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DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 12, 2021

IGas Energy PLC
7 Down Street
London W1J 7AJ
United Kingdom

Ladies and Gentlemen:

Pursuant to your request, we have prepared estimates, as of December 31, 2020, of the extent of the proved, probable, and possible oil, condensate, and sales gas reserves, the value of the proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves, the extent of the 1C, 2C, and 3C contingent resources, and the extent of the prospective resources from certain conventional properties in and offshore the United Kingdom, in which IGas Energy PLC (IGas) has represented it holds an interest.

Estimates of reserves, contingent resources, and prospective resources presented in this report have been prepared in accordance with the Petroleum Resources Management System (PRMS) approved in March 2007 and revised in June 2018 by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysts, and the European Association of Geoscientists & Engineers. PRMS is a referenced standard in published guidance of the United Kingdom Listing Authority. The reserves definitions are discussed in detail under the Definition of Reserves heading of this report. The contingent resources definitions are discussed in detail under the Definition of Contingent Resources heading of this report. The prospective resources definitions are discussed in detail under the Definition of Prospective Resources heading of this report.

This report is compliant with the Competent Person's Report requirements as published in the European Securities and Markets Authority (ESMA) update of the

Committee of European Securities Regulators' recommendations for the implementation of the European Commission Regulation on Prospectuses No. 809/2004 dated March 20, 2013 (ESMA/2013/319).

Reserves estimated in this report are expressed as gross reserves and net reserves. Gross reserves are defined as the total estimated petroleum remaining to be produced from the fields after December 31, 2020. Net reserves are defined as that portion of the gross reserves attributable to the interests held by IGas evaluated herein after deducting interests held by others, as described herein.

This report presents values for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves that were estimated using initial prices, expenses, and costs provided by IGas and forecast prices, expenses, and costs as described herein. Prices, expenses, and costs were provided in United Kingdom pounds sterling (U.K.£). For the purposes of this report, U.K.£ were converted to United States dollars (U.S.$) using an exchange rate of U.S.$1.34 per U.K.£1.00. All monetary values in this report are expressed in U.S.$. An explanation of the forecast price, expense, and cost assumptions is included under the Valuation of Reserves heading of this report.

Values for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves in this report are expressed in terms of estimated future gross revenue, future net revenue, and present worth. Future gross revenue is defined as that revenue which will accrue to the evaluated interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting operating expenses, abandonment costs, and capital costs from future gross revenue. Operating expenses include field operating expenses, estimated expenses of direct supervision, and an allocation of overhead that directly relates to production activities. Abandonment costs are represented by IGas to be inclusive of those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment. Capital costs include drilling and completion costs, facilities costs, and field maintenance costs. At the request of IGas, consideration of United Kingdom taxes has not been included in this report. Present worth is defined as the future net revenue discounted at a specified arbitrary discount rate compounded monthly over the expected period of realization. Present worth should not be construed as fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold. In this report, present worth values using a nominal discount rate of 10 percent are reported in detail and values using nominal discount rates of 8, 12, and 15 percent are reported as totals.

Contingent resources estimated in this report are expressed as gross contingent resources and net contingent resources. Gross contingent resources are defined as the total estimated petroleum that is potentially recoverable from known accumulations after December 31, 2020. Net contingent resources are defined as that portion of the gross contingent resources attributable to the interests held by IGas evaluated herein after deducting interests attributable to others.

The contingent resources estimated herein are those quantities of petroleum that are potentially recoverable from known accumulations but which are not currently considered to be commercially recoverable. Because of the uncertainty of commerciality, the contingent resources estimated herein cannot be classified as reserves. The contingent resources estimates in this report are provided as a means of comparison to other contingent resources and do not provide a means of direct comparison to reserves. A detailed explanation of the contingent resources estimated herein is included under the Estimation of Contingent Resources heading of this report.

Contingent resources quantities should not be confused with those quantities or values associated with reserves due to the additional risk involved. The quantities that might actually be recovered, should they be developed, may differ significantly from the estimates presented herein. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.

Prospective resources estimated in this report are expressed as gross prospective resources and working interest prospective resources. Gross prospective resources are defined as the total estimated petroleum that is potentially recoverable from undiscovered accumulations after December 31, 2020. Working interest prospective resources are defined as the product of the gross prospective resources and IGas' working interest in the leasehold or concession associated with a given prospect.

The prospective resources estimated herein are those quantities of petroleum that are potentially recoverable from accumulations yet to be discovered. Because of the uncertainty of commerciality and the lack of sufficient exploration drilling, the prospective resources estimated herein cannot be classified as contingent resources or reserves. The prospective resources estimates in this report are not provided as a means of comparison to contingent resources or reserves. Prospective resources can be organized and quantified as prospect(s), lead(s), or play(s) based on several factors, including but not limited to the following: the quantity and quality of the technical data available, the range of technical uncertainty, the magnitude of the geologic chance factors, the prospective resources ready to drill status, and the commercial and economic viability of the potential accumulation(s).

Prospective resources quantities estimates should not be confused with those quantities that are associated with contingent resources or reserves due to the additional risks involved. The quantities that might actually be recovered, should they be discovered and developed, may differ significantly from the estimates presented herein. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

Estimates of reserves and revenue and contingent resources and prospective resources should be regarded only as estimates that may change as further production history and additional information become available. Not only are such estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

In this report, key information has been provided by IGas on the fields evaluated herein. As far as we are aware, there are no special factors that would affect the interests held by IGas that would require additional information for the proper evaluation of these fields. All evaluations herein are considered in the context of current agreements and regulations and do not consider uncertainties that might be associated with political conditions.

Information used in the preparation of this report was obtained from IGas. In the preparation of this report we have relied upon information furnished by or directed to be furnished by IGas with respect to the property interests being evaluated, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sales of production, concession expiration dates, and various other information and data that were accepted as represented. Although we have not had independent verification, the information used in this report appears reasonable. The technical staff of IGas involved with the assessment and implementation of development of IGas' petroleum assets are represented as adherent to the generally accepted practices of the petroleum industry. The staff members appear to be experienced and technically competent in their fields of expertise. No site visit to the fields evaluated herein was made by DeGolyer and MacNaughton. However, existing production data, reports from third parties, and photographic evidence were considered adequate because the fields are in an established producing venue.

Executive Summary

IGas has represented that it holds interests in properties that include 30 discovered fields in the United Kingdom. This report includes evaluations of 7 fields that contain reserves only, 7 fields that contain contingent resources only, 11 fields that contain reserves and contingent resources, and 5 fields with no booked reserves or contingent resources. This evaluation also includes prospective resources for three conventional prospects.

For this report, technical and commercial uncertainties have been considered in each case exclusive of ongoing political events in a given venue. All contracts, regulations, and agreements in place on December 31, 2020, have been considered to be valid for their stated terms, as represented by IGas.

Reserves

Reserves were estimated for oil, condensate, and sales gas in 18 fields. Sales gas reserves were converted to barrels of oil equivalent (boe) using an energy equivalent factor of 5,800 cubic feet of gas per 1 boe.

The estimated gross and net proved, probable, and possible reserves, as of December 31, 2020, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

Reserves Summary

	Oil and Condensate			Sales Gas			Oil Equivalent		
	Proved (10^3bbl)	**Probable (10^3bbl)**	**Possible (10^3bbl)**	**Proved (10^6ft^3)**	**Probable (10^6ft^3)**	**Possible (10^6ft^3)**	**Proved (10^3boe)**	**Probable (10^3boe)**	**Possible (10^3boe)**
Gross	11,057	4,576	3,229	4,590	4,787	5,077	11,849	5,402	4,105
Net	10,945	4,562	3,214	4,590	4,787	5,077	11,736	5,388	4,089

Notes:
1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Sales gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 5,800 cubic feet of gas per 1 boe.

Revenue

Revenue values in this report were estimated using initial prices, expenses, and costs provided by IGas. Forecast price, expense, and cost assumptions used for this report are detailed herein. Estimates of future net revenue and present worth of the proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves estimated in this report were prepared using a Base Case scenario and two price sensitivities. An explanation of the Base Case and two price sensitivity assumptions is included under the Valuation of Reserves heading of this report.

In this report, values for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves were based on projections of estimated future production and revenue prepared for these properties with no risk adjustment applied to the probable and possible reserves. Probable and possible reserves involve substantially higher risks than proved reserves. Revenue values associated with proved-plus-probable and proved-plus-probable-plus-possible reserves have not been adjusted to account for such risks; such an adjustment would be necessary in order to make the values associated with probable or possible reserves comparable to values associated with proved reserves.

The estimated future net revenue and present worth of the future net revenue discounted at 10 percent to be derived from the production and sale of the proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves and quantities, as of December 31, 2020, of the properties evaluated under the three economic scenarios described herein are summarized as follows, expressed in thousands of United States dollars (10^3U.S.$):

Valuation Summary

	Proved		Proved plus Probable		Proved plus Probable plus Possible	
	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
Base Case	363,317	149,591	690,162	203,676	938,610	243,467
Low Case	282,075	115,682	564,545	162,452	782,414	196,487
High Case	448,111	184,748	821,121	245,973	1,104,001	291,267

Note: Values for probable and possible reserves and quantities have not been risk adjusted to make them comparable to values for proved reserves and quantities.

Reserves estimates herein were based on the Base Case price scenario projected to an economic limit, and quantities in the sensitivity cases are those included to the limit of projected Base Case production or when an annual economic limit is reached, whichever occurs first. Details of the annual price, expense, and cost assumptions are presented under the Valuation of Reserves heading of this report.

Contingent Resources

Contingent resources were estimated for oil, condensate, and sales gas in 18 fields and do not include any unconventional assets. Sales gas contingent resources were converted to boe using an energy equivalent factor of 5,800 cubic feet of gas per 1 boe.

The estimated gross and net 1C, 2C, and 3C contingent resources, as of December 31, 2020, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

Contingent Resources Summary

	Gross Contingent Resources			Net Contingent Resources		
	Oil and Condensate (10^3bbl)	Sales Gas (10^6ft^3)	Oil Equivalent (10^3boe)	Oil and Condensate (10^3bbl)	Sales Gas (10^6ft^3)	Oil Equivalent (10^3boe)
1C	11,133	9,866	12,834	10,830	9,841	12,527
2C	17,934	17,803	21,003	17,319	17,561	20,347
3C	28,119	25,563	32,527	26,439	24,055	30,586

Notes:
1. Application of any risk factor to contingent resources quantities does not equate contingent resources with reserves.
2. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.
3. The contingent resources estimated herein are reported as having an economic status of undetermined, since the evaluation of these contingent resources is at a stage such that it is premature to clearly define the associated cash flows.
4. Sales gas contingent resources estimated herein were converted to oil equivalent using an energy equivalent factor of 5,800 cubic feet of gas per 1 boe.

Prospective Resources

Estimates of prospective resources were prepared by the use of standard geological and engineering methods generally accepted by the petroleum industry. Prospective resources in three conventional prospects have been evaluated in three license blocks in the United Kingdom. The prospective resources estimates presented below were based on a statistical aggregation method. The estimated gross and working interest prospective resources, as of December 31, 2020, of the prospects evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl):

	Mean Estimate
Gross P_g-Adjusted Oil Prospective Resources, 10^3bbl	4,611
Working Interest P_g-Adjusted Oil Prospective Resources, 10^3bbl	4,372

Notes:
1. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
2. Recovery efficiency was applied to prospective resources in this table.
3. The prospective resources presented above were based on the statistical aggregation method.
4. P_g is predicated and correlated to the minimum case prospective resources gross recoverable volume(s). The P_g is not linked to economically viable volumes, economic flow rates, or economic field size assumptions.
5. The range in probability of occurrence for the statistical aggregate P_g-adjusted mean oil estimate is 0.10 to 0.15.
6. The prospective resources quantities for the prospects evaluated in this report were aggregated by the arithmetic summation method, as required by the PRMS, and are presented in the prospective resources tables in this report.
7. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

Ownership and Infrastructure

IGas has represented that it holds interests in certain licenses for exploration, production, and development in the United Kingdom. The specific properties evaluated herein are shown in the following list and on Figures 1 through 3.

Field/Discovery/Prospect	License	Working Interest (percent)	License Expiration
Albury	DL4	100.00	11/16/2027
Avington	PEDL70	50.00	9/8/2031
Beckingham	ML4	100.00	3/31/2040
Bletchingley	ML18	100.00	1/11/2027
Bletchingley	ML21	100.00	4/1/2027
Bothamsall	ML6	100.00	3/31/2040
Cold Hanworth	PEDL6	100.00	4/4/2027
Corringham	ML4	100.00	3/31/2040
Dunholme	AL009	100.00	4/7/2025
Eartham	PEDL326	100.00	7/20/2046
East Glentworth	PL179	100.00	11/16/2034
Egmanton	ML3	100.00	12/30/2033
Gainsborough	ML4	100.00	3/31/2040
Glentworth	ML4	100.00	3/31/2040
Godley Bridge	PEDL235	100.00	6/30/2039
Goodworth	PEDL21	100.00	4/3/2027
Horndean	PL211	90.00	4/4/2036
Lea	PED316	35.00	7/20/2046
Lingfield	PEDL257	100.00	7/20/2046
Long Clawson	PL220	100.00	8/8/2026
Lybster	P1270	100.00	12/21/2031
Nettleham	PL179	100.00	11/16/2034
Nettleham	PL199	100.00	10/31/2045
Palmers Wood	PL182	100.00	11/16/2034
Rempstone	PL220	100.00	8/8/2026
Scampton North	PL179	100.00	11/16/2034

Table – (*Continued*)

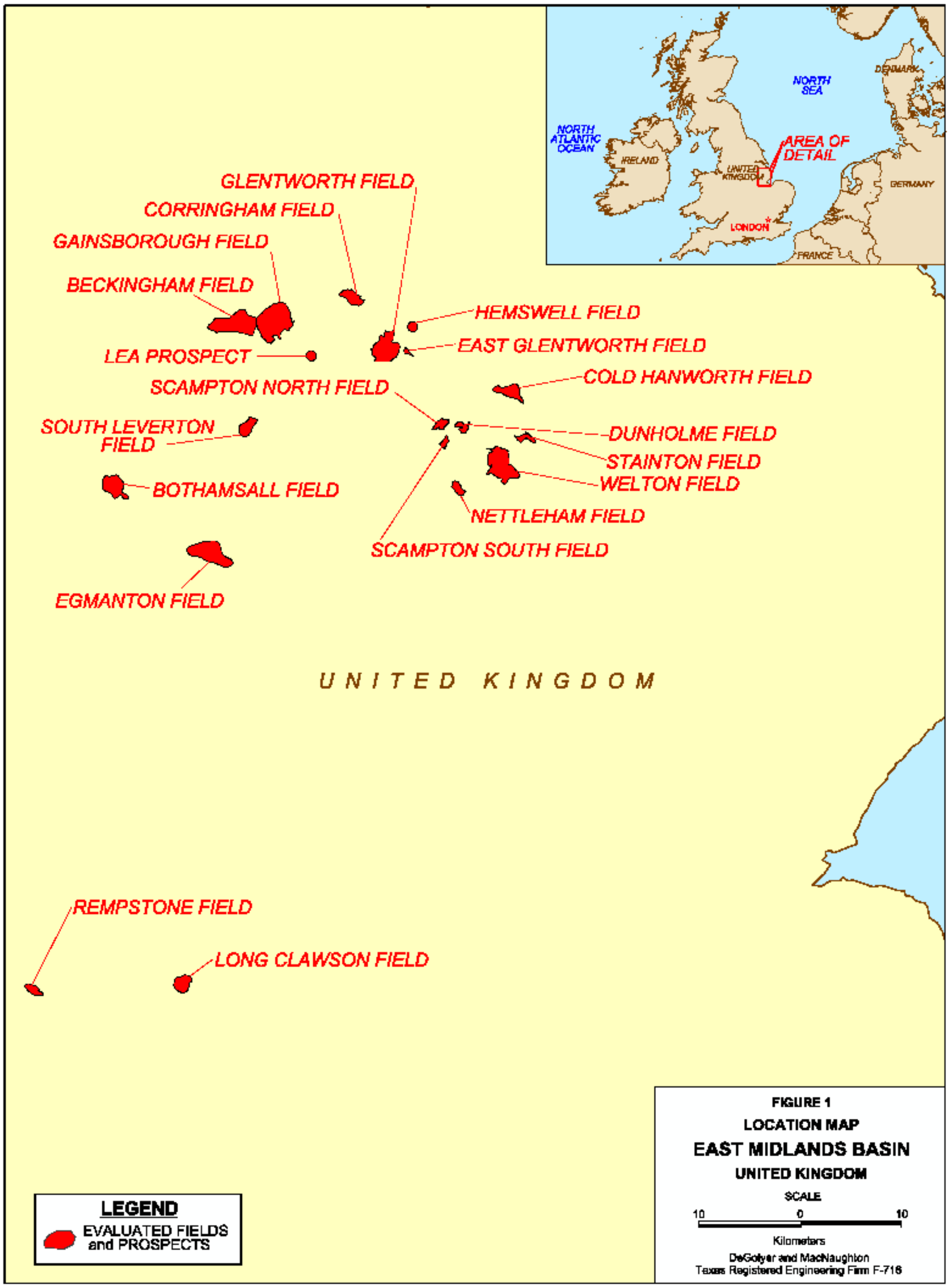
Field/Discovery/Prospect	License	Working Interest (percent)	License Expiration
Scampton South	PL179	100.00	11/16/2034
Singleton	PL240	100.00	12/1/2037
South Leverton	ML7	100.00	3/31/2040
Stainton	PL179b	100.00	11/16/2034
Stockbridge	DL2	100.00	12/31/2030
Stockbridge	PL233	100.00	10/26/2030
Stockbridge	PL249	100.00	11/30/2030
Storrington	PL205	100.00	2/13/2036
Welton	PL179b	100.00	11/16/2034

Note: Lea, Godley Bridge, and Eartham are the prospects evaluated herein.

