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

STIFEL NICOLAUS EUROPE LIMITED
150 CHEAPSIDE
LONDON, EC2V 6ET, UNITED KINGDOM

May 11, 2020

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Diversified Gas & Oil PLC
Attn: Board of Directors
1800 Corporate Drive
Birmingham, AL 35242, United States

Stifel Nicolaus Europe Limited
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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 Alternative Investment Market (AIM) 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

Wright & Company, Inc.
Petroleum Consultants

following table is presented as a summary of the combined results of the Northern and Southern Divisions evaluations as of the Effective Date.

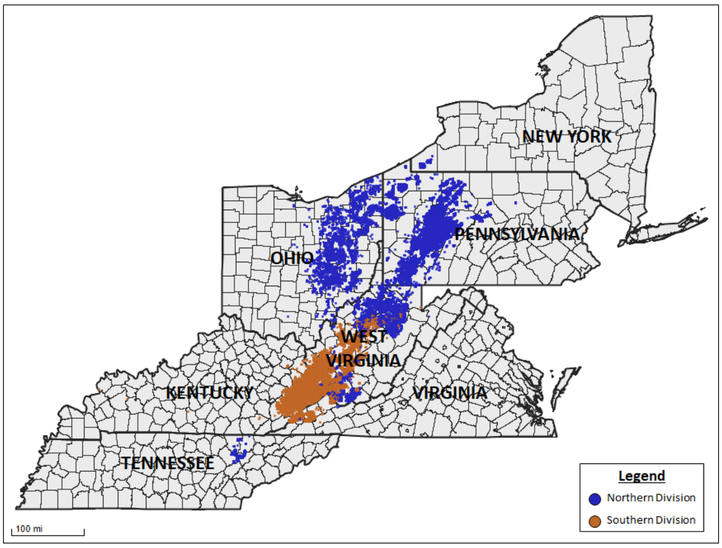
Evaluation of DGO Assets Utilizing Specified Economics Northern and Southern Divisions	Total Proved Developed Northern Division	Total Proved Developed Southern Division	Total Proved Developed
Net 1P Developed Reserves to the Evaluated Interests			
Oil, Mbbl:	3,387	1,404	4,791
Gas, MMcf:	1,309,953	1,632,645	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 in the 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.

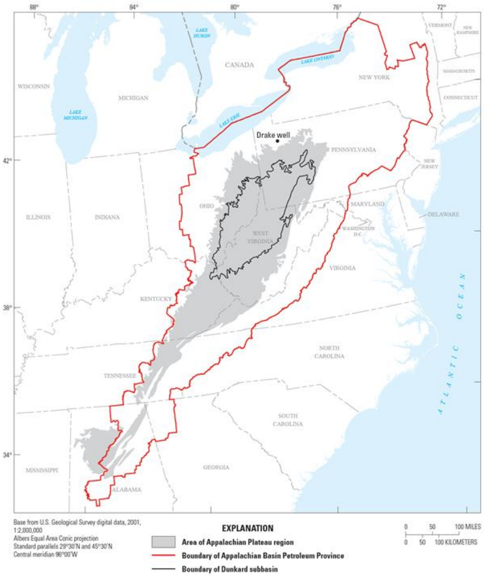
GEOLOGY

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.

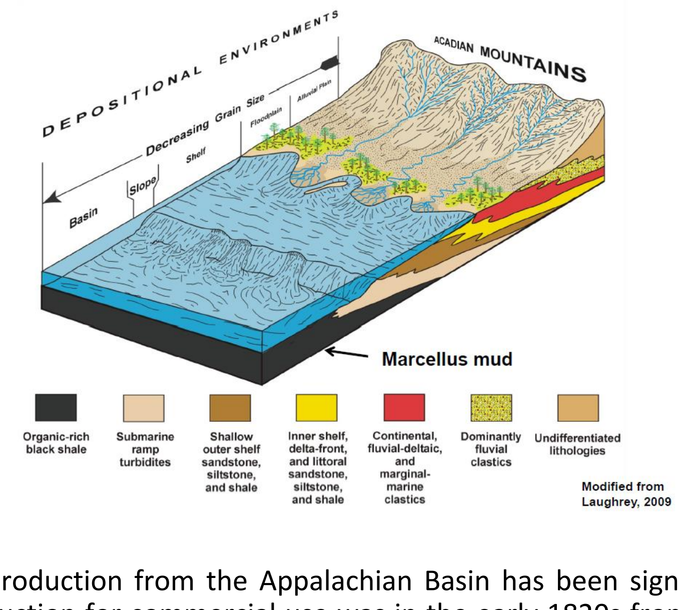
Figure 2



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

DEVONIAN DEPOSITIONAL ENVIRONMENTS



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.

