337)	0.00	(4.91)
Northern	APC	Non-Op	(0.590)	0.00	(6.52)
Northern	APC	PA Marcellus	(0.583)	0.00	0.00
Northern	APC	WV Marcellus	(0.959)	0.00	0.00
Northern	CNX	All Districts	(0.749)	0.00	(5.00)
Northern	EdgeMarc	Monroe	(0.408)	0.00	(9.25)
Northern	EdgeMarc	Washington	(0.413)	0.26	(9.25)
Northern	HG	Ninevah North	(0.426)	0.00	(8.37)
Northern	HG	Normantown	(0.316)	0.00	(8.37)
Northern	HG	TV North	(0.341)	0.00	(8.37)
Northern	HG	TV South	(0.341)	0.00	(8.37)
Southern	Core	Branchland	(0.200)	0.25	(6.47)
Southern	Core	Crawford	(0.200)	0.00	(6.47)
Southern	Core	Elkhorn City	(0.330)	0.45	(6.47)
Southern	Core	Hamlin	(0.200)	0.00	(6.47)
Southern	Core	Inez	(0.200)	0.23	(6.47)
Southern	Core	Kermit	(0.200)	0.39	(6.47)
Southern	Core	KSP	(0.200)	0.00	(6.47)
Southern	Core	Lancer	(0.290)	0.38	(6.47)
Southern	Core	Midas	(0.290)	0.33	(6.47)
Southern	Core	Outside Operated	(0.200)	0.04	(6.47)
Southern	EQT	BCBM	(0.460)	0.5040	(1.50)
Southern	EQT	BREN	(0.460)	0.5040	(1.50)
Southern	EQT	CARN	(0.457)	0.5040	0.45
Southern	EQT	EQUT	(0.457)	0.5040	0.45
Southern	EQT	KY_OTHER	(0.345)	0.5040	(6.18)
Southern	EQT	LANGLEY	(0.345)	0.5040	(6.18)
Southern	EQT	MADI	(0.392)	0.5040	(1.50)
Southern	EQT	MARCWV	(0.345)	0.5040	(1.50)
Southern	EQT	NCBM	0.200	0.5040	(5.53)
Southern	EQT	NORA	0.200	0.5040	(5.53)
Southern	EQT	RCBM	0.200	0.5040	(5.53)
Southern	EQT	RF	0.200	0.5040	(5.53)
Southern	EQT	WEST	(0.460)	0.5040	0.45

** Definitions of terms can be found in Exhibit H.*

Exhibit E
Operating Expenses

Expenses for Northern & Southern Divisions

Division	Acquisition	Well District	OP_NON	GTC/GAS* ($/Mcf)	OPC/GAS* ($/Mcf)	OPC/OGW* ($/M/W)	OPC/OIL* ($/B)	OPC/T* ($/M)	OPC/WTR* ($/B)
NORTHERN	APC	APC/CNX PA		0.000	0.080	62.000	0.450	31.110	0.000
NORTHERN	APC	BUCKHANNON		0.000	0.180	109.000	1.080	136.000	0.000
NORTHERN	APC	INDIANA		0.000	0.080	60.000	0.480	27.000	0.000
NORTHERN	APC	INDIANA AIRPORT		0.000	0.060	62.000	0.360	28.000	0.000
NORTHERN	APC	JEFFERSON		0.000	0.090	57.000	0.540	26.000	0.000
NORTHERN	APC	MAGNOLIA		0.000	0.410	75.000	2.460	135.000	0.000
NORTHERN	APC	MARCELLUS HORZ		0.000	0.170	0.000	1.020	831.000	0.000
NORTHERN	APC	MARIETTA		0.000	0.050	75.000	0.300	38.000	0.000
NORTHERN	APC	NON-OP		0.000	0.180	72.000	1.00	71.243	0.000
NORTHERN	APC	UNDEFINED		0.000	0.102	64.370	0.610	41.150	0.000
NORTHERN	APC	UNKNOWN		0.000	0.170	66.870	0.990	59.430	0.000
NORTHERN	APC	WV MARCELLUS		0.000	0.130	0.000	0.780	265.000	0.000
NORTHERN	CNX	ALL DISTRICTS		0.000	0.100	17.000	0.600	97.000	0.000
NORTHERN	DGO ENERGY & LEGACY	ALL DISTRICTS		0.000	0.110	130.000	0.660	72.000	0.000
NORTHERN	EDGEMARC	MONROE		0.000	0.000	1100.000	0.000	2800.000	5.150
NORTHERN	EDGEMARC	WASHINGTON		0.000	0.790	1000.000	0.000	4500.000	5.150
NORTHERN	HG	NINEVAH NORTH		0.000	0.060	482.000	0.000	1728.000	0.000
NORTHERN	HG	NORMANTOWN		0.000	0.060	482.000	0.000	1728.000	0.000
NORTHERN	HG	TV NORTH		0.000	0.060	482.000	0.000	1728.000	0.000
NORTHERN	HG	TV SOUTH		0.000	0.060	482.000	0.000	1728.000	0.000
SOUTHERN	CORE	BRANCHLAND		0.000	0.096	0.000	0.576	157.990	0.000
SOUTHERN	CORE	CRAWFORD		0.000	0.104	0.000	0.624	198.880	0.000
SOUTHERN	CORE	ELKHORN CITY		0.000	0.077	0.000	0.462	179.620	0.000
SOUTHERN	CORE	HAMLIN		0.000	0.135	0.000	0.810	156.100	0.000
SOUTHERN	CORE	INEZ		0.000	0.069	0.000	0.414	240.030	0.000
SOUTHERN	CORE	KERMIT		0.000	0.086	0.000	0.516	236.610	0.000
SOUTHERN	CORE	KSP		0.000	0.149	0.000	0.894	581.920	0.000
SOUTHERN	CORE	LANCER		0.000	0.051	0.000	0.306	214.780	0.000
SOUTHERN	CORE	MIDAS		0.000	0.060	0.000	0.360	190.540	0.000
SOUTHERN	CORE	OUTSIDE OPERATED		0.000	0.073	0.000	0.438	169.280	0.000
SOUTHERN	EQT	BCBM	OP	0.500	0.017	0.000	0.000	250.000	0.000
SOUTHERN	EQT	BREN	OP	0.500	0.017	0.000	0.000	250.000	0.000
SOUTHERN	EQT	CARN	OP	1.275	0.057	0.000	0.000	139.000	0.000
SOUTHERN	EQT	EQUT	OP	1.186	0.057	0.000	0.000	139.000	0.000
SOUTHERN	EQT	KY_OTHER	OP	0.293	0.005	0.000	0.000	197.000	0.000
SOUTHERN	EQT	LANGLEY	OP	0.337	0.005	0.000	0.000	197.000	0.000
SOUTHERN	EQT	MADI	OP	0.500	0.017	0.000	0.000	250.000	0.000
SOUTHERN	EQT	MARCWV	OP	1.242	0.017	0.000	0.000	250.000	0.000
SOUTHERN	EQT	NCBM	OP	1.280	0.030	0.000	0.000	162.000	0.000
SOUTHERN	EQT	NORA	OP	1.198	0.030	0.000	0.000	162.000	0.000
SOUTHERN	EQT	RCBM	OP	0.352	0.030	0.000	0.000	162.000	0.000
SOUTHERN	EQT	RF	OP	0.098	0.030	0.000	0.000	162.000	0.000
SOUTHERN	EQT	WEST	OP	0.877	0.057	0.000	0.000	139.000	0.000
SOUTHERN	EQT	BCBM	NON	1.331	0.017	0.000	0.000	250.000	0.000
SOUTHERN	EQT	BREN	NON	1.331	0.017	0.000	0.000	250.000	0.000
SOUTHERN	EQT	CARN	NON	1.331	0.057	0.000	0.000	139.000	0.000
SOUTHERN	EQT	EQUT	NON	1.331	0.057	0.000	0.000	139.000	0.000
SOUTHERN	EQT	KY_OTHER	NON	1.331	0.005	0.000	0.000	197.000	0.000
SOUTHERN	EQT	LANGLEY	NON	1.331	0.005	0.000	0.000	197.000	0.000
SOUTHERN	EQT	MADI	NON	1.331	0.017	0.000	0.000	250.000	0.000
SOUTHERN	EQT	MARCWV	NON	1.331	0.017	0.000	0.000	250.000	0.000
SOUTHERN	EQT	NCBM	NON	1.331	0.030	0.000	0.000	162.000	0.000
SOUTHERN	EQT	NORA	NON	1.331	0.030	0.000	0.000	162.000	0.000
SOUTHERN	EQT	RCBM	NON	1.331	0.030	0.000	0.000	162.000	0.000
SOUTHERN	EQT	RF	NON	1.331	0.030	0.000	0.000	162.000	0.000
SOUTHERN	EQT	WEST	NON	1.331	0.057	0.000	0.000	139.000	0.000

** Definitions of terms can be found in Exhibit H.*

Exhibit F
DIVERSIFIED GAS & OIL PLC
Confirmations

In accordance with your instructions, Wright & Company, Inc. (Wright) hereby confirms that:

(a) Wright consents to the inclusion of the CPR, and/or extracts therefrom, in the Prospectus and the reference thereto and to its name in the form and context in which they are included in the Prospectus.

(b) Wright accepts responsibility, for the purposes of the paragraph 5.3.2(R)(2)(f) of the Prospectus Regulation Rules, for the CPR set out in Part XV of the Prospectus and for any information sourced from the CPR in the Prospectus. In accordance with Item 1.2 of Annex 1 and item 1.2 of Annex 11 to Commission Delegated Regulation (EU) 2019/980, Wright confirms, to the best of its knowledge, the information contained therein is in accordance with the facts and contains no omission likely to affect the import of such information;

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

(d) D. Randall Wright, President of Wright, who supervised the evaluation, is professionally qualified and a member in good standing of the Society of Petroleum Engineers (SPE);

(e) Wright has the relevant and appropriate qualifications, experience, and technical knowledge to professionally and independently appraise the assets of DGO, which we have reported on;

(f) Wright considers that the scope of the CPR is appropriate and was prepared to a standard expected in accordance with the Note on Mining and Oil & Gas Companies issued by the London Stock Exchange;

(g) Wright has at least five years relevant experience in the estimation, assessment, and evaluation of oil, gas, and other liquid hydrocarbons under consideration;

(h) Wright is an independent petroleum consulting firm founded in 1988 and is independent of DGO and its directors, senior management and advisers, has no material interest in DGO 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 Wright is an employee, officer, or director of DGO, nor does Wright or any of its employees have direct financial interest in DGO. Neither the employment of nor the compensation received by Wright is contingent upon the values assigned or the opinions rendered regarding the properties covered by this CPR; and

(j) Wright is not a sole practitioner.

Exhibit G
Professional Qualifications
D. Randall Wright, President

I, D. Randall Wright, am the primary technical person in charge of the estimates of reserves and associated cash flow and economics on behalf of Wright & Company, Inc. (Wright) for the results presented in this report to Diversified Gas & Oil PLC. I have a Master of Science degree in Mechanical Engineering from Tennessee Technological University.

I am a qualified Reserves Estimator as set forth in the "*Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information*" promulgated by the Society of Petroleum Engineers. I am also qualified as a Competent Person (CP). This qualification is based on more than 45 years of practical experience in the estimation and evaluation of petroleum reserves with Texaco, Inc., First City National Bank of Houston, Sipes, Williamson & Associates, Inc., Williamson Petroleum Consultants, Inc., and Wright which I founded in 1988.

I am a registered Professional Engineer in the state of Texas (TBPE #43291), granted in 1978, a member of the Society of Petroleum Engineers (SPE) and a member of the Order of the Engineer.

D. Randall Wright, P.E.
TX Reg. No. F-12302

Exhibit H
Glossary of Terms

The terms defined below may be used throughout this CPR.

bbl. One barrel of crude oil, condensate, or other liquids equal to 42 US gallons.

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet of natural gas equivalent.

BOE. Barrels of oil equivalent, determined using the ratio of one Mcf of natural gas to one sixth barrel of oil.

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.

Developed Non-Producing Reserves. Shut-in and behind-pipe Reserves.

Developed Producing Reserves. Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Developed Reserves. Expected quantities to be recovered from existing wells and facilities.

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.

Dry hole. A well found to be incapable of producing either oil or natural gas in a sufficient quantity to justify completion as an oil or gas well.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Lease operating expense. Costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

Mbbl. One thousand barrels.

MBOE. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet.

Mcfd. One thousand cubic feet per day.

Mcfe. One thousand cubic feet of natural gas equivalent.

Mcfed. One thousand cubic feet of natural gas equivalent per day.

MMbbl. One million barrels.

MMBtu. One million Btus.

MMcf. One million cubic feet.

MMcfd. One million cubic feet per day.

MMcfe. One million cubic feet of natural gas equivalent.

Natural gas equivalent. Cubic feet of natural gas equivalent, determined using the ratio of one barrel of crude oil, condensate or natural gas liquids to six Mcf of natural gas.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells.

Net oil and gas sales. Oil and natural gas sales less oil and natural gas production.

On Production. The development project is currently producing or capable of producing and selling petroleum to market.

OPC/OIL. Operating Cost Rate for Oil ($/BBL)

OPC/GAS. Operating Cost Rate for Gas ($/Mcf)

GTC/GAS. Gas Transportation Cost Rate for Gas ($/Mcf)

OPC/OGW. Operating Cost Rate for Oil & Gas Wells ($/Well/Month)

OPC/T. Operating Cost Rate ($/Month or $/Year)

OPC/WTR. Operating Cost Rate for Water ($/BBL)

Overriding royalty interest. A royalty interest that is carved out of a lessee's working interest under an oil and gas lease.

PAJ/GAS. Price Adjustment for Gas (% or $/MMBtu)

PAJ/OIL. Price Adjustment for Oil (% or $/BBL)

PAJ/NGL. Price Adjustment for Natural Gas Liquids (% or $/BBL)

Present Value. The pre-tax present value, discounted at 10% per annum, of future net cash flows from estimated proved reserves (including the estimated cost of abandonment and future development), calculated holding prices and costs constant at amounts in effect on the date of the estimate (unless such prices or costs are subject to change pursuant to contractual provisions) and in all instances in accordance with the Commission's rules for inclusion of oil and gas revere information in financial statements filed with the Commission. The difference between the Present Value and the standardized measure of discounted future net cash flows is the present value of income taxes applicable to such future net cash flows.

Productive well. A well that is producing oil and gas or that is capable of production.

Proved developed producing reserves. Proved developed reserves that are expected to be recovered from currently producing zones under the continuation of present operating methods through existing wells with existing equipment and operating methods.

Proved reserves. Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.

Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

psi. Pound per square inch. One psi is equal to the pressure that is created when one pound force is applied to an area of one square inch.

Recompletion. The completion for production of an existing well bore in another formation from that in which the well has been previously completed.

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.

Reserve life index. Calculated by dividing year-end proved reserves by annual production from the most recent year.

Spud. To start (or restart) the drilling of a new well.

Standardized measure of discounted future net cash flows. The present value, discounted at 10% per annum, of future net cash flows from estimated proved reserves after income taxes, calculated holding prices and costs constant at amounts in effect on the date of the estimate (unless such prices or costs are subject to change pursuant to contractual provisions) and in all instances in accordance with the Commission's rules for inclusion of oil and gas reserve information in financial statements filed with the Commission.

Term overriding royalty interest. An overriding royalty interest with a fixed duration.

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.

Undeveloped Reserves. Quantities expected to be recovered through future significant investments.

Waterflood. The injection of water into a reservoir to fill pores vacated by produced fluids, thus maintaining reservoir pressure and assisting production.

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.

Workover. Operations on a producing well to restore or increase production.

WTI. West Texas Intermediate Oil at Cushing, Oklahoma.

PART XVI

ADDITIONAL INFORMATION

1. PERSONS RESPONSIBLE

The Company and its Directors (whose names and functions appear on page 30 of this Prospectus) accept responsibility for the information contained in this Prospectus. To the best of the knowledge of the Company and the Directors, the information contained in this Prospectus is in accordance with the facts and makes no omission likely to affect the import of such information.

2. INCORPORATION

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.

The principal legislation under which the Company operates and the Ordinary Shares have been created is the UK Companies Act and regulations made thereunder. The Company's registered office is at 27/28 Eastcastle Street, London, W1W 8DH. The Company's trading address and corporate headquarters is at 1800 Corporate Drive, Birmingham, Alabama 35242, United States. The Company's telephone number is +1-205-408-0909 and its website is www.dgoc.com. Information contained on the Company's website or the contents of any website accessible from hyperlinks on the Company's website are not incorporated into and do not form part of this Prospectus.