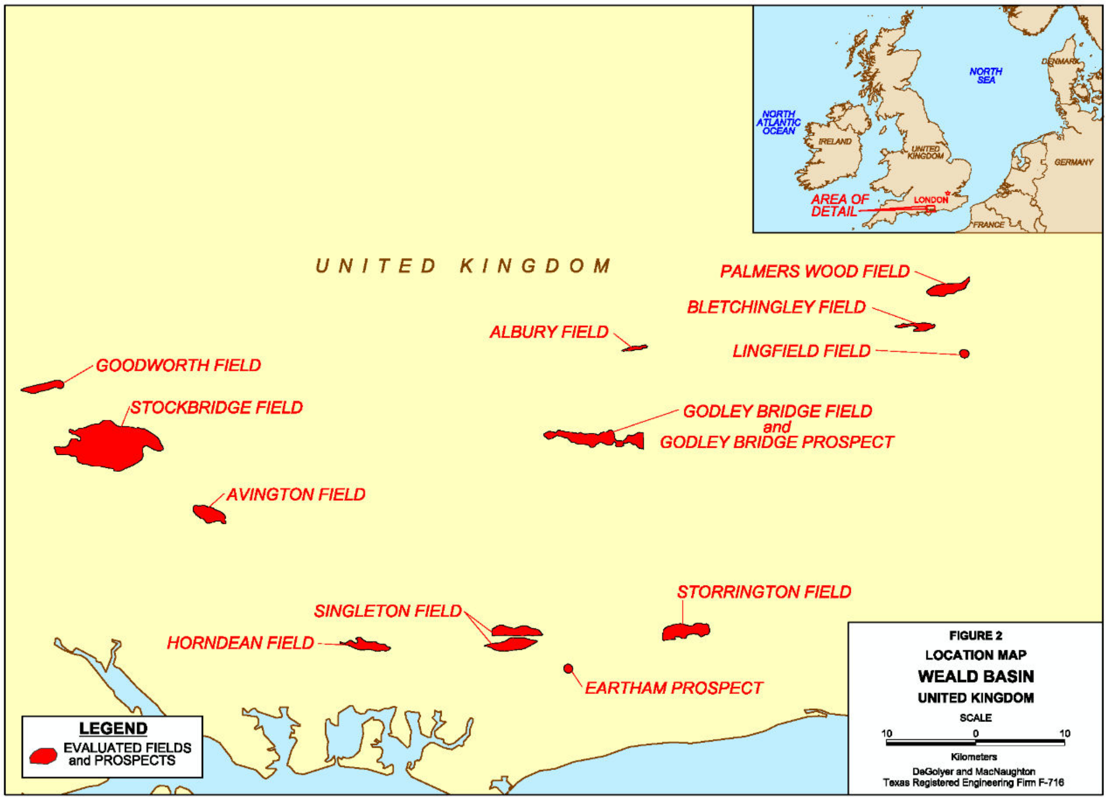
These interests are held through contractual instruments that are common in the petroleum industry. We had an opportunity to review certain segments of pertinent agreements; however, we, as engineers, cannot express an opinion as to the accounting or legal aspects of those agreements.

For this report, technical and commercial uncertainties have been considered in each case exclusive of ongoing political events in a given venue. All contracts, regulations, and agreements in place on December 31, 2020, have been considered to be valid for their stated terms, as represented by IGas.

There are 18 fields and 1 prospect evaluated herein located in the East Midlands Basin, as shown on Figure 1.



There are 11 fields and 2 prospects evaluated herein located in the Weald Basin, as shown on Figure 2.



The Lybster field is the only offshore field evaluated herein, as shown on Figure 3.

The infrastructure in the area of these fields is well established. The United Kingdom petroleum production province has access to a composite of pipelines and service structures. There are numerous established bases in the United Kingdom, and there is an extensive established network of service companies to allow developments of all types, including complex mechanical and operational elements. Power options, including electrical, gas, and diesel sources, are available to operators in this venue.

Environmental Consideration

There are certain environmental considerations in any venue of petroleum production. We are not aware of any extraordinary environmental elements associated with the properties evaluated herein. As such, we have included abandonment costs, as appropriate, to accomplish routine and safe removal of subsurface and surface equipment at the offshore installation. Reclamation costs, if any, are also included in the evaluation herein.

Definition of Reserves

Estimates of proved, probable, and possible reserves presented in this report have been prepared in accordance with the PRMS approved in March 2007 and revised in June 2018 by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysts, and the European Association of Geoscientists & Engineers. The petroleum reserves are defined as follows:

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. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

> *Proved Reserves* are those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate.
>
> *Probable Reserves* are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50%

probability that the actual quantities recovered will equal or exceed the 2P estimate.

Possible Reserves are those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

Once projects satisfy commercial maturity, the associated quantities are classified as Reserves. These quantities may be allocated to the following subdivisions based on the funding and operational status of wells and associated facilities within the reservoir development plan:

Developed Reserves are quantities expected to be recovered from existing wells and facilities. Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.

Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves include shut-in and behind-pipe reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Undeveloped Reserves are quantities expected to be recovered through future significant investments. Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

The extent to which probable and possible reserves ultimately may be recategorized as proved reserves is dependent upon future drilling, testing, and well performance. The degree of risk to be applied in evaluating probable and possible reserves is influenced by economic and technological factors as well as the time element. Estimates of probable and possible reserves in this report have not been adjusted in consideration of these additional risks to make them comparable to estimates of proved reserves.

Estimation of Reserves

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry and in accordance with definitions established by the PRMS. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, development plans provided by IGas, and analyses of areas offsetting existing wells with test or production data, reserves were categorized as proved, probable, or possible.

The proved undeveloped reserves estimates were based on opportunities identified in the plan of development provided by IGas. Proved developed non-producing reserves include those quantities associated with behind-pipe zones and include minor remaining capital expenditure as compared to the cost of a new well.

IGas has represented that its senior management is committed to the development plans provided by IGas and that IGas has the financial capability to execute the development plans, including the drilling and completion of wells and the installation of equipment and facilities.

Where applicable, the volumetric method was used to estimate the original oil in place (OOIP) and original gas in place (OGIP). Structure maps were prepared to delineate each reservoir, and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation (S_w). When adequate data were available and when circumstances justified, material-balance methods were used to estimate OOIP or OGIP.

Where applicable, estimates of ultimate recovery were obtained after applying recovery factors to OOIP and OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories. When applicable, material balance and other engineering methods were used to estimate recovery factors based on an analysis of reservoir performance, including production rate, reservoir pressure, and reservoir fluid properties.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production as defined under the Definition of Reserves heading of this report or the license limit, whichever occurs first.

In certain cases, the reserves were estimated by incorporating elements of analogy with similar wells or reservoirs for which more complete data were available.

Except where noted herein, reserves estimates presented herein were generally based on data available through December 31, 2020, and were supported by details of drilling results, analyses of available geological data, well-test results, pressures, available core data, and production history. The reserves estimates presented herein were based on consideration of daily or monthly production data only through November 2020. Where applicable, estimated cumulative production, as of December 31, 2020, was deducted from the gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 1 month. This report takes into account all relevant information provided to us by IGas.

Oil and condensate reserves estimated herein are to be recovered by normal field separation and are expressed in 10^3bbl. In these estimates, 1 barrel equals 42 United States gallons. For reporting purposes, oil and condensate reserves have been estimated separately and are presented herein as a summed quantity.

Gas quantities estimated herein are expressed as sales gas and fuel gas. Sales gas is defined as the total gas to be produced from the reservoirs, measured at the point of delivery, after reduction for fuel usage, flare, and shrinkage resulting from field separation and processing. Fuel gas is defined as that portion of the gas consumed in field operations. Gas reserves estimated herein are reported as sales gas. Gas quantities are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at a pressure base of 14.7 pounds per square inch absolute (psia). Gas quantities included in this report are expressed in $10^6 ft^3$.

In this report, gas quantities are identified by the type of reservoir from which the gas is or will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Solution gas and gas-cap gas are sometimes produced together and, as a whole, referred to as associated gas. Gas quantities estimated herein consist of both associated and nonassociated gas.

For the purposes of this report, sales gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 5,800 cubic feet of gas per 1 boe.

Procedure and Methodology

IGas has represented that it holds an interest in multiple fields in the United Kingdom, which have been evaluated in this report. Nineteen of the fields have reserves estimated in this report. The fields produce from various reservoirs in the East Midlands and Weald Basins (Figures 4 and 5).

The reserves estimates for the fields were based on the available performance data, incorporating volumetric analysis and analogy when appropriate.

The Albury field, located in license DL4, was discovered in 1987. The field is gas bearing in the Purbeck and Corallian Sandstones. The field previously produced from the Albury-01 well in the Purbeck Sandstone from 1994 until production was suspended in 2007. The field was redeveloped in 2018, with the restoration of the Albury-01 well. The in-place volumes for the Albury field were evaluated using material balance methods. Porosity ranged from 12 to 25 percent, S_w from 21 to 60 percent, and permeability from 0.1 to 100 millidarcys. The recovery factors range from 61 to 79 percent. Proved developed reserves were estimated based on the producing well performance data. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The Avington field, located in license PEDL70, was discovered in 1987 with oil shows in the Cornbrash and Great Oolite reservoirs. Development of the field occurred in 1987 with the Avington-1 well drilled into the upthrown side of a fault defining the field. The field stopped producing from two wells at the end of 2017 due to high operating costs. Porosity ranged from 14 to 23 percent, S_w from 46 to 57 percent, and permeability from 0.08 to 0.1 millidarcys. In this fractured reservoir, the effective permeability can be much higher. The current plan is to bring the two wells back on production in 2023 by disposing the produced water offsite to the Stockbridge field and reducing operating costs. Performance analysis was completed on this field, but after economic evaluation, recoverable quantities were determined to be uneconomic. As such, reserves for this field were estimated to be zero. IGas has represented that additional analysis of this field is ongoing, but no modification or development recommendations had been finalized by the date of this report.

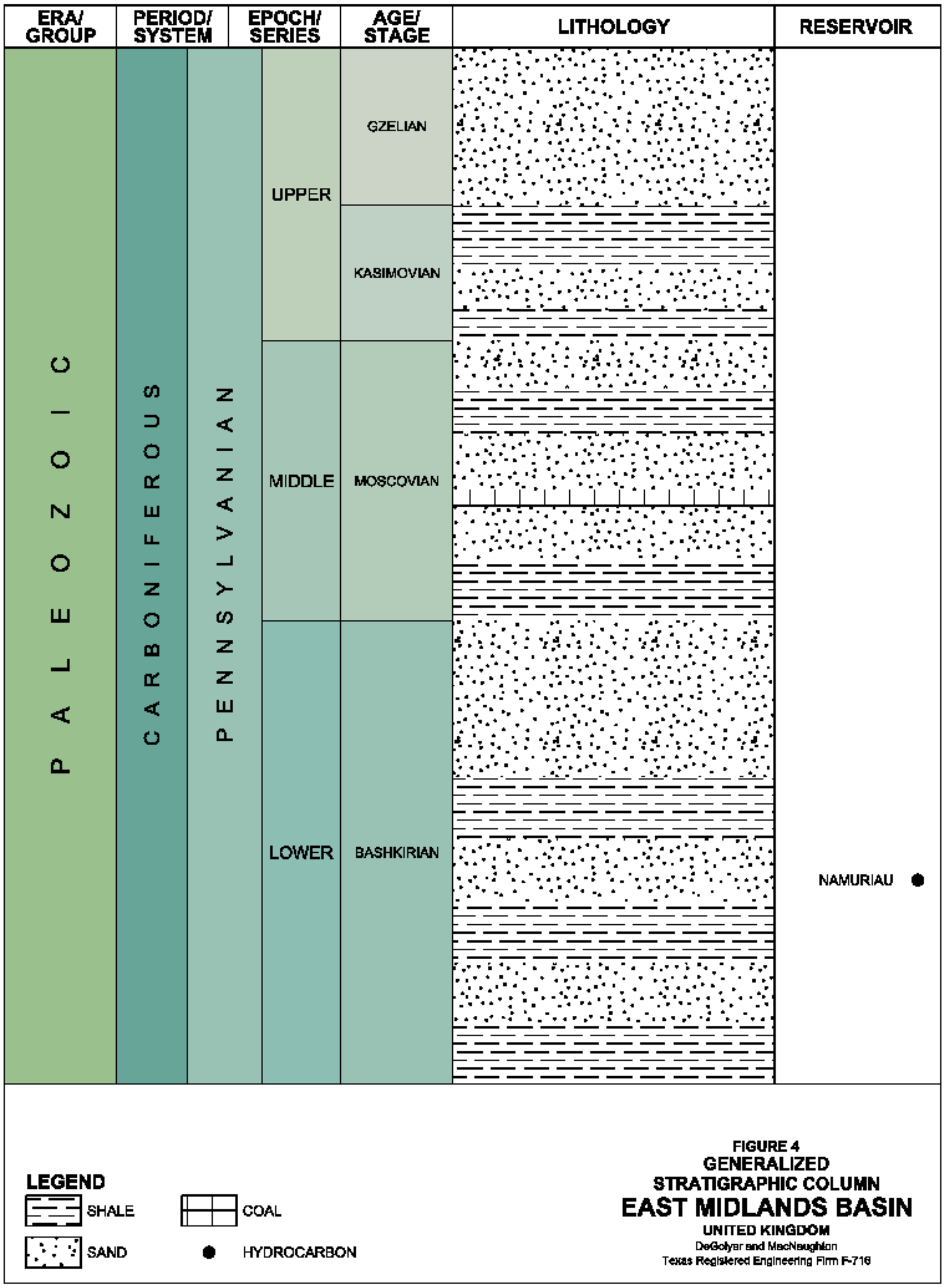
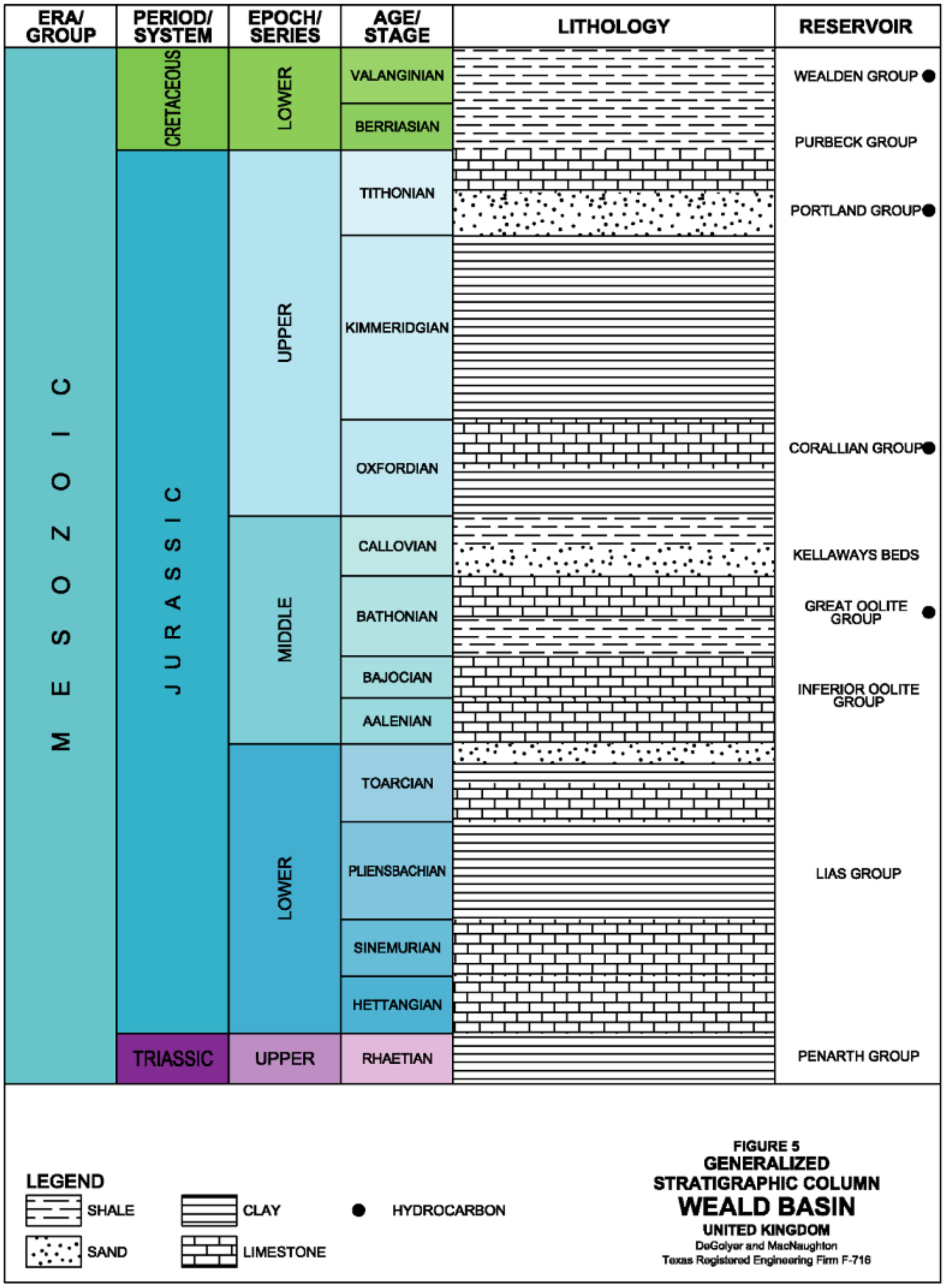


FIGURE 4
GENERALIZED
STRATIGRAPHIC COLUMN
EAST MIDLANDS BASIN
UNITED KINGDOM
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716



The Beckingham field, located in license ML4, was discovered in 1964 and is located on the Lincolnshire-Nottingham border, 40 kilometers east of the city of Sheffield. The main producing reservoirs are the Eagle, Donald, and Condor Sandstones, which produce from three separate blocks in the Beckingham field. The Beckingham field also has the potential to produce nonassociated gas from the

Mexborough/Alexander Formations; however, this development potential has not been considered in this evaluation. In the producing reservoirs, porosity ranged from 8 to 20 percent, S_w from 40 to 70 percent, and permeability from 0.01 to 30 millidarcys. The field produces light oil of approximately 38 degrees API (°API). Proved reserves were estimated based on performance of existing wells, including scheduled workovers. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The Bletchingley field, located in licenses ML18 and ML21, was discovered in 1966. Oil was found in the Corallian Sandstone and the field is currently producing from two wells. Porosity ranged from 5 to 25 percent, S_w from 40 to 70 percent, and permeability from 0.2 to 1,000 millidarcys. Proved reserves were estimated based on individual well performance and proved undeveloped reserves were estimated based on volumetrics analysis of one additional well. Estimates of probable and possible reserves account for the potential for better performance than proved reserves. Reserves estimates for the field include a "gas-to-wire" project to support the building of a 2-megawatt generator.