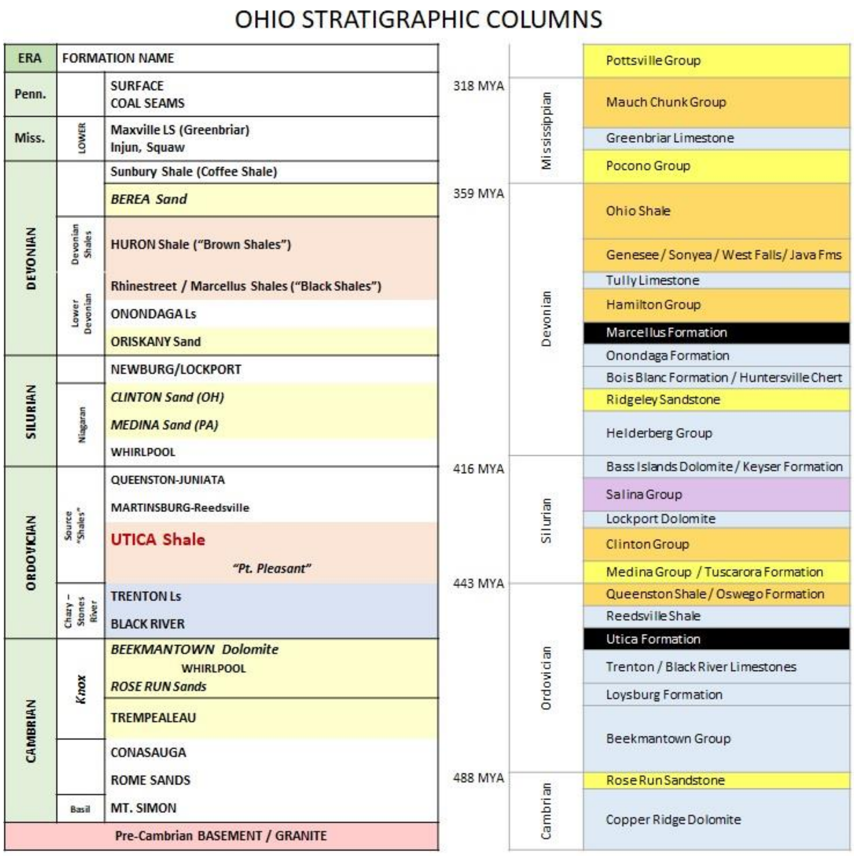
Across much of the Appalachian Basin, there are many prolific and commercially viable hydrocarbon producing zones ranging in depth from less than 2,000 feet in portions of Kentucky and Virginia to more than 13,000 feet in Pennsylvania and West Virginia. Additionally, the types of producing reservoirs 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.

