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DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

DeGolyer and MacNaughton
5001 Spring Valley Road
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Dallas, Texas 75244

March 15, 2019

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

Ladies and Gentlemen:

Pursuant to your request, we have prepared estimates, as of December 31, 2018, 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, and the extent of the 1C, 2C, and 3C contingent resources from certain properties in the United Kingdom, in which IGas Energy PLC (IGas) has represented it holds an interest.

Estimates of reserves and contingent 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.

This report is compliant with the Competent Person's Report requirements as published in the European Securities and Markets Authority (ESMA) update of the Committee of European Securities Regulators' recommendations for the implementation of the European Commission Regulation on Prospectuses No. 809/2004 dated March 20, 2013 (ESMA/2013/319).

Reserves estimated in this report are expressed as gross reserves and net reserves. Gross reserves are defined as the total estimated petroleum remaining to be produced from the fields after December 31, 2018. Net reserves are defined as that portion of the gross reserves attributable to the interests held by IGas after deducting interests held by others, as described herein.

This report presents values for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves that were estimated using initial prices, expenses, and costs provided by IGas and future 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 of U.S.$1.30 per U.K.£1.00. All monetary values in this report are expressed in U.S.$. An explanation of the forecast price, expense, and cost assumptions is included under the Valuation of Reserves heading of this report.

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

The 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, 2018. Net contingent resources are defined as that portion of the gross contingent resources that might potentially be produced from the properties attributable to the interests evaluated herein after deducting interests attributable to others.

The contingent resources estimated herein are those quantities of petroleum that are potentially recoverable from known accumulations but which are not currently considered to be commercially recoverable because of such contingencies as lack of commitment to develop, lack of product sales agreements, and/or lack of defined infrastructure, among other contingencies. 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. 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.

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

Estimates of reserves and revenue and contingent 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 13 fields containing reserves only, 4 fields containing contingent resources only, and 12 fields containing both reserves and contingent resources.

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, 2018, 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 26 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 boe.

The estimated gross and net proved, probable, and possible reserves, as of December 31, 2018, 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	8,940	3,756	3,449	5,350	6,047	5,716	9,862	4,799	4,435
Net	8,855	3,737	3,426	5,350	6,047	5,716	9,777	4,780	4,412

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 boe.

Revenue

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

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

The estimated future net revenue and present worth of the future net revenue discounted at 10 percent to be derived from the production and sale of the proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves and quantities, as of December 31, 2018, of the properties evaluated utilizing the three economic scenarios 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	184,500	109,632	357,948	159,440	518,980	201,309
Low Case	100,963	58,926	230,312	91,568	353,149	123,316
High Case	278,321	157,499	495,142	220,401	696,131	272,037

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

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

Contingent Resources

Contingent resources were estimated for oil, condensate, and sales gas in 16 fields. Sales gas contingent resources were converted to boe using an energy equivalent factor of 5,800 cubic feet of gas per boe.

The estimated gross and net 1C, 2C, and 3C contingent resources, as of December 31, 2018, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

	Contingent Resources Summary					
	Gross Contingent Resources			Net Contingent Resources		
	Oil and Condensate (10^3bbl)	Sales Gas (10^6ft^3)	Oil Equivalent (10^3boe)	Oil and Condensate (10^3bbl)	Sales Gas (10^6ft^3)	Oil Equivalent (10^3boe)
1C	11,064	9,373	12,680	10,776	9,373	12,392
2C	16,875	16,072	19,646	16,425	16,072	19,196
3C	23,299	21,517	27,009	22,668	21,517	26,378

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 boe.

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	11/15/2020
Avington	PEDL70	50.00	9/8/2031
Baxters Copse	PEDL233	50.00	6/30/2039
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
East Glentworth	PL179	100.00	11/16/2034
Egmanton	ML3	100.00	12/30/2033
Gainsborough	ML4	100.00	3/31/2040
Glentworth	ML4	100.00	3/31/2040
Godley Bridge	PEDL235	100.00	6/30/2039
Goodworth	PEDL21	100.00	4/3/2027
Horndean	PL211	90.00	4/4/2036
Lingfield	PEDL257	100.00	7/20/2046
Long Clawson	PL220	100.00	8/8/2026
Lybster	P1270	100.00	12/21/2031
Nettleham	PL179	100.00	11/16/2034
Nettleham	PL199	100.00	10/31/2045
Palmers Wood	PL182	100.00	11/16/2034
Rempstone	PL220	100.00	8/8/2026
Scampton North	PL179	100.00	11/16/2034
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	12/31/2019
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

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.

There are 16 fields evaluated herein located in the East Midlands Basin, as shown on Figure 1.

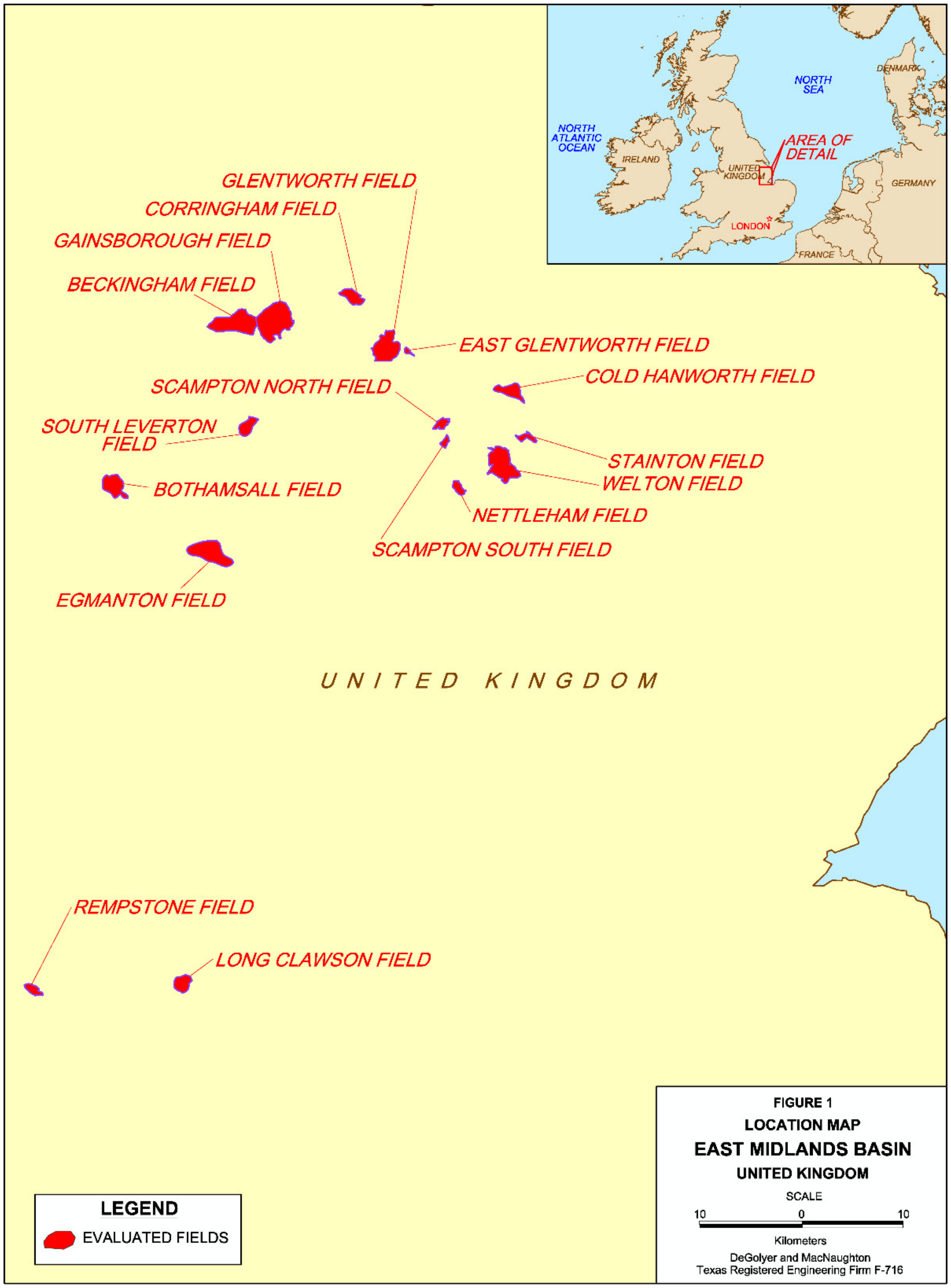
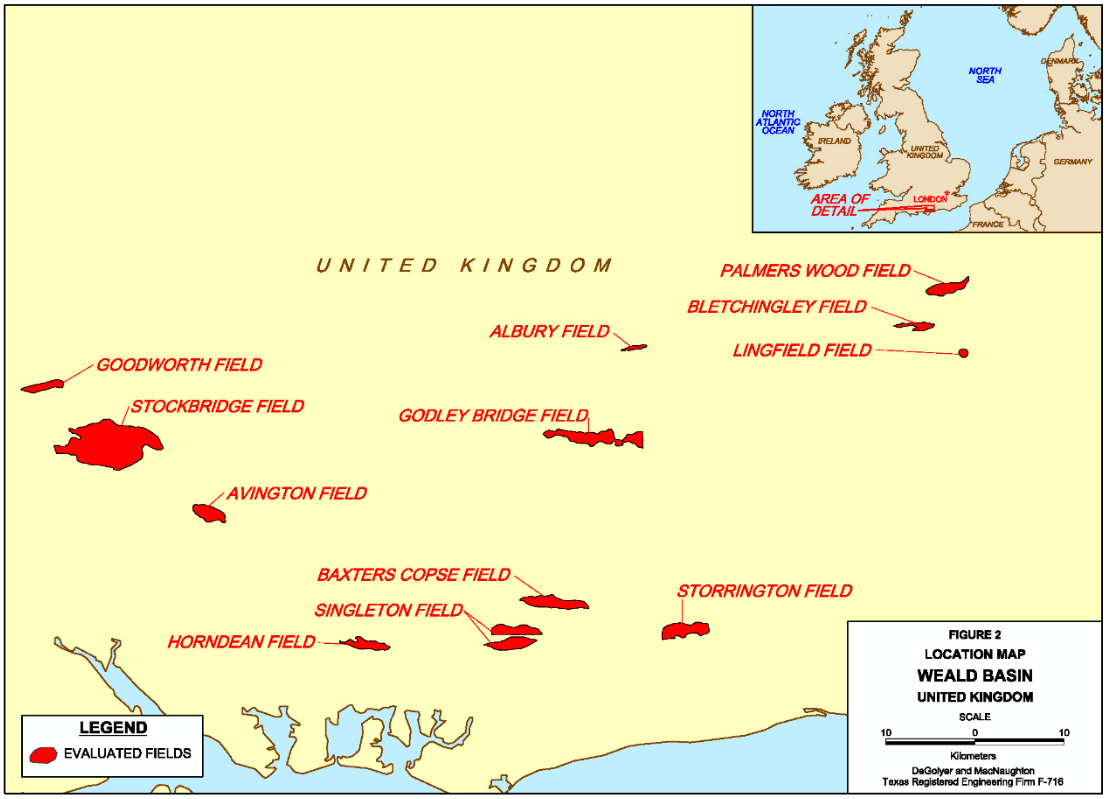


FIGURE 1
LOCATION MAP
EAST MIDLANDS BASIN
UNITED KINGDOM

There are 12 fields evaluated herein located in the Weald Basin, as shown on Figure 2.



