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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 16, 2023

IGas Energy PLC
Barfield Lane, Off Wragby Road
Sudbrooke
Lincoln LN2 2QX
United Kingdom

Ladies and Gentlemen:

Pursuant to your request, we have prepared estimates, as of December 31, 2022, 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 associated with 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). PRMS is a referenced standard therein.

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, 2022. Net reserves are defined as that portion of the gross reserves attributable to the interests held by IGas after deducting all interests held by others.

In the United Kingdom, renewal of license agreements has a track record of administrative extension when requested by the operator of a property. As such, reserves estimated in this report may include quantities that will be produced beyond the current expiration dates of the licenses based on IGas representation that the operators will apply as necessary for renewal of the licenses of interest. As a result, the properties evaluated in this report were projected to a field economic limit unless noted otherwise.

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.$1.22 per U.K.£1.00. All monetary values in this report are expressed in U.S.$. 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. At the request of IGas, abandonment costs were applied for all properties evaluated herein, even if reserves were estimated to be zero. Capital costs include drilling and completion costs, facilities costs, and field maintenance costs. At the request of IGas, United Kingdom taxes were not considered 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 discount rate of 10 percent are reported in detail and values using 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, 2022. Net contingent resources are defined as that portion of the gross contingent resources attributable to the interests held by IGas after deducting all interests held by 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 that are associated with reserves due to the additional risks 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, 2022. 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 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 29 discovered fields in the United Kingdom. This report includes evaluations of 8 fields that contain reserves only, 4 fields that contain contingent resources only, 12 fields that contain reserves and contingent resources, and 5 fields with no reserves or contingent resources. This evaluation also includes prospective resources for two 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, 2022, 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 20 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, 2022, 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	10,219	5,038	4,097	6,159	4,940	6,709	11,281	5,889	5,254
Net	10,112	5,018	4,073	6,159	4,940	6,709	11,174	5,869	5,230

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 and two sensitivity cases. An explanation of the economic assumptions used for the Base Case and two sensitivity cases 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 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.

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, 2022, 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	315,107	144,047	629,425	215,008	933,809	279,380
Low Case	224,904	101,365	483,404	161,392	737,457	216,365
High Case	408,243	187,062	777,826	268,909	1,132,746	342,762

Notes:
1. Values for probable and possible reserves and quantities have not been risk adjusted to make them comparable to values for proved reserves and quantities.
2. Reserves are those estimated using the Base Case, and quantities in the sensitivity cases should not be confused with reserves.

Reserves estimates herein were based on the Base Case 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 regarding 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 16 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, 2022, 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	9,943	9,031	11,500	9,656	9,006	11,210
2C	16,143	18,539	19,339	15,565	18,314	18,721
3C	24,451	28,644	29,390	23,307	27,854	28,110

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 two conventional prospects have been evaluated in two 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, 2022, 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)
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	716
Statistical Aggregate	**6,297**	**8,633**	**11,836**	**8,899**	**5,746**	**7,484**	**9,710**	**7,567**

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, 2022, are summarized as follows, expressed in thousands of barrels (10^3bbl):

	Mean Estimate
Gross P_g-Adjusted Oil Prospective Resources, 10^3bbl	3,328
Working Interest P_g-Adjusted Oil Prospective Resources, 10^3bbl	3,088

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 0.11 to 0.17.
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	53.67	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
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
Hemswell	PEDL6	100.00	6/30/2039
Hemswell	PEDL210	75.00	6/30/2039
Horndean	PL211	90.00	4/4/2036
Lea	PED316	35.00	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

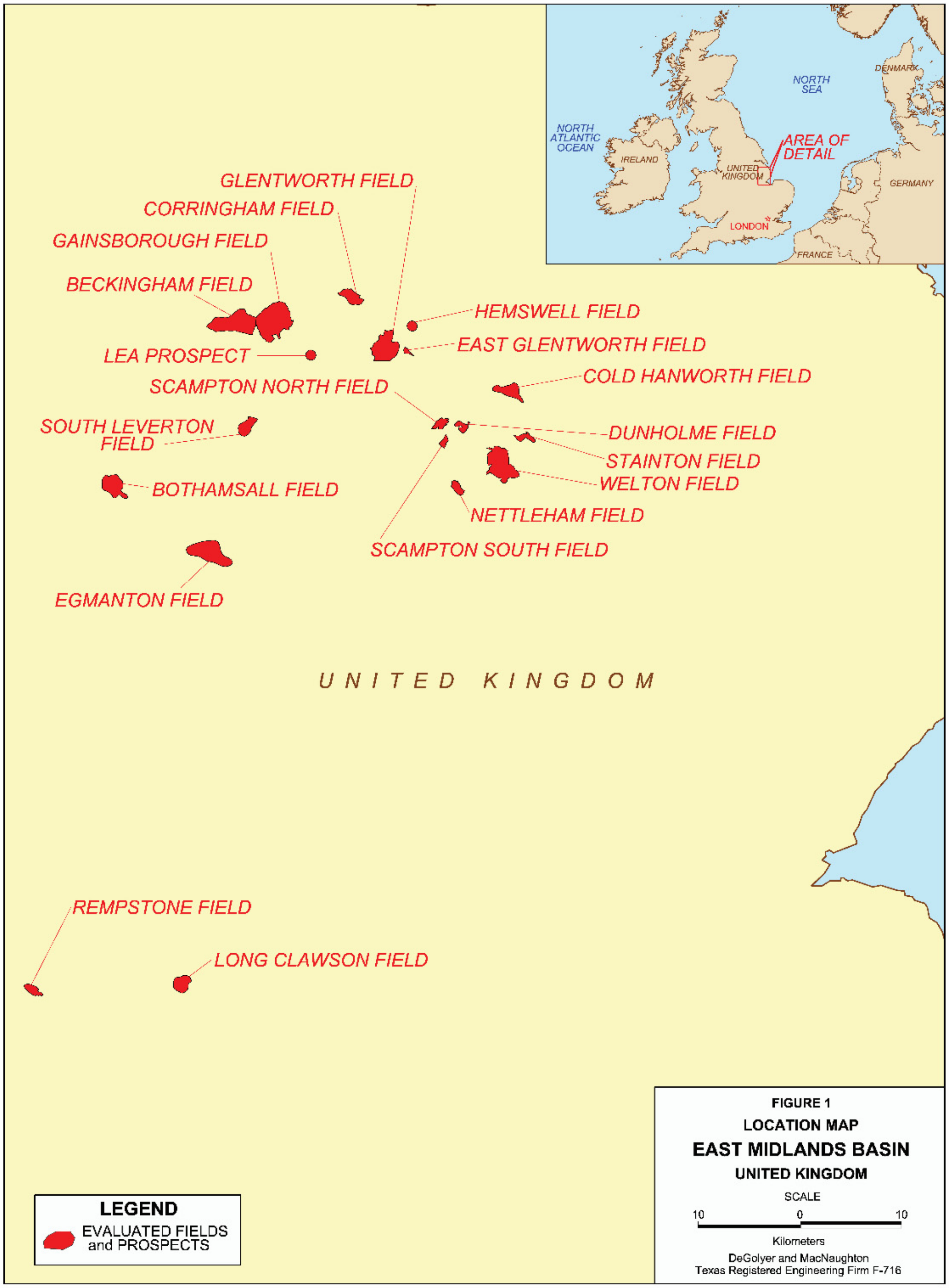
Scampton South	PL179	100.00	11/16/2034
Singleton	PL240	100.00	12/1/2037
South Leverton	ML7	100.00	3/31/2040
Stainton	PL179b	100.00	11/16/2034
Stockbridge	DL2	100.00	12/31/2030
Stockbridge	PL233	100.00	10/26/2030
Stockbridge	PL249	100.00	11/30/2030
Storrington	PL205	100.00	2/13/2036
Welton	PL179b	100.00	11/16/2034

Note: Godley Bridge and Lea 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, 2022, 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.


NORTH ATLANTIC OCEAN
IRELAND
NORTH SEA
DENMARK
AREA OF DETAIL
UNITED KINGDOM
GERMANY
LONDON
FRANCE
GLENTWORTH FIELD
CORRINGHAM FIELD
GAINSBOROUGH FIELD
BECKINGHAM FIELD
HEMSWELL FIELD
EAST GLENTWORTH FIELD
LEA PROSPECT
SCAMPTON NORTH FIELD
COLD HANWORTH FIELD
SOUTH LEVERTON FIELD
DUNHOLME FIELD
STAINTON FIELD
WELTON FIELD
BOTHAMSALL FIELD
NETTLEHAM FIELD
SCAMPTON SOUTH FIELD
EGMANTON FIELD
UNITED KINGDOM
REMPSTONE FIELD
LONG CLAWSON FIELD
LEGEND
EVALUATED FIELDS and PROSPECTS
FIGURE 1
LOCATION MAP
EAST MIDLANDS BASIN
UNITED KINGDOM
SCALE
10
0
10
Kilometers
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716

There are 10 fields and 1 prospect evaluated herein located in the Weald Basin, as shown on Figure 2.