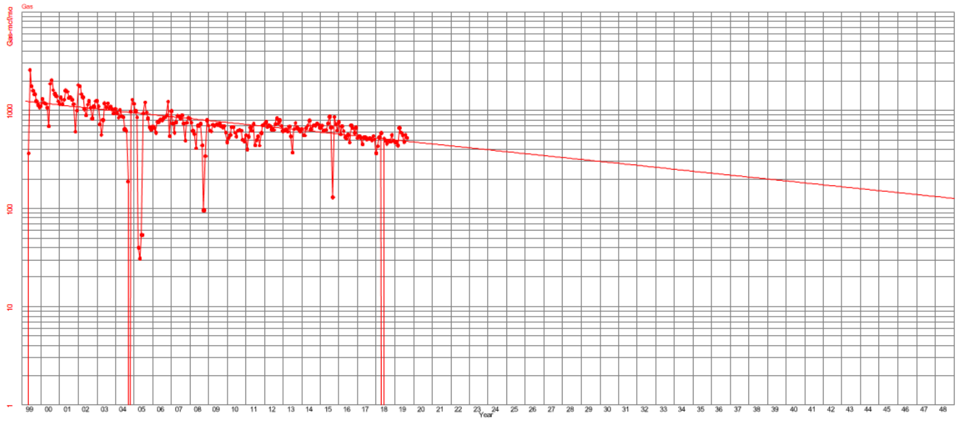
Figure 4



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

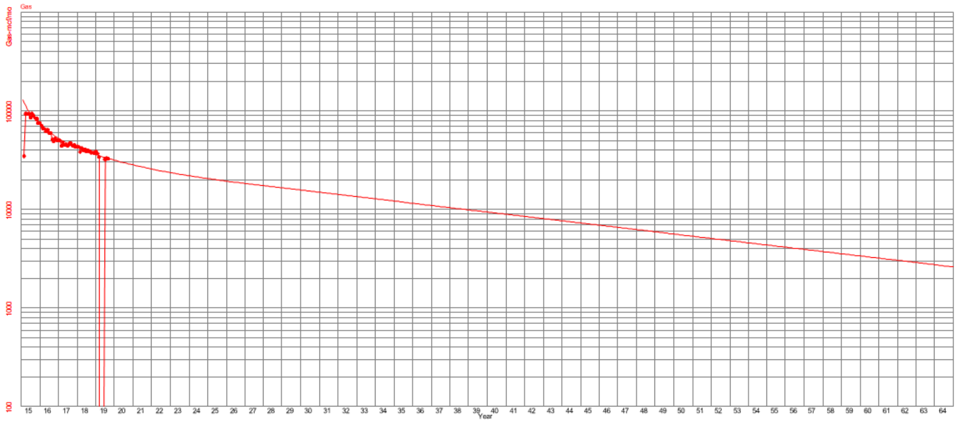
Rhinestreet in the Big Sandy Field, the Marcellus was not considered a primary target for development before 2007. Although the Marcellus had been identified as an exploration target in the central and northern Appalachian Basin in the 1970s, successful attempts to achieve commercial production were 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.

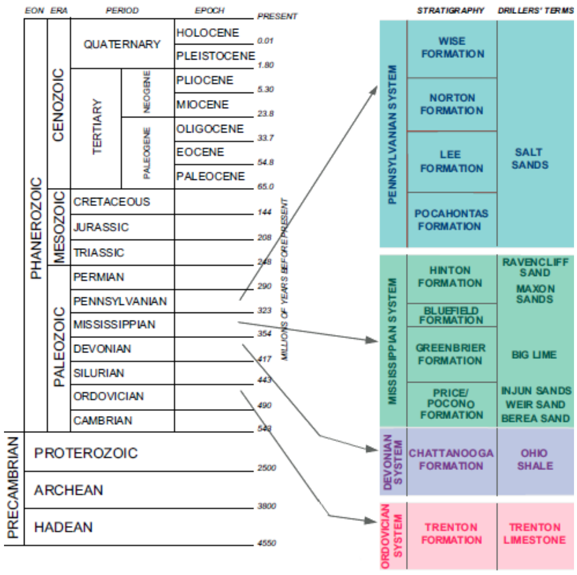
Like other low-permeability plays, key geologic criteria that control play boundaries and high productivity areas include thermal maturity, total organic carbon (TOC) content, formation thickness, porosity, depth, pressure, and the ability of the formation to be hydraulically fractured. However, there 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