The Bothamsall field was discovered in 1958 and is located in license ML6, which is southwest of the town of Retford, Nottinghamshire. The field has produced from the Sub-Alton and Crawshaw Sandstones, both of which are fluvial channel deposits. Porosity ranged from 6 to 16 percent, S_w from 26 to 60 percent, and permeability from 0.1 to 100 millidarcys. The field currently produces light oil from three wells. Proved developed reserves were estimated based on performance of existing wells. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The Cold Hanworth field, located in license PEDL6, was discovered in April 1996 and produces from the Westphalian Basal Succession sand unit. The field is located about 25 kilometers to the southwest of the town of Gainsborough. The field is producing from two wells. Porosity ranged from 7 to 16 percent, S_w from 40 to 70 percent, and permeability from 0.05 to 10 millidarcys. The oil has a gravity of 28 °API. Proved reserves were estimated based on individual well performance of existing wells. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The Corringham field, located in license ML4, was discovered in 1958 and consists of three main fault blocks. The Corringham field produces oil from the Silkstone and Chatsworth reservoirs. Porosity ranged from 14 to 27 percent, S_w from

37 to 44 percent, and permeability from 160 to 500 millidarcys. Proved reserves were estimated based on performance of existing wells. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The East Glentworth field, located in license PL179, was discovered in March 1987 by the East Glentworth-1 well, which encountered oil in the Westphalian C Mexborough Rock. The field is currently producing from two wells. Porosity ranged from 16 to 20 percent, S_w from 42 to 47 percent, and permeability from 1 to 20 millidarcys. Proved reserves were estimated based on individual well performance. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The Egmanton field was discovered in 1955 and produces oil from the Upper Namurian and Lower Westphalian reservoirs through two wells. The field is located in license ML3, southwest of the Gainsborough Trough. Porosity ranged from 13 to 17 percent, S_w from 45 to 55 percent, and permeability from 1 to 100 millidarcys. Performance analysis was completed on this field. After economic evaluation, recoverable quantities were determined to be uneconomic. As such, reserves for this field were estimated to be zero.

The Gainsborough field, located in license ML4, was discovered in 1959 and is located on the Lincolnshire-Nottingham border, 25 miles east of Sheffield. The main producing reservoirs are the Eagle, Donald, and Condor Sandstones. Porosity ranged from 8 to 20 percent, S_w from 40 to 70 percent, and permeability from 0.01 to 30 millidarcys. The field produces light oil of approximately 38 °API. Performance analysis was completed on this field. After economic evaluation, recoverable quantities were determined to be uneconomic. As such, reserves for this field were estimated to be zero.

The Glentworth field was discovered in 1961 and is located in license ML4 near Lincolnshire. The field is a four-way dip closure and produces from the Mexborough Formation. The field was shut in from 1965 to 1971 and is currently producing low-shrinkage oil from four wells. Porosity ranged from 16 to 20 percent, S_w from 50 to 65 percent, and permeability from 0.1 to 30 millidarcys. Proved developed reserves were estimated based on performance of existing wells. Estimates of probable and possible reserves account for the potential for better performance than proved reserves and estimates of probable undeveloped and possible undeveloped reserves account for one new well.

The Goodworth field, located in license PEDL21, was discovered in 1987. The field produces from the Great Oolite reservoir across three main blocks and is currently producing from one well. Porosity ranged from 12 to 16 percent, S_w from 50 to 70 percent, and permeability from 0.1 to 5 millidarcys. Proved developed reserves were estimated based on performance of the existing well, including scheduled workovers. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The Horndean field, located in license PL211, was discovered in 1983 by well Horndean-1A. Production commenced in 1987 from the Great Oolite structure and four wells are currently producing. Porosity ranged from 12 to 19 percent, S_w from 70 to 80 percent, and permeability from 0.01 to 5 millidarcys. Proved reserves were estimated based on performance of existing wells. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The Long Clawson field was discovered in 1986. The field is located in license PL220 in Leicestershire and is currently producing from three wells. Porosity ranged from 13 to 18 percent, S_w from 68 to 79 percent, and permeability from 90 to 1,100 millidarcys. The oil has a gravity of 35 °API. Proved reserves were estimated based on individual well performance. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The Lybster field (Figure 6) was discovered in 1996 by well 11/24-1 and is located offshore the Caithness coast in license P1270. The field is gas bearing in the Beatrice Sandstone. The Lybster field was evaluated volumetrically, and reserves were estimated using analogous recovery factors based on other similar fields in the area. Recovery factors ranged from 55 to 80 percent. In this field, porosity is 12 percent, S_w ranges from 35 to 45 percent, and permeability ranges from 90 to 1,115 millidarcys. Proved, probable, and possible undeveloped reserves estimated herein were based the approved redevelopment plan with recovery factors that ranged from 55 to 80 percent. Well 11/24-3V2 stopped producing at the end of 2014 due to a high gas-oil ratio (GOR), and the current plan is to restore production in 2024.

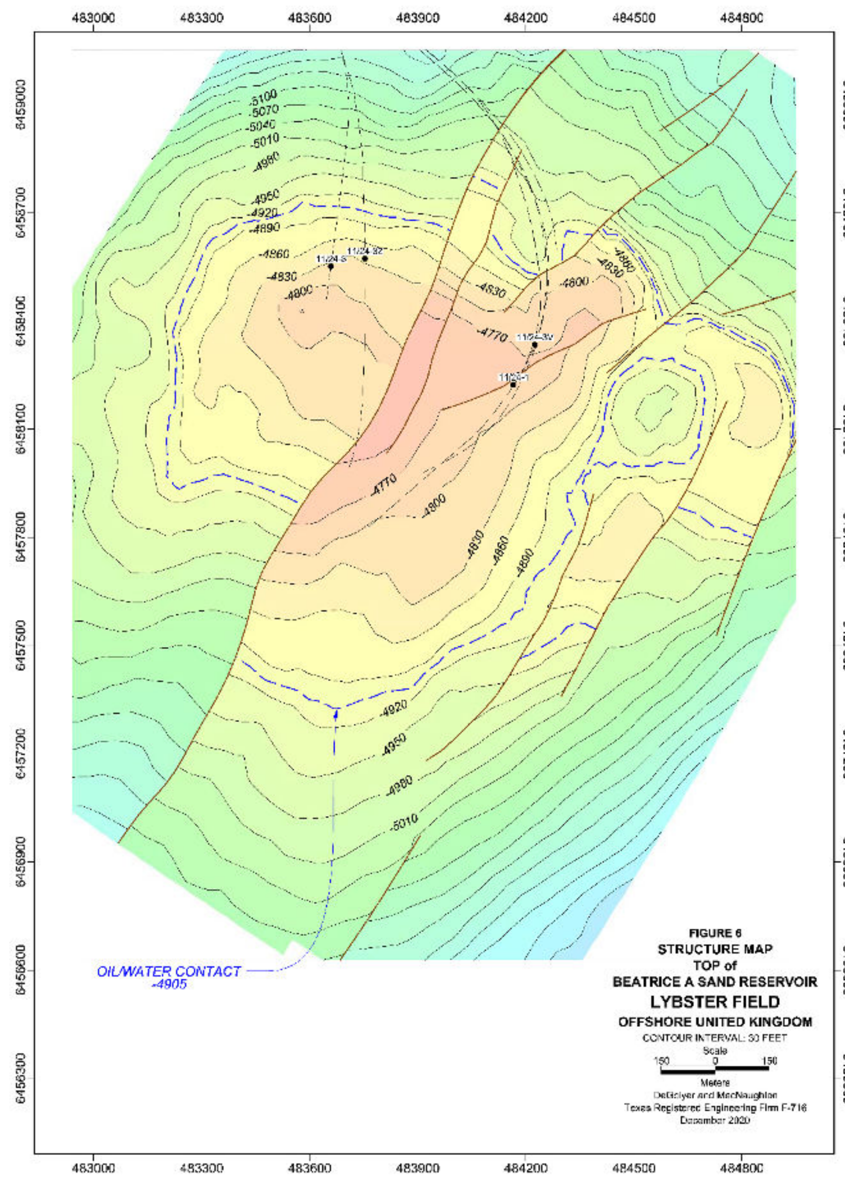


FIGURE 6
STRUCTURE MAP
TOP of
BEATRICE A SAND RESERVOIR
LYBSTER FIELD
OFFSHORE UNITED KINGDOM
CONTOUR INTERVAL: 30 FEET

The Nettleham field, located in licenses PL179 and PL199, was discovered in 1983 and is located approximately 5 kilometers northeast of the city of Lincoln. The primary reservoir is the Basal Westphalian. The field is not currently producing. Porosity ranged from 19 to 22 percent, S_w from 30 to 60 percent, and permeability from 6 to 1,000 millidarcys. Production was stopped in February 2016 due to high water cut. No plans were presented to bring this field back on production; as such, reserves for this field were estimated to be zero.

The Palmers Wood field was discovered in 1983 and is located 5 kilometers east of Redhill within license PL182. The Palmers Wood field currently produces from the Upper Jurassic Corallian Sandstone through four wells. In addition, there has been an active waterflood through three injectors since the beginning of production. Porosity ranged from 16 to 20 percent, S_w from 40 to 60 percent, and permeability from 0.5 to 50 millidarcys. Proved reserves were estimated based on performance of existing wells, including scheduled workovers. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The Rempstone field was discovered in 1985. The primary reservoir is the Lower Namurian, with gas from the H-Sandstone and oil from the C-Sandstone. The field is located in license PL220 and is currently producing from one well. Porosity ranged from 16 to 19 percent, S_w from 40 to 50 percent, and permeability from 0.1 to 20 millidarcys. Performance analysis was completed on this field. After economic evaluation, recoverable quantities were determined to be uneconomic. Therefore, reserves for this field were estimated to be zero.

The Scampton North field was discovered in 1985 by well SNA1. The field is located within license PL 179 in Lincolnshire. Scampton North produces light oil of approximately 35 API through five wells from the Basal Succession Sandstone. Porosity ranged from 12 to 18 percent, S_w from 30 to 50 percent, and permeability from 0.5 to 400 mllidarcys. Proved developed reserves were estimated based on performance of existing wells, including scheduled workovers. Estimates of probable and possible developed reserves account for the potential for better performance than proved reserves. In addition, proved, probable, and possible developed non-producing reserves were estimated based on the conversion of a shut-in well to water injection, which will enhance production.

The Scampton South field is located in license PL179 in Lincolnshire to the northwest of the Welton field. The field was discovered in 1985, but development was delayed due to consideration of high sulfur levels. The field is not currently producing and was shut in due to high water production. Porosity ranged from 10 to 16 percent, S_w from 26 to 40 percent, and permeability from 5 to 500 millidarcys. No plans were presented to bring this field back on production; as such, reserves for this field were estimated to be zero.

The Singleton field was discovered in 1989 by the Singleton-1 well. The field is located within production license PL240 near the village of Singleton. The field currently produces light oil of approximately 39°API through six wells from the Great Oolite Formation. Porosity ranged from 13 to 16 percent, S_w from 30 to 62 percent, and permeability from 0.1 to 10 millidarcys. Proved reserves were estimated based on performance of existing wells. Estimates of probable and possible reserves account for the potential for better performance than proved reserves from existing and future wells. The current plan is to install a new 1-megawatt generator by 2022, which may allow future additions of gas reserves, but those potential quantities are not included in the reserves estimates herein.

The South Leverton field, located in license ML7, was discovered in 1960. The field is currently producing from a single well, the SL-7. Porosity ranged from 9 to 13 percent, S_w from 22 to 27 percent, and permeability from 0.2 to 10 millidarcys. Performance analysis was completed on this field and, after economic evaluation, quantities were determined to be uneconomic. As such, reserves for this field were estimated to be zero.

The Stainton field was discovered in 1984 by well Stainton-1. The field is located within license PL179b, 10 kilometers northeast of Lincoln. The field currently produces low-shrinkage oil through one well from the Basal Sandstone Formation. Porosity ranged from 12 to 16 percent, S_w from 30 to 50 percent, and permeability from 0.4 to 50 millidarcys. Performance analysis was completed on this field and after economic evaluation, quantities were determined to be uneconomic. As such, reserves for this field were also estimated to be zero.

The Stockbridge field was discovered in 1984. This field is located within the DL2, PL233, and PL249 licenses and is in the northwest portion of the Weald Basin. The field produces from the Great Oolite reservoir. Water injection began in 1998 after converting the STK-16 well to a water injector. The field is currently producing from four wells, with three wells currently suspended due to lack of available water disposal. Porosity ranged from 12 to 24 percent, S_w from 66 to 79 percent, and permeability from 0.1 to 5 millidarcys. Proved reserves were estimated based on individual well performance and include workovers and restoration of wells closed due to current water disposal limitations. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The Storrington field has been producing from the Great Oolite Formation since 1998. The field is located in license PL205 in West Sussex County. Porosity ranged from 10 to 17 percent, S_w from 45 to 60 percent, and permeability from 0.01 to 50 millidarcys. Proved reserves were estimated based on performance of existing wells, including scheduled workovers. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The Welton field was discovered in 1981. The field is located 7 kilometers northeast of Lincoln in license PL179b. The field has produced from several formations, including the Basal Succession and the Upper Succession. Porosity ranged from 12 to 20 percent, S_w from 20 to 40 percent, and permeability from 10 to 1,000 millidarcys. Proved reserves were estimated based on individual well performance, including planned workovers to restore several wells to production, and include the conversion of an existing suspended producer to a water injector. Estimates of probable and possible reserves account for the potential for better performance than proved reserves and improved injection and sweep water efficiency of the planned injector.

The estimated gross proved, probable, and possible reserves, as of December 31, 2020, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

	Gross Reserves								
	Oil and Condensate			Sales Gas			Oil Equivalent		
Field	Proved (10^3bbl)	Probable (10^3bbl)	Possible (10^3bbl)	Proved (10^6ft^3)	Probable (10^6ft^3)	Possible (10^6ft^3)	Proved (10^3boe)	Probable (10^3boe)	Possible (10^3boe)
Albury	0	0	0	1,269	485	460	219	84	79
Avington	0	0	0	0	0	0	0	0	0
Beckingham	483	141	144	0	0	0	483	141	144
Bletchingley	256	81	102	1,754	3,314	4,075	558	652	805
Bothamsall	129	29	69	0	0	0	129	29	69
Cold Hanworth	184	82	76	0	0	0	184	82	76
Corringham	270	31	31	0	0	0	270	31	31
Dunholme	0	0	0	0	0	0	0	0	0
East Glentworth	84	26	26	0	0	0	84	26	26
Egmanton	0	0	0	0	0	0	0	0	0
Gainsborough	0	0	0	0	0	0	0	0	0
Glentworth	1,237	605	525	0	0	0	1,237	605	525
Godley Bridge	0	0	0	0	0	0	0	0	0
Goodworth	68	23	40	0	0	0	68	23	40
Hemswell (PEDL6)	0	0	0	0	0	0	0	0	0
Hemswell (PEDL210)	0	0	0	0	0	0	0	0	0
Horndean	1,124	131	152	0	0	0	1,124	131	152
Lingfield	0	0	0	0	0	0	0	0	0
Long Clawson	155	30	33	0	0	0	155	30	33
Lybster	121	23	31	450	85	115	199	38	51
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	237	48	319	0	0	0	237	48	319
Rempstone	0	0	0	0	0	0	0	0	0
Scampton North	561	165	188	0	0	0	561	165	188
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	1,928	786	376	1,117	903	427	2,121	942	450
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	774	220	55	0	0	0	774	220	55
Storrington	116	86	40	0	0	0	116	86	40
Welton	3,330	2,069	1,022	0	0	0	3,330	2,069	1,022
Total	**11,057**	**4,576**	**3,229**	**4,590**	**4,787**	**5,077**	**11,849**	**5,402**	**4,105**

Notes:
1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Sales gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 5,800 cubic feet of gas per 1 boe.