3. SHARE CAPITAL OF THE COMPANY

3.1 The Company is not required to, and does not, have an authorised share capital. The Company was incorporated with an issued share capital of £50,000 divided into 5,000,000 Ordinary Shares of £0.01, each which were fully paid. The initial subscribers were Robert Hutson Jr. and Robert Post, each of whom subscribed for 2,500,000 Ordinary Shares. The Ordinary Shares, when admitted to trading, will be registered with ISIN GB00BYX7JT74.

3.2 Immediately prior to the publication of this Prospectus, the share capital of the Company was as follows:

Class of shares	Number	Amount (£)
Ordinary Shares	642,805,002	£6,428,050.02

Following Admission, the share capital of the Company will be as follows:

Class of shares	Number	Amount (£)
Ordinary Shares	707,085,502	£7,070,855.02

3.3 Since incorporation of the Company the following changes have been made to its share capital:

(a) on or around 10 June 2015: (i) 17,500,000 Ordinary Shares were issued to Robert Hutson Jr.; and (ii) 17,500,000 Ordinary Shares were issued to Robert Post in consideration for the transfer to the Company of the entire issued share capital of Diversified Gas & Oil Corporation pursuant to a share exchange agreement dated 10 June 2015;

(b) on 2 December 2015, 1,200,000 Ordinary Shares were issued to Martin Thomas for cash;

(c) on 19 May 2016, 800,000 Ordinary Shares were issued to Martin Thomas for cash;

(d) on 24 October 2016, 2,210,481 Ordinary Shares were issued to Bradley Gray upon his joining the Company;

(e) on 30 January 2017, 61,380,769 Ordinary Shares were issued for cash;

(f) on 14 June 2017, 184,837 Ordinary Shares were issued to bondholders in consideration for the redemption of the bondholder's unlisted bonds of the Company pursuant to a bond instrument dated 6 October 2016;

(g) on 14 June 2017, 11,400,000 Ordinary Shares were issued for cash;

(h) on 15 June 2017, 27,900,000 Ordinary Shares were issued for cash;

(i) on 19 February 2018, 166,400,000 Ordinary Shares were issued for cash;

(j) on 17 July 2018, 195,330,000 Ordinary Shares were issued for cash;

(k) on 18 April 2019, 151,515,151 Ordinary Shares were issued for cash; and

(l) on 11 May 2020, 61,813,500 Ordinary Shares were allotted pursuant to the Placing, subject to the terms and conditions of the Placing Agreement summarised in paragraph 12.5 of this Part XVI and 2,467,000 Ordinary Shares were alloted to certain institutional investors in the United States for cash (the "**US Subscription**"). The Company intends to use the net proceeds of approximately £66.1 million it will receive from the Placing and the US Subscription to partially finance the potential acquisition of the Carbon Assets and the EQT Corporation Assets in the event such acquisitions proceed. In the event that the Company does not proceed with the acquisition of the Carbon Assets and/or the EQT Assets, the Company intends to use the net proceeds of approximately £66.1 million it will receive from the Placing and the US Subscription to finance future acquisitions and/or repay its borrowing facilities;

Immediately prior to publication of the Prospectus, the share capital of the Company was £6,428,050.02 divided into 642,805,002 Ordinary Shares and following Admission, the share capital of the Company will be £7,070,855.02 divided into 707,085,502 Ordinary Shares.

3.4 Between 7 June 2019 and the Last Practicable Date, the Company has bought back 51,620,015 Ordinary Shares for cash under its existing share buyback programme.

3.5 Save as disclosed above, since 1 January 2017 (being the first day covered by the historical financial information for the Group set out in Section B "*Historical financial information of the Group*" of Part XIV "*Historical Financial Information*" of this Prospectus), there has been no issue of share capital of the Company, fully or partly paid, either in cash or for other consideration, and no such issues are proposed. As at the Last Practicable Date, the Company did not hold any Shares in treasury.

3.6 The rights attaching to the Ordinary Shares are summarised in Section 4 "*Articles of Association of the Company*" of this Part XVI "*Additional Information*" of this Prospectus.

3.7 Save as disclosed in this Part XVI "*Additional Information*" and Part IX "*Directors, Senior Managers and Corporate Governance*" of this Prospectus:

- there has been no change in the amount of the share or loan capital of the Company and no material change in the amount of the share or loan capital of any of its subsidiaries (other than intra-Group issues by wholly-owned subsidiaries) since incorporation;
- no commissions, discounts, brokerages or other special terms have been granted by the Company or any of its subsidiaries in connection with the allotment of any share or loan capital of the Company or any of its subsidiaries since incorporation;
- no share or loan capital of the Company or any of its subsidiaries is under option or is agreed, conditionally or unconditionally, to be put under option;
- there are no acquisition rights or obligations in relation to the issue of Ordinary Shares in the capital of the Company or an undertaking to increase the capital of the Company; and
- there are no convertible securities, exchangeable securities, or securities with warrants in the Company.

4. ARTICLES OF ASSOCIATION OF THE COMPANY

The Articles of the Company adopted on 29 January 2017, as amended on 15 April 2020, include provisions to the following effect:

4.1 Objects

The objects of the Company, in accordance with section 31(1) of the UK Companies Act, are unrestricted.

4.2 **Limited liability**

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

4.3 **Rights attaching to shares**

Voting rights of members

Subject to the Articles and to any special rights or restrictions as to voting for the time being attached to any shares (as to which there are none at present) the provisions of the UK Companies Act shall apply in relation to voting rights. On a show of hands, every member or authorised corporate representative present has one vote and every proxy present has one vote except if the proxy has been duly appointed by more than one member and has been instructed by (or exercises his discretion given by) one or more of those members to vote for the resolution and has been instructed by (or exercises his discretion given by) one or more other of those members to vote against it, in which case a proxy has one vote for and one vote against the resolution. On a poll, every member present in person or by proxy has one vote for every share of which he is a holder. In the case of joint holders, the vote of the person whose name stands first in the register of members and who tenders a vote is accepted to the exclusion of any votes tendered by any other joint holders.

Dividends

Subject to the rights attached to any shares issued on any special terms and conditions (as to which there are none at present), dividends shall be declared and paid according to the amounts paid up on the shares in respect of which the dividend is paid, but no amount paid up on a share in advance of calls should be treated for these purposes as paid up on the share.

Return of capital

If the Company is in liquidation, the liquidator may, with the authority of a special resolution of the Company and any other authority required by any applicable statutory provision (A) divide among the members in specie the whole or any part of the assets of the Company, and for that purpose, value any assets and determine how the division shall be carried out as between the members or different classes of members; or (B) vest the whole or any part of the assets in trustees on such trusts for the benefit of members as the liquidator, with the necessary authority, shall think fit, but no member shall be compelled to accept any assets upon which there is any liability.

Capitalisation of reserves

The Board may, with the authority of an ordinary resolution of the Company: (A) resolve to capitalise any sum standing to the credit of any reserve account of the Company (including the share premium account and capital redemption reserve) or any sum standing to the credit of the profit and loss account not required for the payment of any preferential dividend (whether or not it is available for distribution); and (B) appropriate that sum as capital to the holders of shares in proportion to the nominal amount of the share capital held by them respectively and apply that sum on their behalf in paying up in full any shares or debentures of the Company of a nominal amount equal to that sum and allot the shares or debentures credited as fully paid to those members, or as they may direct, in those proportions or in paying up the whole or part of any amounts which are unpaid in respect of any issued shares in the Company held by them respectively, or otherwise deal with such sum as directed by the resolution provided that the share premium account, the capital redemption reserve, any redenomination reserve and any sum not available for distribution in accordance with the applicable statutory provisions may only be applied in paying up shares to be allotted credited as fully paid up.

Issue of shares

The Company may from time to time pass an ordinary resolution authorising, in accordance with section 551 of the UK Companies Act, the Board to exercise all the powers of the Company to allot shares in the Company or to grant rights to subscribe for or to convert any security into shares in the Company up to the maximum nominal amount specified in the resolution. The authority shall expire on the day specified in the resolution (not being more than five years from the date on which the resolution is passed) but any authority given under this article shall allow the Company, before the authority expires, to make an offer or agreement which would or might require shares to be allotted or rights to be granted after it expires. Subject (other than in relation to the sale of treasury shares) to the Board being generally authorised to allot shares and grant rights to subscribe for or to convert any security into shares in the Company in accordance with section 551 of the UK Companies Act, the Company may from time to time resolve, by special resolution, that the Board be given power to allot equity securities for cash as if section 561 of the UK Companies Act did not apply to the allotment but that power shall be limited: (i) to the allotment of equity securities in connection with a rights issue; and (ii) to the allotment (other than in connection with a rights issue) of equity securities having a nominal amount not exceeding in aggregate the sum specified in the special resolution. Unless previously revoked, that power shall (if so provided in the special resolution) expire on the date specified in the special resolution of the Company but the Company may before the power expires make an offer or agreement which would or might require equity securities to be allotted after it expires.

Alteration of share capital

The Company may exercise the powers conferred by the applicable statutory provisions to increase its share capital by allotting new shares; reduce its share capital; sub-divide or consolidate and divide all or any of its share capital; redenominate all or any of its shares and reduce its share capital in connection with such redenomination; issue redeemable shares and purchase all or any of its shares of any class including any redeemable shares.

Variation of class rights

Whenever the share capital of the Company is divided into different classes of shares, all or any of the rights for the time being attached to any class of shares in issue may from time to time (whether or not the Company is being wound up) be varied in such manner as those rights may provide or (if no such provision is made) either with the consent in writing of the holders of three-fourths in nominal value of the issued shares of that class or with the authority of a special resolution passed at a separate general meeting of the holders of those shares.

Transfer of Ordinary Shares

Save as described below, the Ordinary Shares will be freely transferable upon Admission.

A member may transfer all or any of his shares in any manner which is permitted by any applicable statutory provision and is from time to time approved by the Board. The Company shall maintain a record of uncertified shares in accordance with the relevant statutory provisions.

A member may transfer all or any of his certificated shares by an instrument of transfer in any usual form, or in such other form as the Board may approve. The instrument of transfer shall be signed by or on behalf of the transferor and, except in the case of a fully paid share, by or on behalf of the transferee. The Board may, in its absolute discretion, refuse to register any instrument of transfer of any certificated share: (i) which is not fully paid up but, in the case of a class of shares which has been admitted to the Official List of the FCA, not so as to prevent dealings in those shares from taking place on an open and proper basis; or (ii) on which the Company has a lien. The Board may also refuse to register any instrument of transfer of a certificated share unless it is left at the registered office, or such other place as the Board may decide, for registration, accompanied by the certificate for the shares to be transferred and such other evidence (if any) as the Board may reasonably require to prove title of the intending transferor or his right to transfer the shares; and it is in respect of only one class of shares. If the Board refuses to register a transfer of a certificated share it shall, as soon as practicable and in any event within two months after the date on which the instrument was lodged, give to the transferee notice of the refusal together with its reasons for refusal. The Board shall provide the transferee with such further information about the reasons for the refusal as the transferee may reasonably request. Unless otherwise agreed by the Board in any particular case, the maximum number of persons who may be entered on the register as joint holders of a share is four.

Disclosure of interests in Ordinary Shares

If the holder of, or any person appearing to be interested in, any share has been given a notice requiring any of the information mentioned in section 793 of the UK Companies Act (the "**Section 793 Notice**") and, in respect of that share (a "**Default Share**"), has been in default for a period of 14 days after the Section 793 Notice has been given in supplying to the Company the information required by the Section 793 Notice, the following restrictions shall apply: (a) if the Default Shares in which any one person is interested or appears to the Company to be interested represent less than 0.25 per cent. of the issued shares of the class, the holders of the Default Shares shall not be entitled, in respect of those shares, to attend or to vote, either personally or by proxy, at any general meeting of the Company; or (b) if the Default Shares in which any one person is interested or appears to the Company to be interested represent at least 0.25 per cent. of the issued shares of the class, the holders of the Default Shares shall not be entitled, in respect of those shares (i) to attend or to vote, either personally or by proxy, at any general meeting of the Company or (ii) to receive any dividend or other distribution or (iii) to transfer or agree to transfer any of those shares or any rights in them.

The above restrictions shall continue for the period specified by the Board, being not more than seven days after the earlier of (i) the Company being notified that the Default Shares have been sold pursuant to an exempt transfer; and (ii) due compliance, to the satisfaction of the Board, with the Section 793 Notice. The Board may waive these restrictions, in whole or in part, at any time. The restrictions shall not prejudice the right of either the member holding the Default Shares or, if different, any person having a power of sale over those shares to sell or agree to sell those shares under an exempt transfer.

Forfeiture of shares

If the whole or any part of any call or instalment remains unpaid on any share after the due date for payment, the Board may give a notice to the holder requiring him to pay so much of the call or instalment as remains unpaid, together with any accrued interest.

If the requirements of a notice are not complied with, any share in respect of which it was given may (before the payment required by the notice is made) be forfeited by a resolution of the Board. The forfeiture shall include all dividends declared and other moneys payable in respect of the forfeited share and not actually paid before the forfeiture.

Every share which is forfeited or surrendered shall become the property of the Company and (subject to the applicable statutory provisions) may be sold, re-allotted or otherwise disposed of, upon such terms and in such manner as the Board shall decide either to the person who was before the forfeiture the holder of the share or to any other person and whether with or without all or any part of the amount previously paid up on the share being credited as so paid up.

Uncertificated shares—general powers

In relation to any uncertificated share, the Company may utilise the relevant system in which it is held to the fullest extent available from time to time in the exercise of any of its powers or functions under any applicable statutory provision or the Articles or otherwise in effecting any action. Any provision in the Articles in relation to uncertificated shares which is inconsistent with (i) any applicable statutory provision or (ii) the exercise of any powers or functions by the Company or the effecting by the Company of any actions by means of a relevant system, shall not apply. The Company may, by notice to the holder of an uncertificated share, require the holder to change the form of that share to certificated form within such period as may be specified in the notice. For the purpose of effecting any action by the Company, the Board may determine that shares held by a person in uncertificated form shall be treated as a separate holding from shares held by that person in certificated form but shares of a class held by a person in uncertificated form shall not be treated as a separate class from shares of that class held by that person in certificated form.

4.4 **Communications by the Company**

Subject to the applicable statutory provisions and other rules applicable to the Company, a document or information may be sent or supplied by the Company to any member in electronic form to such address as may from time to time be authorised by the member concerned or by making it available on a website and notifying the member concerned (in accordance with the applicable statutory provisions and other rules applicable to the Company) that it has been made available. A member shall be deemed to have agreed that the Company may send or supply a document or information by means of a website if the applicable statutory provisions have been satisfied.

4.5 **General meetings**

An annual general meeting shall be held in accordance with the statutory provisions. Other general meetings shall be held whenever the Board thinks fit or on the requisition of shareholders in accordance with the applicable statutory provisions.

Subject to the applicable statutory provisions, an annual general meeting shall be called by at least 21 clear days' notice and all other general meetings shall be called by not less than 14 clear days' notice or by not less than such minimum notice period as is permitted by the applicable statutory provisions.

The requisite quorum for general meetings of the Company shall be two qualifying persons, representing different members and entitled to vote on the business to be transacted at the meeting. A qualifying person is an individual who is a member of the Company, a corporate representative or a proxy.

4.6 **Directors**

Election, Retirement and Removal of Directors

The Directors (other than alternate directors) shall not, unless otherwise determined by an ordinary resolution of the Company, be less than two.

A Director need not be a member of the Company.

Subject to the Articles, the Company may by ordinary resolution elect any person who is willing to act to be a director, either to fill a vacancy or as an additional director, but so that the total number of directors shall not exceed any maximum number fixed by or in accordance with the Articles.

Every resolution of a general meeting for the election of a director shall relate to one named person and a single resolution for the election of two or more persons shall be void, unless a resolution that it shall be so proposed has been first agreed to by the meeting without any vote being cast against it. The Board may appoint any person who is willing to act to be a director, either to fill a vacancy or by way of addition to their number, but so that the total number of directors shall not exceed any maximum number fixed by or in accordance with the Articles.