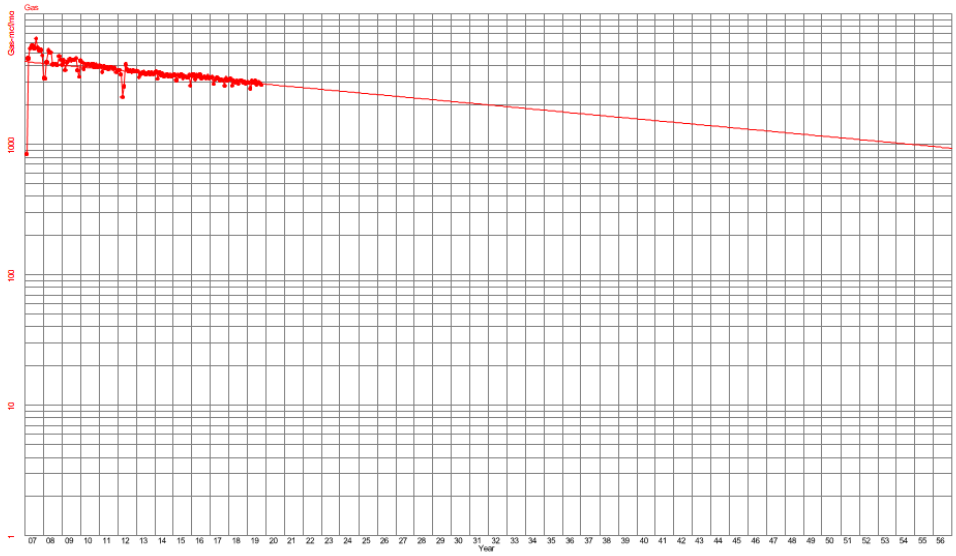
The majority of DGO's assets in the Southern Division are located in Kentucky, Virginia, and West Virginia and are conventional vertical wells. These wells typically produce from intervals that span geologic time from the Upper Cambrian to the Lower Mississippian as shown in **Figure 7**. Productive 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

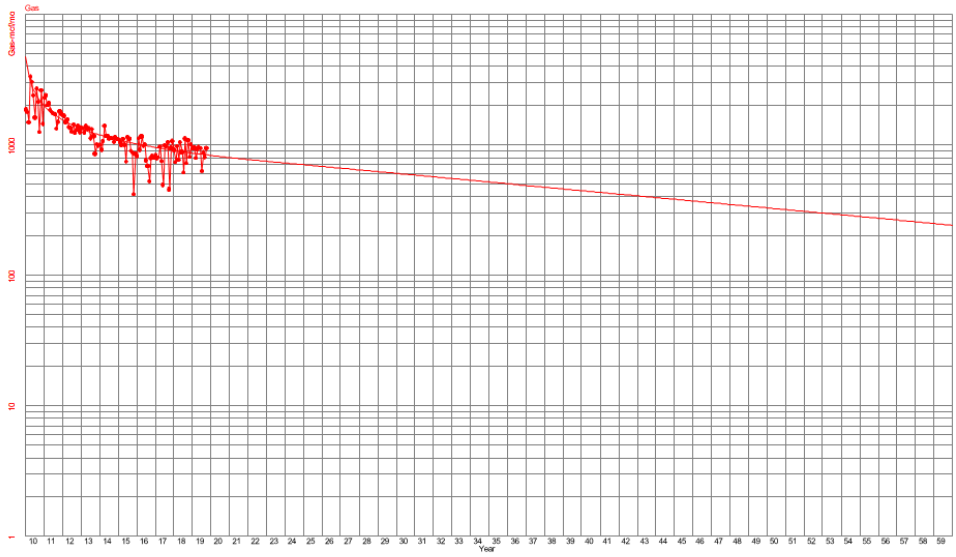


Example Conventional Well from DGO's Southern Division (50-year time-frame)

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)

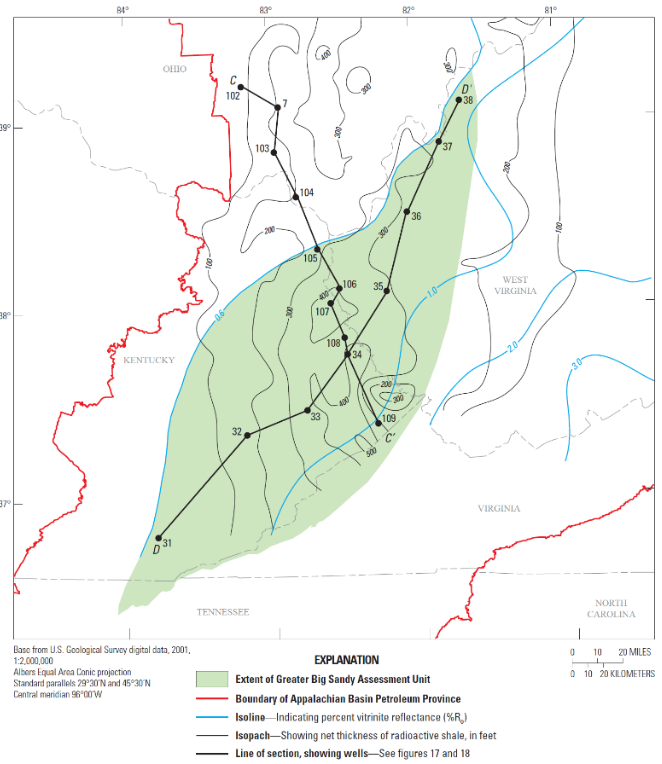
US-DOCS\112290753.1

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.