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

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.

<u>Environmental Consideration</u>

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

Definition of Reserves

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

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

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

will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

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

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

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

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

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

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

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

Estimation of Reserves

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

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

IGas has represented that its senior management is committed to the development plan provided by IGas and that IGas has the financial capability to execute the development plan, 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. When adequate data were available and when circumstances justified, material-balance methods were used to estimate OOIP or OGIP.

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

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

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

Except where noted herein, reserves estimates presented herein were generally based on data available through December 31, 2018, and were supported by details of drilling results, analyses of available geological data, well-test results, pressures, available core data, and production history. The reserves estimates presented herein were based on consideration of daily or monthly production data only through November 2018. Where applicable, estimated cumulative production, as of December 31, 2018, was deducted from the gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 1 month. This report takes into account all relevant information provided to us by IGas.

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

Gas quantities estimated herein are expressed as sales gas. 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 reserves estimated herein are reported as sales gas. Gas reserves estimated herein 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) and are reported in 10^6ft^3.

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

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

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. Eighteen 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 analogy when appropriate.

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

The Avington field, located in license PEDL70, was discovered in 1987 with oil shows in the Cornbrash and Great Oolite reservoirs. Development of the field occurred in 1987 with the Avington-1 well drilled into the upthrown side of a fault defining the field. The field stopped producing from two wells at the end of 2017 due to high operating costs. Porosity ranged from 14 to 23 percent, S_w from 46 to 57 percent, and permeability from 0.08 to 0.1 millidarcy. In this fractured reservoir, the effective permeability can be much higher. Since there are no firm plans to restart production, all reserves for the Avington field were estimated to be zero.

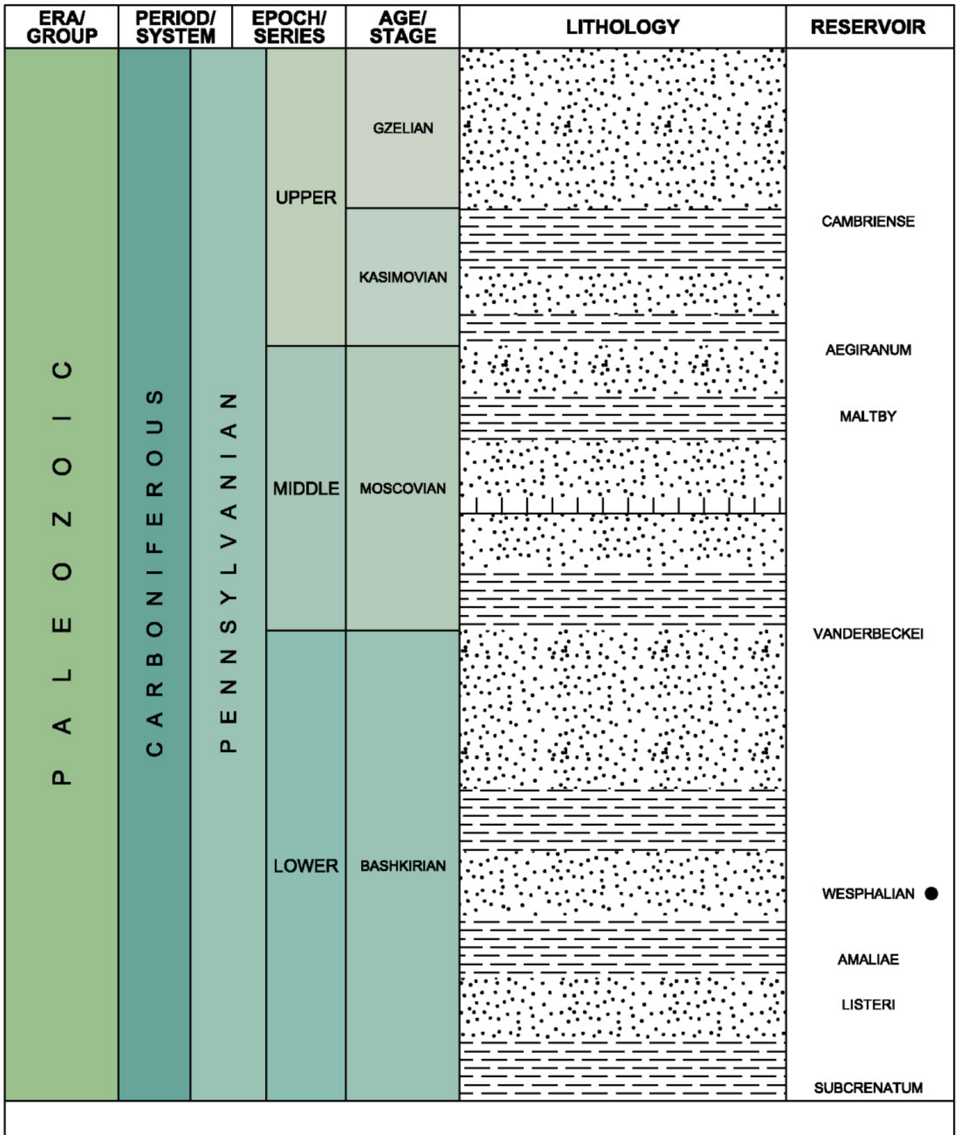


FIGURE 4
GENERALIZED
STRATIGRAPHIC COLUMN
EAST MIDLANDS BASIN
UNITED KINGDOM
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716

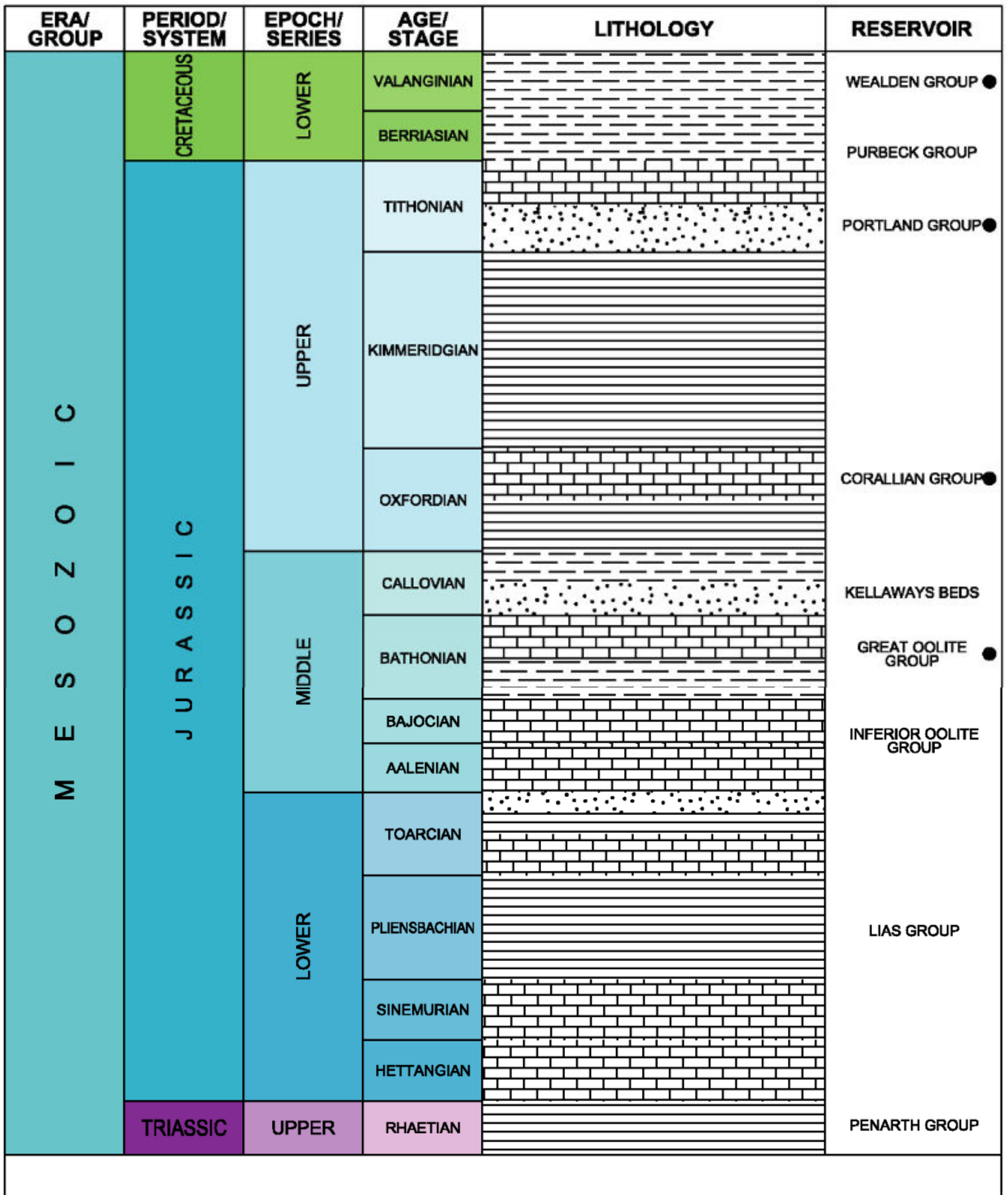


FIGURE 5
GENERALIZED
STRATIGRAPHIC COLUMN
WEALD BASIN
UNITED KINGDOM
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716

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

The Bletchingley field, located in licenses ML18 and ML21, was discovered in 1966. Oil was found in the Corallian Sandstone and the field is currently producing from two wells. Porosity ranged from 5 to 25 percent, S_w from 40 to 70 percent, and permeability from 0.2 to 1000 millidarcys. Proved reserves were estimated based on individual well performance and proved undeveloped reserves were estimated based on volumetrics for one new well. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

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

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

The Corringham field, located in license ML4, was discovered in 1958 and consists of three main fault blocks. The Corringham field produces oil from the Silkstone and Chatsworth reservoirs. Porosity ranged from 14 to 27 percent, S_w from 37 to 44 percent, and permeability from 160 to 500 millidarcys. Proved reserves were estimated based on performance of existing wells. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

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

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

The Gainsborough field, located in license ML4, was discovered in 1959 and is located on the Lincolnshire-Nottingham border, 25 miles east of Sheffield. The main producing reservoirs are the Eagle, Donald, and Condor Sandstones. Porosity ranged from 8 to 20 percent, S_w from 40 to 70 percent, and permeability from 0.01 to 30 millidarcys. The field produces light oil of approximately 38 °API. Proved reserves were estimated based on performance of existing wells, including scheduled workovers. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The 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 rock. The field was shut in from 1965 to 1971 and is currently producing low-shrinkage oil from four wells. Porosity ranged from 16 to 20 percent, S_w from 50 to 65 percent, and permeability from 0.1 to 30 millidarcys. Proved developed reserves were estimated based on performance of existing wells. Estimates of probable and possible reserves account for the potential for better performance than proved reserves and estimates of probable undeveloped and possible undeveloped reserves account for one new well.

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

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

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

The Lybster field (Figure 6) was discovered in 1996 by well 11/24-1 and is located offshore the Caithness coast in license P1270. The field is gas bearing in the Beatrice Sandstone. The Lybster field was evaluated volumetrically, and reserves were estimated using analogous recovery factors based on other similar fields in the area. Recovery factors ranged from 55 to 80 percent. The following ranges were also used in volumetrics: porosity of 12 percent, S_w from 35 to 45 percent, and permeability from 90 to 1,115 millidarcys.