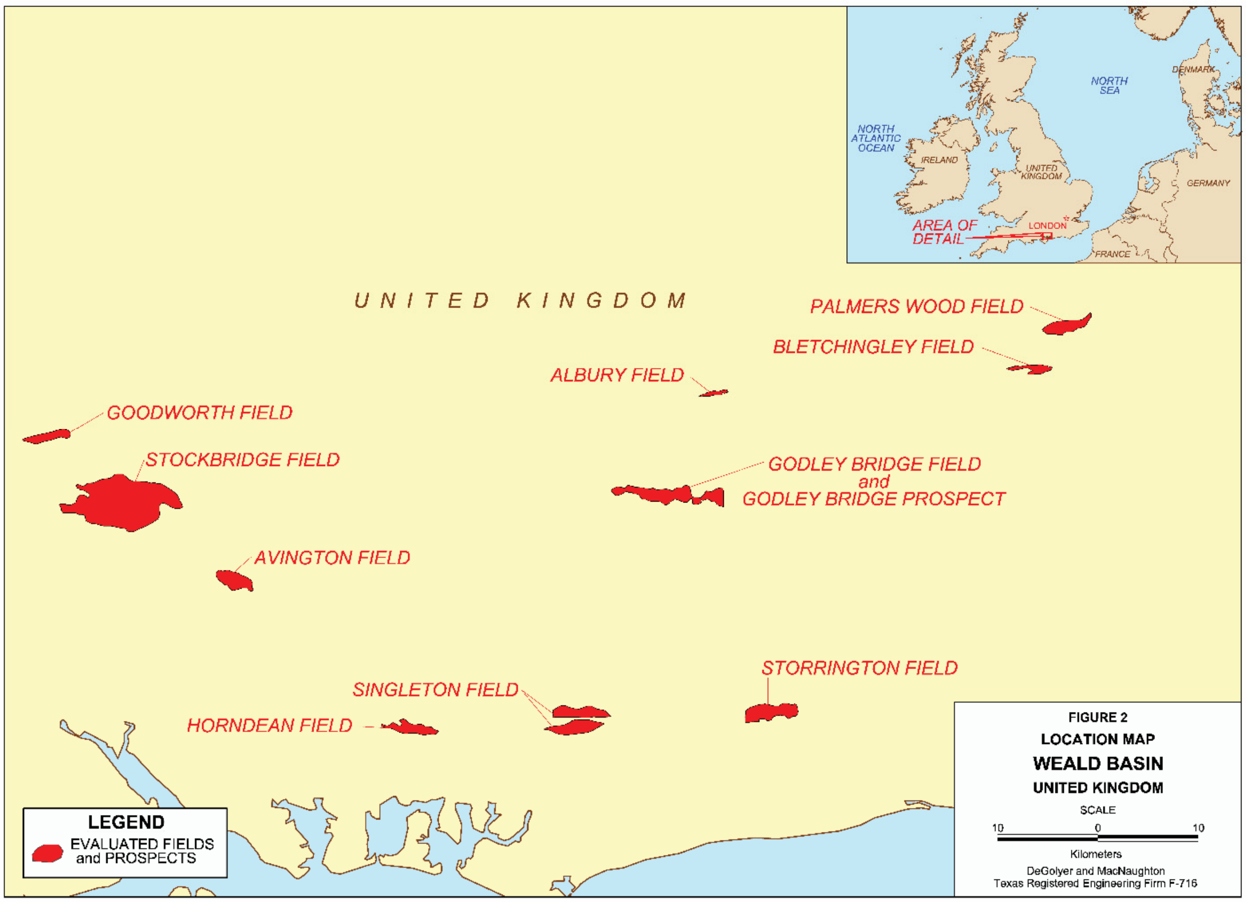


FIGURE 2
LOCATION MAP
WEALD BASIN
UNITED KINGDOM

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

FIGURE 3
LOCATION MAP
LYBSTER FIELD
OFFSHORE UNITED KINGDOM

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. 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 [P50] 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 (P10) 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 plans 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.

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, 2022, 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 September 2022. Where applicable, estimated cumulative production, as of December 31, 2022, was deducted from the gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 3 months.

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 10^6ft^3.

Gas quantities are identified by the type of reservoir from which the gas will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Associated gas is both gas-cap gas and solution gas. 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. Gas quantities estimated herein consist of both associated and nonassociated gas.

At the request of IGas, 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. Twenty 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.

In the United Kingdom, renewal of license agreements has a track record of administrative extension when requested by the operator of a property. As such, reserves estimated in this report may include quantities that will be produced beyond the current expiration dates of the licenses based on IGas representation that the operators will apply as necessary for renewal of the licenses of interest. As a result, the properties evaluated in this report were projected to a field economic limit unless noted otherwise.

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 was estimated to range from 12 to 25 percent, S_w was estimated to range from 21 to 60 percent, and permeability was estimated to range from 0.1 to 100 millidarcys. The recovery factors were estimated to range from 70 to 79 percent. Proved developed producing reserves were estimated based on the performance data from producing wells. There are no proved developed non-producing or proved undeveloped reserves for this field. 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 was estimated to range from 14 to 23 percent, S_w was estimated to range from 46 to 57 percent, and permeability was estimated to range from 0.08 to 0.1 millidarcys. In this fractured reservoir, the effective permeability can be much higher. The current plan is to bring one well AV3z back to production in 2024 by disposing the produced water offsite and reducing operating costs. There are no proved developed producing reserves for this field. Proved developed non-producing reserves were estimated bases on the performance of the existing well and are 46 10^3boe. There are no proved undeveloped reserves for this field. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

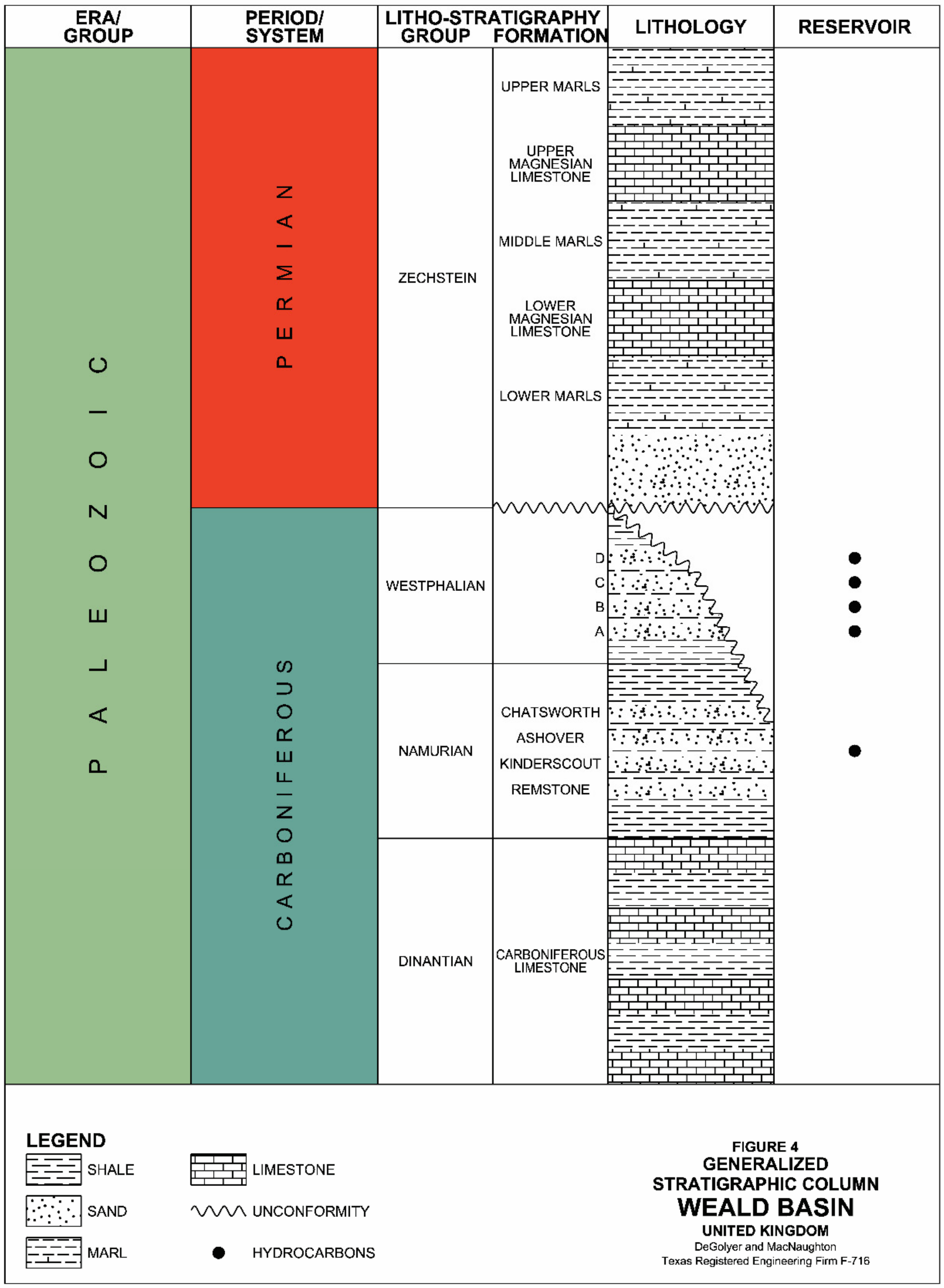


FIGURE 4
GENERALIZED
STRATIGRAPHIC COLUMN
WEALD BASIN
UNITED KINGDOM
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716

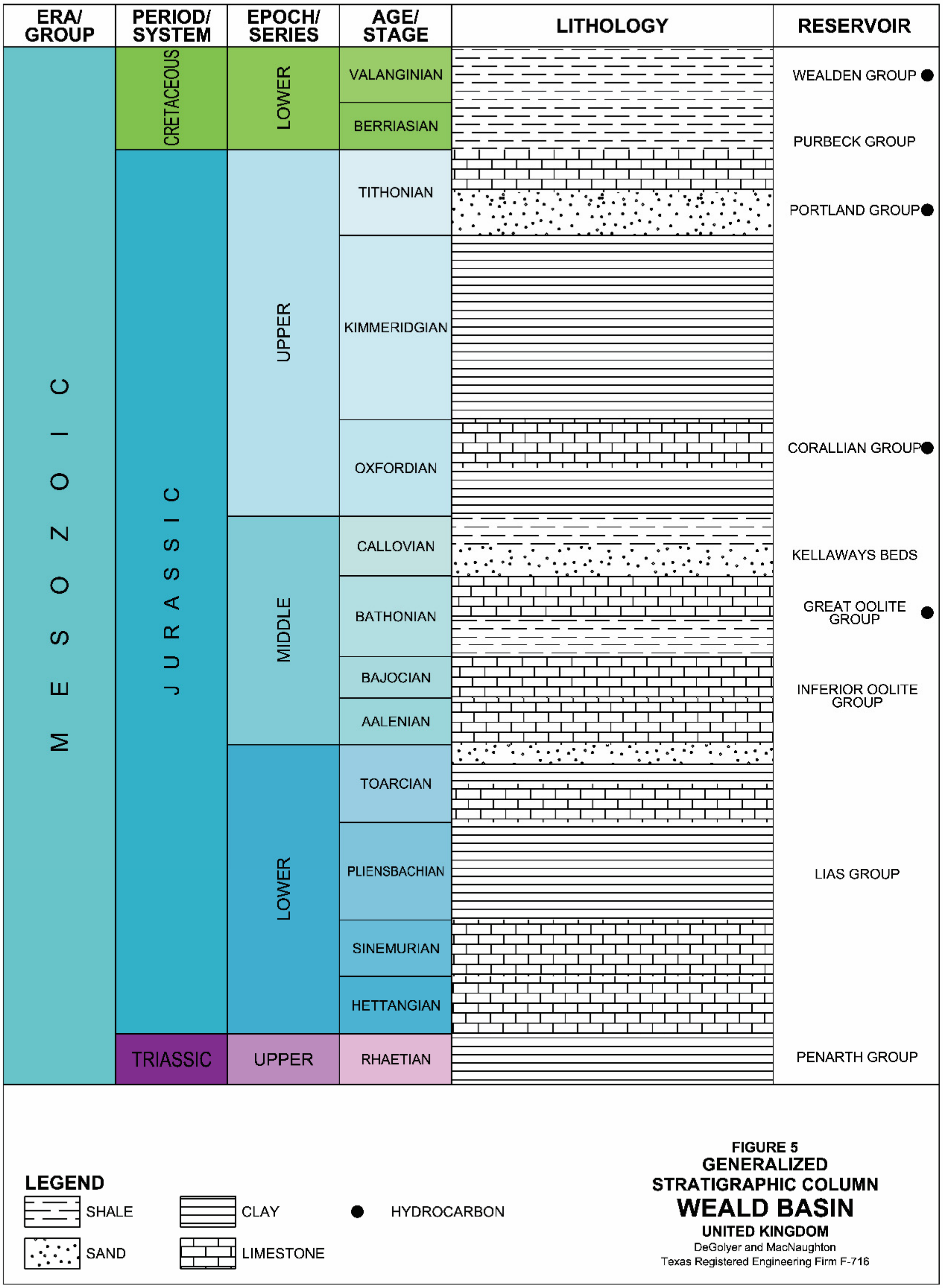


FIGURE 5
GENERALIZED
STRATIGRAPHIC COLUMN
WEALD BASIN
UNITED KINGDOM
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716