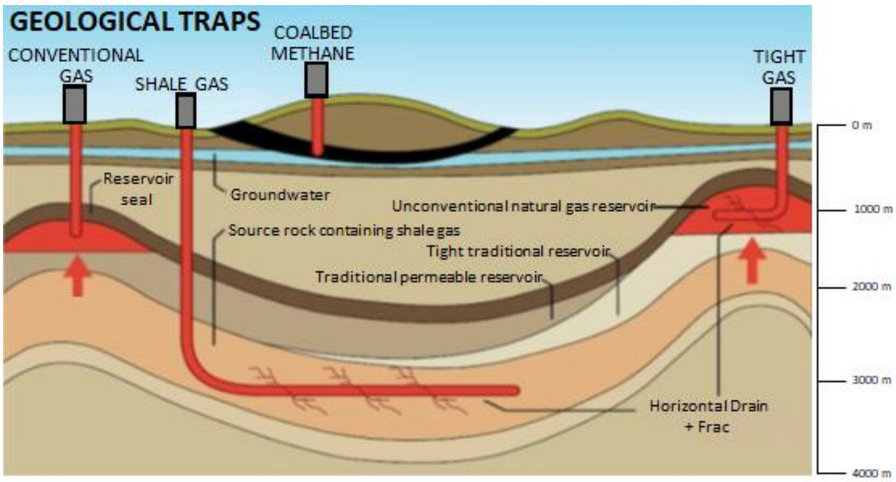
	Conventional	Unconventional	TOTALS*
Northern Division			
Number of Wells	41,942	503	**42,445**
Net Oil Equivalent, MBOE:	102,148	120,058	**222,206**
Cash Flow Before Tax (BTAX), M$			
Undiscounted:	770,806	1,321,758	**2,092,564**
Discounted at 10% per Annum:	305,828	492,353	**798,181**
Southern Division			
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

<u>Conventional Operations</u>

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.

<u>Unconventional Operations</u>

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.

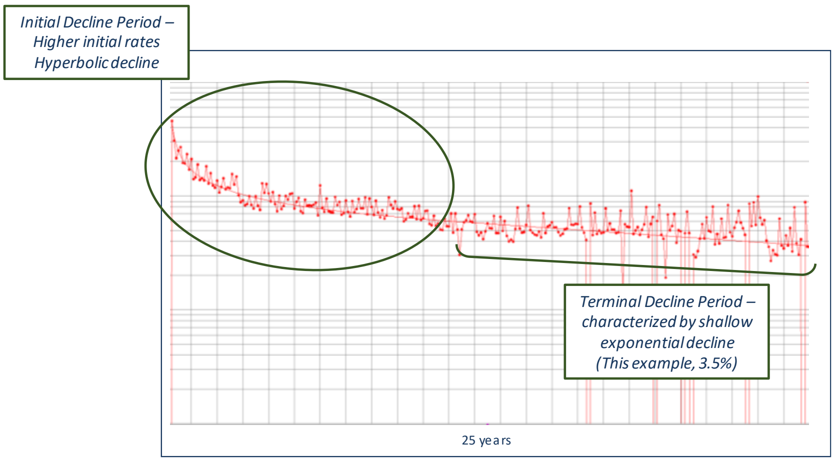
This method is suited to forecast certain DGO wells that have historically demonstrated a hyperbolic production decline profile and not yet reached a terminal exponential decline rate. These wells are typically newer wells that have been producing for less than approximately 10 to 15 years. This method 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