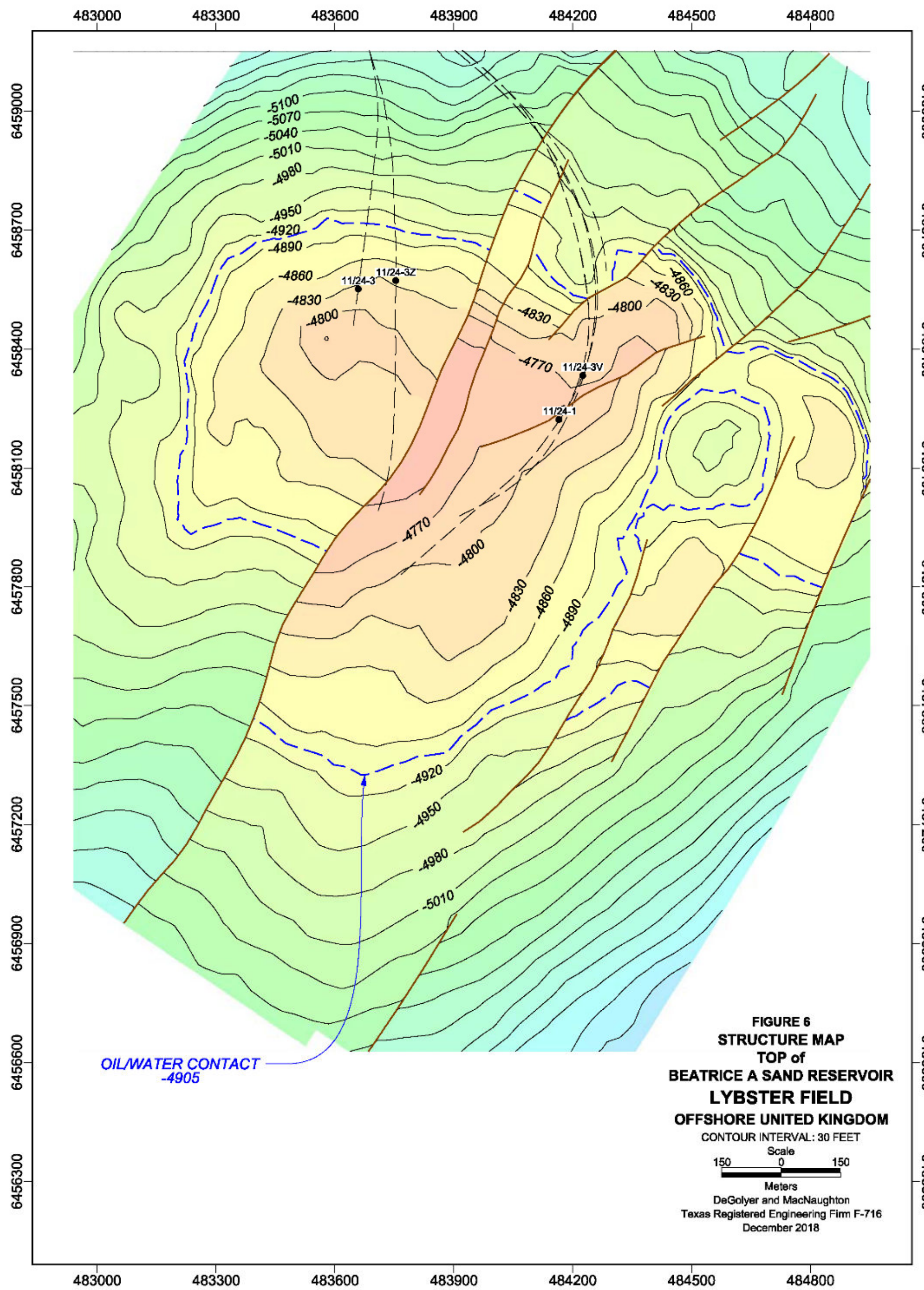


FIGURE 6
STRUCTURE MAP
TOP of
BEATRICE A SAND RESERVOIR
LYBSTER FIELD
OFFSHORE UNITED KINGDOM
CONTOUR INTERVAL: 30 FEET
Scale
150 0 150
Meters
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716
December 2018

The Nettleham field, located in licenses PL179 and PL199, was discovered in 1983 and is located approximately 5 kilometers northeast of the city of Lincoln. The primary reservoir is the Basal Westphalian. The field is not currently producing. Porosity ranged from 19 to 22 percent, S_w from 30 to 60 percent, and permeability from 6 to 1,000 millidarcys. No reserves were estimated for this field because production stopped in February 2016, and the projections that might have allowed the field to come back on line were determined to be uneconomic.

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

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

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

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 high sulfur levels. The field is not currently producing. Porosity ranged from 10 to 16 percent, S_w from 26 to 40 percent, and permeability from 5 to 500 millidarcys. Reserves for this field were estimated to be zero, as the field has watered out.

The Singleton field was discovered in 1989 by the Singleton-1 well. The field is located within production license PL240 near the village of Singleton. The field currently produces light oil of approximately 39°API through six wells from the Great Oolite Formation. Porosity ranged from 13 to 16 percent, S_w from 30 to 62 percent, and permeability from 0.1 to 10 millidarcys. Proved reserves were estimated based on performance of existing wells, including restoration of production from the Singleton-6 well. Estimates of probable and possible reserves account for the potential for better performance than proved reserves from existing and future wells.

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

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

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

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

The Welton field was discovered in 1981. The field is located 7 kilometers northeast of Lincoln in license PL179b. The field has produced from several formations, including the Basal Succession and the Upper Succession. Porosity ranged from 12 to 20 percent, S_w from 20 to 40 percent, and permeability from 10 to 1,000 millidarcys. Proved reserves were estimated based on individual well performance, including workovers for several wells, and reflect the recent waterflooding of the Upper Succession. Estimates of probable and possible reserves account for the potential for better performance than proved reserves.

The estimated gross proved, probable, and possible reserves, as of December 31, 2018, 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	1,661	494	493	286	85	85
Avington	0	0	0	0	0	0	0	0	0
Baxter's Copse	0	0	0	0	0	0	0	0	0
Beckingham	423	112	227	0	0	0	423	112	227
Bletchingley	237	101	92	810	2,894	3,755	377	600	739
Bothamsall	78	40	74	0	0	0	78	40	74
Cold Hanworth	238	69	107	0	0	0	238	69	107
Corringham	184	36	36	0	0	0	184	36	36
East Glentworth	75	14	15	0	0	0	75	14	15
Egmanton	0	0	0	0	0	0	0	0	0
Gainsborough	105	49	118	431	261	606	179	94	222
Glentworth	589	615	552	0	0	0	589	615	552
Godley Bridge	0	0	0	0	0	0	0	0	0
Goodworth	24	9	24	0	0	0	24	9	24
Horndean	844	202	226	0	0	0	844	202	226
Lingfield	0	0	0	0	0	0	0	0	0
Long Clawson	0	0	0	0	0	0	0	0	0
Lybster	117	19	35	436	70	130	192	31	57
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	266	74	105	0	0	0	266	74	105
Rempstone	0	0	0	0	0	0	0	0	0
Scampton North	412	343	239	0	0	0	412	343	239
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	1,778	1,028	423	1,793	2,271	667	2,087	1,420	538
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	889	208	287	0	0	0	889	208	287
Storrington	133	67	39	0	0	0	133	67	39
Welton	2,548	770	850	219	57	65	2,586	780	861
Total	**8,940**	**3,756**	**3,449**	**5,350**	**6,047**	**5,716**	**9,862**	**4,799**	**4,435**

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 boe.

The estimated net proved, probable, and possible reserves, as of December 31, 2018, 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	1,661	494	493	286	85	85
Avington	0	0	0	0	0	0	0	0	0
Baxter's Copse	0	0	0	0	0	0	0	0	0
Beckingham	423	112	227	0	0	0	423	112	227
Bletchingley	237	101	92	810	2,894	3,755	377	600	739
Bothamsall	78	40	74	0	0	0	78	40	74
Cold Hanworth	238	69	107	0	0	0	238	69	107
Corringham	184	36	36	0	0	0	184	36	36
East Glentworth	75	14	15	0	0	0	75	14	15
Egmanton	0	0	0	0	0	0	0	0	0
Gainsborough	105	49	118	431	261	606	179	94	222
Glentworth	589	615	552	0	0	0	589	615	552
Godley Bridge	0	0	0	0	0	0	0	0	0
Goodworth	24	9	24	0	0	0	24	9	24
Horndean	759	183	203	0	0	0	759	183	203
Lingfield	0	0	0	0	0	0	0	0	0
Long Clawson	0	0	0	0	0	0	0	0	0
Lybster	117	19	35	436	70	130	192	31	57
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	266	74	105	0	0	0	266	74	105
Rempstone	0	0	0	0	0	0	0	0	0
Scampton North	412	343	239	0	0	0	412	343	239
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	1,778	1,028	423	1,793	2,271	667	2,087	1,420	538
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	889	208	287	0	0	0	889	208	287
Storrington	133	67	39	0	0	0	133	67	39
Welton	2,548	770	850	219	57	65	2,586	780	861
Total	**8,855**	**3,737**	**3,426**	**5,350**	**6,047**	**5,716**	**9,777**	**4,780**	**4,412**

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 boe.

Valuation of Reserves

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

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

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

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

Oil, Condensate, and Gas Prices

Base Case Price Assumptions

Oil prices for the Base Case were based on the futures market forward curve at the end of 2018, namely, the Intercontinental Exchange (ICE) forward curve averaged for the month of December 2018. After the forward curve ends in 4 years, a 2-percent escalation was applied to subsequent years but capped at U.S.\$100. 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 prevailing United Kingdom national balancing point gas price at the end of 2018 and held constant for the duration of the projects. IGas has represented that its produced gas is sold in two outlets: through direct sales to the United Kingdom national gas grid and "gas to power." Gas to power is a portion of produced gas that receives a net price related to the amount of electricity it produces through generation. The gas price assumptions are shown in the table below, expressed in United States dollars per thousand cubic feet (U.S.\$/10^3ft^3):

Year	Base Case Prices Oil (U.S.$/bbl)	Condensate (U.S.$/bbl)	Gas Export (U.S.$/$10^3$ft^3)	Gas to Power (U.S.$/$10^3$ft^3)
2019	58.25	52.43	6.94	6.64
2020	58.73	52.86	6.94	6.64
2021	59.01	53.11	6.94	6.64
2022	59.47	53.52	6.94	6.64
2023	60.66	54.59	6.94	6.64
2024	61.87	55.68	6.94	6.64

Note: From 2025 forward, oil and condensate prices are escalated at 2 percent per year. Gas prices are held constant.

Low Case Price Assumptions

Oil prices for the Low Case are U.S.$10.00 per barrel lower than the Base Case, and the Low Case gas price is U.S.$1.00 per 10^3ft^3 lower than the Base Case. Reserves estimates herein were based on the Base Case scenario, and quantities in the sensitivity cases are those estimated prior to the Base Case limit of projected production or when an annual economic limit is reached, whichever comes first. All other components of the evaluation, including costs, for the sensitivity cases are the same as those stated for the Base Case herein.