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 was estimated to range from 8 to 20 percent, S_w was estimated to range from 40 to 70 percent, and permeability was estimated to range from 0.01 to 30 millidarcys. The field produces light oil of approximately 38 degrees API (°API). Proved developed producing reserves were estimated based on the performance of existing wells. Proved developed non-producing reserves were based on performance of four existing wells and are workovers to remove wax in three wells and repair casing integrity in one well and total 44 10^3boe. There are no proved undeveloped reserves for this field. 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 was estimated to range from 5 to 25 percent, S_w was estimated to range from 40 to 70 percent, and permeability was estimated to range from 0.2 to 1,000 millidarcys. Proved developed producing reserves were estimated based on individual-well performance. There are no proved developed non-producing reserves for this field. Proved undeveloped reserves were estimated based on volumetric analysis of one additional well and are 356 10^3boe. Estimates of probable and possible reserves account for the potential for better performance than proved reserves. Undeveloped reserves estimates for the field also include a “gas-to-wire” project to support the building of a 6-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 was estimated to range from 6 to 16 percent, S_w was estimated to range from 26 to 60 percent, and permeability was estimated to range from 0.1 to 100 millidarcys. The field currently produces light oil from two wells. Proved developed producing reserves were estimated based on the performance of existing wells. There are no proved developed non-producing or proved undeveloped reserves for this field. 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 was estimated to range from 7 to 16 percent, S_w was estimated to range from 40 to 70 percent, and permeability was estimated to range from 0.05 to 10 millidarcys. The oil has a gravity of 28 °API. Proved developed producing reserves were estimated based on individual-well performance of existing wells. There are no proved developed non-producing or proved undeveloped reserves for this field. 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 was estimated to range from 14 to 27 percent, S_w was estimated to range from 37 to 44 percent, and permeability was estimated to range from 160 to 500 millidarcys. Proved developed producing reserves were estimated based on the performance of existing wells. There are no proved developed non-producing reserves for this field. Proved undeveloped reserves were based on historical performance of recovery per well and are 260 10^3boe. Estimates of probable and possible reserves account for the potential for better performance than proved reserves. Undeveloped reserves estimates for the field include a new Silkstone producer, the CR13 well.

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 was estimated to range from 16 to 20 percent, S_w was estimated to range from 42 to 47 percent, and permeability was estimated to range from 1 to 20 millidarcys. Proved developed producing reserves were estimated based on individual well performance. There are no proved developed non-producing or proved undeveloped reserves for this field. 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 was estimated to range from 13 to 17 percent, S_w was estimated to range from 45 to 55 percent, and permeability was estimated to range 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 field will be abandoned, with site restorations, in 2023. For the purposes of this report abandonment was scheduled in 2023.

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 was estimated to range from 8 to 20 percent, S_w was estimated to range from 40 to 70 percent, and permeability was estimated to range 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. For the purposes of this report abandonment was scheduled for 2028.

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 was estimated to range from 16 to 20 percent, S_w was estimated to range from 50 to 65 percent, and permeability was estimated to range from 0.1 to 30 millidarcys. Proved developed producing reserves were estimated based on the performance of existing wells. There are no proved developed non-producing reserves for this field. Proved undeveloped reserves for this field are based on performance of existing wells for a new producer in the Mexborough Rock reservoir and are 600 10^3boe. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

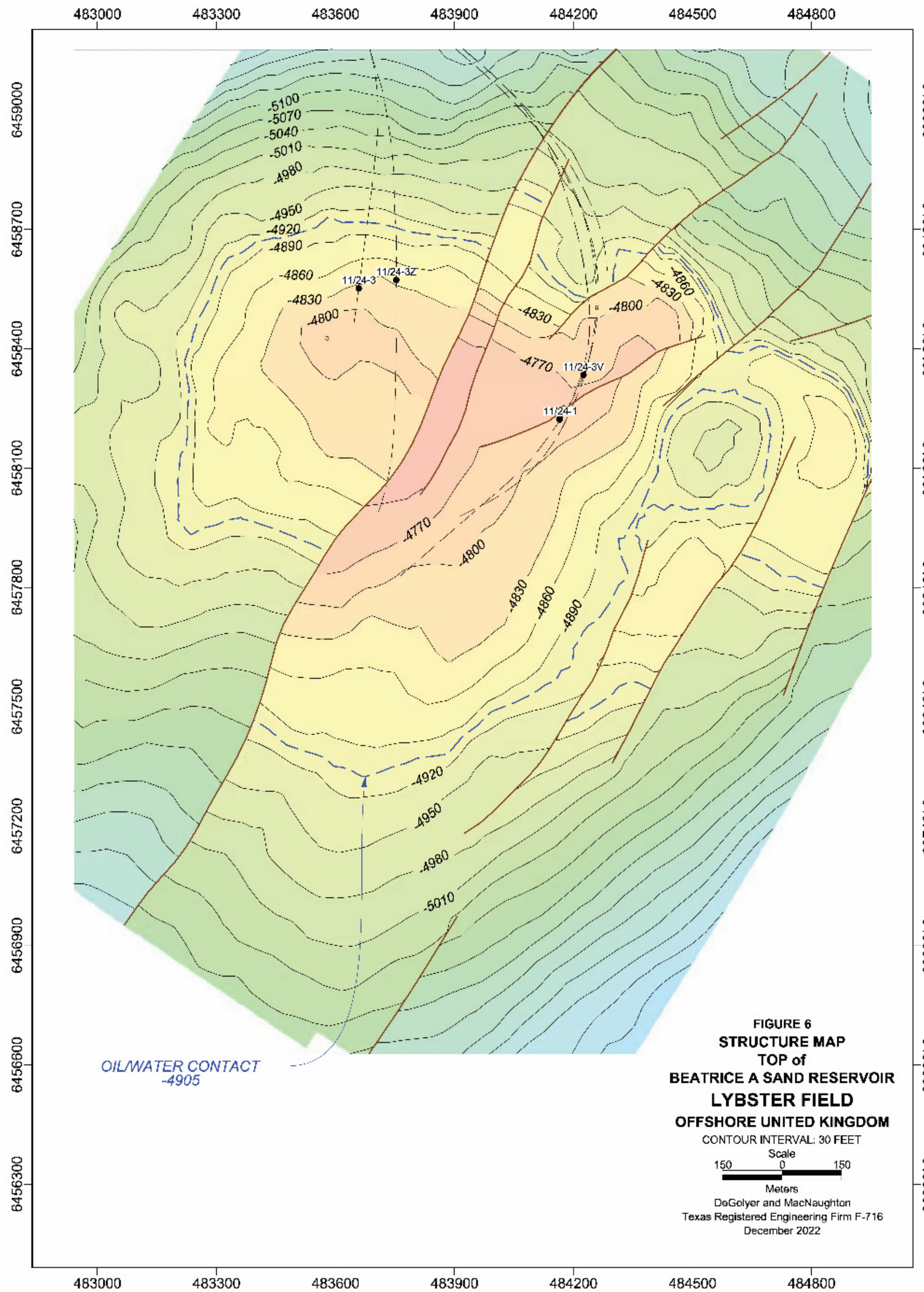
The Goodworth field, located in license PEDL21, was discovered in 1987. The field produces from the Great Oolite reservoir across three main blocks and is currently producing from one well. Porosity was estimated to range from 12 to 16 percent, S_w was estimated to range from 50 to 70 percent, and permeability was estimated to range from 0.1 to 5 millidarcys. Proved developed producing reserves were estimated based on the performance of the existing well. There are no proved developed non-producing or proved undeveloped reserves for this field. 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 was estimated to range from 12 to

19 percent, S_w was estimated to range from 70 to 80 percent, and permeability was estimated to range from 0.01 to 5 millidarcys. Proved developed producing reserves were estimated based on the performance of existing wells. There are no proved developed non-producing or proved undeveloped reserves for this field. 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 was estimated to range from 13 to 18 percent, S_w was estimated to range from 68 to 79 percent, and permeability was estimated to range from 90 to 1,100 millidarcys. The oil has a gravity of 35 °API. Proved developed producing reserves were estimated based on individual-well performance. Proved developed non-producing reserves were based on performance of the existing well that requires replacement of surface unit equipment and are 10 10^3boe. There are no proved undeveloped reserves for this field. 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 were estimated to range from 55 to 80 percent. In this field, porosity was estimated to be 12 percent, S_w was estimated to range from 35 to 45 percent, and permeability was estimated to range from 90 to 1,115 millidarcys. 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 2025. The development plan includes wellsite upgrades, well recompletion with 3½" tubing, installation of an ESP pump, onsite processing, and compression of the produced gas as part of a Compressed Natural Gas (CNG) monetization scheme. There are no proved developed producing or proved developed non-producing reserves for this field. Proved undeveloped reserves for this field were based on volumetrics and are 274 10^3boe. Estimates of probable, and possible reserves account for the potential for better recovery than proved undeveloped reserves.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-4860
-4830
-4800
-4770
11/24-3
11/24-3Z
11/24-3V
11/24-1
OIL/WATER CONTACT
-4905
FIGURE 6
STRUCTURE MAP
TOP of
BEATRICE A SAND RESERVOIR
LYBSTER FIELD
OFFSHORE UNITED KINGDOM
CONTOUR INTERVAL: 30 FEET
Scale
150 0 150
Meters
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716
December 2022

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 was estimated to range from 19 to 22 percent, S_w was estimated to range from 30 to 60 percent, and permeability was estimated to range 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. For the purposes of this report abandonment costs are scheduled for 2027.