No person (other than a director retiring in accordance with the Articles) shall be elected or re-elected a director at any general meeting unless (i) he is recommended by the Board or (ii) not less than 14 nor more than 42 days before the date appointed for the meeting there has been given to the Company, by a member (other than the person to be proposed) entitled to vote at the meeting, notice of his intention to propose a resolution for the election of that person, stating the particulars which would, if he were so elected, be required to be included in the Company's register of directors and a notice executed by that person of his willingness to be elected.

At each annual general meeting in every year, one third of the Directors for the time being or if their number is not a multiple of three then the number nearest to but not exceeding 33.3 per cent. shall retire from office: provided always that if in any year the number of Directors (other than those retiring as aforesaid) is two, one of such Directors shall retire, and if in any year there is only one Director (other than those retiring as aforesaid) that Director shall retire.

A retiring director shall be eligible for re-election, and a director who is re-elected will be treated as continuing in office without a break. A retiring director who is not re-elected shall retain office until the close of the meeting at which he retires. If the Company, at any meeting at which a director retires in accordance with the Articles, does not fill the office vacated by such director, the retiring director, if willing to act, shall be deemed to be re-elected, unless at the meeting a resolution is passed not to fill the vacancy or to elect another person in his place or unless the resolution to re-elect him is put to the meeting and lost.

The Company may by special resolution, or by ordinary resolution of which special notice has been given in accordance with the applicable statutory provisions, remove any director before his period of office has expired notwithstanding anything in the Articles or in any agreement between him and the Company. A director may also be removed from office by giving him notice to that effect signed by or on behalf of not less than three quarters of the other directors (or their alternates). Any such removal of a director shall be without prejudice to any claim which such director may have for damages for breach of any agreement between him and the Company.

Conflicts of interest

If a situation (a "**Relevant Situation**") arises in which a director has, or can have, a direct or indirect interest that conflicts, or possibly may conflict, with the interests of the Company (including, without limitation, in relation to the exploitation of any property, information or opportunity, whether or not the Company could take advantage of it but excluding any situation which cannot reasonably be regarded as likely to give rise to a conflict of interest) the following provisions shall apply if the conflict of interest does not arise in relation to a transaction or arrangement with the Company: (i) if the Relevant Situation arises from the appointment or proposed appointment of a person as a director of the Company, the Directors (other than the director, and any other director with a similar interest, who shall not be counted in the quorum at the meeting and shall not vote on the resolution) may resolve to authorise the appointment of the director and the Relevant Situation on such terms as they may determine; (ii) if the Relevant Situation arises in circumstances other than in paragraph (i) above, the Directors (other than the director and any other director with a similar interest who shall not be counted in the quorum at the meeting and shall not vote on the resolution) may resolve to authorise the Relevant Situation and the continuing performance by the director of his duties on such terms as they may determine. Any terms of such authorisation may be imposed at the time of the authorisation or may be imposed or varied subsequently and may include (without limitation):

(a) whether the interested directors may vote (or be counted in the quorum at a meeting) in relation to any resolution relating to the Relevant Situation;

(b) the exclusion of the interested directors from all information and discussion by the Company of the Relevant Situation; and

(c) (without prejudice to the general obligations of confidentiality) the application to the interested directors of a strict duty of confidentiality to the Company for any confidential information of the Company in relation to the Relevant Situation.

Any authorisation of a Relevant Situation may provide that, where the interested director obtains (other than through his position as a director of the Company) information that is confidential to a third party, he will not be obliged to disclose it to the Company or to use it in relation to the Company's affairs in circumstances where to do so would amount to a breach of that confidence.

If a director is in any way, directly or indirectly, interested in a proposed or an existing transaction or arrangement with the Company, he must declare the nature and extent of that interest to the other directors.

Subject to any applicable statutory provisions and to having declared his interest to the other directors, a director may:

(a) enter into or be interested in any transaction or arrangement with the Company, either with regard to his tenure of any office or position in the management, administration or conduct of the business of the Company, or as vendor, purchaser or otherwise;

(b) hold any other office or place of profit with the Company (except that of auditor) in conjunction with his office of director for such period (subject to applicable statutory provisions) and upon such terms as the Board may decide and be paid such extra remuneration for so doing (whether by way of salary, commission, participation in profits or otherwise) as the Board may decide, either in addition to or in lieu of any remuneration under any other provision of the Articles;

(c) act by himself or his firm in a professional capacity for the Company (except as auditor) and be entitled to remuneration for professional services as if he were not a director;

(d) be or become a member or director of, or hold any other office or place of profit under, or otherwise be interested in, any holding company or subsidiary undertaking of that holding company or any other company in which the Company may be interested. The Board may cause the voting rights conferred by the shares in any other company held or owned by the Company or exercisable by them as directors of that other company to be exercised in such manner in all respects as it thinks fit (including the exercise of voting rights in favour of any resolution appointing the Directors or any of them as directors or officers of the other company or voting or providing for the payment of any benefit to the Directors or officers of the other company); and

(e) be or become a director of any other company in which the Company does not have an interest if that cannot reasonably be regarded as likely to give rise to a conflict of interest at the time of his appointment as a director of that other company.

Managing and other Executive Directors

Subject to the Act, the Board may from time to time appoint one or more of its body to be the holder of any executive office, including the office of Managing or Joint or Assistant Managing Director, on such terms and for such period as it may determine.

The appointment of any Director to any executive office shall be capable of being terminated by the Board at any time, unless the contract or resolution under which he holds office shall expressly state otherwise, but without prejudice to any claim he may have for damages for breach of any contract of service between him and the Company.

A Director holding any executive office shall receive such remuneration, whether in addition to or in substitution for his ordinary remuneration as a Director and whether by way of salary, commission, participation in profits or otherwise as the remuneration committee (if established) or the Board (if no remuneration committee is in existence at the time) may determine.

City Code

If at any time when the City Code does not apply to the Company, a person (together with any persons held to be acting in concert with him) acquires any interest in Ordinary Shares in the Company which would have obliged them to extend an offer (a ''mandatory offer'') to the holders of all other Ordinary Shares in the Company had the City Code applied, the Directors have the discretion (but not the obligation) to disenfranchise such person until a compliant mandatory offer is made. At the current time the City Code does apply to the Company.

Remuneration

The Directors (other than Directors appointed to an executive office or alternate directors) shall be paid such fees not exceeding in aggregate £750,000 per annum (or such larger sum as the Company may, by ordinary resolution, determine) as the Board may decide to be divided among them in such proportion and manner as they may agree or, failing agreement, equally. Any such fee shall be distinct from any remuneration or other amounts payable to a director under other provisions of the Articles and shall accrue from day to day.

The Board may grant special remuneration to any director who performs any special or extra services to or at the request of the Company. Such special remuneration may be paid by way of lump sum, salary, commission, participation in profits or otherwise as the Board may decide in addition to any remuneration payable under or pursuant to any other of the Articles.

A director shall be paid out of the funds of the Company all travelling, hotel and other expenses properly incurred by him in and about the discharge of his duties, including his expenses of travelling to and from Board meetings, committee meetings and general meetings. Subject to any guidelines and procedures established from time to time by the Board, a director may also be paid out of the funds of the Company all expenses incurred by him in obtaining professional advice in connection with the affairs of the Company or the discharge of his duties as a director.

The Board may exercise all the powers of the Company to:

(a) pay, provide, arrange or procure the grant of pensions or other retirement benefits, death, disability or sickness benefits, health, accident and other insurances or other such benefits, allowances, gratuities or insurances, including in relation to the termination of employment, to or for the benefit of any person who is or has been at any time a director of the Company or in the employment or service of the Company or of any corporate body which is or was associated with the Company or of the predecessors in business of the Company or any such associated body corporate, or the relatives or dependants of any such person. For that purpose the Board may procure the establishment and maintenance of, or participation in, or contribution to, any pension fund, scheme or arrangement and the payment of any insurance premiums;

(b) establish, maintain, adopt and enable participation in any profit sharing or incentive scheme including shares, share options or cash or any similar schemes for the benefit of any director or employee of the Company or of any associated body corporate, and to lend money to any such director or employee or to trustees on their behalf to enable any such schemes to be established, maintained or adopted; and

(c) support and subscribe to any institution or association which may be for the benefit of the Company or of any associated body corporate or any directors or employees of the Company or associated body corporate or their relatives or dependants or connected with any town or place where the Company or an associated body corporate carries on business, and to support and subscribe to any charitable or public object whatsoever.

Indemnity

Subject always to the provisions of the Act, and without prejudice to any protection from liability which may otherwise apply, the Company may, at its discretion and subject to any policies adopted by the Directors from time to time, indemnify every Director or other officer or auditor of the Company out of the assets of the Company against all costs, charges, losses, expenses and liabilities which he may sustain or incur in relation to the Company in or about the actual or purported execution of the duties of his office or the exercise or purported exercise of his powers or otherwise in relation thereto, including any liability incurred by him in defending any criminal or civil proceedings, provided that no such indemnity shall be provided in respect of any liability incurred:

by a Director:

(a) to the Company or any associated company of the Company;

(b) to pay a fine imposed in any criminal proceedings or a penalty imposed by a regulatory authority for non-compliance with any requirement of a regulatory nature (however arising);

(c) in defending any criminal proceedings in which he is convicted;

(d) in defending any civil proceedings brought by the Company, or an associated company of the Company, in which judgement is given against him; or

(e) in connection with any application for relief under sections 661(3) or (4) or 1157 of the Companies Act 2006 in which the court refuses to grant him relief; or

by an auditor in defending any proceedings (whether civil or criminal) in which judgment is given against him or he is convicted.

The Directors shall also have power to purchase and maintain insurance for or for the benefit of any persons who are or were at any time Directors, officers or employees of the Company, or of any other company in which the Company or any of the predecessors of the Company has any interest whether direct or indirect or which is in any way allied to or associated with the Company, or of any subsidiary undertaking of the Company or of any such other company, or who are or were at any time trustees of any pension fund in which employees of the Company or of any such other company or subsidiary undertaking are interested, including, (without prejudice to the generality of the foregoing) insurance against any liability incurred by such persons in respect of any act or omission in the actual or purported execution and/or discharge of their duties and/or in the exercise or purported exercise of their powers and/or otherwise in relation to their duties, powers or offices in relation to the Company or any such other company, subsidiary undertaking or pension fund. For the purposes of the Articles "subsidiary undertaking" shall have the meaning assigned to it in Section 1162 of the Act.

4.7 **Proceedings of the Board**

A director may at any time, and the secretary may at the request of a director, call a meeting of the Board. The Board may meet for the dispatch of business, adjourn and otherwise regulate its meeting as it thinks fit. This includes at a meeting which consists of a conference between directors some or all of whom are in different places provided that each director may participate in the business of the meeting by any means which allows him both to hear each of the other participating directors (or receive real time communications made by them), and, if he so wishes, to address all of the other participating directors simultaneously (or otherwise communicate in real time with them).

The quorum for Board meetings, unless fixed by the Board at any other number, shall be two. A Board meeting at which a quorum is present shall be competent to exercise all the powers, authorities and discretions vested in or exercisable by the Board.

The Board may appoint a chair and one or more deputy chairs and may at any time revoke such an appointment. The chair, or failing him any deputy chair (the longest in office taking precedence, if more than one is present), shall, if present and willing, preside at all Board meetings but, if no chair or deputy chair has been appointed, or if he is not present within five minutes after the time fixed for holding the meeting or is unwilling to act as chair of the meeting, the Directors present shall choose one of their number to act as chair of the meeting.

Questions arising at a Board meeting shall be determined by a majority of votes and, in the case of equality of votes, the chair of the meeting shall have a second or casting vote. A resolution which is signed or approved by all the Directors entitled to vote on that resolution shall be valid and effectual as if it had been passed at a Board meeting duly called and constituted.

All acts *bona fide* done by a meeting of the Board, or of a committee, or by any person acting as a director or committee member, shall, notwithstanding that it is afterwards discovered that there was some defect in the appointment of any member of the Board or committee or of the person so acting, or that they or any of them were disqualified or had vacated office or were not entitled to vote, be as valid as if every such person had been duly appointed and qualified to be a director and had continued to be a director or member of the committee and had been entitled to vote.

4.8 **Borrowing powers**

There is no requirement on the Directors to restrict the borrowing of the Company or any of its subsidiary undertakings.

4.9 **Dividends**

Declaration of dividends

The Company may, by ordinary resolution, declare a dividend to be paid to the members, according to their respective rights and interests in the profits, and may fix the time for payment of such dividend, but no dividend shall exceed the amount recommended by the Board.

Fixed and interim dividends

The Board may pay such interim dividends as appear to the Board to be justified by the financial position of the Company and may also pay any dividend payable at a fixed rate at intervals settled by the Board whenever the financial position of the Company, in the opinion of the Board, justifies its payment. If the Board acts in good faith, none of the Directors shall incur any liability to the holders of shares conferring preferred rights for any loss such holders may suffer in consequence of the payment of an interim dividend on any shares having non-preferred or deferred rights.

Calculation and currency of dividends

Except insofar as the rights attaching to, or the terms of issue of, any share otherwise provide: (a) all dividends shall be declared and paid according to the amounts paid up on the shares in respect of which the dividend is paid, but no amount paid up on a share in advance of calls shall be treated as paid up on the share; (b) all dividends shall be apportioned and paid *pro rata* according to the amounts paid up on the shares during any portion or portions of the period in respect of which the dividend is paid; and (c) dividends may be declared or paid in any currency and the Board may agree with any member that dividends which may at any time or from time to time be declared or become due on his shares in one currency shall be paid or satisfied in another, and may agree the basis of conversion to be applied and how and when the amount to be paid in the other currency shall be calculated and paid and for the Company or any other person to bear any costs involved.

Dividends not to bear interest

No dividend or other moneys payable by the Company on or in respect of any share shall bear interest as against the Company unless otherwise provided by the rights attached to the share.

Calls or debts may be deducted from dividends

The Board may deduct from any dividend or other moneys payable to any person (either alone or jointly with another) on or in respect of a share all such sums as may be due from him (either alone or jointly with another) to the Company on account of calls or otherwise in relation to shares of the Company.

Dividends in specie

With the authority of an ordinary resolution of the Company and on the recommendation of the Board, payment of any dividend may be satisfied wholly or in part by the distribution of specific assets and in particular of paid up shares or debentures of any other company.

Scrip dividends

The Board may, with the authority of an ordinary resolution of the Company, offer any holders of shares the right to elect to receive further shares, credited as fully paid, instead of cash in respect of all (or some part) of any dividend specified by the ordinary resolution (a scrip dividend) in accordance with the provisions of the relevant provisions of the Articles.

Unclaimed dividends

Any dividend unclaimed for a period of twelve years after having been declared shall be forfeited and cease to remain owing by the Company.

5. MAJOR INTERESTS IN ORDINARY SHARES

As at the Last Practicable Date, insofar as is known to the Company, the following persons hold, and will following Admission hold, directly or indirectly, 3 per cent. or more of the Company's voting rights, being the level at which notification is required to be made to the Company pursuant to the Disclosure Guidance and Transparency Rules:

Shareholders	Number of Ordinary Shares	Percentage of issued ordinary share capital
Sand Grove Capital Management LLP	62,995,394	9.80
Aberdeen Standard Investments	53,170,038	8.27
AXA Framlington Investment Managers	44,182,709	6.87
Caius Capital	42,043,322	6.54
Pelham Capital Management	37,628,621	5.85
Premier Miton Investors	34,529,569	5.37
JO Hambro Capital Management	28,617,925	4.45
River and Mercantile Asset Management	24,850,800	3.87
GLG Partners	24,457,339	3.80
Santander Asset Management	23,667,532	3.68
Ninety One	21,149,457	3.29
Chelverton Asset Management	20,800,000	3.24
Robert Hutson Jr	20,860,000	3.24
Robert M. Post	20,350,000	3.17

Save as disclosed above, in so far as is known to the Directors, there is no other person who is or will be immediately following Admission, directly or indirectly, interested in 3 per cent. or more of the issued share capital of the Company, or any other person who can, will or could, directly or indirectly, jointly or severally, exercise control over the Company. The Directors have no knowledge of any arrangements the operation of which may at a subsequent date result in a change of control of the Company. None of the Company's majority shareholders have or will have voting rights attached to the shares they hold in the Company, which are different from the voting rights attached to the shares of other shareholders.