High Case Price Assumptions

Oil prices for the High Case are U.S.$10.00 per barrel higher than the Base Case, and the High Case gas price is U.S.$1.00 per 10^3ft^3 higher than the Base Case. Reserves estimates herein were based on the Base Case scenario, and quantities in the sensitivity cases are those estimated prior to the Base Case limit of projected production or when an annual economic limit is reached, whichever comes first. All other components of the evaluation, including costs, for the sensitivity cases are the same as those stated for the Base Case herein.

Operating Expenses, Capital Costs, and Abandonment Costs

Current operating expenses and operating expense forecasts provided by IGas were used in estimating future expenses required to operate the fields for all three economic scenarios. In certain cases, future expenses, either higher or lower than current expenses, may have been used because of anticipated changed operating conditions. Pipeline and processing tariffs are paid for access to markets. Future capital expenditures and abandonment costs were estimated using current forecasts provided by IGas. A 2-percent cost escalation per year was applied for fixed operating expenses, capital costs, and abandonment costs for 2020 and beyond. Generally, abandonment costs were assigned the year after cessation of production, except where other anticipated abandonment dates were represented by IGas. Economic limits for each field have been estimated based on annual operating expenses with no consideration of taxes.

Royalty

No royalty is applicable for these United Kingdom fields.

Exchange Rate

Where applicable, an exchange rate of U.S.$1.30 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, 2018, of the properties evaluated under the Base Case economic assumptions described herein are 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	636,578	967,545	1,281,526
Operating Expenses	329,804	468,616	610,682
Abandonment and Capital Costs	122,274	140,981	151,864
Future Net Revenue	184,500	357,948	518,980
Present Worth at 10 Percent	109,632	159,440	201,309

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, 2018, of the properties evaluated under the Low Case and High Case economic assumptions described herein are 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	485,754	788,343	1,054,769	730,399	1,104,739	1,458,677
Operating Expenses	277,168	423,383	556,738	329,804	468,616	610,682
Abandonment and Capital Costs	107,623	134,648	144,882	122,274	140,981	151,864
Future Net Revenue	100,963	230,312	353,149	278,321	495,142	696,131
Present Worth at 10 Percent	58,926	91,568	123,316	157,499	220,401	272,037

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

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

Definition of Contingent Resources

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

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

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

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

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

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

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

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

Estimation of Contingent Resources

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

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.

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, 2018. The development and economic status represents the status applicable on December 31, 2018.

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 estimated herein are expressed as sales 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. Gas contingent resources estimated herein are reported as sales gas. Gas contingent resources estimated herein 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) and are reported in $10^6 ft^3$.

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

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

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, Baxters Copse, Beckingham, Bletchingley, Corringham, Gainsborough, Glentworth, Godley Bridge, Horndean, Lingfield, Long Clawson, Palmers Wood, Scampton North, Singleton, Stockbridge, and Welton.

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

<u>Procedure and Methodology</u>

The Baxters Copse field was discovered in 1983. The field is located in southeast England in the Weald Basin within license PL233. The Great Oolite is the main reservoir (Figure 7), with the Cornbrash Formation being non-reservoir. The following ranges were estimated: porosity from 3 to 15 percent, S_w from 60 to 67 percent, and permeability from 0.1 to 10 millidarcys. The oil has a gravity of 37 °API. Estimated recovery factors ranged from 10 to 15 percent. This field is contingent based on the lack of a firm development plan. IGas has represented that the field has been relinquished; therefore, no contingent resources were estimated for the field.

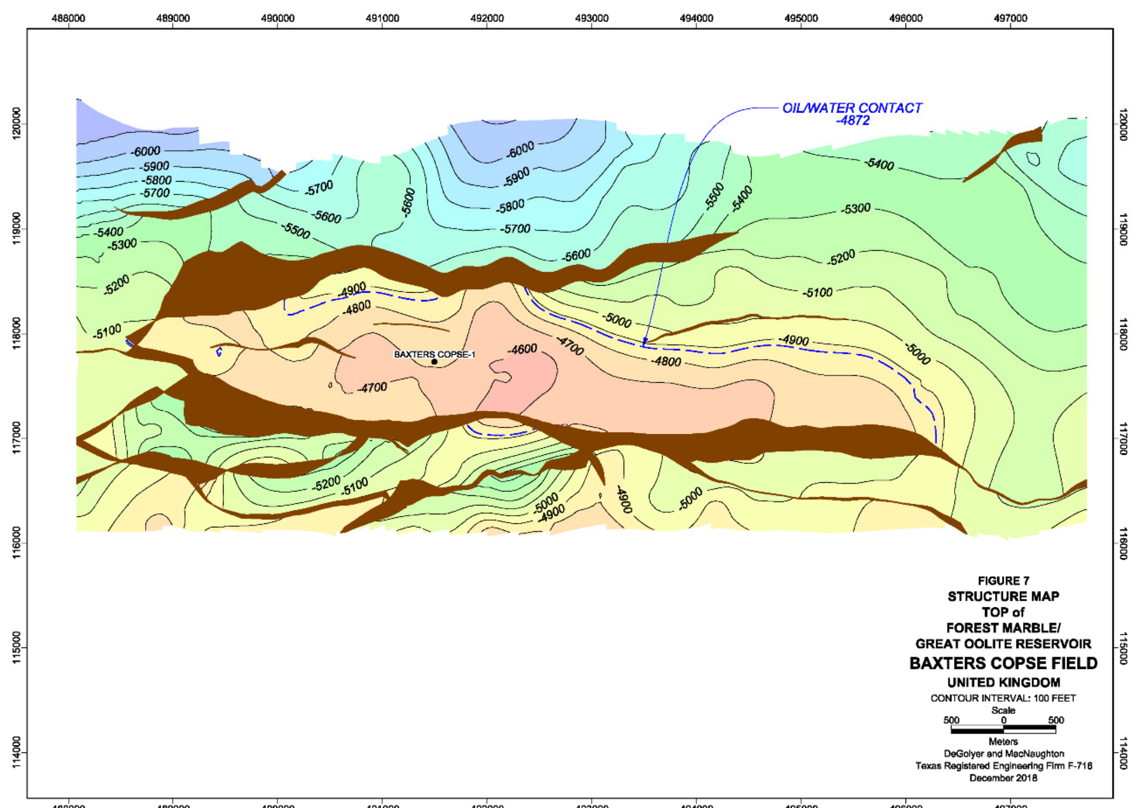
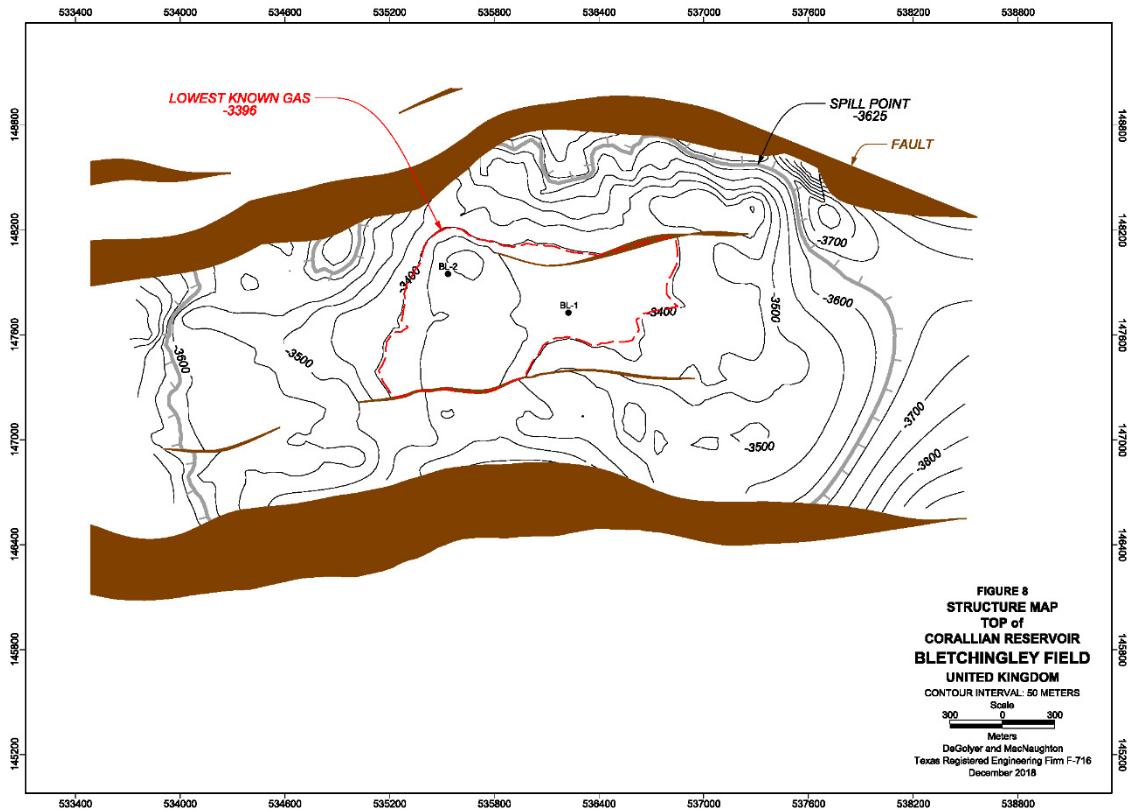


FIGURE 7
STRUCTURE MAP
TOP of
FOREST MARBLE/
GREAT OOLITE RESERVOIR
BAXTERS COPSE FIELD
UNITED KINGDOM
CONTOUR INTERVAL: 100 FEET

The Bletchingley field, located in licenses ML18 and ML21, was discovered in 1966. Oil was found in the Corallian Sandstone (Figure 8) and the field is currently producing from two wells. Porosity ranged from 5 to 25 percent, S_w from 40 to 70 percent, and permeability from 0.2 to 1000 millidarcys. Contingent resources were estimated for the drilling of one well in the western part of the reservoir and are contingent based on economics.



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 rock. The field was shut in from 1965 to 1971 and is currently producing low-shrinkage oil from four wells. Porosity ranged from 16 to 20 percent, S_w from 50 to 65 percent, and permeability from 0.1 to 30 millidarcys. Contingent resources were estimated for five additional infill wells and four waterflood wells and were based on a total field recovery ranging from 24 to 34 percent. The field is contingent based on a lack of firm development plans.

The Godley Bridge field (Figure 9), located in license PEDL235, was discovered in 1982. The field is gas bearing in the Portland Sandstone. The Godley Bridge field was evaluated volumetrically and contingent resources were estimated using analogous recovery factors based on other, similar fields in the area. The following ranges were estimated: porosity from 11 to 18 percent, S_w from 50 to 80 percent, and permeability from 0.1 to 0.3 millidarcy. The recovery factors used ranged from 55 to 80 percent. This field is contingent based on the lack of firm development plans.