The estimated net proved, probable, and possible reserves, as of December 31, 2020, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

	Net Reserves								
	Oil and Condensate			Sales Gas			Oil Equivalent		
Field	Proved (10^3bbl)	Probable (10^3bbl)	Possible (10^3bbl)	Proved (10^6ft^3)	Probable (10^6ft^3)	Possible (10^6ft^3)	Proved (10^3boe)	Probable (10^3boe)	Possible (10^3boe)
Albury	0	0	0	1,269	485	460	219	84	79
Avington	0	0	0	0	0	0	0	0	0
Beckingham	483	141	144	0	0	0	483	141	144
Bletchingley	256	81	102	1,754	3,314	4,075	558	652	805
Bothamsall	129	29	69	0	0	0	129	29	69
Cold Hanworth	184	82	76	0	0	0	184	82	76
Corringham	270	31	31	0	0	0	270	31	31
Dunholme	0	0	0	0	0	0	0	0	0
East Glentworth	84	26	26	0	0	0	84	26	26
Egmanton	0	0	0	0	0	0	0	0	0
Gainsborough	0	0	0	0	0	0	0	0	0
Glentworth	1,237	605	525	0	0	0	1,237	605	525
Godley Bridge	0	0	0	0	0	0	0	0	0
Goodworth	68	23	40	0	0	0	68	23	40
Hemswell (PEDL6)	0	0	0	0	0	0	0	0	0
Hemswell (PEDL210)	0	0	0	0	0	0	0	0	0
Horndean	1,012	117	137	0	0	0	1,012	117	137
Lingfield	0	0	0	0	0	0	0	0	0
Long Clawson	155	30	33	0	0	0	155	30	33
Lybster	121	23	31	450	85	115	199	38	51
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	237	48	319	0	0	0	237	48	319
Rempstone	0	0	0	0	0	0	0	0	0
Scampton North	561	165	188	0	0	0	561	165	188
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	1,928	786	376	1,117	903	427	2,121	942	450
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	774	220	55	0	0	0	774	220	55
Storrington	116	86	40	0	0	0	116	86	40
Welton	3,330	2,069	1,022	0	0	0	3,330	2,069	1,022
Total	**10,945**	**4,562**	**3,214**	**4,590**	**4,787**	**5,077**	**11,736**	**5,388**	**4,089**

Notes:
1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Sales gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 5,800 cubic feet of gas per 1 boe.

Valuation of Reserves

This report has been prepared using initial prices, expenses, and costs provided by IGas and certain forecast price, expense, and cost assumptions as described herein. Three economic scenario cases (Base Case, Low Case, High Case) were evaluated. Gross and net reserves estimated herein were based on the Base Case price, expense, and cost estimations. Only the prices are varied in each economic scenario.

In this report, values for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves were based on projections of estimated future production and revenue prepared for these properties with no risk adjustment applied to the probable or possible reserves. Probable and possible reserves involve substantially higher risks than proved reserves. Revenue values associated with proved-plus-probable and proved-plus-probable-plus-possible reserves have not been adjusted to account for such risks; such an adjustment would be necessary in order to make the values associated with probable or possible reserves comparable to values associated with proved reserves.

Revenue values of the proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves were estimated utilizing methods generally accepted by the petroleum industry. Production forecasts of the proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves were based on the development plan for the fields. The future net revenue and present worth of the fields' reserves were estimated using the price and cost assumptions, monetary conversion values, and the appropriate concession terms described herein.

The following economic assumptions were used for estimating the revenue values reported herein:

Oil, Condensate, and Gas Prices

Base Case Price Assumptions

Oil prices for the Base Case were anchored at the prevailing Brent oil price at the end of 2020, followed by price changes that match historical price levels. For this analysis, the oil price escalates annually between 2 and 6 percent until reaching a maximum price in real terms by 2039. From 2039 forward, the oil price was escalated 2 percent per year until reaching a nominal price of U.S.$100.00 per barrel. The condensate price was assumed to be 90 percent of the oil price. The oil and condensate price assumptions are shown in the table below, expressed in United States dollars per barrel (U.S.$/bbl).

Gas sales prices for the Base Case were based on the European Gas Trading Hubs (TTF) forecast at the end of 2020. IGas has represented that its produced gas is sold in two outlets: through direct sales to the United Kingdom national gas grid and "gas to power." Gas to power is a portion of produced gas that receives a net price related to the amount of electricity it produces through generation. The gas price assumptions are shown in the table below, expressed in United States dollars per thousand cubic feet (U.S.$/$10^3ft^3$).

Year	Base Case Prices Oil (U.S.$/bbl)	Condensate (U.S.$/bbl)	Gas Export (U.S.$/$10^3ft^3$)	Gas to Power (U.S.$/$10^3ft^3$)
2021	53.08	47.77	7.27	7.18
2022	55.59	50.03	8.21	8.11
2023	57.67	51.90	9.52	9.41
2024	58.94	53.05	10.95	10.82
2025	62.38	56.14	10.19	10.07
2026	64.44	58.00	10.46	10.33
2027	66.79	60.11	10.74	10.61
2028	68.77	61.89	11.03	10.89
2029	70.73	63.66	11.32	11.19
2030	72.10	64.89	11.63	11.49
2031	74.09	66.68	11.95	11.81
2032	76.07	68.46	12.28	12.14
2033	77.99	70.19	12.63	12.47
2034	79.90	71.91	12.98	12.82
2035	81.81	73.63	13.35	13.19
2036	83.82	75.44	13.48	13.32
2037	85.84	77.26	13.70	13.54
2038	87.87	79.08	13.93	13.76
2039	89.93	80.94	14.15	13.98
2040	91.73	82.56	14.39	14.21
2041	93.56	84.20	14.63	14.45
2042	95.43	85.89	14.87	14.69
2043	97.34	87.61	15.12	14.93
2044	99.29	89.36	15.37	15.18
2045	100.00	90.00	15.62	15.44

Note: From 2045 forward, all prices were held flat.

Low Case Price Assumptions

Oil and condensate prices for the Low Case are 10 percent lower than the Base Case, and the Low Case gas price is 10 percent lower than the Base Case. All other components of the evaluation, including costs, for the sensitivity cases are the same as those stated for the Base Case herein.

High Case Price Assumptions

Oil and condensate prices for the High Case are 10 percent higher than the Base Case, and the High Case gas price is 10 percent higher than the Base Case. All other components of the evaluation, including costs, for the sensitivity cases are the same as those stated for the Base Case herein.

Operating Expenses, Capital Costs, and Abandonment Costs

Current operating expenses and operating expense forecasts provided by IGas were used in estimating future expenses required to operate the fields for all three economic scenarios. In certain cases, future expenses, either higher or lower than current expenses, may have been used because of anticipated changed operating conditions. Pipeline and processing tariffs are paid for access to markets. Future capital expenditures and abandonment costs were estimated using current forecasts provided by IGas. No cost escalation or inflation was applied to any expenses or costs estimated herein. Generally, abandonment costs, which are those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment, were assigned the year after cessation of production, except where other anticipated abandonment dates were represented by IGas. Economic limits for each field have been estimated based on annual operating expenses with no consideration of taxes.

Operating expenses, capital costs, and abandonment costs were considered, as appropriate, in determining the economic viability of non-producing and undeveloped reserves estimated herein.

Royalty

No royalty is considered for these United Kingdom fields.

Exchange Rate

Where applicable, an exchange rate of U.S.$1.34 per U.K.£1.00 was used for this report.

Host Country Taxes

At the request of IGas, United Kingdom income taxes were not considered in this report.

As in any evaluation, there may be risk of unexpected cost variances and timing delays or accelerations. For this evaluation, consideration has been given to these elements to the extent possible. The resulting scheduling of production and costs is represented as a reliable estimate incorporating operational variances and timing delays where reasonable.

The estimated future revenue to be derived from the production and sale of the net proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves, as of December 31, 2020, of the properties evaluated under the Base Case economic assumptions described herein is summarized as follows, expressed in thousands of United States dollars (10^3U.S.$):

Valuation of Reserves Summary
Base Case

	Proved (10^3U.S.$)	Proved plus Probable (10^3U.S.$)	Proved plus Probable plus Possible (10^3U.S.$)
Future Gross Revenue	847,985	1,321,171	1,676,371
Operating Expenses	384,886	531,227	637,979
Abandonment and Capital Costs	99,782	99,782	99,782
Future Net Revenue	363,317	690,162	938,610
Present Worth at 10 Percent	149,591	203,676	243,467

Note: Values for probable and possible reserves have not been risk adjusted to make them comparable to values for proved reserves.

The estimated future revenue to be derived from the production and sale of the proved, proved-plus-probable, and proved-plus-probable-plus-possible quantities, as of December 31, 2020, of the properties evaluated under the Low Case and High Case economic assumptions described herein is summarized as follows, expressed in thousands of United States dollars (10^3U.S.$):

Valuation of Quantities Summary – Sensitivity Cases

	Low Case			High Case		
	Proved (10^3U.S.$)	Proved plus Probable (10^3U.S.$)	Proved plus Probable Plus Possible (10^3U.S.$)	Proved (10^3U.S.$)	Proved plus Probable (10^3U.S.$)	Proved plus Probable Plus Possible (10^3U.S.$)
Future Gross Revenue	748,869	1,172,749	1,511,470	942,114	1,459,604	1,848,568
Operating Expenses	368,525	509,935	629,274	394,221	538,701	644,785
Abandonment and Capital Costs	98,269	98,269	99,782	99,782	99,782	99,782
Future Net Revenue	282,075	564,545	782,414	448,111	821,121	1,104,001
Present Worth at 10 Percent	115,682	162,452	196,487	184,748	245,973	291,267

Note: Values for probable and possible quantities have not been risk adjusted to make them comparable to values for proved quantities.

The estimated future net revenue of all fields for the Base, Low, and High Cases is shown in Tables A-1 through A-9 in the appendix to this report.

Definition of Contingent Resources

Estimates of contingent resources presented in this report have been prepared in accordance with the PRMS approved in March 2007 and revised in June 2018 by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysts, and the European Association of Geoscientists & Engineers. Because of the lack of commerciality or sufficient development drilling, the contingent resources estimated herein cannot be classified as reserves. The petroleum contingent resources are classified as follows:

> *Contingent Resources* are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.

Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status.

> *Economically Viable Contingent Resources* are those quantities associated with technically feasible projects where cash flows are positive under reasonably forecast conditions but are not Reserves because it does not meet the other commercial criteria.

> *Economically Not Viable Contingent Resources* are those quantities for which development projects are not expected to yield positive cash flows under reasonable forecast conditions. May also be subject to additional unsatisfied contingencies.

Where evaluations are incomplete and it is premature to clearly define the associated cash flows, it is acceptable to note that the project economic status is "undetermined."

The estimation of petroleum resources is subject to both technical and commercial uncertainties and, in general, may be quoted as a range. The range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities. In all cases, the range of uncertainty is dependent on the amount and quality of both technical and commercial data that are available and may change as more data become available.

1C (Low), 2C (Best), and 3C (High) Estimates – Estimates of contingent resources in this report are expressed using the terms 1C (low) estimate, 2C (best) estimate, and 3C (high) estimate to reflect the range of uncertainty.

Estimation of Contingent Resources

Estimates of contingent resources were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry and in accordance with definitions established by the PRMS. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Where applicable, the volumetric method was used to estimate the original quantities of petroleum in place. Structure maps were prepared to delineate each reservoir, and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and S_w.

Where applicable, estimates of ultimate recovery were obtained after applying recovery factors to original quantities of petroleum in place. These recovery factors were based on consideration of the type of energy inherent in the reservoir, analyses of the fluid and rock properties, and the structural position of the properties.

In certain cases, contingent resources were estimated by incorporating elements of analogy with similar wells or reservoirs for which more complete data were available.

The contingent resources estimates presented herein were generally based on consideration of drilling results, analyses of available geological data, well-test results, pressures, and other data available through December 31, 2020. The development and economic status represents the status applicable on December 31, 2020.

Oil and condensate contingent resources estimated herein are to be recovered by normal field separation and are expressed in 10^3bbl. In these estimates, 1 barrel equals 42 United States gallons. For reporting purposes, oil and condensate contingent resources have been estimated separately and are presented herein as a summed quantity.

Gas quantities associated with contingent resources estimated herein are expressed as sales gas contingent resources. Sales gas is defined as the total gas to be produced from the reservoirs, measured at the point of delivery, after reduction for fuel usage, flare, and shrinkage resulting from field separation and processing. Gas quantities are expressed at a temperature base of 60 °F and at a pressure base of 14.7 psia. Gas quantities included in this report are expressed in 10^6ft^3.

In this report, gas quantities are identified by the type of reservoir from which the gas is or will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Solution gas and gas-cap gas are sometimes produced together and, as a whole, referred to as associated gas. Gas quantities estimated herein consists of both associated and nonassociated gas.

For the purposes of this report, sales gas contingent resources estimated herein were converted to oil equivalent using an energy equivalent factor of 5,800 cubic feet of gas per 1 boe.

After a review of the data available for the fields evaluated herein, 17 fields located in the United Kingdom were estimated to contain contingent resources: Avington, Beckingham, Bletchingley, Corringham, Dunholme, Gainsborough, Glentworth, Godley Bridge, Hemswell, Horndean, Lingfield, Long Clawson, Palmers Wood, Scampton North, Singleton, Stockbridge, and Welton.

The contingent resources estimated for the fields evaluated herein are those quantities of petroleum that are potentially recoverable from discovered accumulations but which are not currently considered to be commercially recoverable because of one or more contingencies, including lack of internal IGas approval or partner agreement for commitment to develop and produce. Because of the uncertainty of commerciality, the contingent resources estimated herein are not classified as reserves. At the request of IGas, the contingent resources estimated herein are reported as having an economic status of undetermined, since the evaluation of these contingent resources is at a stage such that it is premature to clearly define the associated cash flows.

Procedure and Methodology

The Bletchingley field, located in licenses ML18 and ML21, was discovered in 1966. Oil was found in the Corallian Sandstone (Figure 7) and the field is currently producing from two wells. Porosity ranged from 5 to 25 percent, S_w from 40 to 70 percent, and permeability from 0.2 to 1,000 millidarcys. Contingent resources were estimated for the drilling of one well in the western part of the reservoir and are contingent based on a lack of a firm development plan.

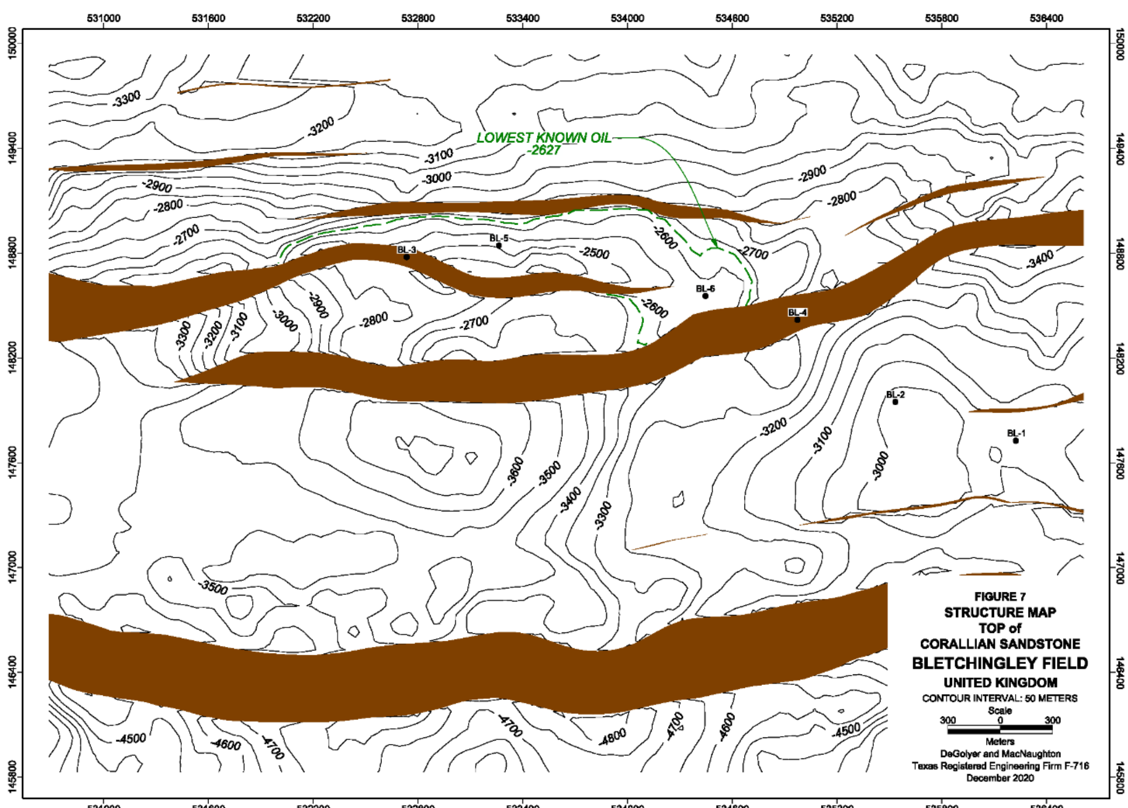


FIGURE 7
STRUCTURE MAP
TOP of
CORALLIAN SANDSTONE
BLETCHINGLEY FIELD
UNITED KINGDOM

The Dunholme field was discovered in 1983 by British Petroleum with the Dunholme-1 well. The field is located in the United Kingdom in the East Midlands

Platform in license AL009. The Dunholme-1 well encountered a thin oil column in the Carboniferous Westphalian-age Basal Sand reservoir. The well is interpreted to have intersected the oil column very near the oil/water contact, and additional OOIP quantities were estimated updip of the Dunholme-1 well. The estimated porosity is 19.8 percent, and the estimated S_w is 58 percent. Permeability ranged from 5 to 100 millidarcys. The Dunholme field was evaluated volumetrically and contingent resources were estimated using analogous recovery factors based on other, similar fields in the area. Estimated recovery factors used a range from 5 to 15 percent. The field is considered contingent because it does not have an approved development plan.