6. DIRECTORS AND SENIOR MANAGERS

6.1 Interests of the Directors and Senior Managers

As at the Last Practicable Date, insofar as is known to the Company, the interests in the share capital of the Company of the Directors and Senior Managers (all of which, unless otherwise stated, are beneficial interests or are interests of a person connected with a Director or a Senior Manager) as at the time indicated, are:

Name	Number of Ordinary Shares	Percentage of holdings
Directors		
Robert Hutson Jr.	20,860,000	3.17
Bradley Gray	2,282,981	0.36
Martin Keith Thomas	2,150,000	0.33
David Johnson	375,000	0.06
David J. Turner, Jr.	247,000	0.04
Sandra Stash	—	—
Melanie Litte	—	—
Senior Managers		
Michael Garrett	16,337	0.002
Eric Williams	117,712	0.02
Bryan Keith Berry	92,549	0.02
Benjamin Sullivan	—	—
James Rode	350,000	0.05

At the date of this Prospectus, there are no restrictions agreed by any Director or Senior Manager on the disposal within a certain time of their holdings in the Company's securities. None of the Shareholders have different voting rights from any other Shareholder in respect of any Ordinary Shares held by them.

6.2 Director service agreements and letters of appointment

Save as disclosed in this Part XVI "*Additional Information*" of this Prospectus, there are no existing or proposed service agreements or letters of appointment between the Directors and any members of the Group. Certain terms of the Directors' service agreements and letters of appointment are summarised below.

Service Agreements

The principal terms of the service contracts entered into by the Company with each of the Executive Directors are as follows:

Rusty Hutson, Jr.

On 30 January 2017, Rusty Hutson, Jr. ("**RH**") entered into a service agreement with the Company under the terms of which he agreed to act as Chief Executive Officer of the Company on a full time basis, further amended on 28 April 2020. The remuneration payable under this agreement is determined annually by the Board, provided that it shall not be less than $675,000 gross per annum. RH is also entitled to partake in any employee benefit plans, programs, practices or arrangements of the Company in which other employees of the Company located in the United States are eligible to participate, including, without limitation, any qualified or non-qualified pension, profit sharing and savings plans, any death benefit and disability benefit plans, and any medical, dental, health and welfare insurance plans. The service agreement was for an initial fixed term of 12 months from February 2017 and continues thereafter until terminated by either party giving not less than 6 months' notice in writing. RH is entitled to be reimbursed for all expenses reasonably incurred by him in the proper performance of his duties.

Depending on the circumstances of his severance from service as Chief Executive Officer, RH may be entitled to certain payments, including previously accrued salary plus 12 months' salary.

Bradley Gray

On 30 January 2017, Brad Gray ("**BG**") entered into a service agreement with the Company under the terms of which he agreed to act as Chief Operating Officer of Diversified Gas & Oil Corporation on a full time basis. The remuneration payable under this agreement is determined annually by the Board, provided that it shall not be less than $275,000 gross per annum. In connection with his appointment to the Board, BG was issued 2,210,481 Ordinary Shares, which are subject to the terms of the Restricted Stock Agreement. BG is also entitled to partake in any employee benefit plans, programs, practices or arrangements of the Company in which other employees of the Company located in the United States are eligible to participate, including, without limitation, any qualified or non-qualified pension, profit sharing and savings plans, any death benefit and disability benefit plans, and any medical, dental, health and welfare insurance plans. The service agreement was for an initial fixed term of 12 months from February 2017 continuing thereafter until terminated by either party giving not less than 6 months' notice in writing. BG is entitled to be reimbursed for all expenses reasonably incurred by him in the proper performance of his duties.

Depending on the circumstances of his severance from service as Chief Operating Officer, BG may be entitled to certain payments, including previously accrued salary plus 6 months' salary.

Save as disclosed in this Part XV "*Additional Information*" of this Prospectus, there are no existing service contracts between any Executive Director and any member of the Group, which provide for benefits upon termination.

Letters of appointment

General terms

The principal terms of the letters of appointments for the Non-Executive Directors are as follows:

Name	Title	Date of appointment to the Board
David Edward Johnson	Chair	3 February 2017
Martin Keith Thomas	Non-executive Vice Chairman	1 January 2015
David Jackson Turner Jr.	Independent Non-executive Director	27 May 2019
Sandra (Sandy) Mary Stash	Independent Non-executive Director	21 October 2019
Melanie Little	Independent Non-executive Director	18 December 2019

Each of the Non-Executive Directors have entered into an appointment agreement under the terms of which they each agreed to act, with effect from their respective dates of appointment, each as a Non-Executive director of the Company and to devote such time as is reasonably necessary for the proper performance of their respective duties under their respective agreements, including attending or participating in all board meetings. The remuneration payable to each of the Non-Executive Directors under their respective letters of appointment does not exceed £75,000 gross per annum (or such higher rate as may from time to time be agreed in writing). Each of their agreement is for an initial period of 12 months from the date of their appointment and continues thereafter unless terminated by either party to the agreement giving not less than 3 months' notice.

Termination provisions

The appointment of the Chair is terminable by either party on three months' notice, and the appointment of each of the Non-Executive Directors is terminable by either party on three months' notice.

The appointment of the Chair and each Non-Executive Director may also be terminated with immediate effect by the Company if he or she, among other things,: (i) commits a serious or repeated breach or non-observance of his or her obligations to the Company (which includes his or her obligations not to breach fiduciary duties); or (ii) been guilty of any fraud or dishonesty or acted in any manner which, in the opinion of the Company, brings or is likely to bring the Director or the Company into disrepute or is materially adverse to the interests of the Company; (iii) a bankruptcy order made against him or her or entered into a voluntary arrangement within the meaning of the Insolvency Act 1986 or enter into a Deed of Arrangement under the Deeds of Arrangement Act 1914 or make any composition with some or all of his creditors; (iv) become incapacitated from performing his duties hereunder for a period of 90 days (whether concurrently or in aggregate) in any 12 month period (without prejudice to any rights the Director may have under the Equality Act 2012); (v) been disqualified from acting as a director; or (vi) fails to be re-appointed or re-elected, or vacates his or her office, or otherwise stops being a director in accordance with the Articles.

6.3 Other directorships and partnerships

In addition to their directorships of the Company and members of the Group, the Directors and Senior Managers hold, or have held within the past five years, the following directorships, partnerships and/or membership to administrative, management or supervisory bodies outside the Group.

Name	Current or former directorships/partnerships	Position still held (Y/N)
Directors		
David Johnson	Bilby plc., Non-executive Director	Y
	Fit Together (UK) Limited, Director	N
	Tribeca Nominee Limited, Director	N
	Chelverton Equity Partners plc, Non-executive Director	Y
Bradley Gray	Royal Cup, Inc., Senior Vice President and Chief Financial Officer	N
	The McPherson Companies, Inc., Executive Vice President and Chief Financial Officer	N
Martin Thomas	Wedlake Bell LLP, Partner	Y
	Jasper Consultants Limited, Director	Y
	Pristec AG, Member of the Supervisory Board	N
	Blue Ocean Consolidated Holding Limited, Director	Y
	Energy Everything Investments PLC, Director	N
	Pemar Capital Partners PLC, Director	N
	Watson Farley & Williams LLP, Partner	N
David J. Turner, Jr.	Regions Financial Corporation, Chief Financial Officer	Y
	Junior Achievement of Alabama	Y
Sandra (Sandy) Stash	Board of Governors at Colorado School of Mines	Y
	Institute for Sustainable Communities	N
	International Women's Forum	Y
	The Pointe at Georgetown LLC	N
	EDF Energy Thermal Generation Limited	Y
	Montana Tech Foundation	N
	Trans Mountain Pipeline Company	Y
	First Montana Bank	Y
Melanie Little	The Discovery Lab	Y
	Independent Liquids Terminal Association	Y
	BridgeTex Pipeline Company LLC	N
	Double Eagle Pipeline LLC	N
	HoustonLink Pipeline Company LLC	N
	Osage Pipe Line Company LLC	N
	Saddlehorn Pipeline Company LLC	N
	Seabrook Logistics LLC	N
Rusty Hutson, Jr.	—	—
Senior Managers		
Eric Michael Williams	N/A	N/A
Bryan Keith Berry	N/A	N/A
Michael Walton Garrett	N/A	N/A

Name	Current or former directorships/partnerships	Position still held (Y/N)
Benjamin Sullivan	Independent Oil and Gas Association of West Virginia	Y
	West Virginia Chamber of Commerce	Y
	Energy & Mineral Law Foundation	Y
	Hatfield & McCoy Regional Recreation Authority	N
James Rode	Core Royalty, LLC	Y
	Core Minerals III, LLC	Y
	Core Minerals Operating Co., Inc.	Y
	Core Minerals Management II, LLC	Y
	Core II Holdings LLC	N
	Core Holdings Management LLC	N
	Core EIP LLC	N
	TCFII Core LLC	N
	Core Appalachia Operating LLC	N
	Core Appalachia Production LLC	N
	Core Appalachia Midstream LLC	N
	Core Appalachia Compression LLC	N
	Independent Oil and Gas Association of West Virginia	N
	Kentucky Oil and Gas Association	N

Save as set out above and elsewhere in this Part XVI "*Additional Information*" of this Prospectus, none of the Directors or Senior Managers has any business interests, or performs any activities, outside the Group which are significant to the Group.

6.4 **Directors' confirmations**

At the date of this Prospectus, none of the Directors or Senior Managers, at any time within the last five years:

(a) has had any convictions in relation to fraudulent offences;

(b) has been or is a member of the administrative, management or supervisory bodies or partner, director or senior manager (who is relevant in establishing that a company has the appropriate expertise and experience for management of that company) of any company at the time of any bankruptcy, receivership, liquidation or administration of such company; or

(c) has received any official public incrimination and/or sanction by any statutory or regulatory authorities (including designated professional bodies) or has ever been disqualified by a court from acting as a director or member of the administrative, management or supervisory bodies of any company or from acting in the management or conduct of the affairs of any company.

6.5 **Conflicts of interest**

There are:

(a) no potential conflicts of interest between any duties to the Company of the Directors and Senior Managers and their private interests and/or other duties; and

(b) no arrangements or understandings with any of the shareholders of the Company, customers, suppliers or others pursuant to which any Director or Senior Manager was selected to be a Director or Senior Manager.

There are no family relationships between any Directors or Senior Managers.

6.6 **Remuneration**

Executive Directors

The following table sets out the pre-tax remuneration for the Executive Directors for the year ended 31 December 2019.

Name	Salary $	Taxable Benefits $	Annual bonus $	Total $
Rusty Hutson Jr	425,000	1,946	616,250	1,043,196
Brad Gray	350,000	9,313	507,500	886,813

Non-executive Directors

The following table sets out the pre-tax remuneration for the Non-executive Directors for the year ended 31 December 2019.

Name	Fees $
David Johnson	97,500
Martin Thomas	97,500
David Turner Jr	56,000
Sandy Stash	20,000
Melanie Little	4,000

Senior Managers

The aggregate remuneration paid (including salary and other benefits) to the Senior Managers of the Group in the year ended 31 December 2019 was $1,742,345, all of which comprised salaries and short-term benefits.

6.7 **Options, awards and employee share option schemes**

(a) As at the date of this Prospectus:

- the Company has not, save as set out in this section 6.7 below, issued any options or warrants to subscribe for Ordinary Shares, nor any other equity securities convertible into Ordinary Shares; and
- on 30 January 2017 and 15 June 2017, the Company issued warrants to Mirabaud as more fully described in paragraphs 12.9 of this Part XVI "*Additional Information*" of this Prospectus.

(b) The Directors believe that the success of the Group will depend to a significant degree on the future performance of the executive management team. The Directors also recognise the importance of employees being well motivated and identifying closely with the success of the Group.

(c) On 30 January 2017, the Directors implemented an equity incentive plan, which was amended and restated on 11 May 2020 (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 50,680,609 new Ordinary Shares of the Company from time to time shall be available to satisfy awards under the Equity Incentive Plan. Shares available for distribution under the Equity Incentive Plan may consist, in whole or in part, of authorised and unissued shares, treasury shares or shares reacquired by the Company in any manner. 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.

(d) Effective 14 April 2020, the Remuneration Committee approved certain awards under the Equity Incentive Plan for each of Rusty Hutson, Jr. (Chief Executive Officer) and Brad Gray (Chief Operating Officer) (the "2020 Awards"). The 2020 Awards comprise:

(i) an annual bonus award of up to a maximum of one hundred fifty percent (150%) for Mr. Hutson and Mr. Gray of each recipient's annual base salary. Subject to the relevant performance criteria being met, the annual bonus awards will be paid no later than 15 March 2021 in cash (up to one hundred per cent (100%) of each recipient's annual base salary). Any portion of an award that exceeds one hundred percent (100%) of the recipient's annual base salary will be granted in restricted stock units pursuant to the Equity Incentive Plan with a deferred vesting and settlement date of 28 February 2022; and

(ii) a performance share award with a value up to a maximum of two hundred percent (200%) for Mr. Hutson and Mr. Gray of each recipient's annual base salary. The performance share awards are expected to vest no later than 15 March 2023, subject to certain performance targets being met over the three-year performance period of 1 January 2020 through 31 December 2022. The performance targets measure three year average return on equity, three year absolute total shareholder return ("**TSR**") and TSR relative to FTSE 250 Index TSR.

(e) 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 "**Units**") in the Company to acquire new Ordinary Shares under the Share Option Scheme. As at the Last Practicable Date, 1,816,209 Units are currently outstanding. Each Unit 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 Units, including the rights to vote or to dividends, until the Units vest and are settled by the issuance of new Ordinary Shares. In order for the Units to vest, the Recipient must remain actively employed with the Company.

(f) As of the date of this Prospectus, under the Share Option Scheme, the Company has a total of 23,220,000 options outstanding to certain directors and employees of the Group, none of which have been vested. The Company has Share Options under the Share Option Scheme over 14,650,000 new Ordinary Shares outstanding in aggregate at an exercise price of 84 pence per share to a total of 15 employees (including the Executive Directors) and over 800,000 new Ordinary Shares outstanding in aggregate at an exercise price of 96 pence per share to two employees. These Share Options will vest in three to five years' time. In addition, the Company has Share Options under the Share Option Scheme over 8,520,000 new Ordinary Shares outstanding in aggregate at an exercise price of 120 pence per share to a total of 26 employees (including Executive Directors).

(g) 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	Exercise period	Exercise price per share (£)
Directors			
Rusty Hutson, Jr.	6,000,000	In three tranches, ending on 1 March 2023	0.84
....	2,400,000	In three tranches, ending on 1 March 2024	1.20
	78,351[(1)]	In one tranche, ending on 23 April 2021	—
Brad Gray	2,750,000	In three tranches, ending on 1 March 2023	0.84
....	1,100,000	In three tranches, ending on 1 March 2024	1.20
	64,524[(1)]	In one tranche, ending on 26 April 2021	—
Senior Managers			
Eric Michael Williams ..	1,750,000	In three tranches, ending on 1 March 2023	0.84
....	700,000	In three tranches, ending on 1 March 2024	1.20
	400,000[(1)]	In five tranches, ending on 1 August 2024	—
Bryan Keith Berry..........	750,000	In three tranches, ending on 1 March 2023	0.84
	200,000	In three tranches, ending on 1 March 2024	1.20
Michael Walton Garrett..	750,000	In three tranches, ending on 1 March 2023	0.84
	200,000	In three tranches, ending on 1 March 2024	1.20
	25,000[(1)]	In three tranches, ending on 1 January 2021	—
Benjamin Sullivan..........	250,000	In three tranches, ending on 1 July 2023	1.20
	500,000[(1)]	In four tranches, ending on 1 July 2023	—
James Rode	300,000	In three tranches, ending on 1 March 2024	1.20
	500,000[(1)]	In two tranches, ending on 1 June 2022	—

Notes:

(1) *Restricted stock units issued by the Company*

7. SUBSIDIARIES

The Company is the holding company of the Group.

The following table shows details of the Company's material subsidiaries. The issued share capital of each of these companies is fully paid and each is included in the consolidated accounts of the Group.

Name of subsidiary	Country of incorporation	Principal activity	Percentage directly or indirectly held by the Company
Diversified Gas & Oil Corporation....................	United States	Oil and natural gas operations	100
Diversified Production LLC	United States	Oil and natural gas operations	100
Diversified Midstream LLC	United States	Oil and natural gas operations	100
Diversified Energy Marketing, LLC..................	United States	Oil and natural gas operations	100
Diversified ABS Holdings LLC	United States	Holding company	100
Diversified ABS LLC	United States	Oil and natural gas non-operated assets	100
Diversified ABS Phase II Holdings LLC	United States	Holding company	100
Diversified ABS Phase II LLC	United States	Oil and natural gas non-operated assets	100
DGOC Holdings LLC..	United States	Holding company	100
DGOC Holdings Sub I LLC	United States	Holding company	100
DGOC Holdings Sub II LLC	United States	Holding company	100
DGOC Holdings Sub III LLC	United States	Holding company	100

Save as described above, there are no undertakings in which the Company holds a proportion of the share capital which are likely to have a significant effect on the assessment of the Group's assets and liabilities, financial position or profits and losses.