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 through four wells from the Upper Jurassic Corallian Sandstone. In addition, there has been an active waterflood through three injectors since the beginning of production. Porosity was estimated to range from 16 to 20 percent, S_w was estimated to range from 40 to 60 percent, and permeability was estimated to range from 0.5 to 50 millidarcys. Proved developed producing reserves were estimated based on the performance of existing wells. There are no proved developed non-producing or proved undeveloped reserves for this field. 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 was estimated to range from 16 to 19 percent, S_w was estimated to range from 40 to 50 percent, and permeability was estimated to range from 0.1 to 20 millidarcys. Proved developed producing reserves were estimated based on individual-well performance. There are no proved developed non-producing or proved undeveloped reserves for this field. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The Scampton North field was discovered in 1985 by well SNA1. The field is located within license PL179 in Lincolnshire. Scampton North produces light oil of approximately 35 API through five wells from the Basal Succession Sandstone. Porosity was estimated to range from 12 to 18 percent, S_w was estimated to range from 30 to 50 percent, and permeability was estimated to range from 0.5 to 400 millidarcys. Proved developed producing reserves were estimated based on the performance of existing wells and a waterflood injector that is being optimized for injection rate. Proved developed non-producing reserves were based on performance of existing wells which require site upgrades to restore production and are 150 10^3boe. There are no proved undeveloped reserves for this field. Estimates of probable and possible reserves account for the potential for better performance than proved reserves and improved injection and sweep water efficiency in the injector.

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 was estimated to range from 10 to 16 percent, S_w was estimated to range from 26 to 40 percent, and permeability was estimated to range 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. For the purposes of this report abandonment costs are scheduled for 2024.

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 was estimated to range from 13 to 16 percent, S_w was estimated to range from 30 to 62 percent, and permeability was estimated to range from 0.1 to 10 millidarcys. Proved developed producing reserves were estimated based on the performance of existing wells. There are no proved developed non-producing reserves for this field. Proved undeveloped reserves were based on performance of existing wells and include a north block development of one new producer, the conversion of one existing well to a water injector, and deepening one existing well for oil production and total 759 10^3boe. 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 2-megawatt generator by 2025, which may allow future additions of gas reserves.

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 was estimated to range from 9 to 13 percent, S_w was estimated to range from 22 to 27 percent, and permeability was estimated to range from 0.2 to 10 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. For the purposes of this report abandonment costs are scheduled for 2029.

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 was estimated to range from 12 to 16 percent, S_w was estimated to range from 30 to 50 percent, and permeability was estimated to range from 0.4 to 50 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. For the purposes of this report abandonment costs are scheduled for 2027.

The Stockbridge field was discovered in 1984. This field is located within the DL2, PL233, and PL249 licenses, 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 six wells, and two wells are currently suspended pending workovers to address integrity problems. Porosity was estimated to range from 12 to 24 percent, S_w was estimated to range from 66 to 79 percent, and permeability was estimated to range from 0.1 to 5 millidarcys. Proved developed producing reserves were estimated based on individual-well performance. Proved developed non-producing reserves are based on performance of four existing wells that require workovers to repair split tubing to reinstate production and total 22 10^3boe. There are no proved undeveloped reserves for this field. 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 was estimated to range from 10 to 17 percent, S_w was estimated to range from 45 to 60 percent, and permeability was estimated to range from 0.01 to 50 millidarcys. Proved developed producing reserves were estimated based on the performance of existing wells. There are no proved developed non-producing or proved undeveloped reserves for this field. 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 was estimated to range from 12 to 20 percent, S_w was estimated to range from 20 to 40 percent, and permeability was estimated to range from 10 to 1,000 millidarcys. Proved developed producing reserves were estimated based on individual-well performance and a waterflood injector which is now injecting. Proved developed non-producing reserves were based on performance of five existing wells which require workovers to reinstate production and total 323 10^3boe. There are no proved undeveloped reserves for this field. Estimates of probable and possible reserves account for the potential for better performance than proved reserves and improved injection and sweep water efficiency in the injector.

The estimated gross proved, probable, and possible reserves, as of December 31, 2022, 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	1,192	215	261	206	37	45
Avington	46	12	16	0	0	0	46	12	16
Beckingham	342	101	105	0	0	0	342	101	105
Bletchingley	200	46	106	2,067	3,438	5,092	556	639	984
Bothamsall	10	0	1	0	0	0	10	0	1
Cold Hanworth	184	45	69	0	0	0	184	45	69
Corringham	521	129	114	0	0	0	521	129	114
Dunholme	0	0	0	0	0	0	0	0	0
East Glentworth	65	22	26	0	0	0	65	22	26
Egmanton	0	0	0	0	0	0	0	0	0
Gainsborough	0	0	0	0	0	0	0	0	0
Glentworth	1,250	562	526	0	0	0	1,250	562	526
Godley Bridge	0	0	0	0	0	0	0	0	0
Goodworth	44	8	17	0	0	0	44	8	17
Hemswell (PEDL6)	0	0	0	0	0	0	0	0	0
Hemswell (PEDL210)	0	0	0	0	0	0	0	0	0
Horndean	859	136	172	0	0	0	859	136	172
Long Clawson	52	12	20	0	0	0	52	12	20
Lybster	147	62	48	734	310	243	274	115	90
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	52	16	3	0	0	0	52	16	3
Rempstone	20	1	5	0	0	0	20	1	5
Scampton North	601	129	432	0	0	0	601	129	432
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	2,357	1,022	1,214	2,166	977	1,113	2,730	1,190	1,406
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	683	338	122	0	0	0	683	338	122
Storrington	49	22	11	0	0	0	49	22	11
Welton	2,737	2,375	1,090	0	0	0	2,737	2,375	1,090
Total	**10,219**	**5,038**	**4,097**	**6,159**	**4,940**	**6,709**	**11,281**	**5,889**	**5,254**

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, 2022, 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	1,192	215	261	206	37	45
Avington	25	6	9	0	0	0	25	6	9
Beckingham	342	101	105	0	0	0	342	101	105
Bletchingley	200	46	106	2,067	3,438	5,092	556	639	984
Bothamsall	10	0	1	0	0	0	10	0	1
Cold Hanworth	184	45	69	0	0	0	184	45	69
Corringham	521	129	114	0	0	0	521	129	114
Dunholme	0	0	0	0	0	0	0	0	0
East Glentworth	65	22	26	0	0	0	65	22	26
Egmanton	0	0	0	0	0	0	0	0	0
Gainsborough	0	0	0	0	0	0	0	0	0
Glentworth	1,250	562	526	0	0	0	1,250	562	526
Godley Bridge	0	0	0	0	0	0	0	0	0
Goodworth	44	8	17	0	0	0	44	8	17
Hemswell (PEDL6)	0	0	0	0	0	0	0	0	0
Hemswell (PEDL210)	0	0	0	0	0	0	0	0	0
Horndean	773	122	155	0	0	0	773	122	155
Long Clawson	52	12	20	0	0	0	52	12	20
Lybster	147	62	48	734	310	243	274	115	90
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	52	16	3	0	0	0	52	16	3
Rempstone	20	1	5	0	0	0	20	1	5
Scampton North	601	129	432	0	0	0	601	129	432
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	2,357	1,022	1,214	2,166	977	1,113	2,730	1,190	1,406
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	683	338	122	0	0	0	683	338	122
Storrington	49	22	11	0	0	0	49	22	11
Welton	2,737	2,375	1,090	0	0	0	2,737	2,375	1,090
Total	**10,112**	**5,018**	**4,073**	**6,159**	**4,940**	**6,709**	**11,174**	**5,869**	**5,230**

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.

For the fields evaluated in this report, there are 8,437 10^3boe proved developed producing reserves, 595 10^3boe proved developed non-producing reserves, and 2,249 10^3boe proved undeveloped reserves, in total.

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 cases were evaluated in this report: Base Case, Low Case, and High Case. The sensitivity cases were evaluated in this report to present alternative outcomes to the future revenue estimates for estimated reserves. Projections of gross and net reserves summarized herein were based on the Base Case, and quantities in the sensitivity cases are those included prior to the limit of projected production under the Base Case or when an annual economic limit for each case is reached, whichever occurs first. Only the prices were varied in each economic scenario. Unless noted otherwise, all other components of the evaluation for the sensitivity cases are the same as those stated for the Base Case herein.

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 2022, followed by price changes that match historical price levels. 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 2022. 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.$/$10^3$ft^3).

	Base Case Prices			
Year	Oil (U.S.$/bbl)	Condensate (U.S.$/bbl)	Gas Export (U.S.$/$10^3$ft^3)	Gas to Power (U.S.$/$10^3$ft^3)
2023	82.47	74.22	28.16	27.82
2024	76.07	68.46	19.27	19.04
2025	71.60	64.44	10.81	10.68
2026	72.12	64.91	11.03	10.89
2027	72.63	65.37	11.25	11.11
2028	73.13	65.82	11.47	11.33
2029	73.63	66.26	11.70	11.56
2030	74.11	66.70	11.94	11.79
2031	74.58	67.13	12.17	12.03
2032	76.74	69.06	12.42	12.27
2033	78.95	71.05	12.67	12.51
2034	81.21	73.09	12.92	12.76
2035	83.54	75.19	13.18	13.02
2036	85.93	77.33	13.44	13.28
2037	88.38	79.54	13.71	13.55
2038	90.89	81.80	13.98	13.82
2039	93.47	84.12	14.26	14.09
2040	96.11	86.50	14.55	14.37
2041	98.82	88.94	14.84	14.66
2042	100.80	90.72	15.14	14.95
2043	102.82	92.53	15.44	15.25
2044	104.87	94.38	15.75	15.56
2045	106.97	96.27	16.06	15.87
2046	109.11	98.20	16.38	16.19
2047	111.29	100.16	16.71	16.51
2048	113.52	102.16	17.05	16.84
2049	115.79	104.21	17.39	17.18
2050	118.10	106.29	17.73	17.52

Note: From 2050 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 gas price for the Low Case is 10 percent lower than the Base Case.

High Case Price Assumptions

Oil and condensate prices for the High Case are 10 percent higher than the Base Case, and the gas price for the High Case is 10 percent higher than the Base Case.

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. A 2-percent per year cost escalation 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. At the request of IGas, abandonment costs were applied for all properties evaluated herein, even if reserves were estimated to be zero. 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 the developed 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.$1.22 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, 2022, 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	932,966	1,492,056	1,991,766
Operating Expenses	461,231	702,715	895,747
Abandonment and Capital Costs	156,628	159,916	162,210
Future Net Revenue	315,107	629,425	933,809
Present Worth at 10 Percent	144,047	215,008	279,380

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, 2022, 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	813,963	1,320,952	1,765,138	1,051,526	1,664,801	2,211,201
Operating Expenses	434,051	679,471	866,914	485,284	725,343	915,145
Abandonment and Capital Costs	155,008	158,077	160,767	157,999	161,632	163,310
Future Net Revenue	224,904	483,404	737,457	408,243	777,826	1,132,746
Present Worth at 10 Percent	101,365	161,392	216,365	187,062	268,909	342,762

Notes:
1. Values for probable and possible quantities have not been risk adjusted to make them comparable to values for proved quantities.
2. Reserves are those estimated using the Base Case, and quantities in the sensitivity cases should not be confused with reserves.

The estimated future net revenue of all fields for the Base, Low, and High Cases is shown in Tables A-1 through A-12 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, 2022. The development and economic status represents the status applicable on December 31, 2022.