The Glentworth field was discovered in 1961 and is located in license ML4 near Lincolnshire. The field is a four-way dip closure and produces from the Mexborough Formation. The field was shut in from 1965 to 1971 and is currently producing low-shrinkage oil from four wells. Porosity ranged from 16 to 20 percent, S_w from 50 to 65 percent, and permeability from 0.1 to 30 millidarcys. Contingent resources were estimated for five additional infill wells and two waterflood wells and were based on a total field recovery ranging from 24 to 34 percent. The field is contingent based on a lack of firm development plans.

The Godley Bridge field (Figure 8), located in license PEDL235, was discovered in 1982. The field is gas bearing in the Portland Sandstone. The Godley Bridge field was evaluated volumetrically and contingent resources were estimated using analogous recovery factors based on other, similar fields in the area. The estimated porosity ranges from 17 to 18 percent, and the estimated S_w is 45 percent. Permeability ranged from 0.1 to 0.3 millidarcys. The recovery factors used ranged from 71 to 84 percent. This field is contingent based on the lack of firm development plans. The contingent resources estimated herein for the Godley Bridge field do not include the Kimmeridge Micrites reservoir.

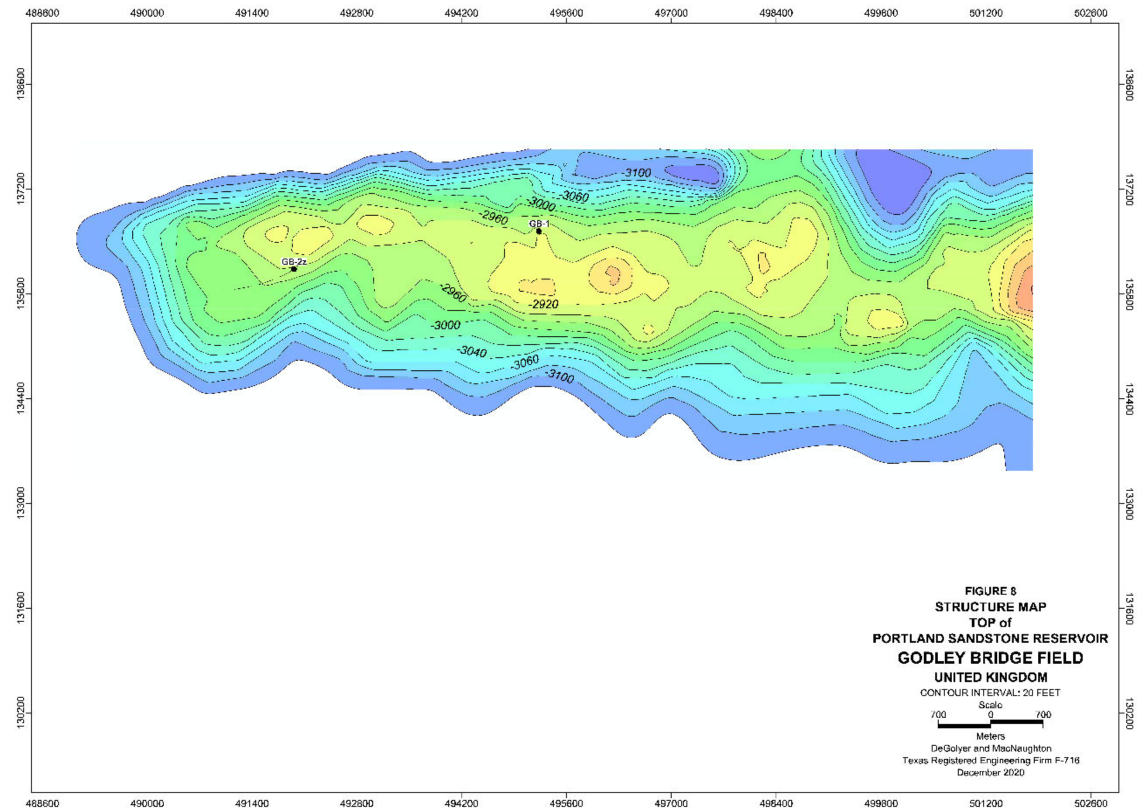


FIGURE 8
STRUCTURE MAP
TOP of
PORTLAND SANDSTONE RESERVOIR
GODLEY BRIDGE FIELD
UNITED KINGDOM
CONTOUR INTERVAL: 20 FEET
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716
December 2020

The Lingfield field (Figure 9) was discovered in 1999 by the Lingfield-1 well. The discovery is located in the United Kingdom in license PEDL257, near the village of Lingfield in Surrey, England. The Lingfield field is located on trend and southeast of the Bletchingley gas field. The Lingfield-1 well found gas pay in the Portland D sandstone and had oil shows in the Corallian Limestone. Average porosity is 18.2 percent and average S_w is 59 percent. The Lingfield-1 well tested the Portland D sandstone and the well flowed at a rate of 110 thousand cubic feet per day. No development plan has been approved. The Lingfield field was evaluated volumetrically and contingent resources were estimated using analogous recovery factors based on other, similar fields in the area. The recovery factors used ranged from 50 to 60 percent.

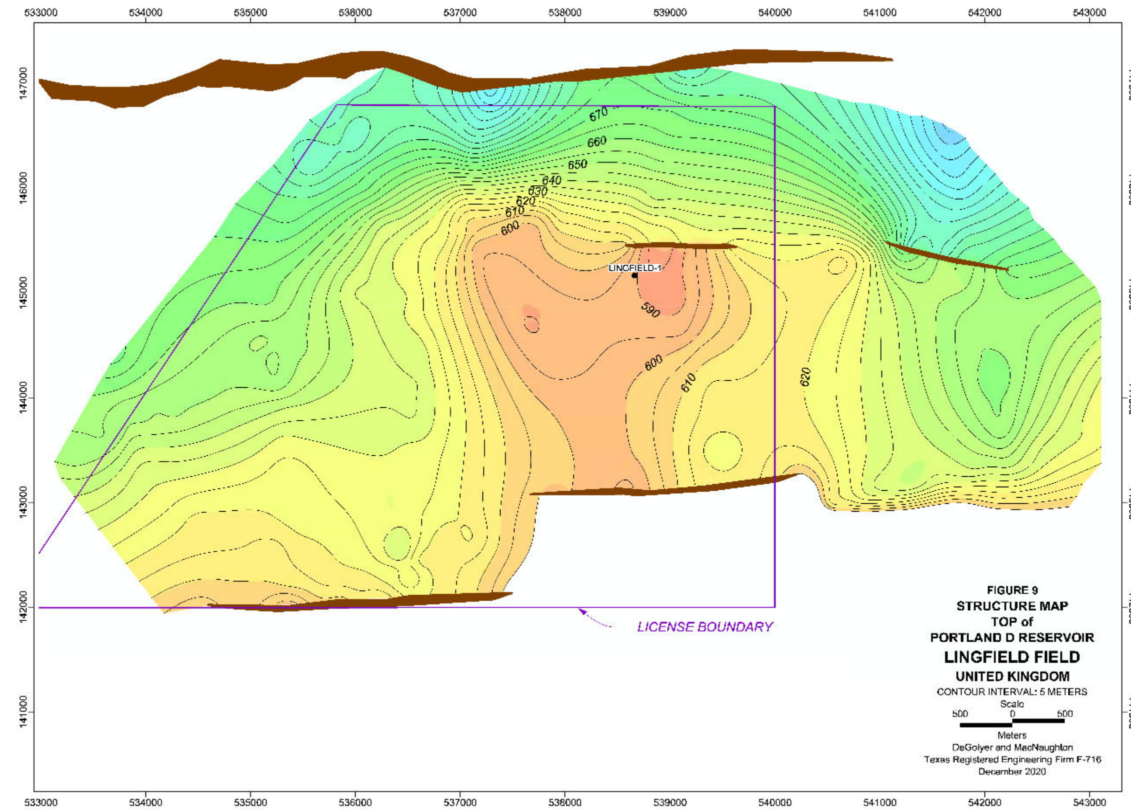


FIGURE 9
STRUCTURE MAP
TOP of
PORTLAND D RESERVOIR
LINGFIELD FIELD
UNITED KINGDOM

The Scampton North field was discovered in 1985 by well SNA-1. The field is located within license PL 179 in Lincolnshire. Scampton North produces light oil of approximately 35 API through five wells from the Basal Succession Sandstone. Porosity ranged from 12 to 18 percent, S_w from 30 to 50 percent, and permeability from 0.5 to 400 millidarcys. Contingent resources were estimated for drilling a well to an undrained eastern target of the reservoir, and the field is contingent based on a lack of firm development plans.

Several of the producing fields also include contingent resources for certain projects that currently do not have firm development plans.

The estimated gross 1C, 2C, and 3C contingent resources, as of December 31, 2020, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

	Gross Contingent Resources								
	1C			2C			3C		
Field	**Oil and Condensate (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Oil Equivalent (10^3boe)**	**Oil and Condensate (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Oil Equivalent (10^3boe)**	**Oil and Condensate (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Oil Equivalent (10^3boe)**
Albury	0	0	0	0	0	0	0	0	0
Avington	505	0	505	740	0	740	1,001	0	1,001
Beckingham	65	218	103	232	317	287	301	387	368
Bletchingley	435	15	438	608	23	612	843	32	849
Bothamsall	0	0	0	0	0	0	0	0	0
Cold Hanworth	0	0	0	0	0	0	0	0	0
Corringham	947	0	947	1,309	0	1,309	1,483	0	1,483
Dunholme	8	0	8	185	0	185	422	0	422
East Glentworth	0	0	0	0	0	0	0	0	0
Egmanton	0	0	0	0	0	0	0	0	0
Gainsborough	83	39	90	272	141	296	509	183	541
Glentworth	2,130	319	2,185	2,992	449	3,068	3,074	461	3,153
Godley Bridge	0	6,654	1,147	0	12,490	2,153	0	14,173	2,444
Goodworth	0	0	0	0	0	0	0	0	0
Hemswell (PEDL6)	0	0	0	44	64	55	2,002	2,872	2,497
Hemswell (PEDL310)	69	99	86	627	900	782	2,202	3,159	2,747
Horndean	349	0	349	798	0	798	1,296	0	1,296
Lingfield	195	2,148	565	489	2,608	939	900	2,983	1,414
Long Clawson	690	0	690	950	0	950	1,360	0	1,360
Lybster	0	0	0	0	0	0	0	0	0
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	299	147	324	392	189	424	532	247	575
Rempstone	0	0	0	0	0	0	0	0	0
Scampton North	338	0	338	496	0	496	566	0	566
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	1,693	227	1,732	3,565	622	3,672	6,206	1,066	6,390
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	598	0	598	731	0	731	904	0	904
Storrington	0	0	0	0	0	0	0	0	0
Welton	2,729	0	2,729	3,504	0	3,504	4,518	0	4,518
Total	**11,133**	**9,866**	**12,834**	**17,934**	**17,803**	**21,003**	**28,119**	**25,563**	**32,527**

Notes:

1. Application of any risk factor to contingent resources quantities does not equate contingent resources with reserves.
2. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.
3. The contingent resources estimated herein are reported as having an economic status of undetermined, since the evaluation of these contingent resources is at a stage such that it is premature to clearly define the associated cash flows.
4. Sales gas contingent resources estimated herein were converted to oil equivalent using an energy equivalent factor of 5,800 cubic feet of gas per 1 boe.

The estimated net 1C, 2C, and 3C contingent resources, as of December 31, 2020, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

	Net Contingent Resources								
	1C			2C			3C		
Field	Oil and Condensate (10^3bbl)	Sales Gas (10^6ft^3)	Oil Equivalent (10^3boe)	Oil and Condensate (10^3bbl)	Sales Gas (10^6ft^3)	Oil Equivalent (10^3boe)	Oil and Condensate (10^3bbl)	Sales Gas (10^6ft^3)	Oil Equivalent (10^3boe)
Albury	0	0	0	0	0	0	0	0	0
Avington	254	0	254	371	0	371	501	0	501
Beckingham	65	218	103	232	317	287	301	387	368
Bletchingley	435	15	438	608	23	612	843	32	849
Bothamsall	0	0	0	0	0	0	0	0	0
Cold Hanworth	0	0	0	0	0	0	0	0	0
Corringham	947	0	947	1,309	0	1,309	1,483	0	1,483
Dunholme	8	0	8	185	0	185	422	0	422
East Glentworth	0	0	0	0	0	0	0	0	0
Egmanton	0	0	0	0	0	0	0	0	0
Gainsborough	83	39	90	272	141	296	509	183	541
Glentworth	2,130	319	2,185	2,992	449	3,069	3,074	461	3,153
Godley Bridge	0	6,654	1,147	0	12,490	2,153	0	14,173	2,444
Goodworth	0	0	0	0	0	0	0	0	0
Hemswell (PEDL6)	0	0	0	33	48	41	1,502	2,154	1,873
Hemswell (PEDL310)	52	74	65	471	675	587	1,652	2,369	2,060
Horndean	314	0	314	719	0	719	1,166	0	1,166
Lingfield	195	2,148	565	489	2,608	939	900	2,983	1,414
Long Clawson	690	0	690	950	0	950	1,360	0	1,360
Lybster	0	0	0	0	0	0	0	0	0
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	299	147	324	392	188	424	532	247	575
Rempstone	0	0	0	0	0	0	0	0	0
Scampton North	338	0	338	496	0	496	566	0	566
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	1,693	227	1,732	3,565	622	3,672	6,206	1,066	6,390
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	598	0	598	731	0	731	904	0	904
Storrington	0	0	0	0	0	0	0	0	0
Welton	2,729	0	2,729	3,504	0	3,504	4,518	0	4,518
Total	**10,830**	**9,841**	**12,527**	**17,319**	**17,561**	**20,347**	**26,439**	**24,055**	**30,586**

Notes:
1. Application of any risk factor to contingent resources quantities does not equate contingent resources with reserves.
2. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.
3. The contingent resources estimated herein are reported as having an economic status of undetermined, since the evaluation of these contingent resources is at a stage such that it is premature to clearly define the associated cash flows.
4. Sales gas contingent resources estimated herein were converted to oil equivalent using an energy equivalent factor of 5,800 cubic feet of gas per 1 boe.

Definition of Prospective Resources

Estimates of petroleum resources included in this report are classified as prospective resources and have been prepared in accordance with the PRMS approved in March 2007 and revised in June 2018 by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysts, and the European Association of Geoscientists & Engineers. Because of the lack of commerciality or sufficient drilling, the prospective resources estimated herein cannot be classified as contingent resources or reserves. The petroleum prospective resources are classified as follows:

> *Prospective Resources* – Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.

The estimation of petroleum resources is subject to both technical and commercial uncertainties and, in general, may be quoted as a range. The range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities. In all cases, the range of uncertainty is dependent on the amount and quality of both technical and commercial data that are available and may change as more data become available.

> *1U (Low), 2U (Best), 3U (High), and Median Estimates* – Estimates of prospective resources in this report are expressed using the terms 1U (low) estimate, 2U (best) estimate, 3U (high) estimate, and mean estimate to reflect the range of uncertainty.

A detailed explanation of the probabilistic terms used herein and identified with an asterisk (*) is included in the glossary bound with this report. For probabilistic estimates of petroleum resources, the low estimate reported herein is the P_{90}* quantity derived from probabilistic analysis. This means that there is at least a 90-percent probability that, assuming the prospect is discovered and developed, the quantities actually recovered will equal or exceed the low estimate. The best (median) estimate is the P_{50}* quantity derived from probabilistic analysis. This means that there is at least a 50-percent probability that, assuming the prospect is discovered and developed, the quantities actually recovered will equal or exceed the best (median) estimate. The high estimate is the P_{10}* quantity derived from probabilistic analysis. This means that there is at least a 10-percent probability that, assuming the prospect is discovered and developed, the quantities actually recovered will equal or exceed the high estimate. The expected value* (EV), an outcome of the probabilistic analysis, is the mean estimate.

Uncertainties Related to Prospective Resources – The quantity of petroleum discovered by exploration drilling depends on the number of prospects that are successful as well as the quantity that each success contains. Reliable forecasts of these quantities are, therefore, dependent on accurate predictions of the number of discoveries that are likely to be made if the entire portfolio of prospects is drilled. The accuracy of this forecast depends on the portfolio size and an accurate assessment of the P_g*.

Probability of Geologic Success – The probability of geologic success (P_g) is defined as the probability of discovering reservoirs that flow hydrocarbons at a measurable rate. The P_g is estimated by quantifying with a probability each of the following individual geologic chance factors: trap, source, reservoir, and migration. The product of the probabilities of these four chance factors is P_g. P_g is predicated and correlated to the minimum case prospective resources gross recoverable volume(s). Consequently, the P_g is not linked to economically viable volumes, economic flow rates, or economic field size assumptions.

In this report, estimates of prospective resources are presented both before and after adjustment for P_g. Total prospective resources estimates are based on the probabilistic summation (statistical aggregate) of the quantities for the total inventory of prospects. The statistical aggregate P_g-adjusted mean estimate, or "aggregated geologic chance-adjusted mean estimate," is a probability-weighted average geologic success case expectation (average) of the hydrocarbon quantities potentially recoverable if all of the prospects in a portfolio were drilled. The P_g-adjusted mean estimate is a "blended" quantity; it is a product of the statistically aggregated mean volume estimate and the portfolio's probability of geologic success. This statistical measure considers and stochastically quantifies the geological success and geological failure outcomes. Consequently, it represents the average or mean "geologic success case" volume outcome of drilling all of the prospects in the exploration program.