8. PROPERTY

For details of the material properties of the Group, see Part V "*Business: Overview of Assets and Principal Activities*" of this Prospectus.

9. PENSIONS

The Group does not operate a defined contribution pension scheme for its employees or a defined benefit pension scheme. However, the Company operates a tax-qualified, defined-contribution pension account in accordance with subsection 401(k) of the Internal Revenue Code.

The Group recorded an expense of $1.84 million for obligations for contributions to its defined contribution pension plan in the year ended 31 December 2019. No amounts have been set aside or accrued by the Group to provide pension, retirement or similar benefits.

10. DIVIDEND POLICY

The Board's target is to return not less than 40 per cent. of free cash flow to Shareholders by way of dividend, on a quarterly basis, in line with the strength and consistency of the Group's cash flows.

For the three months ended 31 March 2019, the Company paid a dividend of 3.42 cents per Ordinary Share on 27 September, 2019. For the three months ended 30 June 2019, the Company paid a dividend of 3.50 cents per Ordinary Share on 18 December 2019. For the three months ended 30 September 2019, the Company paid a dividend of 3.50 cents per Ordinary Share in March 2020. For the three months ended 31 December 2019, the Company expects to pay a dividend of 3.50 cents per Ordinary Share in June 2020. For the three months ended 31 March 2020, the Company expects to pay a dividend of 3.50 cents per Ordinary Share in September 2020.

The Directors may further revise the Group's dividend policy from time to time in line with the actual results and financial position of the Group.

The Board's dividend policy reflects the Company's current and expected future cash flow generation potential.

11. TAXATION

Material UK tax considerations

Taxation in the United Kingdom

11.1 The following statements are based on current UK tax law and current HMRC published practice currently in force in the UK. Such law and practice (including, without limitation, rates of tax) is in principle subject to change at any time. The information that follows is for guidance purposes only. All potential investors, and in particular any person who is in any doubt about their position should contact their professional advisor immediately.

Tax treatment of UK investors

11.2 The following statements only apply to Shareholders who are resident (and in the case of individuals, domiciled or deemed domiciled) in the UK and who beneficially own Ordinary Shares as investments and not as securities to be realised in the course of a trade. It is based on the law and practice currently in force in the UK. The information is not exhaustive and does not apply to potential investors:

(a) who are dealers in securities, insurance companies, collective investment schemes or Shareholders who have (or are deemed to have) acquired their Ordinary Shares by virtue of an office or employment, who may be subject to special rules;

(b) who intend to acquire, or may acquire (either on their own or together with persons with whom they are connected or associated for tax purposes), more than 10 per cent., of any of the classes of shares in the Company; or

(c) who intend to acquire Ordinary Shares as part of tax avoidance arrangements; or

(d) who are in any doubt as to their taxation position.

11.3 Such Shareholders should consult their professional advisers without delay. Shareholders should note that tax law and interpretation can change and that, in particular, the levels, basis of and reliefs from taxation may change. Such changes may alter the benefits of investment in the Company.

11.4 Shareholders who are neither resident nor temporarily non-resident in the UK and who do not carry on a trade, profession or vocation through a branch, agency or permanent establishment in the UK with which the Ordinary Shares are connected, will not normally be liable to UK taxation on dividends paid by the Company or on capital gains arising on the sale or other disposal of Ordinary Shares. Such Shareholders should consult their own tax advisers concerning their tax liabilities.

Dividends

Withholding tax

11.5 The Company will not be required to withhold amounts on account of UK tax at source when paying dividends in respect of Ordinary Shares.

11.6 Subject to certain limitations, any US tax withheld from a dividend and paid over to the relevant taxing authority will be eligible for credit against a UK tax resident Shareholder's UK tax liability except to the extent that a refund is available under US tax law or under any applicable tax treaty to the Shareholder or a connected person. If a refund becomes available after the UK tax resident Shareholder has submitted its tax return, the UK tax resident Shareholder will be required to notify HMRC and will lose the credit to the extent of the refund.

11.7 Where a UK tax resident Shareholder is not liable to UK tax on dividends or benefits from exemption, no credit will be available for any US tax withheld and paid over to the relevant taxing authority.

Individual Shareholders

11.8 Shareholders who are resident and domiciled in the UK for taxation purposes may, depending on their circumstances, be liable to UK income tax in respect of dividends paid by the Company.

11.9 A nil rate of income tax will apply to the first £2,000 of dividend income received by an individual shareholder in a tax year from 6 April 2019 (the "**Nil Rate Amount**"), regardless of what tax rate would otherwise apply to that dividend income. Any dividend income received by an individual shareholder in a tax year in excess of the Nil Rate Amount will be subject to income tax at the following dividend rates for 2020/21: 7.5 per cent. for basic rate taxpayers, 32.5 per cent. for higher rate taxpayers, and 38.1 per cent. for additional rate taxpayers.

11.10 Dividend income that is within the dividend nil rate amount counts towards an individual's basic or higher rate limits – and will therefore affect the level of savings allowance to which they are entitled, and the rate of tax that is due on any dividend income in excess of the nil rate amount. In calculating into which tax band any dividend income over the nil rate amount falls, savings and dividend income are treated as the highest part of an individual's income. Where an individual has both savings and dividend income, the dividend income is treated as the top slice

Corporate shareholders

11.11 A UK resident corporate Shareholder which is considered to be a "small company" for the purposes of Chapter 2 of Part 9A of the Corporation Tax Act 2009 will be liable to UK corporation tax as the Company is dual tax resident company. As such, small UK corporate shareholders receiving dividends from the Company will be liable to UK corporation tax (currently at a rate of 19 per cent).

11.12 A UK resident corporate Shareholder (which is not a "small company" for the purposes of the UK taxation of dividends legislation in Part 9A of the Corporation Tax Act 2009) will be liable to UK corporation tax (currently at a rate of 19 per cent) unless the dividend falls within one of the exempt classes set out in Part 9A. Examples of exempt classes (as defined in Chapter 3 of Part 9A of the Corporation Tax Act 2009) include dividends paid on shares that are ''ordinary shares'' (that is shares that do not carry any present or future preferential right to dividends or to the Company's assets on its winding up) and which are not "redeemable", and dividends paid to a person holding less than 10 per cent. of the issued share capital of the payer (or any class of that share capital in respect of which the distribution is made). However, the exemptions are not comprehensive and are subject to anti-avoidance rules.

Disposals of Ordinary Shares

11.13 For the purpose of UK tax on chargeable gains, the amounts paid by a Shareholder for Ordinary Shares will generally constitute the base cost of their holdings in those Ordinary Shares.

11.14 A disposal or deemed disposal of Ordinary Shares by a Shareholder who is resident in the UK for tax purposes may give rise to a chargeable gain or an allowable loss for the purposes of UK taxation of chargeable gains depending upon the Shareholder's circumstances and subject to any available exemption or relief.

UK resident individual Shareholders

11.15 For an individual Shareholder within the charge to UK capital gains tax, a disposal (or deemed disposal) of Ordinary Shares may give rise to a chargeable gain or an allowable loss for the purposes of capital gains tax. The rate of capital gains tax on disposal of shares is 10 per cent. (2020/2021) for individuals who are subject to income tax at the basic rate and 20 per cent. (2020/2021) for individuals who are subject to income tax at the higher or additional rates. An individual Shareholder is entitled to realise an annual exempt amount of gains (currently £12,300) for the year to 5 April 2021 without being liable to UK capital gains tax.

UK resident corporate Shareholders

11.16 For a corporate Shareholder within the charge to UK corporation tax, a disposal (or deemed disposal) of Ordinary Shares may give rise to a chargeable gain at the rate of corporation tax applicable to that Shareholder (currently 19 per cent) or an allowable loss for the purposes of UK corporation tax.

Stamp Duty and Stamp Duty Reserve Tax

11.17 The statements below are intended as a general guide to the current position. They do not apply to certain intermediaries who are not liable to stamp duty or stamp duty reserve tax or (except where stated otherwise) to persons connected with depositary arrangements or clearance services who may be liable at a higher rate.

11.18 No stamp duty or stamp duty reserve tax will generally be payable on the issue of Ordinary Shares.

11.19 The transfer of, or agreement to transfer, Ordinary Shares will generally give rise to a liability to both stamp duty and/or stamp duty reserve tax ("**SDRT**"). Both taxes are payable at a rate of 0.5 per cent. In the case of stamp duty this would apply to the consideration provided rounded up to the nearest £5 or to the higher of the consideration provided and the market value if the shares are transferred between connected persons. In the case of SDRT this would apply to the amount or value of the consideration payable or the higher of the consideration provided and the market value if transferred between connected persons. Payment of the appropriate amount of stamp duty would cancel the parallel charge to SDRT. An exemption from stamp duty is available on an instrument transferring Ordinary Shares where the amount or value of the consideration payable is £1,000 or less, and it is certificated on the instrument that the transaction effected by the instrument does not form part of a larger transaction or series of transactions for which the aggregate consideration exceeds £1,000. Unless the transaction takes place within a clearance system or depositary receipt system (to which special rules apply), a charge to SDRT will also arise on an unconditional agreement to transfer Ordinary Shares as set out above. However, if within six years of the date of the agreement becoming unconditional an instrument of transfer is executed pursuant to the agreement, and stamp duty is paid on that instrument, any SDRT already paid will be refunded (generally, but not necessarily, with interest) provided that a claim for repayment is made, and any outstanding liability to SDRT will be cancelled. The liability to pay stamp duty or SDRT is generally satisfied by the purchaser or transferee. In the event that the shares are in dematerialised form and the sale of the shares is settled in CREST, stamp duty would not apply and SDRT is automatically deducted at 0.5 per cent and paid to HMRC.

11.20 The above comments are intended as a guide to the general stamp duty and stamp duty reserve tax position and may not relate to persons such as charities, market makers, brokers, dealers, intermediaries and persons connected with depositary arrangements or clearance services to whom special rules apply.

Material US Federal Income Tax Considerations

11.21 The following discussion is a summary of the material US federal income tax consequences to Non-US Holders and US Holders (each, as defined below) of the purchase, ownership and disposition of the Ordinary Shares, but does not purport to be a complete analysis of all potential tax effects. The effects of other US federal tax laws, such as estate and gift tax laws, and any applicable state, local or non-US tax laws are not discussed. This discussion is based on the US Internal Revenue Code of 1986, as amended, or the Code, Treasury Regulations promulgated under the Code, judicial decisions, and published rulings and administrative pronouncements of the US Internal Revenue Service, or the IRS, in each case in effect as of the date of this Prospectus. These authorities may change or be subject to differing interpretations. Any such change or differing interpretation may be applied retroactively in a manner that could adversely affect a holder of the Ordinary Shares. The Company has not sought any rulings from the IRS regarding the matters discussed below. There can be no assurance the IRS or a court will not take a contrary position to that discussed below regarding the tax consequences of the purchase, ownership and disposition of the Ordinary Shares.

11.22 This discussion is limited to Non-US Holders and US Holders that each hold the Ordinary Shares as a "capital asset" within the meaning of Section 1221 of the Code (generally, property held for investment). This discussion does not address all US federal income tax consequences relevant to a holder's particular circumstances, including the impact of the Medicare contribution tax on net investment income. In addition, it does not address consequences relevant to holders subject to special rules, including, without limitation:

- US expatriates and former citizens or long-term residents of the United States;
- persons subject to the alternative minimum tax;
- persons holding the Ordinary Shares as part of a hedge, straddle or other risk reduction strategy or as part of a conversion transaction or other integrated investment;
- banks, insurance companies, and other financial institutions;
- brokers, dealers or traders in securities;
- "controlled foreign corporations," "passive foreign investment companies," and corporations that accumulate earnings to avoid US federal income tax;
- partnerships or other entities or arrangements treated as partnerships for US federal income tax purposes and other pass-through entities (and investors in such entities);
- tax-exempt organisations or governmental organisations;
- persons deemed to sell the Ordinary Shares under the constructive sale provisions of the Code;
- persons who hold or receive the Ordinary Shares pursuant to the exercise of any employee stock option or otherwise as compensation;
- tax-qualified retirement plans;
- "qualified foreign pension funds" as defined in Section 897(l)(2) of the Code and entities all of the interests of which are held by qualified foreign pension funds; and
- persons subject to special tax accounting rules as a result of any item of gross income with respect to the Ordinary Shares being taken into account in an applicable financial statement.

11.23 If an entity or arrangement treated as a partnership for US federal income tax purposes holds the Ordinary Shares, the tax treatment of a partner in the partnership will depend on the status of the partner, the activities of the partnership and certain determinations made at the partner level. Accordingly, partnerships holding the Ordinary Shares and the partners in such partnerships should consult their tax advisors regarding the US federal income tax consequences to them.

11.24 **THIS DISCUSSION IS FOR INFORMATIONAL PURPOSES ONLY AND IS NOT TAX ADVICE. INVESTORS SHOULD CONSULT THEIR TAX ADVISORS WITH RESPECT TO THE APPLICATION OF THE US FEDERAL INCOME TAX LAWS TO THEIR PARTICULAR**

SITUATIONS AS WELL AS ANY TAX CONSEQUENCES OF THE PURCHASE, OWNERSHIP AND DISPOSITION OF THE ORDINARY SHARES ARISING UNDER THE US FEDERAL ESTATE OR GIFT TAX LAWS OR UNDER THE LAWS OF ANY STATE, LOCAL OR NON-US TAXING JURISDICTION OR UNDER ANY APPLICABLE INCOME TAX TREATY.

US Tax Status of the Company

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

US Holders

11.26 For purposes of this discussion, a "US Holder" is any person that, for US federal income tax purposes, is or is treated as any of the following:

- an individual who is a citizen or resident of the United States;
- a corporation created or organized under the laws of the United States, any state thereof, or the District of Columbia;
- an estate, the income of which is subject to US federal income tax regardless of its source; or
- a trust that (1) is subject to the primary supervision of a US court and the control of one or more "United States persons" (within the meaning of Section 7701(a)(30) of the Code), or (2) has a valid election in effect to be treated as a United States person for US federal income tax purposes.

Distributions

11.27 Distributions, if any, made on the Ordinary Shares, other than certain *pro rata* distributions of common shares, generally will be included in a US Holder's income as ordinary dividend income to the extent of the Company's current or accumulated earnings and profits and treated as US source income for US foreign tax credit purposes. Distributions in excess of the Company's current and accumulated earnings and profits will be treated as a tax-free return of capital to the extent of a US Holder's tax basis in the Ordinary Shares and thereafter as capital gain from the sale or exchange of such Ordinary Shares. Dividends received by a corporate US Holder may be eligible for a dividends-received deduction, subject to applicable limitations. Dividends received by certain non-corporate US Holders (including individuals) are generally taxed at the lower applicable long-term capital gains rates, provided certain holding period and other requirements are satisfied.

Sales, Certain Redemptions or Other Taxable Dispositions of Ordinary Shares

11.28 Upon sales, certain redemptions or other taxable dispositions of the Ordinary Shares, a US Holder generally will recognise gain or loss equal to the difference between the amount realised and the US Holder's tax basis in the Ordinary Shares. Any gain or loss recognised on a taxable disposition of the Ordinary Shares will be capital gain or loss and treated as US source for US foreign tax credit purposes. Such capital gain or loss will be long-term capital gain or loss if a US Holder's holding period at the time of the sale, redemption or other taxable disposition of the Ordinary Shares is more than one year. Long-term capital gains recognised by certain non-corporate US Holders (including individuals) are generally subject to a reduced rate of US federal income tax. The deductibility of capital losses is subject to limitations.

11.29 If the consideration received upon the sale or other taxable disposition of the Ordinary Shares is paid in foreign currency, the amount realised will be the US Dollar value of the payment received, translated at the spot rate of exchange on the date of taxable disposition. If the Ordinary Shares are treated as traded on an established securities market for US federal income tax purposes and the relevant US Holder is either a cash basis taxpayer or an accrual basis taxpayer who has made a special election (which must be applied consistently from year to year and cannot be changed without the consent of the IRS), such holder will determine the US Dollar value of the amount realised in foreign currency by translating the amount received at the spot rate of exchange on the settlement date of the taxable disposition. An accrual basis taxpayer that does not make the special election will recognise exchange gain or loss to the extent attributable to the difference between the exchange rates on the date of disposition and the settlement date, and such exchange gain or loss generally will constitute US-source ordinary income or loss.