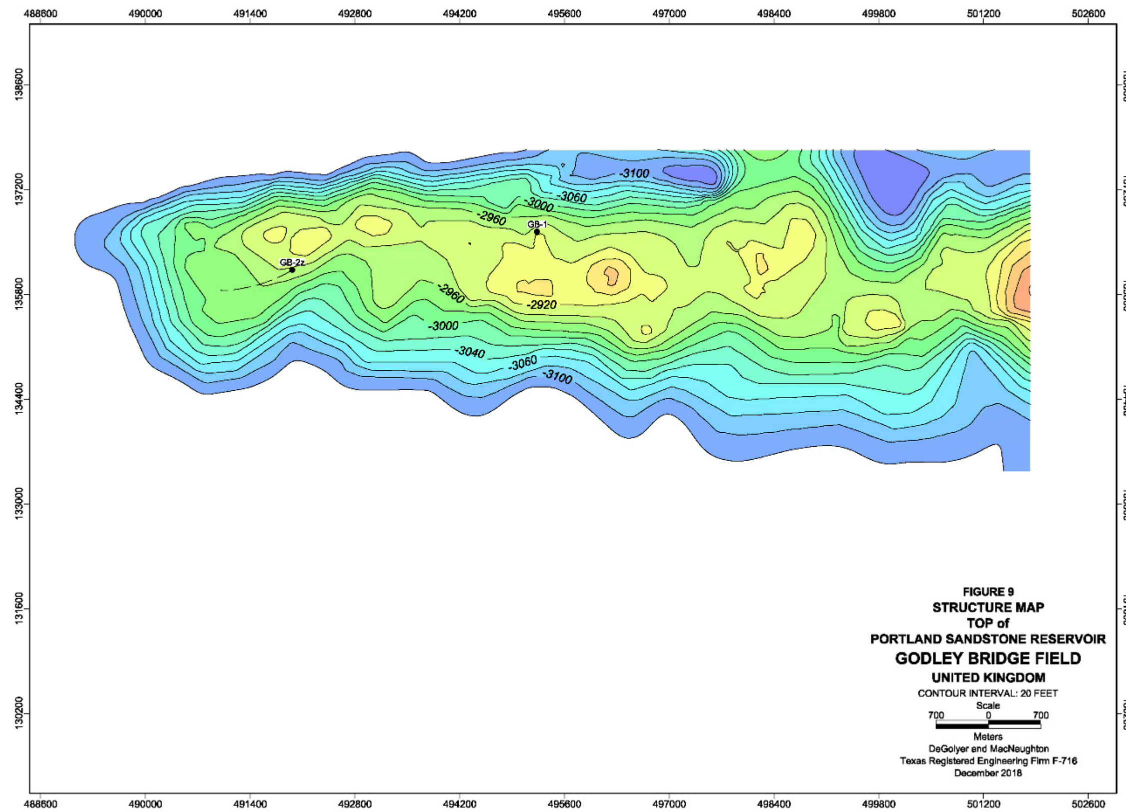
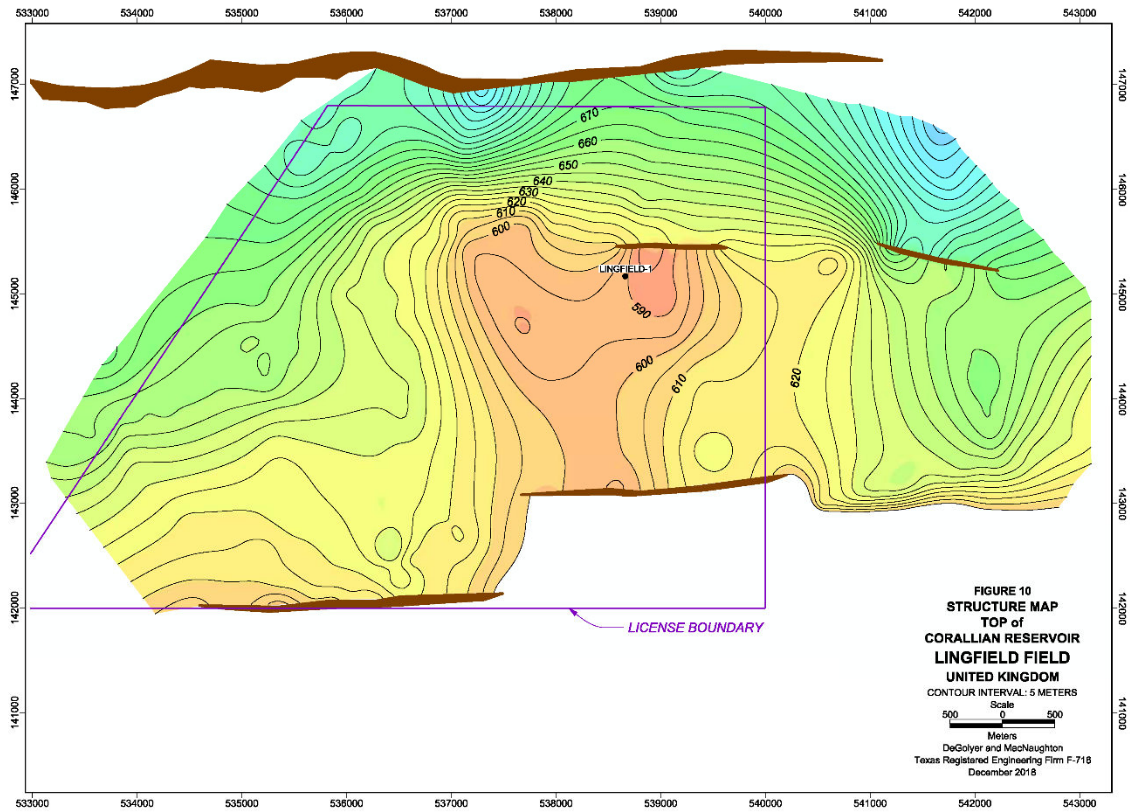


FIGURE 9
STRUCTURE MAP
TOP of
PORTLAND SANDSTONE RESERVOIR
GODLEY BRIDGE FIELD
UNITED KINGDOM

The Lingfield field (Figure 10) was discovered in 1999 by the Lingfield-1 well. The discovery is located in the United Kingdom in license PEDL257, near the town of Surrey. The Lingfield field is located on trend and southeast of the Bletchingley gas field. The Lingfield-1 well found gas pay in the Portland D sandstone and had oil shows in the Corallian Limestone. Average porosity is 18.2 percent and average S_w is 59 percent. The Lingfield-1 well tested the Portland D sandstone and the well flowed at a rate of 110 thousand cubic feet per day. No development plan has been approved. The Lingfield field was evaluated volumetrically and contingent resources were estimated using analogous recovery factors based on other, similar fields in the area. The recovery factors used ranged from 50 to 60 percent.



The Scampton North field was discovered in 1985 by well SNA1. The field is located within license PL 179 in Lincolnshire. Scampton North produces light oil of approximately 35 API through five wells from the Basal Succession Sandstone. Porosity ranged from 12 to 18 percent, S_w from 30 to 50 percent, and permeability from 0.5 to 400 millidarcys. Contingent resources were estimated for drilling a well to an undrained eastern target of the reservoir, and the field is contingent based on a lack of firm development plans.

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

The estimated gross 1C, 2C, and 3C contingent resources, as of December 31, 2018, 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
Baxters Copse	0	0	0	0	0	0	0	0	0
Beckingham	65	0	65	232	0	232	301	0	301
Bletchingley	435	17	438	608	24	612	843	34	849
Bothamsall	0	0	0	0	0	0	0	0	0
Cold Hanworth	0	0	0	0	0	0	0	0	0
Corringham	115	447	192	273	1,067	457	480	1,871	803
East Glentworth	0	0	0	0	0	0	0	0	0
Egmanton	0	0	0	0	0	0	0	0	0
Gainsborough	82	413	153	268	1,353	501	509	2,538	947
Glentworth	2,130	0	2,130	2,992	0	2,992	3,074	0	3,074
Godley Bridge	0	3,748	646	0	8,009	1,381	0	10,417	1,796
Goodworth	0	0	0	0	0	0	0	0	0
Horndean	349	0	349	798	0	798	1,296	0	1,296
Lingfield	0	3,767	649	0	4,143	714	0	4,520	779
Long Clawson	690	0	690	950	0	950	1,360	0	1,360
Lybster	0	0	0	0	0	0	0	0	0
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	299	0	299	392	0	392	532	0	532
Rempstone	0	0	0	0	0	0	0	0	0
Scampton North	338	51	347	496	74	509	567	85	582
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	1,693	253	1,737	3,564	533	3,656	6,203	931	6,364
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	598	0	598	731	0	731	905	0	905
Storrington	0	0	0	0	0	0	0	0	0
Welton	3,763	677	3,880	4,830	869	4,980	6,227	1,121	6,420
Total	**11,064**	**9,373**	**12,680**	**16,875**	**16,072**	**19,646**	**23,299**	**21,517**	**27,009**

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 boe.

The estimated net 1C, 2C, and 3C contingent resources, as of December 31, 2018, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

	Net Contingent Resources								
	1C			2C			3C		
Field	Oil and Condensate (10^3bbl)	Sales Gas (10^6ft^3)	Oil Equivalent (10^3boe)	Oil and Condensate (10^3bbl)	Sales Gas (10^6ft^3)	Oil Equivalent (10^3boe)	Oil and Condensate (10^3bbl)	Sales Gas (10^6ft^3)	Oil Equivalent (10^3boe)
Albury	0	0	0	0	0	0	0	0	0
Avington	254	0	254	371	0	371	501	0	501
Baxters Copse	0	0	0	0	0	0	0	0	0
Beckingham	65	0	65	232	0	232	301	0	301
Bletchingley	435	17	438	608	24	612	843	34	849
Bothamsall	0	0	0	0	0	0	0	0	0
Cold Hanworth	0	0	0	0	0	0	0	0	0
Corringham	115	447	192	273	1,067	457	480	1,871	803
East Glentworth	0	0	0	0	0	0	0	0	0
Egmanton	0	0	0	0	0	0	0	0	0
Gainsborough	82	413	153	268	1,353	501	509	2,538	947
Glentworth	2,130	0	2,130	2,992	0	2,992	3,074	0	3,074
Godley Bridge	0	3,748	646	0	8,009	1,381	0	10,417	1,796
Goodworth	0	0	0	0	0	0	0	0	0
Horndean	314	0	314	718	0	718	1,166	0	1,166
Lingfield	0	3,767	649	0	4,143	714	0	4,520	779
Long Clawson	690	0	690	950	0	950	1,360	0	1,360
Lybster	0	0	0	0	0	0	0	0	0
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	299	0	299	392	0	392	532	0	532
Rempstone	0	0	0	0	0	0	0	0	0
Scampton North	338	51	347	496	74	509	567	85	582
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	1,693	253	1,737	3,564	533	3,656	6,203	931	6,364
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	598	0	598	731	0	731	905	0	905
Storrington	0	0	0	0	0	0	0	0	0
Welton	3,763	677	3,880	4,830	869	4,980	6,227	1,121	6,420
Total	**10,776**	**9,373**	**12,392**	**16,425**	**16,072**	**19,196**	**22,668**	**21,517**	**26,378**

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 boe.

Professional Qualifications

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

The evaluation has been supervised by Mr. Regnald A. Boles, a Senior Vice President with DeGolyer and MacNaughton in the firm's Europe Africa Division, a Registered Professional Engineer in the State of Texas, a member of the International Society of Petroleum Engineers, and a member of the European Association of Geoscientists & Engineers. He has over 35 years of oil and gas industry experience.