Application of P_g to estimate the P_g-adjusted prospective resources quantities does not equate prospective resources with reserves or contingent resources. P_g-adjusted prospective resources quantities cannot be compared directly to or aggregated with either reserves or contingent resources. Estimates of P_g are interpretive and are dependent on the quality and quantity of data currently made available. Future data acquisition, such as additional drilling or seismic acquisition, can have a significant effect on P_g estimation. These additional data are not confined to the study area, but also include data from similar geologic settings or technological advancements that could affect the estimation of P_g.

Predictability versus Portfolio Size – The accuracy of forecasts of the number of discoveries that are likely to be made is constrained by the number of prospects in the exploration portfolio. The size of the portfolio and P_g together are helpful in gauging the limits on the reliability of these forecasts. A high P_g, which indicates a high chance of discovering measurable petroleum, may not require a large portfolio to ensure that at least one discovery will be made (assuming the P_g does not change during drilling of some of the prospects). By contrast, a low P_g, which indicates a low chance of discovering measurable petroleum, could require a large number of prospects to ensure a high confidence level of making even a single discovery. The relationship between portfolio size, P_g, and the probability of a fully unsuccessful drilling program that results in a series of wells not encountering measurable hydrocarbons is referred to herein as the predictability versus portfolio size (PPS) relationship*. It is critical to be aware of PPS, because an unsuccessful drilling program, which results in a series of wells that do not encounter measurable hydrocarbons, can adversely affect any exploration effort, resulting in a negative present worth.

For a large prospect portfolio, the P_g-adjusted mean (statistical aggregate) estimate of the prospective resources quantity should be a reasonable estimate of the recoverable petroleum quantities found if all prospects are drilled. When the number of prospects in the portfolio is small and the P_g is low, the recoverable petroleum actually found may be considerably smaller than the statistical aggregate P_g-adjusted mean estimate would indicate. It follows that the probability that all of the prospects will be unsuccessful is smaller when a large inventory of prospects exist.

Prospect Technical Evaluation Stage – Prospective resources can often be subclassified based on their current stage of technical evaluation. The different stages of technical evaluation relate to the amount of geologic, geophysical, engineering, and petrophysical data as well as the quality of available data.

Prospect – A project associated with an undrilled potential accumulation that is sufficiently well defined to be a viable drilling target. For a prospect, sufficient data and analyses exist to identify and quantify the technical uncertainties, to determine reasonable ranges of geologic chance factors and engineering and petrophysical parameters, and to estimate prospective resources.

Lead – A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect. An example would be a poorly defined closure mapped using sparse regional seismic data in a basin containing favorable source and reservoir(s). A lead may or may not be elevated to prospect status depending on the results of additional technical work. A lead must have a P_g equal to or less than 0.05 to reflect the inherent technical uncertainty.

Play – A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific Leads or Prospects.

Estimation of Prospective Resources

Estimates of prospective resources were prepared by the use of standard geological and engineering methods generally accepted by the petroleum industry. The method or combination of methods used in the analysis of the reservoirs was tempered by experience with similar reservoirs and quality and completeness of basic data.

The probabilistic analysis of the prospective resources in this study considered the uncertainty in the amount of petroleum that may be discovered and the P_g. The uncertainty analysis addresses the range of possibilities for any given volumetric parameter. Minimum, maximum, low, best, high, and mean estimates of prospective resources were estimated to address this uncertainty. The P_g analysis addresses the probability that the identified prospect will contain petroleum that flows at a measurable rate.

Standard probabilistic methods were used in the uncertainty analysis. Probability distributions were estimated from representations of rock volume, porosity, hydrocarbon saturation, recovery efficiency, and formation volume factor for each prospect. These representations were prepared based on known data, analogy, and other standard estimation methods including experience. Statistical measures describing the probability distributions of these representations were identified and input to a Monte Carlo simulation to produce low estimate (P_{90}), best estimate (P_{50}), high estimate (P_{10}), and mean estimate prospective resources for each prospect.

Estimates of recovery efficiency presented in this report are based on analog data and global experience and reflect the potential range in recovery for the potential reservoirs considered in each prospect. Recovery efficiency estimates do not incorporate development or economic input and are subject to change upon selection of specific development options and costs, economic parameters, and product price scenarios.

It is not certain whether prospective reservoirs will be gas bearing, oil bearing, or water bearing. Hydrocarbon phase determination is based on the phase chance of occurrence per the present interpretation of the petroleum system. Therefore, prospective resources volumes in this report are identified herein as oil. In this report, three potential accumulations are referred to as prospects to reflect the current stage of technical evaluation.

Assumed recovery of the potential oil prospective resources estimated herein would be by normal separation in the field. Estimates of oil prospective resources are expressed herein in 10^3bbl. In these estimates, 1 barrel equals 42 United States gallons.

Volumetrics, Quantitative Risk Assessment, and the Application of P_g

Minimum, low, modal, best, mean, high, and maximum representations of potential productive area were interpreted from maps, available seismic data, and/or analogy. Representations for the petrophysical parameters (porosity, hydrocarbon saturation, and net hydrocarbon thickness) and engineering parameters (recovery efficiency and fluid properties) were also estimated based on available well data, regional data, analog field data, and global experience. Individual probability distributions for rock volume and petrophysical and engineering parameters were estimated from these representations.

The distributions for the variables were derived from (1) scenario-based interpretations, (2) the geologic, geophysical, petrophysical, and engineering data available, (3) local, regional, and global knowledge, and (4) field and case studies in the literature. The parameters used to model the recoverable quantities were potential productive area, net hydrocarbon thickness, geometric correction factor, porosity, hydrocarbon saturation, formation volume factor, and recovery efficiency. Minimum, mean, and maximum representations were used to statistically model and shape the input P_{90}, P_{50}, and P_{10} parameters. Potential productive area, net hydrocarbon thickness, and recovery efficiency were modeled using truncated lognormal distributions. Truncated normal distributions were used to model geometric correction factor, formation volume factor, porosity, and hydrocarbon saturation. Latin hypercube sampling was used to better represent the tails of the distributions.

Each individual volumetric parameter was investigated using a probabilistic approach with attention to variability. Deterministic data were used to anchor and shape the various distributions. The rock volume parameters had the greatest range of variability, and therefore had the greatest impact on the uncertainty of the simulation. The volumetric parameter variability was based on the structural and stratigraphic uncertainties due to the depositional environment and quality of the seismic data. Analog field data were statistically incorporated to derive uncertainty limits and constraints on the net hydrocarbon saturation pore volume. Uncertainties associated with the depth conversion, seismic interpretation, gross sand thickness mapping, and net hydrocarbon thickness assumptions were also derived from studies of analogous reservoirs, multiple interpretative scenarios, and sensitivity analyses.

A P_g analysis was applied to estimate the quantities that may actually result from drilling these prospects. In the P_g analysis, the P_g estimates were made for each prospect from the product of the probabilities of the four geologic chance factors: trap, reservoir, migration, and source. The P_g is predicated and correlated to the minimum case prospective resources gross recoverable volume(s). The P_g is not linked to economically viable volumes, economic flow rates, or economic field size assumptions.

Estimates of gross prospective resources and the P_g estimates, as of December 31, 2020, are evaluated herein. The P_g-adjusted mean estimate of the prospective resources was then made by the probabilistic product of P_g and the resources distributions for the prospect. These results were then stochastically summed (zero dependency) to produce the statistical aggregate P_g-adjusted mean estimate prospective resources. The range in probability of the mean occurrence (P_{MEAN})* for the prospective resources volumes were estimated as defined in the glossary of this report. The range in P_{MEAN} for the statistical aggregate P_g-adjusted mean oil estimate is 0.10 to 0.15.

Application of the P_g factor to estimate the P_g-adjusted prospective resources quantities does not equate prospective resources with reserves or contingent resources. The P_g-adjusted estimates of prospective resources quantities cannot be compared directly to or aggregated with either reserves or contingent resources. Estimates of P_g are interpretive and are dependent on the quality and quantity of data currently available. Future data acquisition, such as additional drilling or seismic acquisition, can have a significant effect on P_g estimation. These additional data are not confined to the area of study, but also include data from similar geologic settings or from technological advancements that could affect the estimation of P_g or impact the interpretation of the petroleum system.

Estimates of prospective resources and related distributions herein are the results of probabilistic estimation. These estimates are expressed as a distribution rather than a single value. Probabilistic outcomes involve thousands of iterations using distributions. Deterministic estimations utilizing non-stochastic mathematical operations (addition, subtraction, multiplication, and division) performed on the prospective resources distributions estimated herein produce results that are not comparable.

There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

Prospective resources in three prospects have been evaluated in various license blocks in United Kingdom. The prospective resources estimates presented below were based on a statistical aggregation method. The estimated gross and working interest unrisked prospective resources, as of December 31, 2020, of the prospects evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl):

	Gross Oil Prospective Resources Summary				**Working Interest Oil Prospective Resources Summary**			
Prospect	**1U (Low) Estimate (10^3bbl)**	**2U (Best) Estimate (10^3bbl)**	**3U (High) Estimate (10^3bbl)**	**Mean Estimate (10^3bbl)**	**1U (Low) Estimate (10^3bbl)**	**2U (Best) Estimate (10^3bbl)**	**3U (High) Estimate (10^3bbl)**	**Mean Estimate (10^3bbl)**
Eartham	2,139	4,137	8,059	4,753	2,139	4,137	8,059	4,753
Godley Bridge	3,900	6,359	10,297	6,851	3,900	6,359	10,297	6,851
Lea	606	1,638	3,931	2,048	212	573	1,376	717
Statistical Aggregate	**8,571**	**13,560**	**21,093**	**13,651**	**8,063**	**12,370**	**18,674**	**12,320**

Notes:
1. 1U (Low), 2U (Best), 3U (High), and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean, respectively.
2. P_g and the probability of economic success (P_e) have not been applied to the volumes in this table.
3. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
4. Recovery efficiency is applied to prospective resources in this table.
5. The prospective resources presented above were based on the statistical aggregation method.
6. The prospective resources quantities for the prospects evaluated in this report were aggregated by the arithmetic summation method, as required by the PRMS, and are presented in the prospective resources tables in this report.
7. Summations may vary from those shown here due to rounding.
8. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

The gross and working interest statistical aggregate P_g-adjusted mean estimate oil prospective resources, as of December 31, 2020, are summarized as follows, expressed in thousands of barrels (10^3bbl):

	Mean Estimate
Gross P_g-Adjusted Oil Prospective Resources, 10^3bbl	4,611
Working Interest P_g-Adjusted Oil Prospective Resources, 10^3bbl	4,372

Notes:
1. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
2. Recovery efficiency was applied to prospective resources in this table.
3. The prospective resources presented above were based on the statistical aggregation method.
4. P_g is predicated and correlated to the minimum case prospective resources gross recoverable volume(s). The P_g is not linked to economically viable volumes, economic flow rates, or economic field size assumptions.5. The range in probability of occurrence for the statistical aggregate P_g-adjusted mean oil estimate is 0.10 to 0.15.
6. The prospective resources quantities for the prospects evaluated in this report were aggregated by the arithmetic summation method, as required by the PRMS, and are presented in the prospective resources tables in this report.
7. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

The prospects evaluated in this report are included in the prospective resources tables located in the appendix bound with this report.

Professional Qualifications

DeGolyer and MacNaughton is a Delaware Corporation with offices at 5001 Spring Valley Road, Suite 800 East, Dallas, Texas 75244, U.S.A. The firm has been providing petroleum consulting services throughout the world since 1936. The firm's professional engineers, geologists, geophysicists, petrophysicists, and economists are engaged in the independent evaluation of oil and gas properties, evaluation of hydrocarbon and other mineral prospects, basin evaluations, comprehensive field studies, equity studies, and studies of supply and economics related to the energy industry. Except for the provision of professional services on a fee basis, DeGolyer and MacNaughton has no commercial arrangement with any other person or company involved in the interests which are the subject of this report.

The evaluation has been supervised by Mr. Regnald A. Boles, a Senior Vice President with DeGolyer and MacNaughton in the firm's Europe Africa Division, a Registered Professional Engineer in the State of Texas, a member of the International Society of Petroleum Engineers, and a member of the European Association of Geoscientists & Engineers. He has over 37 years of oil and gas industry experience.

Submitted,

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

Regnald A. Boles, P.E.
Senior Vice President
DeGolyer and MacNaughton

PROSPECTIVE RESOURCES GLOSSARY

Accumulation – An individual body of naturally occurring petroleum. A known accumulation (one determined to contain reserves or contingent resources) must have been penetrated by a well. The well must have clearly demonstrated the existence of moveable petroleum by flow to the surface or at least some recovery of a sample of petroleum through the well. However, log and/or core data from the well may establish an accumulation, provided there is a good analogy to a nearby and geologically comparable known accumulation.

Arithmetic Summation – The process of adding a set of numbers that represent estimates of resources quantities at the reservoir, prospect, or portfolio level and estimates of PPW_{10} at the prospect or portfolio level. Statistical aggregation yields different results.

Best (Median) Estimate – The 2U (best or median) estimate is the P_{50} quantity. P_{50} means that there is a 50 percent chance that an estimated quantity, such as a prospective resources volume or associated quantity, will be equaled or exceeded.

Barrel of Oil Equivalent – Gas quantities are converted to barrels of oil equivalent (BOE) using an energy equivalent factor of 6,000 cubic feet of gas per barrel.

Contingent Resources – Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.

Geometric Correction Factor – The geometric correction factor (GCF) is a geometry adjustment correction that takes into account the relationship of the potential fluid contact to the geometry of the reservoir and trap. Input parameters used to estimate the geometric correction factor include trap shape, length-to-width ratio, potential reservoir thickness, and the height of the potential trapping closure (potential hydrocarbon column height).

High Estimate – The 3U (high) estimate is the P_{10} quantity. P_{10} means there is a 10-percent chance that an estimated quantity, such as a prospective resources volume or associated quantity, will be equaled or exceeded.

Lead – A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect. An example would be a poorly defined closure mapped using sparse regional seismic data in a basin containing favorable source and reservoir(s). A lead may or may not be elevated to prospect status depending on the results of additional technical work. A lead must have a P_g equal to or less than 0.05 to reflect the inherent technical uncertainty.

Low Estimate – The 1U (low) estimate is the P_{90} quantity. P_{90} means there is a 90 percent chance that an estimated quantity, such as a prospective resources volume or associated quantity, will be equaled or exceeded.

Mean Estimate – In accordance with petroleum industry standards, the mean estimate is the probability-weighted average (expected value), which typically has a probability in the P_{45} to P_{15} range, depending on the variance of prospective resources volume or associated quantity. Therefore, the probability of a prospect or accumulation containing the probability-weighted average volume or greater is usually between 45 and 15 percent. The mean estimate is the preferred probabilistic estimate of prospective resources volumes.

Median – Median is the P_{50} quantity, where the P_{50} means there is a 50 percent chance that a given variable (such as prospective resources, porosity, or water saturation) is equaled or exceeded. The median of a data set is a number such that half the measurements are below the median and half are above.

The median is the best estimate in probabilistic estimations of prospective resources, as required by the PRMS guidelines.

Migration Chance Factor – Migration chance factor ($P_{migration}$) is defined as the probability that a trap either predates or is coincident with hydrocarbon migration and that there exists vertical and/or lateral migration pathways linking the source to the trap.

Mode – The mode is the quantity that occurs with the greatest frequency in the data set and therefore is the quantity that has the greatest probability of occurrence. However, the mode may not be uniquely defined, as is the case in multimodal distributions.

P_g-adjusted Mean Estimate, statistical aggregate – The statistical aggregate P_g-adjusted mean estimate, or "aggregated geologic chance-adjusted mean estimate," is a probability-weighted average geologic success case expectation (average) of the hydrocarbon quantities potentially discovered if all of the prospects in a portfolio were drilled. The P_g-adjusted mean estimate is a "blended" quantity; it is a product of the statistically aggregated mean volume estimate and the portfolio's probability of geologic success. This statistical measure considers and stochastically quantifies the geological success and geological failure outcomes. Consequently, it represents the average or mean "geologic success case" volume outcome of drilling all of the prospects in the exploration portfolio. The P_g-adjusted mean volume estimate for a single prospect is calculated as follows:

P_g-adjusted mean estimate = $P_g \times$ mean estimate (mean geologic success case volume)

The probability of the statistical aggregate P_g-adjusted mean estimate is estimated by the product of the portfolio P_g and the probability of the mean volume occurrence for the entire prospect portfolio. The equation is as follows:

Statisitcal aggregate P_g-adjusted mean estimate, probability of occurrence = Portfolio P_g x mean volume probability estimate for the portfolio

P_n Nomenclature – This report uses the convention of denoting probability with a subscript representing the greater than cumulative probability distribution. As such, the notation P_n indicates the probability that there is an n-percent chance that a specific input or output quantity will be equaled or exceeded. For example, P_{90} means that there is a 90 percent chance that a variable (such as prospective resources, porosity, or water saturation) is equaled or exceeded.

Play – A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation to define specific Leads or Prospects.