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.

Gas quantities are identified by the type of reservoir from which the gas will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Associated gas is both gas-cap gas and solution gas. 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. Gas quantities estimated herein consists of both associated and nonassociated gas.

At the request of IGas, 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, 16 fields located in the United Kingdom were estimated to contain contingent resources: Avington, Beckingham, Bletchingley, Corringham, Dunholme, Gainsborough, Glentworth, Godley Bridge, Hemswell, Horndean, 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 was estimated to range from 5 to 25 percent, S_w was estimated to range from 40 to 70 percent, and permeability was estimated to range 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 the lack of a firm development plan.

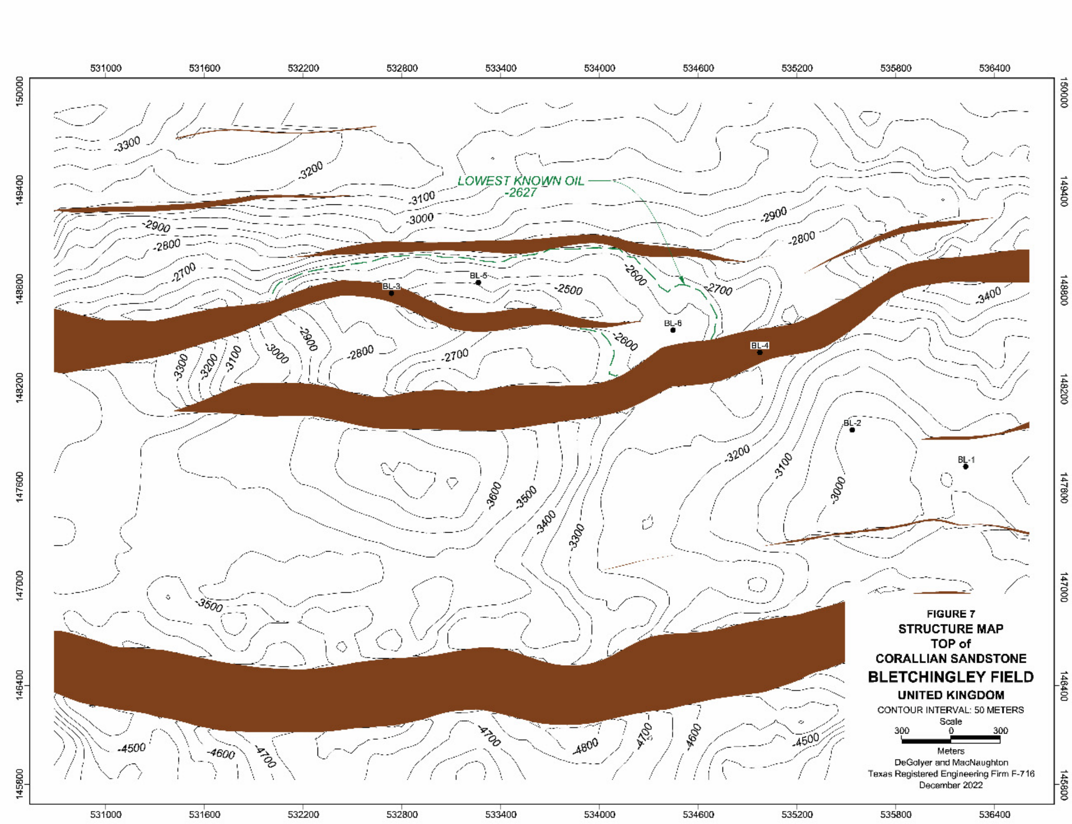

FIGURE 7
STRUCTURE MAP
TOP of
CORALLIAN SANDSTONE
BLETCHINGLEY FIELD
UNITED KINGDOM
CONTOUR INTERVAL: 50 METERS

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 porosity was estimated to be 19.8 percent, and the S_w was estimated to be 58 percent. Permeability was estimated to range 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. Recovery factors were estimated to 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 was estimated to range from 16 to 20 percent, S_w was estimated to range from 50 to 65 percent, and permeability was estimated to range from 0.1 to 30 millidarcys. Contingent resources were estimated for four additional infill wells and one waterflood well and were based on a total field recovery ranging from 24 to 34 percent. The additional potential development in the field is considered 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. Porosity was estimated to range from 17 to 18 percent, and Sw was estimated to range from 30 to 80 percent. Permeability was estimated to range from 0.1 to 548 millidarcys. The recovery factors were estimated to range from 71 to 84 percent. This field is contingent based on the lack of firm development plans. IGas has indicated that new data will be incorporated into future evaluations beginning in 2023 for the Godley Bridge Portland Sandstone. The contingent resources estimated herein for the Godley Bridge field do not include the Kimmeridge Micrites reservoir.

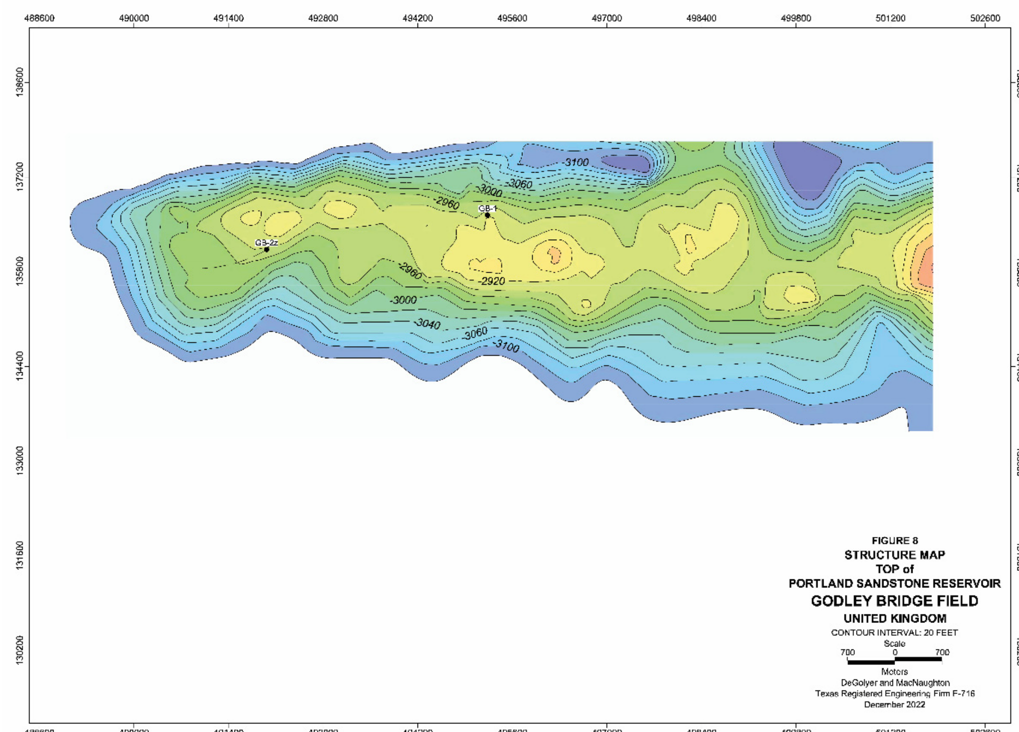

FIGURE 8
STRUCTURE MAP
TOP of
PORTLAND SANDSTONE RESERVOIR
GODLEY BRIDGE FIELD
UNITED KINGDOM
CONTOUR INTERVAL: 20 FEET
Scale
700 0 700
Meters
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716
December 2022

The Scampton North field was discovered in 1985 by well SNA-1. The field is located within license PL179 in Lincolnshire. Scampton North produces light oil of approximately 35 API through five wells from the Basal Succession Sandstone. Porosity was estimated to range from 12 to 18 percent, S_w was estimated to range from 30 to 50 percent, and permeability was estimated to range from 0.5 to 400 millidarcys.

Contingent resources were estimated for drilling a well to an undrained eastern target of the reservoir as well as reperforation of the existing SCN-C3 well. The additional drilling in the field to the eastern target 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. These fields include the Avington, Beckingham, Corringham, Gainsborough, Hemswell, Horndean, Long Clawson, Palmers Wood, Singleton, Stockbridge, and Welton.

The estimated gross 1C, 2C, and 3C contingent resources, as of December 31, 2022, 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	507	0	507	741	0	741	1,002	0	1,002
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	687	0	687	959	0	959	1,048	0	1,048
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	0	2,130	2,992	0	2,992	3,074	0	3,074
Godley Bridge	0	6,888	1,188	0	12,490	2,153	0	14,658	2,527
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
Long Clawson	690	0	690	950	0	950	1,360	0	1,360
Lybster	0	0	0	0	0	0	0	0	0
Nettleham	10	0	10	31	0	31	59	0	59
Palmers Wood	299	147	324	392	188	424	532	247	575
Rempstone	0	0	0	0	0	0	0	0	0
Scampton North	350	0	350	531	0	531	644	0	644
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	948	1,625	1,228	2,577	4,416	3,338	3,801	7,106	5,026
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	7	0	7	10	0	10	14	0	14
Stockbridge	577	0	577	690	0	690	826	0	826
Storrington	0	0	0	0	0	0	0	0	0
Welton	2,729	0	2,729	3,504	0	3,504	4,516	0	4,516
Total	**9,943**	**9,031**	**11,500**	**16,143**	**18,539**	**19,339**	**24,451**	**28,644**	**29,390**

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, 2022, 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	272	0	272	398	0	398	538	0	538
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	687	0	687	959	0	959	1,048	0	1,048
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	0	2,130	2,992	0	2,992	3,074	0	3,074
Godley Bridge	0	6,888	1,188	0	12,490	2,153	0	14,658	2,527
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)	52	74	65	471	675	587	1,652	2,369	2,060
Horndean	314	0	314	719	0	719	1,166	0	1,166
Long Clawson	690	0	690	950	0	950	1,360	0	1,360
Lybster	0	0	0	0	0	0	0	0	0
Nettleham	10	0	10	31	0	31	59	0	59
Palmers Wood	299	147	324	392	188	424	532	247	575
Rempstone	0	0	0	0	0	0	0	0	0
Scampton North	350	0	350	531	0	531	644	0	644
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	948	1,625	1,228	2,577	4,416	3,338	3,801	7,106	5,026
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	7	0	7	10	0	10	14	0	14
Stockbridge	577	0	577	690	0	690	826	0	826
Storrington	0	0	0	0	0	0	0	0	0
Welton	2,729	0	2,729	3,504	0	3,504	4,516	0	4,516
Total	**9,656**	**9,006**	**11,210**	**15,565**	**18,314**	**18,721**	**23,307**	**27,854**	**28,110**

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, two 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 and working interest prospective resources and the P_g estimates, as of December 31, 2022, 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 0.11 to 0.17.