Submitted,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

STATE OF TEXAS
REGNALD A. BOLES
65092
LICENSED
PROFESSIONAL ENGINEER

Regnald A. Boles

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

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE A-1
SUMMARY PROJECTION of TOTAL PROVED RESERVES and REVENUE
as of
DECEMBER 31, 2018
IGAS ENERGY PLC
UNITED KINGDOM

Base Case

	Net				Product Prices								
Year	Oil (10^3bbl)	Condensate (10^3bbl)	Sales Gas Export (10^6ft^3)	Sales Gas to Power (10^6ft^3)	Oil (U.S.$/bbl)	Condensate (U.S.$/bbl)	Sales Gas Export (U.S.$/$10^3$ft^3)	Sales Gas to Power (U.S.$/$10^3$ft^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.$)
2019	772	0	232	256	58.25	-	6.94	6.64	48,350	26,224	8,190	13,936	13,209
2020	767	11	423	198	58.73	52.86	6.94	6.64	49,785	24,900	14,523	10,362	8,890
2021	698	22	575	219	59.01	53.11	6.94	6.64	47,706	24,309	0	23,397	18,172
2022	628	17	610	224	59.47	53.52	6.94	6.64	44,055	22,634	737	20,684	14,542
2023	553	13	475	112	60.66	54.59	6.94	6.64	38,356	18,841	13,185	6,330	4,030
2024	509	11	343	99	61.87	55.68	6.94	6.64	35,041	17,234	0	17,807	10,258
2025	465	8	245	92	63.11	56.80	6.94	6.64	32,085	15,857	0	16,228	8,464
2026	424	7	176	86	64.37	57.93	6.94	6.64	29,543	14,727	0	14,816	6,993
2027	387	5	128	78	65.66	59.09	6.94	6.64	27,273	13,758	0	13,515	5,776
2028	358	4	110	12	66.97	60.27	6.94	6.64	25,098	12,652	914	11,532	4,461
2029	324	0	58	9	68.31	-	6.94	6.64	22,527	11,176	5,300	6,051	2,120
2030	298	0	49	8	69.68	-	6.94	6.64	21,072	10,638	0	10,434	3,308
2031	274	0	45	7	71.07	-	6.94	6.64	19,859	10,200	0	9,659	2,771
2032	253	0	42	7	72.49	-	6.94	6.64	18,678	9,801	0	8,877	2,307
2033	223	0	39	6	73.94	-	6.94	6.64	16,881	8,779	1,660	6,442	1,515
2034	186	0	35	6	75.42	-	6.94	6.64	14,186	6,686	8,695	(1,195)	(255)
2035	160	0	33	6	76.93	-	6.94	6.64	12,654	5,704	6,470	480	92
2036	150	0	30	5	78.47	-	6.94	6.64	11,904	5,505	0	6,399	1,116
2037	135	0	27	4	80.04	-	6.94	6.64	11,127	5,235	930	4,962	783
2038	126	0	25	4	81.64	-	6.94	6.64	10,519	5,084	0	5,435	777
2039	118	0	23	4	83.27	-	6.94	6.64	9,933	4,955	0	4,978	643
2040	108	0	21	4	84.94	-	6.94	6.64	9,402	4,840	0	4,562	535
2041	102	0	19	3	86.64	-	6.94	6.64	8,899	4,738	0	4,161	441
2042	94	0	17	3	88.37	-	6.94	6.64	8,422	4,649	0	3,773	361
2043	80	0	16	3	90.14	-	6.94	6.64	7,424	3,998	15,131	(11,705)	(1,015)
Subtotal	**8,192**	**98**	**3,796**	**1,455**					**580,779**	**293,124**	**75,735**	**211,920**	**110,294**
Remaining	565	0	83	16					55,799	36,680	46,539	(27,420)	(662)
Total	**8,757**	**98**	**3,879**	**1,471**					**636,578**	**329,804**	**122,274**	**184,500**	**109,632**

Present Worth at (10^3U.S.$)	
8 Percent	122,059
12 Percent	98,948
15 Percent	85,704

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

TABLE A-2
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE RESERVES and REVENUE
as of
DECEMBER 31, 2018
IGAS ENERGY PLC
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

Base Case

	Net				Product Prices								
Year	**Oil (10^3bbl)**	**Condensate (10^3bbl)**	**Sales Gas Export (10^6ft^3)**	**Sales Gas to Power (10^6ft^3)**	**Oil (U.S.$/bbl)**	**Condensate (U.S.$/bbl)**	**Sales Gas Export (U.S.$/$10^3$ft^3)**	**Sales Gas to Power (U.S.$/$10^3$ft^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.$)**
2019	812	0	237	261	58.25	-	6.94	6.64	50,677	27,220	8,190	15,267	14,472
2020	862	11	461	208	58.73	52.86	6.94	6.64	55,810	27,016	22,857	5,937	5,092
2021	829	22	626	236	59.01	53.11	6.94	6.64	56,021	27,171	0	28,850	22,409
2022	772	19	688	252	59.47	53.52	6.94	6.64	53,246	26,155	0	27,091	19,048
2023	709	15	661	243	60.66	54.59	6.94	6.64	50,132	24,384	751	24,997	15,908
2024	662	12	642	234	61.87	55.68	6.94	6.64	47,663	23,195	0	24,468	14,095
2025	597	10	585	131	63.11	56.80	6.94	6.64	43,112	19,997	13,717	9,398	4,899
2026	556	8	510	130	64.37	57.93	6.94	6.64	40,603	18,830	0	21,773	10,279
2027	515	7	452	129	65.66	59.09	6.94	6.64	38,335	17,808	0	20,527	8,772
2028	485	5	404	128	66.97	60.27	6.94	6.64	36,363	16,933	0	19,430	7,515
2029	450	5	351	114	68.31	61.48	6.94	6.64	34,301	16,012	0	18,289	6,402
2030	420	0	301	47	69.68	-	6.94	6.64	31,631	14,455	1,392	15,784	5,003
2031	393	0	272	42	71.07	-	6.94	6.64	30,150	13,829	0	16,321	4,683
2032	367	0	251	37	72.49	-	6.94	6.64	28,608	13,230	0	15,378	3,994
2033	343	0	228	34	73.94	-	6.94	6.64	27,135	12,672	0	14,463	3,402
2034	316	0	208	30	75.42	-	6.94	6.64	25,523	11,825	5,375	8,323	1,770
2035	298	0	191	27	76.93	-	6.94	6.64	24,292	11,393	0	12,899	2,484
2036	276	0	175	25	78.47	-	6.94	6.64	23,160	11,015	0	12,145	2,118
2037	234	0	159	21	80.04	-	6.94	6.64	19,891	8,463	9,146	2,282	360
2038	219	0	147	20	81.64	-	6.94	6.64	19,147	8,222	0	10,925	1,561
2039	202	0	135	17	83.27	-	6.94	6.64	17,780	7,480	5,613	4,687	606
2040	188	0	125	15	84.94	-	6.94	6.64	16,946	7,169	987	8,790	1,028
2041	176	0	114	13	86.64	-	6.94	6.64	16,160	6,958	0	9,202	976
2042	161	0	106	13	88.37	-	6.94	6.64	15,112	6,436	2,074	6,602	632
2043	152	0	97	11	90.14	-	6.94	6.64	14,446	6,273	0	8,173	710
Subtotal	**10,994**	**114**	**8,126**	**2,418**					**816,244**	**384,141**	**70,102**	**362,001**	**158,218**
Remaining	1,484	0	815	38					151,301	84,475	70,879	(4,053)	1,222
Total	**12,478**	**114**	**8,941**	**2,456**					**967,545**	**468,616**	**140,981**	**357,948**	**159,440**

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	183,657
12 Percent	139,936
15 Percent	117,162

TABLE A-3
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE RESERVES and REVENUE
as of
DECEMBER 31, 2018
IGAS ENERGY PLC
UNITED KINGDOM

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

Base Case

	Net				Product Prices								
Year	Oil (10^3bbl)	Condensate (10^3bbl)	Sales Gas Export (10^6ft^3)	Sales Gas to Power (10^6ft^3)	Oil (U.S.$/bbl)	Condensate (U.S.$/bbl)	Sales Gas Export (U.S.$/$10^3$ft^3)	Sales Gas to Power (U.S.$/$10^3$ft^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.$)
2019	842	0	237	263	58.25	-	6.94	6.64	52,475	28,000	8,190	16,285	15,437
2020	930	11	465	212	58.73	52.86	6.94	6.64	59,759	28,590	22,857	8,312	7,133
2021	911	23	633	244	59.01	53.11	6.94	6.64	61,093	29,123	0	31,970	24,831
2022	861	20	699	267	59.47	53.52	6.94	6.64	58,825	28,301	0	30,524	21,458
2023	810	17	677	265	60.66	54.59	6.94	6.64	56,484	27,063	0	29,421	18,726
2024	762	14	659	258	61.87	55.68	6.94	6.64	54,245	25,921	0	28,324	16,317
2025	718	12	640	251	63.11	56.80	6.94	6.64	52,070	24,823	0	27,247	14,210
2026	671	10	622	245	64.37	57.93	6.94	6.64	49,655	23,429	797	25,429	12,002
2027	628	9	573	239	65.66	59.09	6.94	6.64	47,459	22,383	0	25,076	10,714
2028	596	7	501	232	66.97	60.27	6.94	6.64	45,418	21,384	0	24,034	9,295
2029	560	7	445	226	68.31	61.48	6.94	6.64	43,374	20,436	0	22,938	8,035
2030	514	5	403	129	69.68	62.71	6.94	6.64	39,587	17,667	15,145	6,775	2,147
2031	484	4	378	118	71.07	63.96	6.94	6.64	38,060	16,991	0	21,069	6,044
2032	454	4	371	59	72.49	65.24	6.94	6.64	36,322	16,072	989	19,261	5,001
2033	433	0	346	59	73.94	-	6.94	6.64	34,647	15,161	468	19,018	4,472
2034	408	0	342	58	75.42	-	6.94	6.64	33,524	14,726	0	18,798	3,999
2035	384	0	336	58	76.93	-	6.94	6.64	32,376	14,312	0	18,064	3,480
2036	366	0	331	57	78.47	-	6.94	6.64	31,319	13,947	0	17,372	3,030
2037	346	0	324	57	80.04	-	6.94	6.64	30,244	13,586	0	16,658	2,632
2038	325	0	320	56	81.64	-	6.94	6.64	29,358	13,288	0	16,070	2,297
2039	311	0	315	56	83.27	-	6.94	6.64	28,233	12,960	0	15,273	1,976
2040	293	0	313	56	84.94	-	6.94	6.64	27,493	12,736	0	14,757	1,728
2041	262	0	307	55	86.64	-	6.94	6.64	25,084	10,945	7,955	6,184	656
2042	247	0	302	55	88.37	-	6.94	6.64	24,356	10,764	0	13,592	1,305
2043	227	0	299	54	90.14	-	6.94	6.64	23,026	9,886	2,023	11,117	966
Subtotal	**13,343**	**143**	**10,838**	**3,629**					**1,014,486**	**472,494**	**58,424**	**483,568**	**197,891**
Remaining	2,532	0	2,322	324					267,040	138,188	93,440	35,412	3,418
Total	**15,875**	**143**	**13,160**	**3,953**					**1,281,526**	**610,682**	**151,864**	**518,980**	**201,309**