11.30 A US Holder's initial tax basis in the Ordinary Shares generally will equal the cost of such Ordinary Shares. If a US Holder used foreign currency to purchase the Ordinary Shares, the cost of such Ordinary Shares will be the US dollar value of the foreign currency purchase price on the date of purchase, translated at the spot rate of exchange on that date. If the Ordinary Shares are treated as traded on an established securities market for US federal income tax purposes and the relevant US Holder is either a cash basis taxpayer or an accrual basis taxpayer who has made the special election, the US Holder will determine the US dollar value of the cost of such Ordinary Shares by translating the amount paid at the spot rate of exchange on the settlement date of the purchase.

Non-US Holders

11.31 For purposes of this discussion, a "Non-US Holder" is any beneficial owner of the Ordinary Shares that is neither a US Holder nor an entity treated as a partnership for US federal income tax purposes.

Distributions

11.32 If the Company makes distributions of cash or property on the Ordinary Shares, such distributions will constitute dividends for US federal income tax purposes to the extent paid from the Company's current or accumulated earnings and profits, as determined under US federal income tax principles. Amounts not treated as dividends for US federal income tax purposes will constitute a return of capital and first be applied against and reduce a Non-US Holder's adjusted tax basis in its Ordinary Shares, but not below zero. Any excess will be treated as capital gain and will be treated as described below under "—Sale or Other Taxable Disposition."

11.33 Subject to the discussion below on effectively connected income and the discussion in the subsequent paragraph regarding the Company's USRPHC status, dividends paid to a Non-US Holder of the Ordinary Shares will be subject to US federal withholding tax at a rate of 30 per. cent. of the gross amount of the dividends (or such lower rate specified by an applicable income tax treaty, provided the Non-US Holder furnishes a valid IRS Form W-8BEN or W-8BEN-E (or other applicable documentation) certifying qualification for the lower treaty rate). A Non-US Holder that does not timely furnish the required documentation, but that qualifies for a reduced treaty rate, may obtain a refund of any excess amounts withheld by timely filing an appropriate claim for refund with the IRS. Non-US Holders should consult their tax advisors regarding their entitlement to benefits under any applicable income tax treaty.

11.34 As a result of the Company's status as a USRPHC (as described below), the Company will have additional withholding tax obligations which it will need to satisfy either by treating the entire distribution as a dividend, subject to the withholding rules above (but withhold at a minimum rate of 15 per cent or such lower rate as may be specified by an applicable income tax treaty for distributions from a USRPHC) or by treating only the amount of the distribution equal to the Company's reasonable estimate of its current and accumulated earnings and profits as a dividend, with the excess portion of the distribution possibly being subject to withholding at a rate of 15 per cent or such lower rate as may be specified by an applicable income tax treaty as if such excess were the result of a sale of shares in a USRPHC.

11.35 If dividends paid to a Non-US Holder are effectively connected with the Non-US Holder's conduct of a trade or business within the United States (and, if required by an applicable income tax treaty, the Non-US Holder maintains a permanent establishment in the United States to which such dividends are attributable), the Non-US Holder will be exempt from the US federal withholding tax described above. To claim the exemption, the Non-US Holder must furnish to the applicable withholding agent a valid IRS Form W-8ECI, certifying that the dividends are effectively connected with the Non-US Holder's conduct of a trade or business within the United States.

11.36 Any such effectively connected dividends will be subject to US federal income tax on a net income basis at the regular graduated rates. A Non-US Holder that is a corporation also may be subject to a branch profits tax at a rate of 30.0 per. cent. (or such lower rate specified by an applicable income tax treaty) on such effectively connected dividends, as adjusted for certain items. Non-US Holders should consult their tax advisors regarding any applicable tax treaties that may provide for different rules.

Sale or Other Taxable Disposition

11.37 Subject to the discussion below on information reporting, backup withholding and foreign accounts, a Non-US Holder will not be subject to US federal income tax on any gain realized upon the sale or other taxable disposition of the Ordinary Shares unless:

- the Ordinary Shares constitute a US real property interest, or USRPI, by reason of the Company's status as a US real property holding corporation, or USRPHC, for US federal income tax purposes at any applicable time within the shorter of the five year period preceding the Non-US Holder's disposition of, or the Non-US Holder's holding period for, the Ordinary Shares (such shorter time, "5-Year Period");

- the gain is effectively connected with the Non-US Holder's conduct of a trade or business within the United States (and, if required by an applicable income tax treaty, the Non-US Holder maintains a permanent establishment in the United States to which such gain is attributable); or

- the Non-US Holder is a nonresident alien individual present in the United States for 183 days or more during the taxable year of the disposition and certain other requirements are met.

11.38 Due to the nature of its assets and operations, the Company believes it is a USRPHC under the Code and Ordinary Shares constitute a US real property interest. Non-US Holders in their capacity as sellers or transferors are subject to US federal income tax in respect of a gain on their Ordinary Shares and are required to file a US tax return. Such gain should be determined in US dollars, based on the excess, if any, of US dollar value of the consideration received over the Non-US Holder's basis in the Ordinary Shares determined in US dollars under the rules applicable to US Holders. Furthermore, the amount realized from any disposition is subject to a withholding tax of 15 per cent. required to be collected from disposition proceeds, unless the Ordinary Shares qualify as "regularly traded on an established securities market." Non-US Holder may, by filing a US tax return, be able to claim a refund for any withholding tax deducted in excess of the tax liability on gain. Furthermore, Non-US Holders will be required to pay, by filing a US tax return, any tax liability on gain that is not satisfied by withholding. A Non-US Holder that has owned 5 per cent. or less of the Ordinary Shares during the entire 5-Year Period, taking into account applicable constructive ownership rules, may treat its ownership of the Ordinary Shares as not constituting a USRPI and thereby avoid net income tax payment and tax return filing obligations if the Ordinary Shares are treated as "regularly traded on an established securities market." The Company makes no representations as to whether the Ordinary Shares have been and will be treated as "regularly traded on an established securities market."

11.39 Gain described in the second bullet point above generally will be subject to US federal income tax on a net income basis at the regular graduated rates. A Non-US Holder that is a corporation also may be subject to a branch profits tax at a rate of 30 per cent. (or such lower rate specified by an applicable income tax treaty) on such effectively connected gain, as adjusted for certain items.

11.40 Gain described in the third bullet point above will be subject to US federal income tax at a rate of 30 per cent. (or such lower rate specified by an applicable income tax treaty), which may be offset by US source capital losses of the Non-US Holder (even though the individual is not considered a resident of the United States), provided the Non-US Holder has timely filed US federal income tax returns with respect to such losses.

11.41 Non-US Holders should consult their tax advisors regarding tax consequences of our treatment as a USRPHC and regarding potentially applicable income tax treaties that may provide for different rules.

Information Reporting and Backup Withholding

US Holders

11.42 Information reporting requirements generally will apply to payments of dividends on the Ordinary Shares and the proceeds of a sale of the Ordinary Shares paid to a US Holder unless the US Holder is an exempt recipient and, if requested, certifies as to that status. Backup withholding generally will apply to those payments if the US Holder fails to provide an appropriate certification with its correct taxpayer identification number or certification of exempt status. Any amounts withheld under the backup withholding rules will be allowed as a refund or a credit against a US Holder's US federal income tax liability, provided the required information is timely furnished to the IRS.

Non-US Holders

11.43 Generally, the amount of dividends on the Ordinary Shares paid to non-US Holders and the amount of tax, if any, withheld with respect to those payments must be reported annually to the IRS and to the non-US Holders. Copies of the information returns reporting such dividends and withholding may also be made available to the tax authorities in a country in which the non-US Holder resides under the provisions of an applicable income tax treaty. In general, a non-US Holder will not be subject to backup withholding with respect to payments of dividends on the Ordinary Shares, provided the applicable tax certifications have been received or the non-US Holder otherwise establishes an exemption. In addition, a non-US Holder will be subject to information reporting and, depending on the circumstances, backup withholding with respect to payments of the proceeds of the sale of the Ordinary Shares conducted within the United States or through certain US-related financial intermediaries, unless the statement described above has been received or the non-US Holder otherwise establishes an exemption. Any amounts withheld under the backup withholding rules will be allowed as a refund or a credit against a non-US Holder's US federal income tax liability, if any, provided the required information is timely furnished to the IRS.

Additional Withholding Tax on Payments Made to Foreign Accounts

11.44 Withholding taxes may be imposed under Sections 1471 to 1474 of the Code (such sections commonly referred to as the Foreign Account Tax Compliance Act, or FATCA) on certain types of payments made to non-US financial institutions and certain other non-US entities. Specifically, a 30 per. cent. withholding tax may be imposed on dividends on, or gross proceeds from the sale or other disposition of, the Ordinary Shares paid to a "foreign financial institution" or a "non-financial foreign entity" (each as defined in the Code), unless (1) the foreign financial institution undertakes certain diligence and reporting obligations, (2) the non-financial foreign entity either certifies it does not have any "substantial United States owners" (as defined in the Code) or furnishes identifying information regarding each substantial United States owner, or (3) the foreign financial institution or non-financial foreign entity otherwise qualifies for an exemption from these rules. If the payee is a foreign financial institution and is subject to the diligence and reporting requirements in (1) above, it must enter into an agreement with the US Department of the Treasury requiring, among other things, that it undertake to identify accounts held by certain "specified United States persons" or "United States-owned foreign entities" (each as defined in the Code), annually report certain information about such accounts, and withhold 30 per cent. on certain payments to non-compliant foreign financial institutions and certain other account holders. Foreign financial institutions located in jurisdictions that have an intergovernmental agreement with the United States governing FATCA may be subject to different rules.

11.45 Under the applicable Treasury Regulations and administrative guidance, withholding under FATCA generally applies to payments of dividends on the Ordinary Shares. While withholding under FATCA would have applied also to payments of gross proceeds from the sale or other disposition of Ordinary Shares on or after January 1, 2019 (except to the extent subject to the USRPI rules), recently proposed Treasury Regulations eliminate FATCA withholding on payments of gross proceeds entirely. Taxpayers generally may rely on these proposed Treasury Regulations until final Treasury Regulations are issued.

11.46 Prospective investors should consult their tax advisors regarding the potential application of withholding under FATCA to their investment in the Ordinary Shares.

12. MATERIAL CONTRACTS

The following are the only contracts (not being contracts entered into in the ordinary course of business) which have been entered into by the Company or another member of the Group within the two years immediately preceding the date of this Prospectus or which are expected to be entered into prior to Admission and which are, or may be, material, or which have been entered into at any time by the Company or any member of the Group and which contain any provision under which the Company or any member of the Group has any obligation or entitlement which is, or may be, material to the Company or any member of the Group as at the date of this Prospectus:

12.1 Diversified ABS LLC Agreement

On 13 November 2019, Diversified ABS LLC ("**Diversified ABS**"), a wholly owned subsidiary of the Company, issued and sold $200,000,000 aggregate principal amount of its 5.00% notes due 15 January 2037 (the "**Notes**") in a private placement transaction pursuant to an indenture entered into on the same date (the "**Indenture**") between UMB Bank, N.A., as indenture trustee (the "**Indenture Trustee**"), and Diversified ABS. Diversified ABS also issued membership interests in itself to Diversified ABS Holdings LLC ("**Diversified Holdings**") pursuant to a limited liability company agreement dated 12 November 2019.

Diversified ABS used the proceeds from the issue and sale of the Notes:

(a) to finance the acquisition of an undivided 21.6 per cent. interest in certain wellbores (the "**Wellbore Interests**") owned by Diversified Production LLC ("**Diversified Production**");

(b) to establish a non-interest bearing trust account on behalf of the Indenture Trustee and in the name of the Indenture Trustee (the "**Liquidity Reserve Account**") for the benefit of the Note holders and the counterparties to Hedge Agreements (defined below);

(c) to pay transaction fees and expenses related to the issuance of the Notes; and

(d) for general limited liability company purposes.

Under the terms of the Indenture, Diversified ABS is required to enter into "**Hedge Agreements**" that have the effect of fixing the price of 85.0 per cent. of the applicable natural gas output from the Wellbore Interests ("**Hedge Percentage**") at a price level that is acceptable to the majority of the holders of the Notes (the "**Initial Hedge Strategy**"). Diversified ABS is also required to maintain, at all times thereafter, Hedge Agreements in an amount equal to the Hedge Percentage and based on the Initial Hedge Strategy until (i) the final scheduled payment date of the Notes in January 2037 or (ii) the Notes are redeemed (the "**Hedge Period**").

Early amortization of the Notes' principal and outstanding interest payments will occur if:

(a) any event of default occurs under the Indenture;

(b) as of a payment date under the Indenture, DSCR (as defined in the Indenture) is less than 1.15 to 1.00, production is below 80 per cent. of the agreed amount or the value of the Wellbore Interests is below 85 per cent. of the value of the Notes; and

(c) Diversified Production materially defaults under the "**Management Services Agreement**", dated 13 November 2019, by and among Diversified ABS, Diversified Production and Diversified Gas & Oil Corporation. Among others things, "**Material Manager Defaults**" under the Management Services Agreement include bankruptcy or dissolution of Diversified Production, the failure of Diversified Production to remit funds to Diversified ABS within specified time periods, the acceleration of indebtedness of Diversified Production (subject to a $10 million threshold) and the rendering of a non-appealable judgment in excess of $10 million against Diversified Production.

The Indenture also contains standard representations and warranties, affirmative and negative covenants and events of defaults, including financial reporting and performance covenants, as well as covenants relating to the separation of Diversified ABS from Diversified Production and the replacement of Diversified Production LLC as the manager under the Management Services Agreement.

The Indenture is governed by the laws of the state of New York, and the holders of the Notes irrevocably waived their right to a jury trial and agreed to submit to the jurisdiction of the courts of New York.

12.2 Diversified ABS Phase II LLC Agreement

On 9 April 2020, Diversified ABS Phase II LLC ("**Diversified ABS II**"), a wholly owned subsidiary of the Company, issued and sold $200,000,000 aggregate principal amount of its 5.25% notes due 28 July 2037 (the "**Notes**") in a private placement transaction pursuant to an indenture entered into on the same date (the "**Indenture**") between UMB Bank, N.A., as indenture trustee (the "**Indenture Trustee**"), and Diversified ABS II. Diversified ABS II also issued membership interests in itself to Diversified ABS Phase II Holdings LLC pursuant to an operating agreement dated 23 March 2020.

Diversified ABS II used the proceeds from the issue and sale of the Notes:

(a) to finance the acquisition of an undivided 29.4 per cent. interest in certain wellbores (the "**Wellbore Interests**") owned by Diversified Production LLC ("**Diversified Production**");

(b) to establish a non-interest bearing trust account on behalf of the Indenture Trustee and in the name of the Indenture Trustee (the "**Liquidity Reserve Account**") for the benefit of the Note holders and the counterparties to Hedge Agreements (defined below);

(c) to pay transaction fees and expenses related to the issuance of the Notes; and

(d) for general limited liability company purposes.

Under the terms of the Indenture, Diversified ABS II is required to enter into and maintain until the earlier of (i) the six-year anniversary of the Closing Date or (ii) the redemption of the Notes in accordance with the Indenture, hedge agreements with an aggregate notional volume of (and fixing the price exposure with respect to) at least 85.0 per cent. but no more than 95 per cent. of the projected natural gas output from the Wellbore Interests for each month classified as "proved" on a two-year rolling basis.

Early amortization of the Notes' principal and outstanding interest payments will occur if:

(a) any event of default occurs under the Indenture;

(b) as of a payment date under the Indenture, DSCR (as defined in the Indenture) is less than 1.15 to 1.00, production is below 80 per cent. of the agreed amount or the value of the Wellbore Interests is below 85 per cent. of the value of the Notes; and

(c) Diversified Production materially defaults under the "**Management Services Agreement**", dated 9 April 2020, by and among Diversified ABS II, Diversified Production and Diversified Gas & Oil Corporation. Among others things, "**Material Manager Defaults**" under the Management Services Agreement include bankruptcy or dissolution of Diversified Production, the failure of Diversified Production to remit funds to Diversified ABS II within specified time periods, the acceleration of indebtedness of Diversified Production (subject to a $10 million threshold) and the rendering of a non-appealable judgment in excess of $10 million against Diversified Production.