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 two prospects have been evaluated in 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 unrisked prospective resources, as of December 31, 2022, 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)**
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	716
Statistical Aggregate	**6,297**	**8,633**	**11,836**	**8,899**	**5,746**	**7,484**	**9,710**	**7,567**

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, 2022, are summarized as follows, expressed in thousands of barrels (10^3bbl):

	Mean Estimate
Gross P_g-Adjusted Oil Prospective Resources, 10^3bbl	3,328
Working Interest P_g-Adjusted Oil Prospective Resources, 10^3bbl	3,088

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 0.11 to 0.17.
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 shown in Tables A-13 through A-16 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, an Executive Vice President with DeGolyer and MacNaughton, Manager of the firm's Europe/Africa Division, a Registered Professional Engineer in the State of Texas, and a member of the Society of Petroleum Engineers, the Society of Petroleum Evaluation Engineers, and the European Association of Geoscientists & Engineers. He has over 39 years of oil and gas industry experience.

Submitted,

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

STATE OF TEXAS
REGNALD A. BOLES
65092
LICENSED
PROFESSIONAL ENGINEER

Regnald A. Boles, P.E.
Executive 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 × 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.

Nonassociated Gas – Nonassociated 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 PROVED DEVELOPED RESERVES and REVENUE
as of
DECEMBER 31, 2022
attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

Base 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.$)**
2023	694	0	212	116	66,484	29,464	7,836	29,184	27,659
2024	657	0	213	115	56,052	27,083	3,552	25,417	21,813
2025	626	0	163	262	49,319	27,294	3,288	18,737	14,553
2026	558	0	85	262	44,124	25,148	7,321	11,655	8,194
2027	509	0	34	259	40,400	23,801	1,317	15,282	9,723
2028	461	0	0	243	36,390	18,256	8,030	10,104	5,821
2029	424	0	0	204	33,550	16,861	3,595	13,094	6,829
2030	384	0	0	143	30,235	15,284	2,097	12,854	6,069
2031	358	0	0	130	28,189	14,753	0	13,436	5,738
2032	329	0	0	120	26,658	14,041	1,288	11,329	4,387
2033	302	0	0	108	25,297	13,558	0	11,739	4,108
2034	257	0	0	99	22,178	11,109	6,941	4,128	1,308
2035	232	0	0	89	20,557	10,106	1,693	8,758	2,513
2036	210	0	0	81	19,032	9,208	891	8,933	2,319
2037	195	0	0	74	18,232	8,982	0	9,250	2,176
2038	182	0	0	66	17,485	8,761	0	8,724	1,856
2039	168	0	0	59	16,667	8,519	0	8,148	1,571
2040	160	0	0	54	15,953	8,245	927	6,781	1,182
2041	147	0	0	45	15,253	8,064	0	7,189	1,134
2042	138	0	0	25	14,328	7,868	0	6,460	922
2043	122	0	0	22	12,995	7,012	16,426	(10,443)	(1,350)
2044	116	0	0	19	12,418	6,897	0	5,521	648
2045	108	0	0	15	11,765	6,763	0	5,002	530
2046	101	0	0	13	11,269	6,681	0	4,588	438
2047	96	0	0	10	10,800	6,606	0	4,194	366
Subtotal	**7,534**	**0**	**707**	**2,633**	**655,630**	**340,364**	**65,202**	**250,064**	**130,507**
Remaining	812	0	0	18	95,551	67,230	43,572	(15,251)	381
Total	**8,346**	**0**	**707**	**2,651**	**751,181**	**407,594**	**108,774**	**234,813**	**130,888**

Present Worth at (10^3U.S.$)	
8 Percent	145,310
12 Percent	118,958
15 Percent	104,657

TABLE A-2
SUMMARY PROJECTION of TOTAL PROVED RESERVES and REVENUE
as of
DECEMBER 31, 2022
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.$)
2023	694	0	212	116	66,484	29,464	13,649	23,371	22,150
2024	684	0	213	115	58,157	27,219	30,854	84	77
2025	750	0	403	465	62,986	31,033	15,791	16,162	12,550
2026	723	0	280	667	62,624	30,819	7,321	24,484	17,214
2027	653	0	161	664	56,560	29,133	1,317	26,110	16,615
2028	583	0	83	648	50,955	23,385	8,030	19,540	11,257
2029	531	0	54	609	46,851	21,829	3,595	21,427	11,175
2030	482	0	35	387	40,660	19,078	2,097	19,485	9,199
2031	440	0	0	130	34,289	15,960	1,458	16,871	7,206
2032	403	0	0	120	32,423	15,176	1,288	15,959	6,177
2033	371	0	0	108	30,733	14,624	0	16,109	5,639
2034	321	0	0	99	27,299	12,106	6,941	8,252	2,616
2035	289	0	0	89	25,389	11,042	1,693	12,654	3,630
2036	264	0	0	81	23,599	10,090	891	12,618	3,279
2037	242	0	0	74	22,539	9,805	0	12,734	2,992
2038	229	0	0	66	21,544	9,536	0	12,008	2,556
2039	208	0	0	59	20,497	9,244	0	11,253	2,170
2040	197	0	0	54	19,573	8,927	927	9,719	1,692
2041	182	0	0	45	18,669	8,702	0	9,967	1,575
2042	169	0	0	25	17,522	8,470	0	9,052	1,292
2043	152	0	0	22	15,985	7,576	16,426	(8,017)	(1,036)
2044	143	0	0	19	15,223	7,428	0	7,795	913
2045	132	0	0	15	14,392	7,258	0	7,134	756
2046	124	0	0	13	13,726	7,148	0	6,578	629
2047	117	0	0	10	13,101	7,046	0	6,055	527
Subtotal	**9,083**	**0**	**1,441**	**4,700**	**811,780**	**382,098**	**112,278**	**317,404**	**142,850**
Remaining	1,029	0	0	18	121,186	79,133	44,350	(2,297)	1,197
Total	**10,112**	**0**	**1,441**	**4,718**	**932,966**	**461,231**	**156,628**	**315,107**	**144,047**

Present Worth at (10^3U.S.$)	
8 Percent	165,213
12 Percent	126,913
15 Percent	106,822

TABLE A-3
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE RESERVES and REVENUE
as of
DECEMBER 31, 2022
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.$)
2023	725	0	212	116	69,088	30,294	13,649	25,145	23,832
2024	726	0	213	115	61,491	28,125	30,854	2,512	2,157
2025	845	0	513	465	71,060	33,243	15,791	22,026	17,108
2026	865	0	411	667	73,989	34,738	3,363	35,888	25,230
2027	784	0	257	667	67,241	32,289	5,354	29,598	18,836
2028	725	0	151	666	62,493	27,316	6,560	28,617	16,486
2029	679	0	87	659	58,515	25,907	3,595	29,013	15,132
2030	625	0	61	594	54,031	24,153	2,504	27,374	12,921
2031	581	0	43	584	50,938	23,328	677	26,933	11,512
2032	541	0	0	573	48,482	21,902	1,963	24,617	9,519
2033	509	0	0	560	47,170	21,496	0	25,674	8,992
2034	476	0	0	550	45,767	20,910	1,340	23,517	7,453
2035	452	0	0	540	44,707	20,605	0	24,102	6,917
2036	425	0	0	531	43,637	20,295	0	23,342	6,062
2037	402	0	0	521	42,598	20,016	0	22,582	5,309
2038	370	0	0	417	39,617	18,297	1,797	19,523	4,153
2039	332	0	0	234	34,113	14,462	7,663	11,988	2,311
2040	309	0	0	93	31,042	12,675	1,277	17,090	2,978
2041	294	0	0	86	30,293	12,493	0	17,800	2,811
2042	280	0	0	80	29,413	12,345	0	17,068	2,440
2043	267	0	0	70	28,523	12,193	0	16,330	2,109
2044	256	0	0	44	27,463	12,008	0	15,455	1,811
2045	241	0	0	41	26,643	11,872	0	14,771	1,567
2046	233	0	0	37	25,776	11,628	1,044	13,104	1,257
2047	219	0	0	33	25,085	11,529	0	13,556	1,176
Subtotal	**12,161**	**0**	**1,948**	**8,943**	**1,139,175**	**514,119**	**97,431**	**527,625**	**210,079**
Remaining	2,969	0	0	208	352,881	188,596	62,485	101,800	4,929
Total	**15,130**	**0**	**1,948**	**9,151**	**1,492,056**	**702,715**	**159,916**	**629,425**	**215,008**

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	254,214
12 Percent	184,935
15 Percent	151,362

TABLE A-4
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE RESERVES
and REVENUE
as of
DECEMBER 31, 2022
attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

Base 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.$)**
2023	742	0	212	116	70,219	30,627	13,649	25,943	24,585
2024	757	0	213	115	63,961	28,690	30,854	4,417	3,794
2025	924	0	573	465	77,438	34,625	15,791	27,022	20,989
2026	1,003	0	514	667	85,144	37,310	3,363	44,471	31,265
2027	917	0	369	667	78,236	34,904	5,354	37,978	24,172
2028	861	0	222	666	73,114	30,102	5,587	37,425	21,557
2029	806	0	123	667	68,407	28,437	4,587	35,383	18,454
2030	758	0	73	652	64,678	27,799	233	36,646	17,299
2031	708	0	51	593	60,605	26,205	2,316	32,084	13,710
2032	673	0	36	594	59,227	25,837	0	33,390	12,915
2033	629	0	0	594	57,156	24,585	1,517	31,054	10,875
2034	595	0	0	593	55,756	23,857	1,215	30,684	9,726
2035	563	0	0	594	54,911	23,618	0	31,293	8,979
2036	537	0	0	593	54,034	23,365	0	30,669	7,965
2037	511	0	0	580	53,014	23,100	0	29,914	7,032
2038	482	0	0	570	51,867	22,633	1,451	27,783	5,913
2039	463	0	0	559	51,042	22,452	0	28,590	5,508
2040	441	0	0	549	50,364	22,317	0	28,047	4,890
2041	399	0	0	540	47,250	19,828	7,973	19,449	3,070
2042	383	0	0	531	46,363	19,744	0	26,619	3,804
2043	354	0	0	523	44,745	18,868	1,984	23,893	3,092
2044	344	0	0	516	44,070	18,835	0	25,235	2,954
2045	330	0	0	504	43,192	18,751	0	24,441	2,590
2046	315	0	0	470	42,053	18,607	0	23,446	2,249
2047	305	0	0	466	41,407	18,584	0	22,823	1,984
Subtotal	**14,800**	**0**	**2,386**	**13,384**	**1,438,253**	**623,680**	**95,874**	**718,699**	**269,371**
Remaining	4,403	0	0	2,038	553,513	272,067	66,336	215,110	10,009
Total	**19,203**	**0**	**2,386**	**15,422**	**1,991,766**	**895,747**	**162,210**	**933,809**	**279,380**

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	335,722
12 Percent	237,139
15 Percent	191,047