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	235,543
12 Percent	174,480
15 Percent	143,987

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE A-4
SUMMARY PROJECTION of TOTAL PROVED QUANTITIES and REVENUE
as of
DECEMBER 31, 2018
IGAS ENERGY PLC
UNITED KINGDOM

Low Case

	Net				Product Prices								
Year	Oil (10^3bbl)	Condensate (10^3bbl)	Sales Gas Export (10^6ft^3)	Sales Gas to Power (10^6ft^3)	Oil (U.S.$/bbl)	Condensate (U.S.$/bbl)	Sales Gas Export (U.S.$/$10^3$ft^3)	Sales Gas to Power (U.S.$/$10^3$ft^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.$)
2019	699	0	232	140	48.25	-	5.94	5.64	35,934	22,463	15,408	(1,937)	(1,836)
2020	689	0	375	85	48.73	-	5.94	5.64	36,243	20,218	16,660	(635)	(545)
2021	626	0	352	84	49.01	-	5.94	5.64	33,183	18,725	0	14,458	11,230
2022	571	0	333	83	49.47	-	5.94	5.64	30,720	17,488	0	13,232	9,304
2023	523	0	283	82	50.66	-	5.94	5.64	28,659	16,272	0	12,387	7,884
2024	481	0	213	81	51.87	-	5.94	5.64	26,671	15,113	0	11,558	6,659
2025	442	0	157	80	53.11	-	5.94	5.64	24,793	14,059	0	10,734	5,598
2026	404	0	115	79	54.37	-	5.94	5.64	23,112	13,157	0	9,955	4,698
2027	368	0	86	9	55.66	-	5.94	5.64	21,192	11,962	896	8,334	3,560
2028	342	0	78	9	56.97	-	5.94	5.64	20,012	11,372	0	8,640	3,342
2029	296	0	54	8	58.31	-	5.94	5.64	17,642	9,692	3,136	4,814	1,687
2030	275	0	49	8	59.68	-	5.94	5.64	16,605	9,228	0	7,377	2,340
2031	224	0	45	7	61.07	-	5.94	5.64	14,051	7,135	6,526	390	112
2032	201	0	42	7	62.49	-	5.94	5.64	12,823	6,340	4,887	1,596	415
2033	185	0	39	6	63.94	-	5.94	5.64	12,157	6,098	0	6,059	1,424
2034	174	0	35	6	65.42	-	5.94	5.64	11,489	5,797	876	4,816	1,024
2035	158	0	33	6	66.93	-	5.94	5.64	10,914	5,607	0	5,307	1,023
2036	149	0	30	5	68.47	-	5.94	5.64	10,296	5,408	0	4,888	853
2037	135	0	27	4	70.04	-	5.94	5.64	9,732	5,235	0	4,497	710
2038	126	0	25	4	71.64	-	5.94	5.64	9,224	5,084	0	4,140	592
2039	118	0	23	4	73.27	-	5.94	5.64	8,736	4,955	0	3,781	488
2040	100	0	21	4	74.94	-	5.94	5.64	7,691	4,232	14,258	(10,799)	(1,264)
2041	95	0	19	3	76.64	-	5.94	5.64	7,296	4,139	0	3,157	335
2042	82	0	17	3	78.37	-	5.94	5.64	6,532	3,653	3,802	(923)	(89)
2043	76	0	16	3	80.14	-	5.94	5.64	6,230	3,595	0	2,635	228
Subtotal	**7,539**	**0**	**2,699**	**810**					**441,937**	**247,027**	**66,449**	**128,461**	**59,772**
Remaining	496	0	78	12					43,817	30,141	41,174	(27,498)	(846)
Total	**8,035**	**0**	**2,777**	**822**					**485,754**	**277,168**	**107,623**	**100,963**	**58,926**

Present Worth at (10^3U.S.$)	
8 Percent	66,886
12 Percent	51,994
15 Percent	43,332

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE A-5
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE QUANTITIES and REVENUE
as of
DECEMBER 31, 2018
IGAS ENERGY PLC
UNITED KINGDOM

Low Case

	Net				Product Prices								
Year	Oil (10^3bbl)	Condensate (10^3bbl)	Sales Gas Export (10^6ft^3)	Sales Gas to Power (10^6ft^3)	Oil (U.S.$/bbl)	Condensate (U.S.$/bbl)	Sales Gas Export (U.S.$/$10^3$ft^3)	Sales Gas to Power (U.S.$/$10^3$ft^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.$)
2019	773	0	237	141	48.25	-	5.94	5.64	39,495	24,455	21,585	(6,545)	(6,205)
2020	825	11	461	87	48.73	43.86	5.94	5.64	43,949	24,308	22,857	(3,216)	(2,757)
2021	785	22	626	115	49.01	44.11	5.94	5.64	43,825	24,038	4,155	15,632	12,141
2022	730	19	688	134	49.47	44.52	5.94	5.64	41,722	23,105	0	18,617	13,090
2023	677	15	661	133	50.66	45.59	5.94	5.64	39,736	21,851	0	17,885	11,382
2024	632	12	642	132	51.87	46.68	5.94	5.64	37,903	20,741	0	17,162	9,886
2025	589	10	585	131	53.11	47.80	5.94	5.64	35,918	19,554	0	16,364	8,533
2026	548	8	510	130	54.37	48.93	5.94	5.64	33,924	18,396	0	15,528	7,330
2027	508	7	452	129	55.66	50.09	5.94	5.64	32,118	17,383	0	14,735	6,297
2028	478	5	404	128	56.97	51.27	5.94	5.64	30,551	16,515	0	14,036	5,427
2029	443	0	331	52	58.31	-	5.94	5.64	28,145	14,784	1,364	11,997	4,201
2030	414	0	301	47	59.68	-	5.94	5.64	26,716	14,051	0	12,665	4,015
2031	387	0	272	42	61.07	-	5.94	5.64	25,534	13,431	0	12,103	3,473
2032	362	0	251	37	62.49	-	5.94	5.64	24,295	12,837	0	11,458	2,975
2033	326	0	228	34	63.94	-	5.94	5.64	22,402	11,579	1,660	9,163	2,153
2034	280	0	208	30	65.42	-	5.94	5.64	19,745	9,428	6,925	3,392	721
2035	265	0	191	27	66.93	-	5.94	5.64	18,910	9,075	0	9,835	1,895
2036	239	0	175	25	68.47	-	5.94	5.64	17,619	8,239	5,290	4,090	713
2037	221	0	159	21	70.04	-	5.94	5.64	16,535	7,585	1,879	7,071	1,116
2038	208	0	147	20	71.64	-	5.94	5.64	15,876	7,259	948	7,669	1,096
2039	195	0	135	17	73.27	-	5.94	5.64	15,187	7,021	0	8,166	1,058
2040	184	0	125	15	74.94	-	5.94	5.64	14,600	6,816	0	7,784	911
2041	172	0	114	13	76.64	-	5.94	5.64	13,956	6,610	0	7,346	779
2042	161	0	106	13	78.37	-	5.94	5.64	13,377	6,436	0	6,941	666
2043	149	0	66	4	80.14	-	5.94	5.64	12,359	5,801	1,504	5,054	438
Subtotal	**10,551**	**109**	**8,075**	**1,657**					**664,397**	**351,298**	**68,167**	**244,932**	**91,334**
Remaining	1,358	0	751	28					123,946	72,085	66,481	(14,620)	234
Total	**11,909**	**109**	**8,826**	**1,685**					**788,343**	**423,383**	**134,648**	**230,312**	**91,568**

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	108,911
12 Percent	77,615
15 Percent	61,396

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE A-6
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE QUANTITIES and REVENUE
as of
DECEMBER 31, 2018
IGAS ENERGY PLC
UNITED KINGDOM

Low Case

	Net				Product Prices								
Year	Oil (10^3bbl)	Condensate (10^3bbl)	Sales Gas Export (10^6ft^3)	Sales Gas to Power (10^6ft^3)	Oil (U.S.$/bbl)	Condensate (U.S.$/bbl)	Sales Gas Export (U.S.$/$10^3$ft^3)	Sales Gas to Power (U.S.$/$10^3$ft^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.$)
2019	802	0	237	142	48.25	-	5.94	5.64	40,947	25,207	21,585	(5,845)	(5,540)
2020	892	11	465	87	48.73	43.86	5.94	5.64	47,133	25,814	22,857	(1,538)	(1,319)
2021	875	23	633	116	49.01	44.11	5.94	5.64	48,382	26,373	0	22,009	17,096
2022	826	20	699	135	49.47	44.52	5.94	5.64	46,620	25,565	0	21,055	14,803
2023	777	17	677	134	50.66	45.59	5.94	5.64	44,880	24,365	0	20,515	13,058
2024	731	14	659	134	51.87	46.68	5.94	5.64	43,231	23,286	0	19,945	11,490
2025	687	12	640	133	53.11	47.80	5.94	5.64	41,624	22,250	0	19,374	10,105
2026	648	10	622	132	54.37	48.93	5.94	5.64	40,132	21,318	0	18,814	8,881
2027	607	9	573	131	55.66	50.09	5.94	5.64	38,448	20,311	0	18,137	7,749
2028	575	7	501	130	56.97	51.27	5.94	5.64	36,886	19,353	0	17,533	6,781
2029	540	7	445	130	58.31	52.48	5.94	5.64	35,318	18,448	0	16,870	5,908
2030	514	5	389	60	59.68	53.71	5.94	5.64	33,425	17,195	951	15,279	4,843
2031	484	0	358	59	61.07	-	5.94	5.64	31,934	16,168	449	15,317	4,395
2032	446	0	354	59	62.49	-	5.94	5.64	30,489	15,219	5,166	10,104	2,625
2033	427	0	346	59	63.94	-	5.94	5.64	29,501	14,729	0	14,772	3,473
2034	401	0	342	58	65.42	-	5.94	5.64	28,622	14,297	0	14,325	3,047
2035	378	0	336	58	66.93	-	5.94	5.64	27,706	13,886	0	13,820	2,661
2036	360	0	331	57	68.47	-	5.94	5.64	26,864	13,523	0	13,341	2,327
2037	340	0	324	57	70.04	-	5.94	5.64	26,004	13,164	0	12,840	2,026
2038	297	0	320	56	71.64	-	5.94	5.64	23,666	11,201	7,496	4,969	710
2039	275	0	315	56	73.27	-	5.94	5.64	22,149	10,197	1,869	10,083	1,304
2040	260	0	313	56	74.94	-	5.94	5.64	21,690	10,019	0	11,671	1,367
2041	248	0	307	55	76.64	-	5.94	5.64	21,053	9,802	0	11,251	1,193
2042	227	0	302	55	78.37	-	5.94	5.64	19,865	8,980	6,983	3,902	373
2043	211	0	299	54	80.14	-	5.94	5.64	19,050	8,460	2,116	8,474	735
Subtotal	**12,828**	**135**	**10,787**	**2,203**					**825,619**	**429,130**	**69,472**	**327,017**	**120,091**
Remaining	2,430	0	2,183	290					229,150	127,608	75,410	26,132	3,225
Total	**15,258**	**135**	**12,970**	**2,493**					**1,054,769**	**556,738**	**144,882**	**353,149**	**123,316**

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	148,446
12 Percent	103,724
15 Percent	81,645