Predictability versus Portfolio Size – The number of prospects in a prospect portfolio influences the reliability of the forecast of drilling results. The relationship between predictability versus portfolio size (PPS) is also known in the petroleum industry literature as “Gambler’s Ruin.” The relationship of probability to portfolio size is described by the binomial probability equation given as follows:

$$P_x^n = (C_x^n)(p)^x(1 - p)^{n-x}$$

where:
P_x^n = the probability of x successes in n trials
C_x^n = the number of mutually exclusive ways that x successes can be arranged in n trials
p = the probability of success for a given trial (for petroleum exploration, this is P_g)
x = the number of successes (e.g., the number of discoveries)
n = the number of trials (e.g., the number of wells to be drilled)

Note: For the case of n successive dry holes, C_x^n and p each equals 1, so the probability of failure is the quantity (1 – p) raised to the number of trials.

Probability of Geologic Success – The probability of geologic success (P_g) is defined as the probability of discovering reservoirs that flow hydrocarbons at a measurable rate. The P_g is estimated by quantifying with a probability each of the following individual geologic chance factors: trap, source, reservoir, and migration. The product of the probabilities of these four chance factors is P_g. P_g is predicated and correlated to the minimum case prospective resources gross recoverable volume(s). Consequently, the P_g is not linked to economically viable volumes, economic flow rates, or economic field size assumptions.

Probability of the Mean Occurrence – The probability of the mean occurrence (P_{MEAN}) is defined as the probability of occurrence of the mean quantity as defined by the distribution(s) in the Monte Carlo simulation. The probability associated with the mean is dependent on the variance of the distribution and type of distribution from which the mean is estimated. Typically, the range in probability of occurrence for the statistical mean estimate is 0.45 to 0.15 for lognormal (positively skewed) distributions. The statistical mean has a probability of occurrence of 0.50 for normal (symmetric) distributions.

Prospect – A project associated with an undrilled potential accumulation that is sufficiently well defined to be a viable drilling target. For a prospect, sufficient data and analyses exist to identify and quantify the technical uncertainties, to determine reasonable ranges of geologic chance factors and engineering and petrophysical parameters, and to estimate prospective resources. In addition, a viable drilling target requires that 70 percent of the median potential production area be located within the block or license area of interest.

Prospective Resources – Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.

Raw Natural Gas – Raw natural gas is the total gas produced from the reservoir prior to processing or separation and includes all nonhydrocarbon components as well as any gas equivalent of condensate.

Reservoir Chance Factor – The reservoir chance factor ($P_{reservoir}$) is defined as the probability associated with the presence of porous and permeable reservoir-quality rock.

Source Chance Factor – The source chance factor (P_{source}) is defined as the probability associated with the presence of a hydrocarbon source rock rich enough, of sufficient volume, and in the proper spatial position to charge the prospective area or areas.

Standard Deviation – Standard deviation (SD) is a measure of distribution spread. It is the positive square root of the variance. The variance is the summation of the squared distance from the mean of all possible values. Since the units of standard deviation are the same as those of the sample set, it is the most practical measure of population spread.

$$\sigma = \sqrt{\sigma^2} = \sqrt{\frac{\sum_{i=1}^{n}(x_i - \mu)^2}{n-1}}$$

where:
σ = standard deviation
σ^2 = variance
n = sample size
x_i = value in data set
μ = sample set mean

Statistical Aggregation – The process of probabilistically aggregating distributions that represent estimates of resources quantities at the reservoir, prospect, or portfolio level and estimates of PPW_{10} at the prospect or portfolio level. Arithmetic summation yields different results, except for the mean estimate.

Trap Chance Factor – The trap chance factor (P_{trap}) is defined as the probability associated with the presence of a structural closure and/or a stratigraphic trapping configuration with competent vertical and lateral seals, and the lack of any post migration seal integrity events or breaches.

Variance – The variance (σ^2) is a measure of how much the distribution is spread from the mean. The variance sums up the squared distance from the mean of all possible values of x. The variance has units that are the squared units of x. The use of these units limits the intuitive value of variance.

$$\sigma^2 = \frac{\sum_{i=1}^{n}(x_i - \mu)^2}{n-1}$$

where:
σ^2 = variance
n = sample size
x_i = value in data set
μ = sample set mean

Working Interest – Working interest prospective resources are that portion of the gross prospective resources to be potentially produced from the properties attributable to the interests owned by "Company" before deduction of any associated royalty burdens, net profits payable, or government profit share. Working interest is a percentage of ownership in an oil and gas lease granting its owner the right to explore, drill, and produce oil and gas from a tract of property. Working interest owners are obligated to pay a corresponding percentage of the cost of leasing, drilling, producing, and operating a well or unit. The working interest also entitles its owner to share in production revenues with other working interest owners, based on the percentage of working interest owned.

TABLE A-1
SUMMARY PROJECTION of TOTAL PROVED RESERVES and REVENUE
as of
DECEMBER 31, 2020
attributable to
IGAS ENERGY PLC
UNITED KINGDOM

Base Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2021	726	0	183	116	40,674	25,300	3,069	12,305	11,664
2022	808	0	183	191	48,016	23,595	13,224	11,197	9,608
2023	772	0	151	292	48,740	22,826	4,902	21,012	16,320
2024	712	11	145	325	47,608	22,022	5,225	20,361	14,313
2025	655	22	151	324	46,868	21,154	3,816	21,898	13,937
2026	600	17	101	313	43,879	19,598	2,809	21,472	12,370
2027	549	13	60	303	41,458	18,269	2,775	20,414	10,645
2028	508	11	47	278	39,139	17,134	2,774	19,231	9,080
2029	470	8	37	254	36,881	16,088	3,193	17,600	7,520
2030	428	7	29	208	34,168	14,808	864	18,496	7,153
2031	397	5	24	200	32,363	13,981	0	18,382	6,438
2032	369	4	18	194	30,834	13,293	0	17,541	5,559
2033	334	3	14	181	28,885	12,377	795	15,713	4,509
2034	310	0	0	106	25,877	10,852	1,967	13,058	3,390
2035	276	0	0	60	23,486	9,675	1,517	12,294	2,891
2036	257	0	0	35	22,036	9,171	0	12,865	2,740
2037	221	0	0	23	19,364	7,455	5,794	6,115	1,177
2038	207	0	0	18	18,378	7,145	0	11,233	1,959
2039	192	0	0	15	17,468	6,861	0	10,607	1,673
2040	174	0	0	11	16,270	6,243	1,046	8,981	1,282
2041	166	0	0	0	15,282	5,981	0	9,301	1,204
2042	152	0	0	0	14,490	5,749	0	8,741	1,025
2043	137	0	0	0	13,419	5,167	5,671	2,581	274
2044	130	0	0	0	12,789	4,991	0	7,798	747
2045	117	0	0	0	11,827	4,785	0	7,042	612
Subtotal	**9,667**	**101**	**1,143**	**3,447**	**730,199**	**324,520**	**59,441**	**346,238**	**148,090**
Remaining	1,177	0	0	0	117,786	60,366	40,341	17,079	1,501
Total	**10,844**	**101**	**1,143**	**3,447**	**847,985**	**384,886**	**99,782**	**363,317**	**149,591**

Present Worth at (10^3U.S.$)	
8 Percent	173,480
12 Percent	130,573
15 Percent	108,573

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

TABLE A-2
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE RESERVES and REVENUE
as of
DECEMBER 31, 2020
attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

Base Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2021	745	0	183	116	41,658	25,740	3,069	12,849	12,179
2022	850	0	183	191	50,207	24,399	13,224	12,584	10,797
2023	826	0	184	292	52,414	24,066	4,902	23,446	18,210
2024	777	11	232	325	52,374	23,558	5,225	23,591	16,585
2025	728	22	250	325	52,470	22,944	3,816	25,710	16,365
2026	685	19	176	324	50,351	21,642	2,809	25,900	14,920
2027	646	15	118	325	48,700	20,498	2,775	25,427	13,260
2028	610	12	77	325	47,033	19,499	2,774	24,760	11,691
2029	572	10	44	322	45,345	18,546	3,193	23,606	10,087
2030	541	8	37	299	43,442	17,696	0	25,746	9,957
2031	511	7	30	275	41,991	16,928	0	25,063	8,776
2032	489	5	24	236	40,527	15,950	864	23,713	7,517
2033	457	5	20	230	39,178	15,291	0	23,887	6,856
2034	436	4	16	225	38,052	14,727	0	23,325	6,055
2035	408	2	13	218	36,889	14,170	0	22,719	5,342
2036	391	0	0	213	35,493	13,360	454	21,679	4,613
2037	369	0	0	208	34,401	12,897	0	21,504	4,146
2038	346	0	0	202	33,298	12,285	795	20,218	3,526
2039	330	0	0	199	32,456	11,919	0	20,537	3,240
2040	314	0	0	193	31,625	11,586	0	20,039	2,863
2041	300	0	0	190	30,684	11,244	0	19,440	2,514
2042	283	0	0	185	29,861	10,938	0	18,923	2,217
2043	258	0	0	182	27,489	9,031	7,311	11,147	1,181
2044	242	0	0	178	26,916	8,823	0	18,093	1,736
2045	230	0	0	175	25,835	8,579	0	17,256	1,499
Subtotal	**12,344**	**120**	**1,587**	**5,953**	**988,689**	**406,316**	**51,211**	**531,162**	**196,132**
Remaining	3,043	0	0	1,837	332,482	124,911	48,571	159,000	7,544
Total	**15,387**	**120**	**1,587**	**7,790**	**1,321,171**	**531,227**	**99,782**	**690,162**	**203,676**

Note: Probable reserves and values for probable reserves have not been risk adjusted to make them comparable to proved reserves and values for proved reserves.

Present Worth at (10^3U.S.$)	
8 Percent	245,580
12 Percent	172,327
15 Percent	138,243

TABLE A-3
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE RESERVES and REVENUE
as of
DECEMBER 31, 2020
attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

Base Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2021	784	0	183	116	43,622	26,613	3,069	13,940	13,213
2022	909	0	183	191	53,829	25,793	13,224	14,812	12,709
2023	913	0	184	292	57,054	25,669	4,902	26,483	20,569
2024	854	11	233	325	57,042	25,144	5,225	26,673	18,753
2025	809	23	287	325	57,797	24,643	3,816	29,338	18,671
2026	763	20	271	324	56,494	23,523	2,809	30,162	17,378
2027	723	17	222	325	55,189	22,421	2,775	29,993	15,638
2028	688	14	156	325	53,476	21,385	2,774	29,317	13,845
2029	651	12	104	324	51,757	20,394	3,193	28,170	12,034
2030	622	10	63	325	49,868	19,517	0	30,351	11,741
2031	591	9	39	319	48,602	18,734	0	29,868	10,458
2032	566	7	33	297	47,475	18,048	0	29,427	9,327
2033	535	7	27	243	45,671	17,005	864	27,802	7,978
2034	512	5	24	238	44,660	16,425	0	28,235	7,333
2035	489	4	20	232	43,610	15,862	0	27,748	6,524
2036	465	4	17	228	42,690	15,359	0	27,331	5,815
2037	446	3	14	222	41,618	14,855	0	26,763	5,157
2038	426	0	0	218	40,327	14,073	454	25,800	4,497
2039	404	0	0	213	39,575	13,689	0	25,886	4,088
2040	391	0	0	209	38,828	13,345	0	25,483	3,641
2041	376	0	0	204	37,933	12,980	0	24,953	3,229
2042	360	0	0	200	37,157	12,654	0	24,503	2,866
2043	342	0	0	197	36,391	12,337	0	24,054	2,550
2044	331	0	0	193	35,777	12,063	0	23,714	2,275
2045	305	0	0	190	33,338	10,627	5,794	16,917	1,471
Subtotal	**14,255**	**146**	**2,060**	**6,275**	**1,149,780**	**453,158**	**48,899**	**647,723**	**231,760**
Remaining	4,320	0	0	6,119	526,591	184,821	50,883	290,887	11,707
Total	**18,575**	**146**	**2,060**	**12,394**	**1,676,371**	**637,979**	**99,782**	**938,610**	**243,467**

Note: Probable and possible reserves and values for probable and possible reserves have not been risk adjusted to make them comparable to proved reserves and values for proved reserves.

Present Worth at (10^3U.S.$)	
8 Percent	297,139
12 Percent	204,117
15 Percent	162,105

TABLE A-4
SUMMARY PROJECTION of TOTAL PROVED RESERVES and REVENUE
as of
DECEMBER 31, 2020
attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

Low Case

	Net								
Year	**Oil (10^3bbl)**	**Condensate (10^3bbl)**	**Sales Gas Export (10^6ft^3)**	**Sales Gas to Power (10^6ft^3)**	**Future Gross Revenue (10^3U.S.$)**	**Operating Expenses (10^3U.S.$)**	**Abandonment and Capital Costs (10^3U.S.$)**	**Future Net Revenue (10^3U.S.$)**	**Present Worth at 10 Percent (10^3U.S.$)**
2021	711	0	183	116	35,984	24,527	3,069	8,388	7,950
2022	795	0	183	191	42,646	22,874	13,224	6,548	5,618
2023	760	0	151	292	43,338	22,151	4,902	16,285	12,651
2024	701	11	145	325	42,377	21,390	5,225	15,762	11,081
2025	645	22	151	324	41,728	20,562	3,816	17,350	11,044
2026	591	17	101	313	39,068	19,041	2,809	17,218	9,914
2027	540	13	60	303	36,888	17,746	2,775	16,367	8,538
2028	500	11	47	278	34,827	16,639	2,774	15,414	7,276
2029	463	8	37	254	32,817	15,622	3,193	14,002	5,983
2030	419	7	29	208	30,155	14,126	1,659	14,370	5,561
2031	387	5	24	200	28,569	13,332	0	15,237	5,335
2032	352	4	18	194	26,675	12,106	1,517	13,052	4,133
2033	322	3	14	181	25,168	11,449	0	13,719	3,938
2034	303	0	0	106	22,822	10,318	454	12,050	3,130
2035	258	0	0	60	19,812	8,295	5,794	5,723	1,345
2036	241	0	0	35	18,623	7,865	0	10,758	2,289
2037	221	0	0	23	17,431	7,455	0	9,976	1,923
2038	202	0	0	18	16,159	6,742	1,046	8,371	1,458
2039	187	0	0	15	15,364	6,468	0	8,896	1,405
2040	174	0	0	11	14,646	6,243	0	8,403	1,199
2041	162	0	0	0	13,470	5,692	4,159	3,619	471
2042	149	0	0	0	12,789	5,474	0	7,315	855
2043	137	0	0	0	12,075	5,167	1,512	5,396	571
2044	130	0	0	0	11,511	4,991	0	6,520	629
2045	115	0	0	0	10,448	4,582	4,465	1,401	119
Subtotal	**9,465**	**101**	**1,143**	**3,447**	**645,390**	**310,857**	**62,393**	**272,140**	**114,416**
Remaining	1,150	0	0	0	103,479	57,668	35,876	9,935	1,266
Total	**10,615**	**101**	**1,143**	**3,447**	**748,869**	**368,525**	**98,269**	**282,075**	**115,682**

Present Worth at (10^3U.S.$)	
8 Percent	134,709
12 Percent	100,527
15 Percent	83,020

TABLE A-5
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE RESERVES and REVENUE
as of
DECEMBER 31, 2020
attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

Low Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2021	730	0	183	116	36,840	24,897	3,069	8,874	8,413
2022	836	0	183	191	44,572	23,596	13,224	7,752	6,649
2023	812	0	184	292	46,593	23,301	4,902	18,390	14,284
2024	765	11	232	325	46,610	22,827	5,225	18,558	13,048
2025	716	22	250	325	46,703	22,247	3,816	20,640	13,136
2026	674	19	176	324	44,797	20,976	2,809	21,012	12,103
2027	635	15	118	325	43,307	19,862	2,775	20,670	10,783
2028	601	12	77	325	41,826	18,890	2,774	20,162	9,515
2029	562	10	44	322	40,314	17,963	3,193	19,158	8,188
2030	533	8	37	299	38,618	17,138	0	21,480	8,307
2031	503	7	30	244	36,987	16,053	864	20,070	7,029
2032	481	5	24	236	36,014	15,436	0	20,578	6,522
2033	450	5	20	230	34,815	14,797	0	20,018	5,745
2034	429	4	16	225	33,822	14,252	0	19,570	5,082
2035	399	2	13	218	32,569	13,490	795	18,284	4,299
2036	382	0	0	213	31,335	12,702	454	18,179	3,868
2037	361	0	0	208	30,389	12,261	0	18,128	3,493
2038	341	0	0	202	29,599	11,876	0	17,723	3,090
2039	319	0	0	199	28,338	11,002	1,517	15,819	2,497
2040	303	0	0	193	27,630	10,691	0	16,939	2,422
2041	276	0	0	190	25,636	9,143	5,794	10,699	1,383
2042	261	0	0	185	25,031	8,909	0	16,122	1,888
2043	254	0	0	182	24,447	8,684	0	15,763	1,672
2044	238	0	0	178	23,943	8,485	0	15,458	1,482
2045	227	0	0	175	22,984	8,252	0	14,732	1,280
Subtotal	**12,088**	**120**	**1,587**	**5,922**	**873,719**	**387,730**	**51,211**	**434,778**	**156,178**
Remaining	3,012	0	0	1,837	299,030	122,205	47,058	129,767	6,274
Total	**15,100**	**120**	**1,587**	**7,759**	**1,172,749**	**509,935**	**98,269**	**564,545**	**162,452**

Note: Probable reserves and values for probable reserves have not been risk adjusted to make them comparable to proved reserves and values for proved reserves.