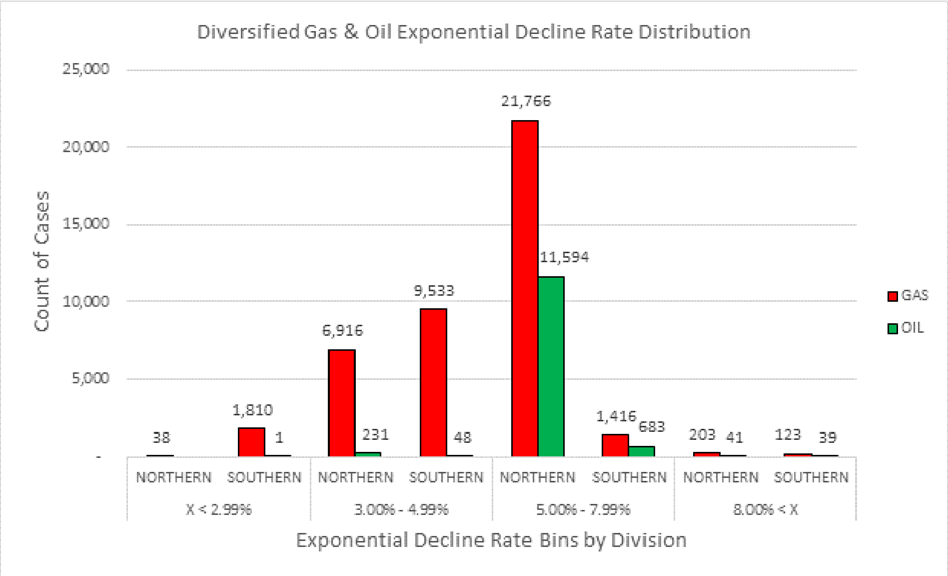
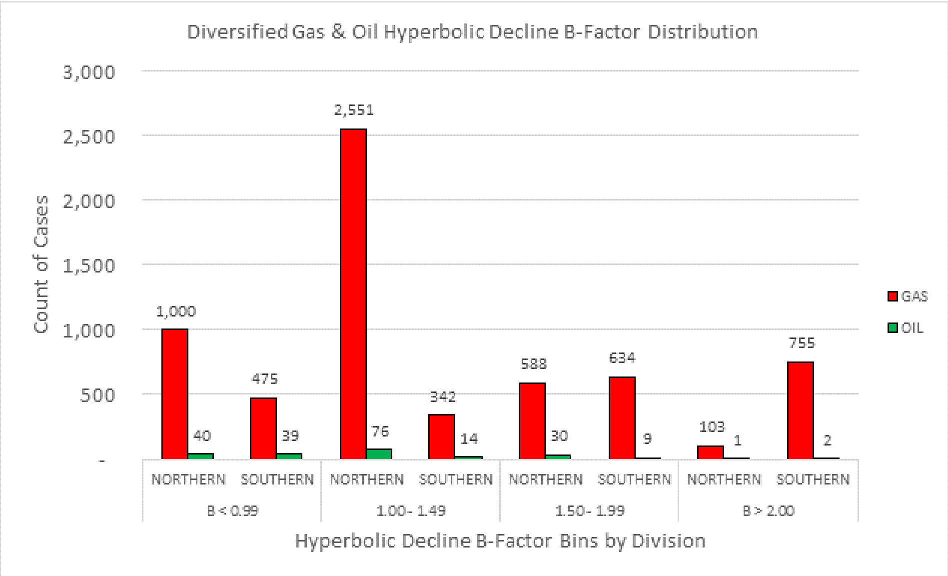


Figure 14



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.

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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.

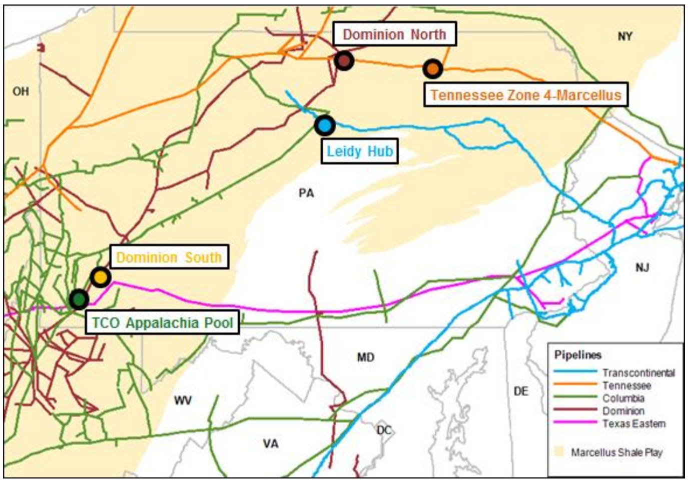
The third-party revenue case that is associated with the EQT asset generates a 10.0 percent Cum. Disc. cash flow (BTAX) value in excess of 62,000 M$ over a 50-year schedule and is summarized in the Southern Division total. Similar to the case described above, the revenues were generated from historical 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