TABLE A-5
SUMMARY PROJECTION of PROVED DEVELOPED QUANTITIES and REVENUE
as of
DECEMBER 31, 2022
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.$)
2023	694	0	212	116	59,873	29,464	7,836	22,573	21,392
2024	657	0	213	115	50,487	27,083	3,552	19,852	17,038
2025	610	0	163	262	43,390	26,213	7,169	10,008	7,774
2026	546	0	85	262	38,924	24,339	5,711	8,874	6,236
2027	498	0	34	259	35,637	23,028	1,317	11,292	7,188
2028	455	0	0	243	32,414	17,915	6,225	8,274	4,764
2029	420	0	0	156	29,382	16,001	4,322	9,059	4,725
2030	384	0	0	143	27,210	15,284	691	11,235	5,305
2031	355	0	0	130	25,138	14,506	1,263	9,369	4,004
2032	298	0	0	120	21,840	11,794	6,671	3,375	1,303
2033	264	0	0	108	20,114	10,677	1,628	7,809	2,735
2034	239	0	0	99	18,664	9,745	856	8,063	2,558
2035	225	0	0	89	17,932	9,496	0	8,436	2,421
2036	210	0	0	81	17,127	9,208	0	7,919	2,054
2037	195	0	0	74	16,410	8,982	0	7,428	1,748
2038	181	0	0	66	15,616	8,640	891	6,085	1,294
2039	167	0	0	59	14,886	8,399	0	6,487	1,250
2040	151	0	0	54	13,605	7,482	15,478	(9,355)	(1,630)
2041	139	0	0	45	13,014	7,311	0	5,703	899
2042	131	0	0	25	12,217	7,124	0	5,093	727
2043	122	0	0	22	11,693	7,012	0	4,681	606
2044	116	0	0	19	11,178	6,897	0	4,281	501
2045	108	0	0	15	10,586	6,763	0	3,823	406
2046	101	0	0	13	10,142	6,681	0	3,461	332
2047	96	0	0	10	9,721	6,606	0	3,115	270
Subtotal	**7,362**	**0**	**707**	**2,585**	**577,200**	**326,650**	**63,610**	**186,940**	**95,900**
Remaining	699	0	0	17	73,928	54,508	43,572	(24,152)	(310)
Total	**8,061**	**0**	**707**	**2,602**	**651,128**	**381,158**	**107,182**	**162,788**	**95,590**

Present Worth at (10^3U.S.$)	
8 Percent	105,830
12 Percent	87,026
15 Percent	76,690

TABLE A-6
SUMMARY PROJECTION of TOTAL PROVED QUANTITIES and REVENUE
as of
DECEMBER 31, 2022
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.$)**
2023	694	0	212	116	59,873	29,464	13,649	16,760	15,883
2024	684	0	213	115	52,382	27,219	30,854	(5,691)	(4,881)
2025	734	0	403	465	55,689	29,952	19,672	6,065	4,714
2026	711	0	280	667	55,570	30,010	5,711	19,849	13,952
2027	642	0	161	664	50,186	28,360	1,317	20,509	13,052
2028	577	0	83	648	45,522	23,044	6,225	16,253	9,363
2029	527	0	54	561	41,350	20,969	4,322	16,059	8,374
2030	475	0	0	387	35,751	18,184	2,121	15,446	7,291
2031	437	0	0	130	30,628	15,713	1,263	13,652	5,835
2032	372	0	0	120	27,027	12,929	6,671	7,427	2,870
2033	333	0	0	108	25,006	11,743	1,628	11,635	4,077
2034	303	0	0	99	23,275	10,742	856	11,677	3,703
2035	282	0	0	89	22,281	10,432	0	11,849	3,400
2036	264	0	0	81	21,234	10,090	0	11,144	2,893
2037	242	0	0	74	20,288	9,805	0	10,483	2,465
2038	228	0	0	66	19,269	9,415	891	8,963	1,907
2039	207	0	0	59	18,334	9,124	0	9,210	1,775
2040	188	0	0	54	16,863	8,164	15,478	(6,779)	(1,182)
2041	174	0	0	45	16,088	7,949	0	8,139	1,283
2042	162	0	0	25	15,091	7,726	0	7,365	1,053
2043	152	0	0	22	14,385	7,576	0	6,809	882
2044	143	0	0	19	13,702	7,428	0	6,274	733
2045	132	0	0	15	12,950	7,258	0	5,692	604
2046	124	0	0	13	12,354	7,148	0	5,206	501
2047	117	0	0	10	11,791	7,046	0	4,745	411
Subtotal	**8,904**	**0**	**1,406**	**4,652**	**716,889**	**367,490**	**110,658**	**238,741**	**100,958**
Remaining	917	0	0	18	97,074	66,561	44,350	(13,837)	407
Total	**9,821**	**0**	**1,406**	**4,670**	**813,963**	**434,051**	**155,008**	**224,904**	**101,365**

Present Worth at (10^3U.S.$)	
8 Percent	117,238
12 Percent	88,486
15 Percent	73,412

TABLE A-7
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE QUANTITIES and REVENUE
as of
DECEMBER 31, 2022
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.$)
2023	725	0	212	116	62,203	30,284	13,649	18,270	17,311
2024	726	0	213	115	55,352	28,114	30,854	(3,616)	(3,093)
2025	829	0	513	465	62,914	32,119	19,672	11,123	8,636
2026	850	0	411	667	65,625	33,672	3,363	28,590	20,098
2027	771	0	257	667	59,688	31,440	3,711	24,537	15,620
2028	716	0	151	666	55,663	26,705	5,587	23,371	13,460
2029	665	0	87	659	51,759	24,960	4,246	22,553	11,764
2030	620	0	61	594	48,302	23,809	975	23,518	11,102
2031	580	0	43	584	45,757	23,231	467	22,059	9,426
2032	538	0	0	573	43,373	21,641	2,775	18,957	7,333
2033	505	0	0	560	42,217	21,244	0	20,973	7,343
2034	476	0	0	550	41,193	20,910	0	20,283	6,430
2035	442	0	0	540	39,484	19,836	1,693	17,955	5,149
2036	416	0	0	531	38,541	19,531	0	19,010	4,939
2037	364	0	0	521	35,362	16,886	7,366	11,110	2,613
2038	344	0	0	417	33,543	15,997	0	17,546	3,735
2039	332	0	0	234	30,702	14,462	0	16,240	3,127
2040	309	0	0	93	27,938	12,675	1,277	13,986	2,439
2041	294	0	0	86	27,266	12,493	0	14,773	2,333
2042	280	0	0	80	26,469	12,345	0	14,124	2,016
2043	267	0	0	70	25,670	12,193	0	13,477	1,745
2044	255	0	0	44	24,585	11,873	1,003	11,709	1,370
2045	231	0	0	41	23,046	10,910	17,089	(4,953)	(523)
2046	225	0	0	37	22,430	10,805	0	11,625	1,115
2047	212	0	0	33	21,838	10,712	0	11,126	966
Subtotal	**11,972**	**0**	**1,948**	**8,943**	**1,010,920**	**498,847**	**113,727**	**398,346**	**156,454**
Remaining	2,898	0	0	208	310,032	180,624	44,350	85,058	4,938
Total	**14,870**	**0**	**1,948**	**9,151**	**1,320,952**	**679,471**	**158,077**	**483,404**	**161,392**

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

Present Worth at (10^3U.S.$)	
8 Percent	192,345
12 Percent	137,674
15 Percent	111,272

TABLE A-8
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE RESERVES
and REVENUE
as of
DECEMBER 31, 2022
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.$)
2023	741	0	212	116	63,195	30,607	13,649	18,939	17,951
2024	757	0	213	115	57,561	28,668	30,854	(1,961)	(1,681)
2025	907	0	573	465	68,601	33,457	19,672	15,472	12,016
2026	987	0	514	667	75,603	36,188	3,363	36,052	25,348
2027	913	0	369	667	70,178	34,666	2,270	33,242	21,157
2028	849	0	222	666	64,973	29,238	7,057	28,678	16,518
2029	797	0	123	667	60,966	27,811	3,595	29,560	15,414
2030	743	0	73	652	57,280	26,817	897	29,566	13,959
2031	703	0	51	593	54,205	25,846	756	27,603	11,793
2032	661	0	0	594	52,077	24,551	1,487	26,039	10,075
2033	625	0	0	594	51,120	24,231	0	26,889	9,416
2034	595	0	0	593	50,186	23,857	496	25,833	8,186
2035	560	0	0	594	49,154	23,347	1,367	24,440	7,014
2036	534	0	0	593	48,375	23,099	0	25,276	6,564
2037	508	0	0	580	47,469	22,840	0	24,629	5,791
2038	452	0	0	570	44,174	20,129	7,513	16,532	3,518
2039	425	0	0	559	42,781	19,198	1,833	21,750	4,190
2040	407	0	0	549	42,347	19,124	0	23,223	4,048
2041	390	0	0	540	41,759	19,014	0	22,745	3,591
2042	375	0	0	531	40,991	18,931	0	22,060	3,153
2043	354	0	0	523	40,269	18,868	0	21,401	2,768
2044	344	0	0	516	39,660	18,835	0	20,825	2,440
2045	330	0	0	504	38,872	18,751	0	20,121	2,131
2046	315	0	0	470	37,846	18,607	0	19,239	1,846
2047	305	0	0	466	37,268	18,584	0	18,684	1,623
Subtotal	**14,577**	**0**	**2,350**	**13,384**	**1,276,910**	**605,264**	**94,809**	**576,837**	**208,829**
Remaining	4,310	0	0	2,038	488,228	261,650	65,958	160,620	7,536
Total	**18,887**	**0**	**2,350**	**15,422**	**1,765,138**	**866,914**	**160,767**	**737,457**	**216,365**

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

Present Worth at (10^3U.S.$)	
8 Percent	261,709
12 Percent	182,382
15 Percent	145,374