Present Worth at (10^3U.S.$)	
8 Percent	197,029
12 Percent	136,660
15 Percent	108,724

TABLE A-6
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE RESERVES and REVENUE
as of
DECEMBER 31, 2020
attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

Low Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2021	784	0	183	116	39,333	26,613	3,069	9,651	9,146
2022	909	0	183	191	48,539	25,793	13,224	9,522	8,171
2023	913	0	184	292	51,460	25,669	4,902	20,889	16,229
2024	854	11	233	325	51,480	25,144	5,225	21,111	14,839
2025	809	23	287	325	52,164	24,643	3,816	23,705	15,088
2026	763	20	271	324	51,002	23,523	2,809	24,670	14,212
2027	723	17	222	325	49,799	22,421	2,775	24,603	12,827
2028	688	14	156	325	48,247	21,385	2,774	24,088	11,371
2029	651	12	104	324	46,688	20,394	3,193	23,101	9,875
2030	622	10	63	325	44,979	19,517	0	25,462	9,849
2031	591	9	39	319	43,834	18,734	0	25,100	8,787
2032	566	7	33	297	42,808	18,048	0	24,760	7,848
2033	535	7	27	243	41,169	17,005	864	23,300	6,687
2034	512	5	24	238	40,259	16,425	0	23,834	6,189
2035	489	4	20	232	39,310	15,862	0	23,448	5,512
2036	465	4	17	228	38,483	15,359	0	23,124	4,924
2037	446	3	14	222	37,518	14,855	0	22,663	4,366
2038	426	0	0	218	36,348	14,073	454	21,821	3,804
2039	404	0	0	213	35,671	13,689	0	21,982	3,470
2040	391	0	0	209	35,000	13,345	0	21,655	3,093
2041	376	0	0	204	34,186	12,980	0	21,206	2,746
2042	346	0	0	200	32,279	11,423	5,794	15,062	1,761
2043	329	0	0	197	31,683	11,155	0	20,528	2,176
2044	320	0	0	193	31,210	10,923	0	20,287	1,948
2045	303	0	0	190	29,852	10,423	795	18,634	1,620
Subtotal	**14,215**	**146**	**2,060**	**6,275**	**1,033,301**	**449,401**	**49,694**	**534,206**	**186,538**
Remaining	4,267	0	0	6,119	478,169	179,873	50,088	248,208	9,949
Total	**18,482**	**146**	**2,060**	**12,394**	**1,511,470**	**629,274**	**99,782**	**782,414**	**196,487**

Note: Probable and possible reserves and values for probable and possible reserves have not been risk adjusted to make them comparable to proved reserves and values for proved reserves.

Present Worth at (10^3U.S.$)	
8 Percent	241,253
12 Percent	163,767
15 Percent	128,976

TABLE A-7
SUMMARY PROJECTION of TOTAL PROVED RESERVES and REVENUE
as of
DECEMBER 31, 2020
attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

High Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2021	726	0	183	116	44,668	25,126	3,069	16,473	15,612
2022	808	0	183	191	52,729	23,595	13,224	15,910	13,653
2023	778	0	151	292	53,914	23,066	4,902	25,946	20,152
2024	717	11	145	325	52,570	22,222	5,225	25,123	17,664
2025	659	22	151	324	51,700	21,322	3,816	26,562	16,903
2026	603	17	101	313	48,373	19,743	2,809	25,821	14,877
2027	551	13	60	303	45,678	18,396	2,775	24,507	12,782
2028	510	11	47	278	43,109	17,246	2,774	23,089	10,897
2029	472	8	37	254	40,596	16,190	2,774	21,632	9,245
2030	428	7	29	208	37,531	14,808	1,283	21,440	8,291
2031	397	5	24	200	35,543	13,981	0	21,562	7,549
2032	369	4	18	194	33,865	13,293	0	20,572	6,524
2033	336	3	14	181	31,955	12,592	0	19,363	5,555
2034	318	0	0	106	29,046	11,423	454	17,169	4,459
2035	286	0	0	60	26,751	10,539	795	15,417	3,625
2036	267	0	0	35	25,097	10,005	0	15,092	3,211
2037	239	0	0	23	22,949	9,004	1,517	12,428	2,395
2038	219	0	0	18	21,377	8,302	1,513	11,562	2,017
2039	192	0	0	15	19,210	6,861	5,794	6,555	1,032
2040	178	0	0	11	18,299	6,625	0	11,674	1,668
2041	166	0	0	0	16,812	5,981	1,046	9,785	1,268
2042	152	0	0	0	15,940	5,749	0	10,191	1,193
2043	138	0	0	0	14,890	5,290	4,159	5,441	578
2044	130	0	0	0	14,068	4,991	1,512	7,565	724
2045	117	0	0	0	13,012	4,785	0	8,227	715
Subtotal	**9,756**	**101**	**1,143**	**3,447**	**809,682**	**331,135**	**59,441**	**419,106**	**182,589**
Remaining	1,204	0	0	0	132,432	63,086	40,341	29,005	2,159
Total	**10,960**	**101**	**1,143**	**3,447**	**942,114**	**394,221**	**99,782**	**448,111**	**184,748**

Present Worth at (10^3U.S.$)	
8 Percent	213,751
12 Percent	161,675
15 Percent	134,990

TABLE A-8
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE RESERVES and REVENUE
as of
DECEMBER 31, 2020
attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DeGolyer and MacNaughton F-716 TEXAS REGISTERED ENGINEERING FIRM

High Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2021	745	0	183	116	45,751	25,566	3,069	17,116	16,223
2022	850	0	183	191	55,141	24,399	13,224	17,518	15,030
2023	833	0	184	292	57,954	24,310	4,902	28,742	22,323
2024	782	11	232	325	57,820	23,769	5,225	28,826	20,268
2025	732	22	250	325	57,874	23,126	3,816	30,932	19,685
2026	689	19	176	324	55,505	21,802	2,809	30,894	17,800
2027	649	15	118	325	53,669	20,640	2,775	30,254	15,779
2028	612	12	77	325	51,812	19,626	2,774	29,412	13,886
2029	574	10	44	322	49,934	18,662	2,774	28,498	12,174
2030	542	8	37	299	47,817	17,802	0	30,015	11,613
2031	511	7	30	275	46,117	16,928	419	28,770	10,071
2032	489	5	24	236	44,520	15,950	864	27,706	8,782
2033	457	5	20	230	43,034	15,291	0	27,743	7,960
2034	436	4	16	225	41,798	14,727	0	27,071	7,029
2035	408	2	13	218	40,520	14,170	0	26,350	6,198
2036	391	0	0	213	38,990	13,360	454	25,176	5,356
2037	369	0	0	208	37,789	12,897	0	24,892	4,797
2038	349	0	0	202	36,803	12,492	0	24,311	4,239
2039	332	0	0	199	35,864	12,122	0	23,742	3,748
2040	316	0	0	193	34,941	11,784	0	23,157	3,311
2041	300	0	0	190	33,709	11,244	795	21,670	2,802
2042	283	0	0	185	32,800	10,938	0	21,862	2,558
2043	274	0	0	182	31,938	10,648	0	21,290	2,256
2044	257	0	0	178	31,189	10,391	0	20,798	1,998
2045	234	0	0	175	28,844	9,048	5,794	14,002	1,215
Subtotal	**12,414**	**120**	**1,587**	**5,953**	**1,092,133**	**411,692**	**49,694**	**630,747**	**237,101**
Remaining	3,063	0	0	1,837	367,471	127,009	50,088	190,374	8,872
Total	**15,477**	**120**	**1,587**	**7,790**	**1,459,604**	**538,701**	**99,782**	**821,121**	**245,973**

Note: Probable reserves and values for probable reserves have not been risk adjusted to make them comparable to proved reserves and values for proved reserves.

Present Worth at (10^3U.S.$)	
8 Percent	295,414
12 Percent	208,937
15 Percent	168,577

TABLE A-9
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE RESERVES and REVENUE
as of
DECEMBER 31, 2020
attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

High Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2021	784	0	183	116	47,911	26,439	3,069	18,403	17,441
2022	909	0	183	191	59,121	25,793	13,224	20,104	17,251
2023	920	0	184	292	63,073	25,918	4,902	32,253	25,054
2024	860	11	233	325	62,978	25,365	5,225	32,388	22,771
2025	813	23	287	325	63,761	24,840	3,816	35,105	22,339
2026	768	20	271	324	62,293	23,700	2,809	35,784	20,617
2027	726	17	222	325	60,823	22,581	2,775	35,467	18,493
2028	691	14	156	325	58,935	21,531	2,774	34,630	16,349
2029	654	12	104	324	57,022	20,528	2,774	33,720	14,408
2030	624	10	63	325	54,930	19,640	0	35,290	13,653
2031	593	9	39	319	53,522	18,849	0	34,673	12,142
2032	567	7	33	297	52,268	18,155	0	34,113	10,811
2033	536	7	27	243	50,286	17,106	864	32,316	9,274
2034	513	5	24	238	49,160	16,521	0	32,639	8,475
2035	489	4	20	232	47,906	15,862	419	31,625	7,438
2036	465	4	17	228	46,898	15,359	0	31,539	6,712
2037	446	3	14	222	45,720	14,855	0	30,865	5,942
2038	426	2	8	218	44,611	14,365	0	30,246	5,276
2039	404	0	0	213	43,478	13,689	454	29,335	4,629
2040	391	0	0	209	42,658	13,345	0	29,313	4,190
2041	376	0	0	204	41,679	12,980	0	28,699	3,711
2042	360	0	0	200	40,821	12,654	0	28,167	3,299
2043	342	0	0	197	39,980	12,337	0	27,643	2,929
2044	331	0	0	193	39,308	12,063	0	27,245	2,614
2045	316	0	0	190	37,773	11,724	0	26,049	2,263
Subtotal	**14,304**	**148**	**2,068**	**6,275**	**1,266,915**	**456,199**	**43,105**	**767,611**	**278,081**
Remaining	4,355	0	0	6,119	581,653	188,586	56,677	336,390	13,186
Total	**18,659**	**148**	**2,068**	**12,394**	**1,848,568**	**644,785**	**99,782**	**1,104,001**	**291,267**

Note: Probable and possible reserves and values for probable and possible reserves have not been risk adjusted to make them comparable to proved reserves and values for proved reserves.

Present Worth at (10^3U.S.$)	
8 Percent	354,014
12 Percent	245,185
15 Percent	195,867

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE A-10
PROSPECT PORTFOLIO SUMMARY
as of
DECEMBER 31, 2020
for
IGAS ENERGY PLC
in
VARIOUS PROSPECTS
VARIOUS LICENSES
UNITED KINGDOM

Prospect	Country	Area/Basin	License/Block	Working Interest (decimal)	Potential Hydrocarbon Phase
Eartham	United Kingdom	Weald	PEDL 326	1.00	Oil
Godley Bridge	United Kingdom	Weald	PEDL 235	1.00	Oil
Lea	United Kingdom	East Midlands	PEDL 316	0.35	Oil

TABLE A-11
ESTIMATE of the GROSS PROSPECTIVE OIL RESOURCES
as of
DECEMBER 31, 2020
for
IGAS ENERGY PLC
in
VARIOUS OIL PROSPECTS
VARIOUS LICENSES
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

				Gross Prospective Oil Resources Summary					
Prospect	**Country**	**Area/Basin**	**License/Block**	**1U (Low) Estimate (10^3bbl)**	**2U (Best) Estimate (10^3bbl)**	**3U (High) Estimate (10^3bbl)**	**Mean Estimate (10^3bbl)**	**Probability of Geologic Success, P_g (decimal)**	**P_g-Adjusted Mean Estimate (10^3bbl)**
Eartham	United Kingdom	Weald	PEDL 326	2,139	4,137	8,059	4,753	0.270	1,283
Godley Bridge	United Kingdom	Weald	PEDL 235	3,900	6,359	10,297	6,851	0.432	2,959
Lea	United Kingdom	East Midlands	PEDL 316	606	1,638	3,931	2,048	0.180	369
Statistical Aggregate				**8,571**	**13,560**	**21,093**	**13,651**	**0.338**	**4,611**
Arithmetic Summation				6,645	12,134	22,287	13,651	0.338	4,611

Notes:

1. 1U (Low), 2U (Best), 3U (High), and mean estimates follow the PRMS guidelines for prospective resources.
2. 1U (Low), 2U (Best), 3U (High), and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean respectively.
3. P_g is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of probabilistic estimates is presented in this table in compliance with PRMS guidelines.
8. Summations may vary from those shown here due to rounding.
9. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.
10. The range in P_{mean} for the statistical aggregate P_g-adjusted mean estimate is 0.10 to 0.15.

TABLE A-12
ESTIMATE of the WORKING INTEREST PROSPECTIVE OIL RESOURCES
as of
DECEMBER 31, 2020
for
IGAS ENERGY PLC
in
VARIOUS OIL PROSPECTS
VARIOUS LICENSES
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

				Working Interest Prospective Oil Resources Summary					
Prospect	Country	Area/Basin	License/Block	1U (Low) Estimate (10^3bbl)	2U (Best) Estimate (10^3bbl)	3U (High) Estimate (10^3bbl)	Mean Estimate (10^3bbl)	Probability of Geologic Success, P_g (decimal)	P_g-Adjusted Mean Estimate (10^3bbl)
Eartham	United Kingdom	Weald	PEDL 326	2,139	4,137	8,059	4,753	0.270	1,283
Godley Bridge	United Kingdom	Weald	PEDL 235	3,900	6,359	10,297	6,851	0.432	2,959
Lea	United Kingdom	East Midlands	PEDL 316	212	573	1,376	717	0.180	129
Statistical Aggregate				**8,063**	**12,370**	**18,674**	**12,320**	**0.355**	**4,372**
Arithmetic Summation				6,251	11,069	19,732	12,320	0.355	4,372

Notes:

1. 1U (Low), 2U (Best), 3U (High), and mean estimates follow the PRMS guidelines for prospective resources.
2. 1U (Low), 2U (Best), 3U (High), and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean respectively.
3. P_g is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of probabilistic estimates is presented in this table in compliance with PRMS guidelines.
8. Summations may vary from those shown here due to rounding.
9. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.
10. The range in P_{mean} for the statistical aggregate P_g-adjusted mean estimate is 0.10 to 0.15.

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE A-13
PROBABILITY DISTRIBUTIONS
for
MONTE CARLO SIMULATION
as of
DECEMBER 31, 2020
for
IGAS ENERGY PLC
in
VARIOUS OIL PROSPECTS
VARIOUS LICENSES
UNITED KINGDOM

Prospect	Potential Target	Parameter	P_{100}	P_{90}	P_{50}	P_{10}	P_0	Mean
Eartham	Upper Great Oolite	Productive area, acres	525	1,027	1,741	2,916	4,553	1,875
		Productive area, sq km	2.12	4.16	7.05	11.80	18.43	7.59
		Porosity, decimal	0.091	0.107	0.120	0.133	0.148	0.120
		Oil saturation, decimal	0.501	0.586	0.650	0.714	0.791	0.650
		Formation volume factor, Bo	1.195	1.164	1.140	1.116	1.085	1.140
		Recovery efficiency, decimal	0.050	0.069	0.100	0.145	0.200	0.104
		Prospective OOIP, barrels	4,198,030	11,254,843	23,878,046	49,338,028	108,528,232	27,957,271
		Prospective gross ultimate recovery, barrels	308,008	1,028,155	2,364,997	5,229,463	16,798,812	2,905,918
Eartham	Lower Great Oolite	Productive area, acres	123	399	945	2,192	4,532	1,151
		Net hydrocarbon thickness, feet	8.28	13.26	22.90	39.48	63.64	24.93
		Porosity, decimal	0.112	0.127	0.140	0.153	0.169	0.140
		Oil saturation, decimal	0.504	0.586	0.650	0.714	0.793	0.650
		Formation volume factor, Bo	1.194	1.164	1.140	1.116	1.085	1.140
		Recovery efficiency, decimal	0.050	0.069	0.100	0.144	0.198	0.104
		Prospective OOIP, barrels	1,542,391	4,764,496	13,157,897	36,406,065	99,928,542	17,768,100
		Prospective gross ultimate recovery, barrels	125,217	467,993	1,319,451	3,763,701	14,452,831	1,846,841
Godley Bridge	Kimmeradge Micrites	Productive area, acres	1,647	2,337	3,048	3,953	4,965	3,103
		Net hydrocarbon thickness, feet	74.90	97.19	131.04	176.53	228.76	134.43
		Porosity, decimal	0.085	0.094	0.100	0.106	0.114	0.100
		Oil saturation, decimal	0.351	0.436	0.500	0.564	0.645	0.500
		Formation volume factor, Bo	1.258	1.225	1.200	1.174	1.142	1.200
		Recovery efficiency, decimal	0.030	0.038	0.050	0.064	0.080	0.051
		Prospective OOIP, barrels	45,211,295	85,486,483	127,338,938	193,815,175	304,102,993	134,851,495
		Prospective gross ultimate recovery, barrels	1,870,336	3,900,317	6,358,598	10,297,080	18,301,803	6,850,524
Lea	Westphalian Eagle Sandstone	Productive area, acres	107	193	301	464	671	316
		Net hydrocarbon thickness, feet	16.42	31.00	56.28	101.84	181.38	62.30
		Porosity, decimal	0.090	0.110	0.140	0.170	0.190	0.140
		Oil saturation, decimal	0.401	0.461	0.550	0.639	0.699	0.550
		Formation volume factor, Bo	1.315	1.223	1.150	1.076	0.986	1.150
		Recovery efficiency, decimal	0.050	0.109	0.191	0.306	0.393	0.200
		Prospective OOIP, barrels	1,135,875	3,768,624	8,652,833	19,613,361	50,696,615	10,240,423
		Prospective gross ultimate recovery, barrels	144,919	606,284	1,637,952	3,931,267	14,711,688	2,048,085