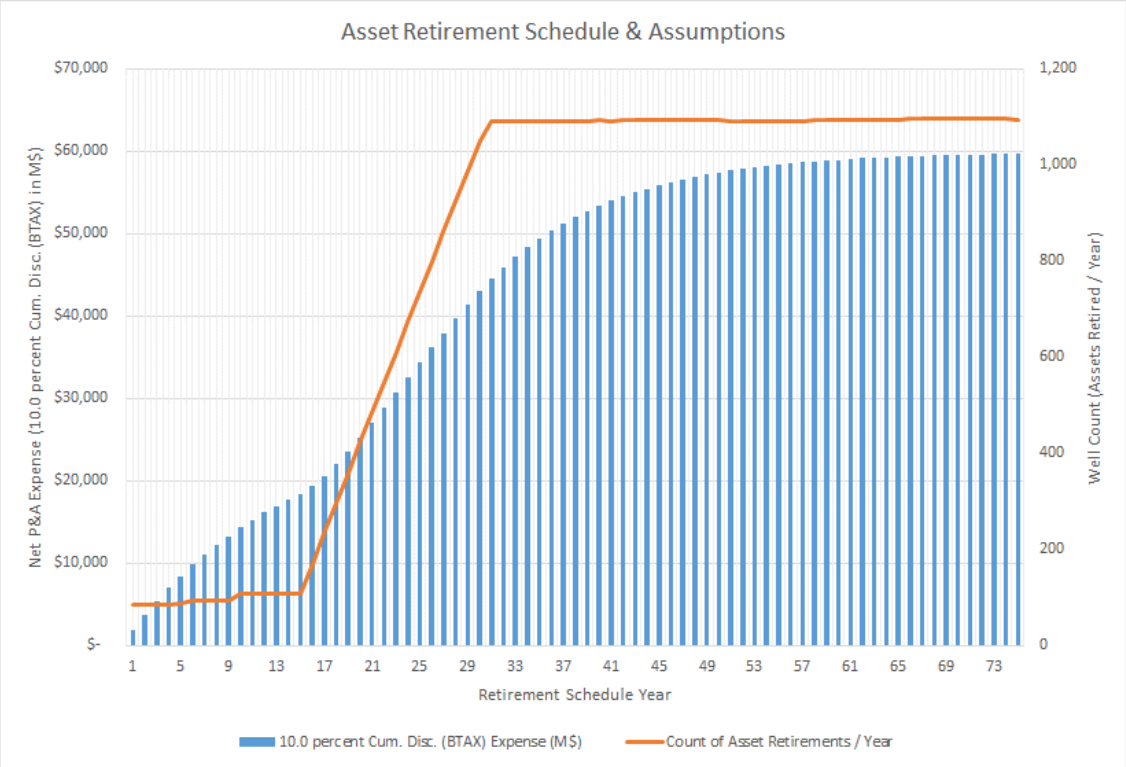
Wright requested and received information on the actual amount paid by well type for the wells that have been plugged or retired to date. An average cost was determined and applied to the remaining wells. According to DGO, these wells were accessible and plugged without issues. In the future, some of 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) under the AIM Rules for Companies (AIM Rules). 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.

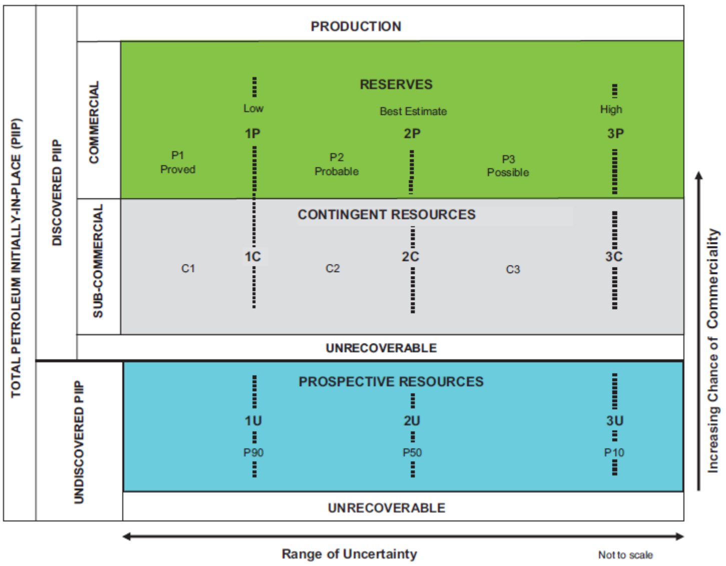


Figure A1—Resources Classification Framework

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. D

iscovered PIIP is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production.