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE A-7
SUMMARY PROJECTION of TOTAL PROVED QUANTITIES and REVENUE
as of
DECEMBER 31, 2018
IGAS ENERGY PLC
UNITED KINGDOM

High Case

	Net				**Product Prices**								
Year	**Oil (10^3bbl)**	**Condensate (10^3bbl)**	**Sales Gas Export (10^6ft^3)**	**Sales Gas to Power (10^6ft^3)**	**Oil (U.S.$/bbl)**	**Condensate (U.S.$/bbl)**	**Sales Gas Export (U.S.$/$10^3$ft^3)**	**Sales Gas to Power (U.S.$/$10^3$ft^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.$)**
2019	772	0	232	256	68.25	-	7.94	7.64	56,571	26,224	8,190	22,157	21,000
2020	767	11	423	198	68.73	61.86	7.94	7.64	58,160	24,900	14,523	18,737	16,077
2021	698	22	575	219	69.01	62.11	7.94	7.64	55,662	24,309	0	31,353	24,353
2022	628	17	610	224	69.47	62.52	7.94	7.64	51,332	22,634	737	27,961	19,659
2023	553	13	475	112	70.66	63.59	7.94	7.64	44,600	18,841	13,185	12,574	8,003
2024	509	11	343	99	71.87	64.68	7.94	7.64	40,660	17,234	0	23,426	13,496
2025	465	8	245	92	73.11	65.80	7.94	7.64	37,141	15,857	0	21,284	11,100
2026	424	7	176	86	74.37	66.93	7.94	7.64	34,114	14,727	0	19,387	9,152
2027	387	5	128	78	75.66	68.09	7.94	7.64	31,415	13,758	0	17,657	7,545
2028	358	4	110	12	76.97	69.27	7.94	7.64	28,847	12,652	914	15,281	5,909
2029	324	0	58	9	78.31	-	7.94	7.64	25,827	11,176	5,300	9,351	3,274
2030	298	0	49	8	79.68	-	7.94	7.64	24,097	10,638	0	13,459	4,266
2031	274	0	45	7	81.07	-	7.94	7.64	22,655	10,200	0	12,455	3,574
2032	253	0	42	7	82.49	-	7.94	7.64	21,256	9,801	0	11,455	2,974
2033	223	0	39	6	83.94	-	7.94	7.64	19,167	8,779	1,660	8,728	2,053
2034	186	0	35	6	85.42	-	7.94	7.64	16,070	6,686	8,695	689	147
2035	160	0	33	6	86.93	-	7.94	7.64	14,303	5,704	6,470	2,129	409
2036	150	0	30	5	88.47	-	7.94	7.64	13,426	5,505	0	7,921	1,381
2037	135	0	27	4	90.04	-	7.94	7.64	12,522	5,235	930	6,357	1,004
2038	126	0	25	4	91.64	-	7.94	7.64	11,811	5,084	0	6,727	961
2039	118	0	23	4	93.27	-	7.94	7.64	11,130	4,955	0	6,175	797
2040	108	0	21	4	94.94	-	7.94	7.64	10,516	4,840	0	5,676	665
2041	102	0	19	3	96.64	-	7.94	7.64	9,931	4,738	0	5,193	551
2042	94	0	17	3	98.37	-	7.94	7.64	9,380	4,649	0	4,731	455
2043	80	0	16	3	100.14	-	7.94	7.64	8,253	3,998	15,131	(10,876)	(944)
Subtotal	**8,192**	**98**	**3,796**	**1,455**					**668,846**	**293,124**	**75,735**	**299,987**	**157,861**
Remaining	565	0	83	16					61,553	36,680	46,539	(21,666)	(362)
Total	**8,757**	**98**	**3,879**	**1,471**					**730,399**	**329,804**	**122,274**	**278,321**	**157,499**

Present Worth at (10^3U.S.$)	
8 Percent	175,257
12 Percent	142,439
15 Percent	123,921

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE A-8
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE QUANTITIES and REVENUE
as of
DECEMBER 31, 2018
IGAS ENERGY PLC
UNITED KINGDOM

High Case

	Net				Product Prices								
Year	Oil (10^3bbl)	Condensate (10^3bbl)	Sales Gas Export (10^6ft^3)	Sales Gas to Power (10^6ft^3)	Oil (U.S.$/bbl)	Condensate (U.S.$/bbl)	Sales Gas Export (U.S.$/$10^3$ft^3)	Sales Gas to Power (U.S.$/$10^3$ft^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.$)
2019	812	0	237	261	68.25	-	7.94	7.64	59,295	27,220	8,190	23,885	22,640
2020	862	11	461	208	68.73	61.86	7.94	7.64	65,204	27,016	22,857	15,331	13,155
2021	829	22	626	236	69.01	62.11	7.94	7.64	65,375	27,171	0	38,204	29,672
2022	772	19	688	252	69.47	62.52	7.94	7.64	62,055	26,155	0	35,900	25,240
2023	709	15	661	243	70.66	63.59	7.94	7.64	58,280	24,384	751	33,145	21,096
2024	662	12	642	234	71.87	64.68	7.94	7.64	55,272	23,195	0	32,077	18,481
2025	597	10	585	131	73.11	65.80	7.94	7.64	49,878	19,997	13,717	16,164	8,427
2026	556	8	510	130	74.37	66.93	7.94	7.64	46,866	18,830	0	28,036	13,232
2027	515	7	452	129	75.66	68.09	7.94	7.64	44,145	17,808	0	26,337	11,255
2028	485	5	404	128	76.97	69.27	7.94	7.64	41,777	16,933	0	24,844	9,611
2029	450	5	351	114	78.31	70.48	7.94	7.64	39,320	16,012	0	23,308	8,163
2030	420	0	301	47	79.68	-	7.94	7.64	36,175	14,455	1,392	20,328	6,443
2031	393	0	272	42	81.07	-	7.94	7.64	34,401	13,829	0	20,572	5,902
2032	367	0	251	37	82.49	-	7.94	7.64	32,567	13,230	0	19,337	5,022
2033	343	0	228	34	83.94	-	7.94	7.64	30,824	12,672	0	18,152	4,269
2034	316	0	208	30	85.42	-	7.94	7.64	28,926	11,825	5,375	11,726	2,495
2035	298	0	191	27	86.93	-	7.94	7.64	27,472	11,393	0	16,079	3,097
2036	276	0	175	25	88.47	-	7.94	7.64	26,138	11,015	0	15,123	2,638
2037	234	0	159	21	90.04	-	7.94	7.64	22,400	8,463	9,146	4,791	756
2038	219	0	147	20	91.64	-	7.94	7.64	21,516	8,222	0	13,294	1,900
2039	202	0	135	17	93.27	-	7.94	7.64	19,939	7,480	5,613	6,846	886
2040	188	0	125	15	94.94	-	7.94	7.64	18,966	7,169	987	10,810	1,265
2041	176	0	114	13	96.64	-	7.94	7.64	18,051	6,958	0	11,093	1,176
2042	161	0	106	13	98.37	-	7.94	7.64	16,848	6,436	2,074	8,338	801
2043	152	0	97	11	100.14	-	7.94	7.64	16,072	6,273	0	9,799	850
Subtotal	**10,994**	**114**	**8,126**	**2,418**					**937,762**	**384,141**	**70,102**	**483,519**	**218,472**
Remaining	1,484	0	815	38					166,977	84,475	70,879	11,623	1,929
Total	**12,478**	**114**	**8,941**	**2,456**					**1,104,739**	**468,616**	**140,981**	**495,142**	**220,401**

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	252,558
12 Percent	194,525
15 Percent	164,281

DeGolyer and MacNaughton F-716 TEXAS REGISTERED ENGINEERING FIRM

TABLE A-9
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE QUANTITIES and REVENUE
as of
DECEMBER 31, 2018
IGAS ENERGY PLC
UNITED KINGDOM

High Case

	Net				Product Prices								
Year	Oil (10^3bbl)	Condensate (10^3bbl)	Sales Gas Export (10^6ft^3)	Sales Gas to Power (10^6ft^3)	Oil (U.S.$/bbl)	Condensate (U.S.$/bbl)	Sales Gas Export (U.S.$/$10^3$ft^3)	Sales Gas to Power (U.S.$/$10^3$ft^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.$)
2019	842	0	237	263	68.25	-	7.94	7.64	61,403	28,000	8,190	25,213	23,900
2020	930	11	465	212	68.73	61.86	7.94	7.64	69,821	28,590	22,857	18,374	15,768
2021	911	23	633	244	69.01	62.11	7.94	7.64	71,306	29,123	0	42,183	32,762
2022	861	20	699	267	69.47	62.52	7.94	7.64	68,568	28,301	0	40,267	28,310
2023	810	17	677	265	70.66	63.59	7.94	7.64	65,676	27,063	0	38,613	24,573
2024	762	14	659	258	71.87	64.68	7.94	7.64	62,916	25,921	0	36,995	21,313
2025	718	12	640	251	73.11	65.80	7.94	7.64	60,242	24,823	0	35,419	18,469
2026	671	10	622	245	74.37	66.93	7.94	7.64	57,314	23,429	797	33,088	15,618
2027	628	9	573	239	75.66	68.09	7.94	7.64	54,650	22,383	0	32,267	13,786
2028	596	7	501	232	76.97	69.27	7.94	7.64	52,182	21,384	0	30,798	11,912
2029	560	7	445	226	78.31	70.48	7.94	7.64	49,724	20,436	0	29,288	10,257
2030	514	5	403	129	79.68	71.71	7.94	7.64	45,277	17,667	15,145	12,465	3,952
2031	484	4	378	118	81.07	72.96	7.94	7.64	43,429	16,991	0	26,438	7,585
2032	454	4	371	59	82.49	74.24	7.94	7.64	41,352	16,072	989	24,291	6,309
2033	433	0	346	59	83.94	-	7.94	7.64	39,358	15,161	468	23,729	5,579
2034	408	0	342	58	85.42	-	7.94	7.64	38,003	14,726	0	23,277	4,955
2035	384	0	336	58	86.93	-	7.94	7.64	36,625	14,312	0	22,313	4,300
2036	366	0	331	57	88.47	-	7.94	7.64	35,356	13,947	0	21,409	3,734
2037	346	0	324	57	90.04	-	7.94	7.64	34,077	13,586	0	20,491	3,234
2038	325	0	320	56	91.64	-	7.94	7.64	33,014	13,288	0	19,726	2,819
2039	311	0	315	56	93.27	-	7.94	7.64	31,686	12,960	0	18,726	2,422
2040	293	0	313	56	94.94	-	7.94	7.64	30,799	12,736	0	18,063	2,115
2041	262	0	307	55	96.64	-	7.94	7.64	28,052	10,945	7,955	9,152	969
2042	247	0	302	55	98.37	-	7.94	7.64	27,191	10,764	0	16,427	1,575
2043	227	0	299	54	100.14	-	7.94	7.64	25,666	9,886	2,023	13,757	1,195
Subtotal	**13,343**	**143**	**10,838**	**3,629**					**1,163,687**	**472,494**	**58,424**	**632,769**	**267,411**
Remaining	2,532	0	2,322	324					294,990	138,188	93,440	63,362	4,626
Total	**15,875**	**143**	**13,160**	**3,953**					**1,458,677**	**610,682**	**151,864**	**696,131**	**272,037**

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	316,537
12 Percent	237,164
15 Percent	197,426