The Indenture also contains standard representations and warranties, affirmative and negative covenants and events of defaults, including financial reporting and performance covenants, as well as covenants relating to the separation of Diversified ABS II from Diversified Production and the replacement of Diversified Production as the manager under the Management Services Agreement.

The Indenture is governed by the laws of the state of New York, and the holders of the Notes irrevocably waived their right to a jury trial and agreed to submit to the jurisdiction of the courts of New York.

12.3 KeyBank Facility and Amended Keybank Facility Agreement

On 14 March 2018, DGO Corp and certain of its subsidiaries entered into a five year, senior secured revolving loan facility (including letters of credit) of up to $500,000,000 with KeyBank, National Association ("**KeyBank**") and certain other lenders (collectively, and together with KeyBank, the "**Lenders**"), the proceeds of which were utilised to finance the Alliance Petroleum Acquisition and the CNX Assets Acquisition, to refinance existing indebtedness and for working capital and transaction costs (the "**KeyBank Facility**"). Certain subsidiaries of the DGO Corp guaranteed the KeyBank Facility and pledged their assets to secure the KeyBank Facility.

The KeyBank Facility was a 5 year facility bearing an interest rate of LIBOR plus a margin based upon utilisation of the KeyBank Facility. DGO Corp was required to pay KeyBank an annual administration fee equal to $50,000 and a quarterly commitment fee based upon utilisation of the KeyBank Facility. The KeyBank Facility contained standard representations and warranties, affirmative and negative covenants and events of default, including financial reporting requirements (e.g., annual audited financial statements, quarterly and monthly unaudited financial statements, compliance certificates, financial plans, reserve reports and information regarding oil and gas properties) and performance covenants (e.g., net leverage ratio and asset coverage ratio).

DGO Corp was responsible for payment of all fees and costs associated with the KeyBank Facility including the fees and costs of legal advisors to the Lenders. DGO Corp provided the Lenders, their respective officers, directors, employees, advisors, representatives and agents with an indemnity relating to certain indemnified liabilities which may be incurred by such person, absent any wilful misconduct or gross negligence of such person as determined by a court or competent jurisdiction.

The KeyBank Facility was governed by the laws of the state of New York.

DGO Corp has arranged a five year, senior secured credit facility of up to $1 billion from KeyBank and certain other lenders to entirely replace the facilities under the KeyBank Facility Agreement (the "**Amended KeyBank Facility**"). Up to $600 million of the Amended KeyBank Facility has been made available to be drawn down to fund the EQT Assets Acquisition, to pay related closing costs and to refinance indebtedness under the KeyBank Facility. The agreement in respect of the Amended KeyBank Facility stipulates that the loan proceeds are to be utilised for the EQT Assets Acquisition, refinancing of the KeyBank Facility, capital expenditures programme, working capital and transaction costs. The Amended KeyBank Facility Agreement has an interest rate of LIBOR plus a margin based on a pricing grid of 2.25 per cent. to 3.25 per cent. based upon utilisation.

The Amended KeyBank Facility Agreement contains standard representations and warranties, affirmative and negative covenants and events of defaults, including financial reporting requirements and performance covenants and other terms all of which are comparable to those contained in the KeyBank Facility.

The Amended KeyBank Facility Agreement is governed by the laws of the state of New York.

In relation to the acquisition of Core, DGO Corp further enlarged the five year facility to $1.5 billion (the "**Amended, Restated and Consolidated Facility**"). The enlarged facility consolidates the Amended KeyBank Facility with Core's facility with an initial borrowing base of $725 million. The Amended, Restated and Consolidated Facility maintained previous pricing but was amended in April 2019 to upsize the borrowing base to $950 million related to the HG Energy Assets Acquisition and reduced the pricing grid to 2.00 per cent to 3.00 per cent based on utilisation. In November 2019, the facility was further amended in relation to the $200 million securitisation agreement reducing the borrowing base to $650 million.

The Amended Restated and Consolidated Facility Agreement contains standard representations and warranties, affirmative and negative covenants and events of defaults, including financial reporting requirements and performance covenants and other terms all of which are comparable to those contained in the Amended KeyBank Facility.

The Amended Restated and Consolidated Facility Agreement is governed by the laws of the state of New York.

12.4 **Sponsor Agreement**

On 13 May 2020, 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 applications for Admission and the publication of this Prospectus (the "**Sponsor Agreement**"). The Sponsor Agreement is conditional upon certain conditions that are typical for an agreement of this nature, including Admission occurring and becoming effective by 8.00 a.m. on or prior to 18 May 2020 (or such later time and/or date as the Company and Stifel may mutually agree). The Sponsor Agreement provides for the payment of a fee of £400,000 by the Company to Stifel plus its legal and all other properly incurred expenses incidental to Admission (in each case plus VAT where applicable). Under the terms of the Sponsor Agreement, the Company has also agreed to provide certain customary warranties, representations and undertakings in favour of Stifel in relation to, amongst other things, the accuracy of information in the Prospectus and other matters relating to the Group. The Company have also agreed to indemnify Stifel and its affiliates against, among other things, claims made against them or losses incurred by them in connection with Admission, subject to certain exceptions. In addition, the Sponsor Agreement provides Stifel with the right to terminate the Sponsor Agreement before Admission in certain specified circumstances typical for a sponsor agreement of this nature.

The Sponsor Agreement is governed by English law.

12.5 Placing agreement

On 11 May 2020, the Company, Stifel, Mirabaud and Credit Suisse (the "**Banks**") entered into a placing agreement pursuant to which the Banks agreed, subject to certain conditions, to use their reasonable endeavours to procure subscribers for the placing shares pursuant to the Placing (the "**Placing Agreement**"). The Placing Agreement is conditional upon certain conditions that are typical for an agreement of this nature, including Admission of the placing shares having become effective by not later than 8.00 a.m. on 18 May 2020. The Placing Agreement also provides for a payment of an advisory fee of £150,000 to Stifel, a commission of 1.5 per cent. of the aggregate value of the Shares under the Placing and US Subscription to each of Stifel and Mirabaud, and a commission of 1 per cent. of the aggregate value of the Shares under the Placing and US Subscription to Credit Suisse. Under the terms of the Placing Agreement, the Company has 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. Pursuant to the Placing Agreement, the Company has agreed that, subject to the exceptions set out below, during the period of 45 days from the date of the Placing Agreement, it will not, without the prior written consent of the Banks (such consent not to be unreasonably withheld or delayed), issue, allot, offer, sell, lend, pledge, grant any option, right, warrant or contract to purchase, purchase any option or contract to sell or otherwise transfer or dispose of, directly or indirectly, any Ordinary Shares or other shares in the capital of the Company or any securities convertible into or exchangeable for Ordinary Shares or other shares in the capital of the Company or enter into any swap or other arrangement that transfers to another, in whole or in part, any of the economic consequences of ownership of Ordinary Shares or other shares in the capital of the Company. The restrictions shall not apply in respect of (a) the issue of new Ordinary Shares pursuant to the Placing and US Subscription, (b) the grant by the Company of any options, awards, restricted stock units or warrants in respect of Ordinary Shares pursuant to any share schemes described in this Prospectus, or (c) the issue of Ordinary Shares pursuant to the grant, vesting or exercise of options or awards under share option schemes or any other restricted stock units or warrants described in this Prospectus. In addition, the Placing Agreement provides the Banks with the right to terminate the Placing Agreement before Admission in certain specified circumstances typical for a placing agreement of this nature.

The Placing Agreement is governed by English law.

12.6 Subscription Agreements

On 12 May 2020, the Company entered into subscription agreements with certain investors pursuant to which the Company agreed to sell and the investors agreed to purchase, subject to certain conditions, placing shares in private placement transactions pursuant to an exemption from the registration requirements of the US Securities Act (collectively, the "**Subscription Agreements**"). The Subscription Agreements are conditional upon the Placing Agreement having not been terminated. Under the terms of the Subscription Agreements, the Company agreed to provide certain customary warranties and representations in favour of the investors in relation to, amongst other things, the accuracy of information in the Placing Announcement and the Company's other publicly available information that it is required to publish on its website regarding certain business and financial information in accordance with applicable law. Investors also agreed to provide certain representations and warranties in favour of the Company that would customarily be provided in connection with a private placement transaction in the United States pursuant to the exemption from the registration requirements of the US Securities Act provided by Section 4(a)(2) of the US Securities Act.

The Subscription Agreements are governed by New York law.

12.7 Carbon Assets purchase and sale agreement

On 7 April 2020, Diversified Gas & Oil Corporation, a subsidiary of the Company, executed a conditional Carbon PSA with Carbon in connection with the possible acquisition of the Carbon Assets. If the acquisition were to complete, the Company currently estimates that the consideration payable would comprise: (i) approximately $110 million, payable in cash at closing; and (ii) a further payment of up to $15 million, subject to the achievement of certain conditions with respect to future gas prices, payable over a period of up to three years after closing. However, the final consideration payable may be less than currently estimated and will be determined following completion of due diligence by the Company and satisfaction of the other conditions under the Carbon PSA.

The potential acquisition of the Carbon Assets is subject to a significant number of conditions. The satisfaction of certain of these conditions are within the sole control of the Group such as completion of due diligence (including all title, environmental, contractual, credit, litigation, and regulatory diligence) to the Company's satisfaction and the Company's right to not complete the acquisition if there is a material change in the conditions, assets, or operational matters of the Carbon Assets prior to completion of the acquisition. In addition, the acquisition is also conditional upon satisfaction of various other conditions, including receipt of all necessary shareholder consents, approvals, authorisations and permits (including any authorisations required from the Federal Energy Regulatory Commission and various State Public Service Commissions).

Carbon has provided customary commercial representations and warranties on the Carbon Assets, which are also conditional upon satisfaction of the conditions under the Carbon PSA and completion of the acquisition.

Under the terms of the Carbon PSA, the Company has a right to exclusivity pursuant to which Carbon has agreed to not enter into any negotiations or discussions with any third party in connection with the disposal of the Carbon Assets for a period ending on 30 June 2020 to enable the Company to complete its due diligence and for the satisfaction of all the conditions under the Carbon PSA. If completed, the Carbon PSA will have an effective date of 1 January 2020.

The Carbon PSA is governed by the laws of Texas.

12.8 **EQT Corporation Assets purchase and sale agreement**

On 11 May 2020, the Company executed a conditional purchase and sale agreement with certain subsidiaries of EQT in connection with the possible acquisition of the EQT Corporation Assets. If the acquisition were to complete, the Company currently estimates that the consideration payable would comprise: (i) approximately \$125 million, payable in cash at closing; and (ii) a further payment of up to \$20 million, subject to the achievement of certain conditions with respect to future gas prices, payable over a period of up to three years after closing. However, the final consideration payable may be less than currently estimated and will be determined following completion of due diligence by the Company and satisfaction of the other conditions under the EQT PSA.

The potential acquisition of the EQT Corporation Assets is subject to a significant number of conditions. The satisfaction of certain of these conditions are within the sole control of the Group such as completion of due diligence (including all title, environmental, contractual, credit, litigation, and regulatory diligence) to the Company's satisfaction and the Company's right to not complete the acquisition if there is a material change in the conditions, assets, or operational matters of the EQT Corporation Assets prior to completion of the acquisition. In addition, the acquisition is also conditional upon satisfaction of various other conditions, including receipt of all necessary shareholder consents, approvals, authorisations and permits.

EQT has provided customary commercial representations and warranties on the EQT Corporation Assets, which are also conditional upon satisfaction of the conditions under the EQT PSA and completion of the acquisition.

Under the terms of the EQT PSA, the Company has a right to exclusivity pursuant to which EQT has agreed to not enter into any negotiations or discussions with any third party in connection with the disposal of the EQT Corporation Assets for a period ending on 28 May 2020 to enable the Company to complete its due diligence and for the satisfaction of all the conditions under the EQT PSA. If completed, the EQT PSA will have an effective date of 1 January 2020.

The EQT PSA is governed by the laws of Pennsylvania.

12.9 **Warrant Agreements between the Company and Mirabaud**

On 30 January 2017, the Company entered into a warrant agreement with Mirabaud (the "**Mirabaud Warrant Agreement**"), pursuant to which the Company granted Mirabaud the right to subscribe for up to 2,364,769 new Ordinary Shares at 65 pence for the period beginning on 3 February 2017 and ending on 3 February 2022.

The Mirabaud Warrant Agreement contains a mechanism whereby the Warrant subscription price (being 65 pence) may be adjusted following the occurrence of certain alterations to the Company's share capital, including a sub-division or consolidation of the Ordinary Shares.

The Mirabaud Warrant Agreement shall be exercised by Mirabaud giving notice to the Company in writing setting out the number of Ordinary Shares in respect of which it wishes to exercise the warrants accompanied by payment of the relevant subscription price.

The Mirabaud Warrant Agreement is governed by English law and the parties irrevocably submit to the exclusive jurisdiction of the Courts of England.

On 15 June 2017, the Company entered into a separate warrant agreement with Mirabaud (the "**June 2017 Mirabaud Warrant Agreement**"), pursuant to which the Company granted Mirabaud the right to subscribe for up to 1,179,000 new Ordinary Shares at 75 pence for the period beginning on 3 July 2017 and ending on 3 July 2022. The terms of the June 2017 Mirabaud Warrant Agreement are substantially similar to the Mirabaud Warrant Agreement.

As at the Last Practicable Date, 3,543,769 Warrants issued to Mirabaud are currently outstanding.

12.10 **EQT Assets Acquisition Agreement**

On 28 June 2018, DGO Corp entered into a membership interest purchase agreement (the "**EQT Assets Acquisition Agreement**") with EQT Production Company and EQT Gathering, LLC, pursuant to which the Group acquired all of the issued and outstanding membership interests of two new entities, Diversified Southern Production LLC and Diversified Southern Midstream LLC, which owned certain producing gas, oil, natural gas liquids and midstream assets located in the states of Kentucky, West Virginia and Virginia. The consideration for this acquisition amounted to $575 million and after customary purchase price adjustments the total cash consideration paid was $527 million.

The EQT Assets Acquisition Agreement contains certain warranties given by the sellers in relation to Diversified Southern Production LLC and Diversified Southern Midstream LLC as well as the assets, subject to certain limitations. Claims under the warranties generally must be brought within one (1) year of closing of the EQT Assets Acquisition.

The EQT Assets Acquisition Agreement is governed by the laws of the Commonwealth of Pennsylvania.

12.11 **Core Acquisition Agreement**

On 10 October 2018, the Company entered into an agreement (the "**Core Acquisition Agreement**") with TCFII Core LLC, pursuant to which the Group acquired Core, including approximately 5,000 conventional natural gas wells and a wholly-owned midstream gathering and compression system with approximately 4,100 miles of pipeline and 47,000 horsepower of compression in the states of Kentucky, West Virginia and Virginia. The consideration for this acquisition amounted to $90.6 million, details of which are provided in Note 5 of "Section B "*Historical financial information relating to the Group*" of Part XIV "*Historical Financial Information*" of this Prospectus.

The Core Acquisition Agreement contains certain warranties given by TCFII Core LLC in relation to the assets, subject to certain limitations.

The Core Acquisition Agreement is governed by the laws of the State of Delaware.

12.12 **HG Energy Assets Acquisition Agreement**

On 27 March 2019, the Company entered into a purchase and sale agreement (the "**HG Energy Assets Acquisition Agreement**") pursuant to which the Group acquired certain producing gas assets from HG Energy, comprising 107 unconventional wells and related surface rights and gathering equipment, located in the states of Pennsylvania and West Virginia. The consideration for this acquisition amounted to $400 million, and after customary purchase price adjustments the total cash consideration paid was $388 million.

The HG Energy Assets Acquisition Agreement contains certain warranties given by HG Energy in relation to the assets, subject to certain limitations.

The HG Energy Assets Acquisition Agreement is governed by the laws of Texas.

12.13 **EdgeMarc Energy Acquisition Agreement**

On 24 July 2019, the Group entered into an asset purchase agreement (the "**EdgeMarc Energy Acquisition Agreement**") pursuant to which the Group acquired certain oil and natural gas development, production and exploration assets located in Ohio from EdgeMarc Energy and certain of its subsidiaries. The consideration for this acquisition was $50 million, or $48 million in cash after customary purchase price adjustments, funded from existing debt facilities, to acquire 12 producing unconventional Utica natural gas wells and related facilities in Monroe and Washington counties within the State of Ohio and three drilled but uncompleted wells ("**DUCS**"), as well as undeveloped land containing deep Utica rights. In November 2019, the Group sold the three DUCS and certain undeveloped land rights to a third party for total consideration of $10 million.