B. P

roduction 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. E

stimated 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).

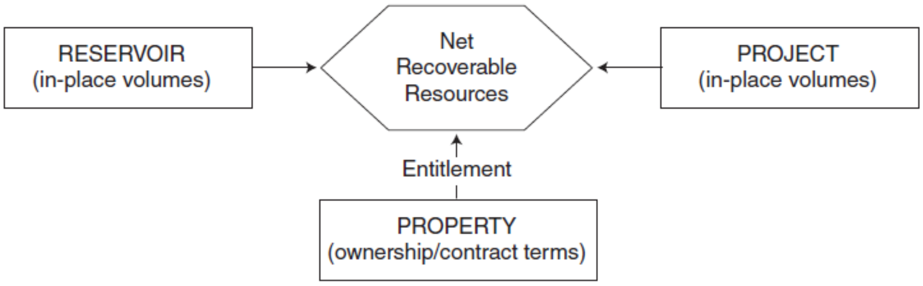


Figure A2—Resources evaluation

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.

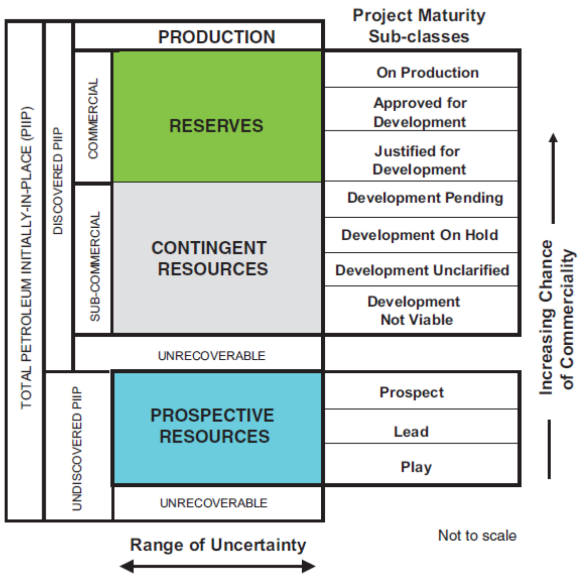


Figure A3—Sub-Classes based on Project Maturity

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. T
he 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. C
onventional 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. U
nconventional 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.*

Wright & Company, Inc.
Petroleum Consultants

Exhibit C

Wright & Company, Inc.
Petroleum Consultants

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--	GROSS PRODUCTION			NET PRODUCTION			PRICES			M$
MO-YEAR	OIL, MBBL	GAS, MMCF	NGL, MBBL	OIL, MBBL	GAS, MMCF	NGL, MBBL	OIL $/B	GAS $/M	NGL $/B	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--	OPERATIONS, M$				CAPITAL COSTS, M$					10.0%
MO-YEAR	SEV & ADV TAXES	NET OPER EXPENSES	T&C EXPENSES	ACTIVE WELLS	TANGIBLE INVEST.	INTANG. INVEST.	TOTAL INVEST.	SALVAGE VALUE	CASH FLOW BTAX, M$	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)

Wright & Company, Inc.
Petroleum Consultants

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 PAYOUT 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

Wright & Company, Inc.
Petroleum Consultants

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.
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Southern Division Cash Flow Summaries - After Federal Income Tax (ATAX)

CONVENTIONAL & UNCONVENTIONAL PROPERTIES & CORPORATE SUMMARY CASES
SOUTHERN DIVISION
TOTAL PROVED (1P) DEVELOPED
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DATE : 02/26/2020
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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	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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BRENTWOOD, TENNESSEE
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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*.

Wright & Company, Inc.
Petroleum Consultants

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.*

<u>Exhibit F</u>
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) as defined by the AIM Market of the London Stock Exchange (AIM). 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.