TABLE A-9
SUMMARY PROJECTION of PROVED DEVELOPED QUANTITIES and REVENUE
as of
DECEMBER 31, 2022
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.$)
2023	694	0	212	116	73,090	29,464	7,836	35,790	33,923
2024	657	0	213	115	61,630	27,083	3,552	30,995	26,593
2025	626	0	163	262	54,246	27,294	3,288	23,664	18,384
2026	572	0	85	262	49,638	26,161	3,363	20,114	14,142
2027	521	0	34	259	45,431	24,754	1,317	19,360	12,318
2028	482	0	0	243	41,738	19,896	5,587	16,255	9,363
2029	431	0	0	204	37,453	17,385	8,788	11,280	5,884
2030	390	0	0	143	33,702	15,701	2,504	15,497	7,317
2031	361	0	0	130	31,324	15,070	467	15,787	6,745
2032	333	0	0	120	29,581	14,279	691	14,611	5,653
2033	304	0	0	108	28,066	13,789	0	14,277	5,001
2034	281	0	0	99	26,533	13,160	1,340	12,033	3,812
2035	241	0	0	89	23,396	10,827	7,080	5,489	1,575
2036	224	0	0	81	22,307	10,503	0	11,804	3,064
2037	201	0	0	74	20,649	9,551	1,762	9,336	2,197
2038	188	0	0	66	19,787	9,313	0	10,474	2,230
2039	168	0	0	59	18,331	8,519	945	8,867	1,706
2040	162	0	0	54	17,679	8,364	0	9,315	1,625
2041	148	0	0	45	16,906	8,182	0	8,724	1,377
2042	138	0	0	25	15,756	7,868	964	6,924	990
2043	129	0	0	22	15,080	7,749	0	7,331	949
2044	123	0	0	19	14,402	7,629	0	6,773	792
2045	108	0	0	15	12,943	6,763	17,089	(10,909)	(1,156)
2046	101	0	0	13	12,394	6,681	0	5,713	548
2047	96	0	0	10	11,880	6,606	0	5,274	458
Subtotal	**7,679**	**0**	**707**	**2,633**	**733,942**	**352,591**	**66,573**	**314,778**	**165,490**
Remaining	894	0	0	18	115,818	77,341	43,572	(5,095)	1,026
Total	**8,573**	**0**	**707**	**2,651**	**849,760**	**429,932**	**110,145**	**309,683**	**166,516**

Present Worth at (10^3U.S.$)	
8 Percent	185,203
12 Percent	151,175
15 Percent	132,874

TABLE A-10
SUMMARY PROJECTION of TOTAL PROVED QUANTITIES and REVENUE
as of
DECEMBER 31, 2022
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.$)
2023	694	0	212	116	73,090	29,464	13,649	29,977	28,412
2024	684	0	213	115	63,946	27,219	30,854	5,873	5,039
2025	750	0	403	465	69,281	31,033	15,791	22,457	17,444
2026	737	0	280	667	69,983	31,832	3,363	34,788	24,461
2027	665	0	161	664	63,209	30,086	1,317	31,806	20,239
2028	604	0	83	648	57,762	25,025	5,587	27,150	15,641
2029	538	0	54	609	52,085	22,353	8,788	20,944	10,921
2030	488	0	35	387	45,170	19,495	2,504	23,171	10,942
2031	443	0	0	130	38,036	16,277	1,925	19,834	8,473
2032	407	0	0	120	35,921	15,414	691	19,816	7,667
2033	373	0	0	108	34,045	14,855	0	19,190	6,721
2034	345	0	0	99	32,166	14,157	1,340	16,669	5,281
2035	298	0	0	89	28,711	11,763	7,080	9,868	2,832
2036	278	0	0	81	27,329	11,385	0	15,944	4,140
2037	248	0	0	74	25,388	10,374	1,762	13,252	3,119
2038	235	0	0	66	24,252	10,087	0	14,165	3,013
2039	208	0	0	59	22,544	9,244	945	12,355	2,379
2040	199	0	0	54	21,661	9,046	0	12,615	2,200
2041	183	0	0	45	20,664	8,820	0	11,844	1,870
2042	169	0	0	25	19,271	8,470	964	9,837	1,407
2043	159	0	0	22	18,368	8,313	0	10,055	1,300
2044	150	0	0	19	17,489	8,160	0	9,329	1,091
2045	132	0	0	15	15,831	7,258	17,089	(8,516)	(902)
2046	124	0	0	13	15,098	7,148	0	7,950	762
2047	117	0	0	10	14,411	7,046	0	7,365	641
Subtotal	**9,228**	**0**	**1,441**	**4,700**	**905,711**	**394,324**	**113,649**	**397,738**	**185,093**
Remaining	1,125	0	0	18	145,815	90,960	44,350	10,505	1,969
Total	**10,353**	**0**	**1,441**	**4,718**	**1,051,526**	**485,284**	**157,999**	**408,243**	**187,062**

Present Worth at (10^3U.S.$)	
8 Percent	213,629
12 Percent	165,605
15 Percent	140,448

TABLE A-11
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE QUANTITIES and REVENUE
as of
DECEMBER 31, 2022
attributable to
IGAS ENERGY PLC
UNITED KINGDOM

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

High 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.$)
2023	725	0	212	116	75,933	30,284	13,649	32,000	30,331
2024	726	0	213	115	67,584	28,114	30,854	8,616	7,393
2025	845	0	513	465	78,166	33,243	15,791	29,132	22,629
2026	865	0	411	667	81,383	34,738	3,363	43,282	30,428
2027	798	0	257	667	75,041	33,303	1,317	40,421	25,727
2028	740	0	151	666	69,986	28,499	5,587	35,900	20,680
2029	679	0	87	659	64,368	25,907	8,788	29,673	15,473
2030	633	0	61	594	60,068	24,738	975	34,355	16,221
2031	592	0	43	584	57,006	24,241	0	32,765	13,999
2032	558	0	30	573	55,179	23,706	476	30,997	11,991
2033	520	0	0	560	52,785	22,378	1,517	28,890	10,116
2034	485	0	0	550	51,163	21,701	719	28,743	9,112
2035	455	0	0	540	49,423	20,845	1,688	26,890	7,715
2036	427	0	0	531	48,236	20,529	0	27,707	7,198
2037	402	0	0	521	46,851	20,016	1,422	25,413	5,972
2038	378	0	0	417	44,394	19,048	0	25,346	5,396
2039	363	0	0	234	40,688	17,443	0	23,245	4,476
2040	343	0	0	93	37,706	16,178	0	21,528	3,756
2041	294	0	0	86	33,325	12,493	11,182	9,650	1,522
2042	280	0	0	80	32,352	12,345	0	20,007	2,858
2043	267	0	0	70	31,376	12,193	0	19,183	2,481
2044	256	0	0	44	30,213	12,008	0	18,205	2,134
2045	241	0	0	41	29,306	11,872	0	17,434	1,846
2046	234	0	0	37	28,499	11,760	0	16,739	1,606
2047	220	0	0	33	27,728	11,661	0	16,067	1,395
Subtotal	**12,326**	**0**	**1,978**	**8,943**	**1,268,759**	**529,243**	**97,328**	**642,188**	**262,455**
Remaining	3,031	0	0	208	396,042	196,100	64,304	135,638	6,454
Total	**15,357**	**0**	**1,978**	**9,151**	**1,664,801**	**725,343**	**161,632**	**777,826**	**268,909**

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

Present Worth at (10^3U.S.$)	
8 Percent	316,502
12 Percent	232,376
15 Percent	191,502

TABLE A-12
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE RESERVES
and REVENUE
as of
DECEMBER 31, 2022
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.$)
2023	741	0	212	116	77,151	30,607	13,649	32,895	31,180
2024	757	0	213	115	70,277	28,668	30,854	10,755	9,226
2025	924	0	573	465	85,181	34,624	15,791	34,766	27,005
2026	1,003	0	514	667	93,654	37,311	3,363	52,980	37,253
2027	931	0	369	667	87,229	35,983	1,317	49,929	31,771
2028	875	0	222	666	81,535	31,146	5,587	44,802	25,812
2029	822	0	123	667	76,513	29,660	3,595	43,258	22,557
2030	760	0	73	652	71,360	28,011	4,518	38,831	18,331
2031	716	0	51	593	67,326	26,814	1,788	38,724	16,546
2032	681	0	36	594	65,797	26,440	0	39,357	15,226
2033	636	0	0	594	63,508	25,178	1,517	36,813	12,890
2034	607	0	0	593	62,442	24,896	0	37,546	11,899
2035	573	0	0	594	61,364	24,545	505	36,314	10,421
2036	548	0	0	593	60,384	24,284	0	36,100	9,377
2037	517	0	0	580	58,887	23,669	763	34,455	8,098
2038	490	0	0	570	57,891	23,451	0	34,440	7,328
2039	466	0	0	559	56,411	22,705	1,828	31,878	6,143
2040	443	0	0	549	55,653	22,566	0	33,087	5,770
2041	422	0	0	540	54,485	22,146	1,540	30,799	4,863
2042	404	0	0	531	53,330	22,014	0	31,316	4,474
2043	361	0	0	523	50,096	19,680	8,295	22,121	2,862
2044	352	0	0	516	49,324	19,649	0	29,675	3,473
2045	330	0	0	504	47,515	18,751	2,064	26,700	2,832
2046	315	0	0	470	46,257	18,607	0	27,650	2,650
2047	305	0	0	466	45,550	18,584	0	26,966	2,343
Subtotal	**14,979**	**0**	**2,386**	**13,384**	**1,599,120**	**639,989**	**96,974**	**862,157**	**330,330**
Remaining	4,428	0	0	2,038	612,081	275,156	66,336	270,589	12,432
Total	**19,407**	**0**	**2,386**	**15,422**	**2,211,201**	**915,145**	**163,310**	**1,132,746**	**342,762**

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

Present Worth at (10^3U.S.$)	
8 Percent	410,253
12 Percent	292,140
15 Percent	236,821

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE A-13
PROSPECT PORTFOLIO SUMMARY
as of
DECEMBER 31, 2022
for
IGAS ENERGY PLC
in
VARIOUS PROSPECTS
VARIOUS LICENSES
UNITED KINGDOM

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

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE A-14
ESTIMATE of the GROSS PROSPECTIVE OIL RESOURCES
as of
DECEMBER 31, 2022
for
IGAS ENERGY PLC
in
VARIOUS OIL PROSPECTS
VARIOUS LICENSES
UNITED KINGDOM

				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)**
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				**6,297**	**8,633**	**11,836**	**8,899**	**0.374**	**3,328**
Arithmetic Summation				4,507	7,997	14,228	8,899	0.374	3,328

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 exceed the minimum case prospective resources recoverable volume(s). P_g is not linked to economically viable volumes, economic flow rates, or economic field size assumptions.
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 0.11 to 0.17.

TABLE A-15
ESTIMATE of the WORKING INTEREST PROSPECTIVE OIL RESOURCES
as of
DECEMBER 31, 2022
for
IGAS ENERGY PLC
in
VARIOUS OIL PROSPECTS
VARIOUS LICENSES
UNITED KINGDOM

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

Prospect	Country	Area/Basin	License/Block	Working Interest Prospective Oil Resources Summary: 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)
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	716	0.180	129
Statistical Aggregate				**5,746**	**7,484**	**9,710**	**7,567**	**0.408**	**3,088**
Arithmetic Summation				4,113	6,932	11,673	7,567	0.408	3,088

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 exceed the minimum case prospective resources recoverable volume(s). P_g is not linked to economically viable volumes, economic flow rates, or economic field size assumptions.
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 0.11 to 0.17.

DeGolyer and MacNaughton F-716 TEXAS REGISTERED ENGINEERING FIRM

TABLE A-16
PROBABILITY DISTRIBUTIONS
for
MONTE CARLO SIMULATION
as of
DECEMBER 31, 2022
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
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