The EdgeMarc Energy Acquisition Agreement contains certain warranties given by EdgeMarc Energy in relation to the assets, subject to certain limitations.

The EdgeMarc Energy Acquisition Agreement is governed by the laws of Delaware.

12.14 **Dominion and Equitrans Acquisition Agreement**

On 12 August 2019, the Company entered into an asset purchase agreement (the "**Dominion and Equitrans Acquisition Agreement**") with Dominion Gathering & Processing, Inc., pursuant to which the Group acquired natural gas gathering systems in Pennsylvania and West Virginia in two separate transactions, comprising approximately 1,700 miles of low-pressure wet and dry gas gathering pipelines together with compressors, measurement stations and related facilities and equipment. The total consideration paid for these two acquisitions was $7.7 million.

The Dominion and Equitrans Acquisition Agreement contains certain warranties given by the seller in relation to the assets, subject to certain limitations.

The Dominion and Equitrans Acquisition Agreement is governed by the laws of the Commonwealth of Virginia.

13. WORKING CAPITAL

In the opinion of the Company, taking into account the Group's existing financing arrangements, the Group has sufficient working capital for its present requirements, that is, for at least the next 12 months following the date of this Prospectus.

14. SIGNIFICANT CHANGE

There has been no significant change in the financial position or financial performance of the Group since 31 December 2019, the date to which the financial information for the Group set out in Section B "*Historical Financial Information of the Group*" of Part XIV "*Historical Financial Information*" of this Prospectus was prepared.

15. LITIGATION

There are no governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened of which the Company is aware) during the twelve months preceding the date of this Prospectus, which may have or have had in the recent past significant effects on the Company's and/or Group's financial position or profitability.

16. RELATED PARTY TRANSACTIONS

For each of the years ended 31 December 2019, 2018 and 2017 and for the period since 31 December 2019 up until the Last Practicable Date, the Company has not entered into any transactions with related parties save as disclosed in Note 27 "*Related party transactions*" to the Group Financial Information set out in Section B "*Historical Financial Information of the Group*" of Part XIV "*Historical Financial Information*" of this Prospectus.

17. CONSENTS

PricewaterhouseCoopers LLP (a member of the Institute of Chartered Accountants in England and Wales), having its registered office at 1 Embankment Place, London WC2N 6RH, United Kingdom, has given and has not withdrawn its written consent to the inclusion in this Prospectus of its report which is set out in Section A "*Accountant's Report on the Historical Financial Information of the Group*" of Part XIV "*Historical Financial Information*" of this Prospectus in the form and context in which they appear and has for the purposes of this Prospectus authorised the contents of that part of this Prospectus which comprises its report for the purposes of Rule 5.3.2R(2)(f) of the Prospectus Regulation Rules. A written consent under the Prospectus Regulation Rules is different from a consent filed with the SEC under section 7 of the US Securities Act. As the Ordinary Shares have not been and will not be registered under the US Securities Act, PricewaterhouseCoopers LLP has not filed a consent under section 7 of the US Securities Act.

Crowe U.K. LLP (a member of the Institute of Chartered Accountants in England and Wales), having its registered office at St Brides House, 10 Salisbury Square, London EC4Y 8EH, has given and has not withdrawn its written consent to the inclusion in this Prospectus of its report which is set out in Section C "*Accountant's Report on the Historical Financial Information of Alliance Petroleum*" of Part XIV "*Historical Financial Information*" of this Prospectus and has for the purposes of this Prospectus authorised the contents of that part of this Prospectus which comprises its report for the purposes of Rule 5.3.2R(2)(f) of the Prospectus Regulation Rules. A written consent under the Prospectus Regulation Rules is different from a consent filed with the SEC under section 7 of the US Securities Act. As the Ordinary Shares have not been and will not be registered under the US Securities Act, Crowe U.K. LLP has not filed a consent under section 7 of the US Securities Act.

Wright & Company, Inc., having its registered office at Twelve Cadillac Drive, Suite 260, Brentwood, TN 37027, has given and has not withdrawn its written consent to the inclusion in this Prospectus of the Competent Person's Report prepared at the request of the Company, as set out in Part XV "*Competent Person's Report*" of this Prospectus. Wright & Company, Inc. has authorised the content of such information for the purposes of paragraph 5.3.2R(2)(f) of the Prospectus Regulation Rules. Wright & Company, Inc. accepts responsibility for the information in this Prospectus which has been sourced to it and declares that, to the best of the knowledge of Wright & Company, Inc., such information is in accordance with the facts and such information makes no omission likely to affect their import.

18. MISCELLANEOUS

The expenses of, and incidental to, Admission payable by the Company, including professional fees and commissions and the costs of preparation, printing and distribution of documents, the London Stock Exchange fee, and the FCA's listing fee, are estimated to amount to approximately £2 million (exclusive of any applicable value added tax).

19. DOCUMENTS AVAILABLE FOR INSPECTION

Copies of the following documents will be available and may be inspected at the Company's website www.dgoc.com:

(a) the Articles;

(b) the report from PricewaterhouseCoopers LLP which are set out in Section A "*Accountant's Report on the Historical Financial Information of the Group*" of Part XIV "*Historical Financial Information*" of this Prospectus;

(c) the report from Crowe U.K. LLP which is set out in Section C "*Accountant's Report on the Historical Financial Information of Alliance Petroleum*" of Part XIV "*Historical Financial Information*" of this Prospectus;

(d) the letter of consent referred to in Section 16 "*Consents*" of Part XVI "*Additional Information*" of this Prospectus; and

(e) this Prospectus.

Dated: 13 May 2020

PART XVII

DEFINITIONS

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

"**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;
"**Admission**"	the admission of all of the issued to the premium listing segment of the Official List and to trading on the London Stock Exchange's main market for listed securities becoming effective in accordance with, respectively, the Listing Rules and the London Stock Exchange's standards for admission and disclosure for securities (as amended from time to time);
"**Alliance Petroleum**"	Alliance Petroleum Corporation;
"**Alliance Petroleum Acquisition**"	the acquisition of the entire share capital of Alliance Petroleum in March 2018;
"**Alliance Petroleum Financial Information**"	the audited historical financial information of Alliance Petroleum for the year ended 31 December 2017 and the two-month period ended 28 February 2018;
"**Articles**"	the articles of association of the Company, from time to time;
"**Board**"	the board of directors of the Company from time to time including a duly constituted committee thereof;
"**Bribery Act**"	the UK Bribery Act 2010;
"**CAGR**"	compound annual growth rate;
"**Carbon**"	Carbon Energy Corporation and Nytis Exploration (USA) Inc.;
"**Carbon Assets**"	certain upstream and midstream assets of Carbon in the Appalachian Basin, including approximately 6,100 net conventional wells located in Appalachia (Tennessee, Kentucky, West Virginia) as well as various non-operated wells, midstream pipeline systems and facilities (including intrastate gathering pipeline of approximately 4,700 miles in West Virginia and two active natural gas storage fields);
"**Carbon PSA**"	has the meaning given in paragraph 12.7 of Part XVI (Additional Information) of this Prospectus;
"**CNX**"	CNX Resources LLC;
"**CNX Assets Acquisition**"	the acquisition of the producing natural gas and oil wells from CNX Resources LLC in the Appalachian Basin, principally in Pennsylvania and West Virginia, with some wells in Ohio in March 2018;
"**Company**"	Diversified Gas & Oil plc;
"**Competent Person**"	Wright & Company, Inc., the competent person and author of the Competent Person's Reports;

"**Competent Person's Report**"	the report relating to the Group's production assets produced by the Competent Person, being the Competent Person's Report, set out in Part XV "*Competent Person's Report*" of this Prospectus;
"**Core**"	Core Appalachia Holding Co, LLC;
"**Core Acquisition**"	the acquisition of the entire issued share capital of Core in October 2018;
"**Core Acquisition Agreement**"	the acquisition agreement dated 10 October 2018, pursuant to which the Company acquired Core;
"**Corporate Governance Code**"	the UK Corporate Governance Code published in July 2018 by the Financial Reporting Council (as amended from time to time);
"**Credit Suisse**"	Credit Suisse Securities (Europe) Limited;
"**DGO Corp**"	Diversified Gas & Oil Corporation, a wholly owned subsidiary of the Company;
"**Directors**"	the directors of the Company (whose names appear on page 30 of this Prospectus);
"**Disclosure Guidance and Transparency Rules**"	the disclosure guidance and transparency rules made by the FCA under Part VI of FSMA;
"**EBITDA**"	earnings before interest, tax, depreciation and amortisation;
"**EdgeMarc Energy**"	EdgeMarc Energy Holdings, LLC;
"**EdgeMarc Energy Acquisition**"	the acquisition of certain oil and natural gas development, production and exploration assets located in Ohio from EdgeMarc Energy and certain of its subsidiaries in September 2019;
"**EdgeMarc Energy Acquisition Agreement**"	the acquisition agreement dated September 2019, pursuant to which the Company affected EdgeMarc Energy Acquisition;
"**EEA**"	the European Economic Area;
"**EnerVest**"	EnerVest Limited;
"**EnerVest Assets**"	approximately 1,300 gas and oil wells and PDP reserves of 14,597.721 MMboe in Ohio, acquired from EnerVest in April 2017;
"**EnerVest Assets Acquisition**"	the acquisition of the EnerVest Assets from EnerVest in April 2017;
"**EQT**"	EQT Corporation;
"**EQT Assets Acquisition**"	the acquisition of all of the issued and outstanding membership interests of two new entities, Diversified Southern Production LLC and Diversified Southern Midstream LLC, which owned certain producing gas, oil, natural gas liquids and midstream assets located in the states of Kentucky, West Virginia and Virginia in July 2018;
"**EQT Assets Acquisition Agreement**"	the acquisition agreement dated July 2018, pursuant to which the Company affected EQT Assets Acquisition;
"**EQT PSA**"	has the meaning given in paragraph 12.7 of Part XVI (*Additional Information*) of this Prospectus;

"**EQT Corporation Assets**"	approximately 900 net operated wells, including 67 horizontal producing wells in Pennsylvania, with the majority of the balance being conventional vertical producing wells in West Virginia, and associated midstream infrastructure as well as a further 13 drilled and completed wells that are not yet connected to the gathering infrastructure;
"**Executive Directors**"	Robert "Rusty" Russell Hutson Jr. and Bradley Grafton Gray;
"**FCA**"	the Financial Conduct Authority of the UK;
"**FSMA**"	the UK Financial Services and Markets Act 2000 (as amended);
"**Group**"	the Company and its subsidiary undertakings (as defined in section 1162 of the UK Companies Act);
"**Group Financial Information**"	the audited historical financial information of the Group for the three years ended 31 December 2019;
"**HG Energy**"	HG Energy II Appalachia, LLC;
"**HG Energy Assets Acquisition**"	the acquisition of certain producing gas assets from HG Energy, comprising 107 unconventional wells and related surface rights and gathering equipment, located in the states of Pennsylvania and West Virginia in April 2019;
"**HG Energy Assets Acquisition Agreement**"	the acquisition agreement dated April 2019, pursuant to which the Company effected the HG Energy Assets Acquisition;
"**IFRS**"	International Financial Reporting Standards, as adopted for use in the European Union;
"**Internal Revenue Code**"	the domestic portion of federal statutory tax law in the United States;
"ISIN"	International Securities Identification Number;
"**LEI**"	Legal Entity Identifier;
"**Last Practicable Date**"	12 May 2020;
"**Listing Rules**"	the listing rules made by the FCA under Part VI of FSMA;
"**London Stock Exchange**"	London Stock Exchange plc;
"**Market Abuse Regulation**"	the Market Abuse Regulation (No 2014/596/EC);
"**Mirabaud**"	Mirabaud Securities Limited;
"**NGO**"	NGO Development Corporation, Inc.;
"**Non-executive Directors**"	David Edward Johnson, Martin Keith Thomas, David Jackson Turner Jr., Sandra (Sandy) Mary Stash and Melanie Little;
"**Official List**"	the official list maintained by the FCA for the purposes of Part VI of FSMA;
"**OPEC**"	the Organization of the Petroleum Exporting Countries;
"**Ordinary Shares**" or "**Shares**"	ordinary shares of £0.01 each in the share capital of the Company;
"**Placing**"	the conditional placing of 61,813,500 Ordinary Shares at a price of 108 pence per Ordinary Share pursuant to the Placing Agreement;

"**Placing Agreement**"	has the meaning given in paragraph 12.5 of Part XVI (*Additional Information)* of this Prospectus;
"**Placing Announcement**"	the announcement dated 11 May 2020 issued by the Company in connection with the Placing;
"**Prospectus**"	this document or prospectus;
"**Prospectus Delegated Regulation**"	Commission Delegated Regulation (EU) 2019/980 supplementing the Prospectus Regulation as regards format, content, scrutiny and approval of the prospectus to be published when securities are offered to the public or admitted to trading on a regulated market, and repealing Commission Regulation (EC) No 809/2004;
"**Prospectus Regulation**"	Regulation (EU) 2017/1129 (and amendments thereto), and includes any relevant implementing measure in each Relevant Member State;
"**Prospectus Regulation Rules**"	the prospectus regulation rules of the FCA;
"**Regulation S**"	Regulation S under the US Securities Act;
"**Relevant Member State**"	Member States to which the Prospectus Regulation is applicable or which has implemented the Prospectus Regulation;
"**SEDOL**"	Stock Exchange Daily Official List number;
"**Senior Independent Director**"	David J. Turner, Jr;
"**Senior Managers**"	the persons named as Senior Managers in Section 1.2 "*Senior Managers*" of Part IX "*Directors, Senior Managers and Corporate Governance*" of this Prospectus;
"**Shareholders**"	holders of Ordinary Shares;
"**Significant Shareholders**"	the Shareholder who owns more than 3 per cent. of the issued share capital of Company;
"**Smarter Well Management**"	precautionary techniques for extending well life that include wellhead compression management, fluid load deduction and pumpjack optimization;
"**Sponsor Agreement**"	has the meaning given in Paragraph 12.4 of Part XVI (*Additional Information*) of the Prospectus;
"stamp duty"	UK stamp duty;
"**Titan Energy**"	Titan Energy, LLC;
"**UK Companies Act**"	the UK Companies Act 2006 (as amended);
"**United Kingdom**" or "**UK**"	the UK of Great Britain and Northern Ireland;
"**United States**" or "**US**"	the United States of America, its territories and possessions, any State of the United States of America and the District of Columbia;
"**US Exchange Act**"	the US Securities Exchange Act of 1934, as amended;
"**US Securities Act**"	the US Securities Act of 1933, as amended;

"**US Subscription**"	the conditional allotment of 2,467,000 Ordinary Shares at a price of 108 pence per share, as described in paragraph 3.3 of Part XV (*Additional Information*) of this Prospectus;
"**Warrants**"	the warrants issued by the Company to certain of its professional advisers, which are exchangeable for Ordinary Shares;
"**£**"	Great British Pounds Sterling; and
"**$**"	United States Dollars.

PART XVIII

GLOSSARY OF TECHNICAL TERMS

"**annual decline rate**"	the annualized 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 5,800 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;
"**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;
"**fractionation**"	the process by which ethane, propane, butane, and longer hydrocarbon chains are separated from a produced natural gas production stream;
"**HBP**"	held by production: a provision in an oil or natural gas property lease that allows the lessee to continue drilling activities on the property as long as it is producing a minimum paying amount of oil or gas, thereby extending the lessee's right to operate the property beyond the initial lease term;
"**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;
"**MMbbl**"	millions of barrels of oil;
"**MMboe**"	millions of barrels of oil equivalent;
"**MMbtu**"	million btus;
"**MMcf**"	million standard cubic feet of natural gas;
"**MMcfed**"	million standard cubic feet of natural gas equivalent per day;

"**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;
"**net production**"	the total production volume attributable to the Group's fractional working interest in the wells in which it has an interest;
"**net wells**"	has the meaning given in Exhibit H (*Glossary of Terms*) of Part XV (*Competent Persons' Report*) of this Prospectus, and "**net conventional wells**" shall be construed accordingly;
"**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;
"**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;
"**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;
"**West Texas Intermediate**"	the underlying commodity of the Chicago Mercantile Exchange's oil futures contracts

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