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DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

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

September 23, 2016

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

Ladies and Gentlemen:

Pursuant to your request, we have prepared estimates, as of July 31, 2016, of the extent of the proved, probable, and possible oil, condensate, and sales gas reserves, the value of the proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves, the extent of the 1C, 2C, and 3C contingent resources, and the extent of the prospective resources for certain fields, discoveries, and prospects in the United Kingdom, in which IGas Energy PLC (IGas) has represented that it owns an interest.

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

This report is compliant with the Competent Persons 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 and net reserves. Gross reserves are defined as the total estimated petroleum to be produced from the fields after July 31, 2016. Net reserves are defined as that portion of the gross reserves attributable to the interests owned by IGas after deducting interests by others, as described herein.

This report presents values for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves that have been estimated using initial prices and costs as of July 31, 2016, and future prices that vary from initial prices. Where applicable, prices and costs provided by IGas were expressed in United Kingdom pounds sterling (U.K.£) and converted to United States dollars (U.S.$) using a factor of U.S.$1.33 per U.K.£1.00. All monetary values in this report are expressed in U.S.$. An explanation of the future price and cost assumptions is included under the Valuation of Reserves heading of this report.

Values of the 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 to be realized by IGas from the sale of the net reserves. Future net revenue is defined as the future gross revenue less tariffs paid, operating expenses, abandonment costs, and capital costs. Operating expenses include field operating expenses, estimated expenses of direct supervision, and an allocation of overhead that directly relates to production activities. 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 discount rate of 10 percent are reported in detail and values using discount rates of 8, 12, and 15 percent are reported as totals.

The contingent resources estimated in this report are expressed as gross and net contingent resources. Gross contingent resources are defined as the total estimated petroleum that is potentially recoverable from known accumulations after July 31, 2016. 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 owned by others.

The contingent resources estimated herein are those quantities of petroleum that are potentially recoverable from known accumulations but which are not currently considered to be commercially recoverable because of 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. 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 ultimate chance of commerciality.

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.

The prospective resources estimated in this report are expressed as gross and net prospective resources. Gross prospective resources are defined as the total estimated petroleum that is potentially recoverable from undiscovered accumulations after July 31, 2016. Net prospective resources are defined as the product of the gross prospective resources and IGas' working interest.

The prospective resources estimated herein are those quantities of petroleum that are potentially recoverable from accumulations yet to be discovered. Because of the uncertainty of commerciality and the lack of sufficient exploration drilling, the prospective resources estimated herein cannot be classified as contingent resources or reserves. The prospective resources estimates in this report are not provided as a means of comparison to contingent resources or reserves.

Prospective resources quantities estimates should not be confused with those quantities that are associated with contingent resources or reserves due to the additional risks involved. The quantities that might actually be recovered, should they be discovered and developed, may differ significantly from the estimates presented herein.

A possibility exists that the prospects will not result in successful discoveries and development, in which case there could be no future revenue. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

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

In this report, key information has been provided by IGas on the fields evaluated herein. As far as we are aware, there are no special factors that would affect the interests owned 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 to be 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, discoveries, and prospects 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, discoveries, and prospects are in an established producing venue.

Executive Summary

IGas has represented that it owns interests in properties that include 32 discovered fields in the United Kingdom. This report includes evaluations of 12 fields containing reserves only, 8 fields containing contingent resources only, and 12 fields containing both reserves and contingent resources. In addition, two prospects were evaluated herein.

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 July 31, 2016, have been considered to be valid for their stated terms, as represented by IGas.

Reserves

Estimated reserves are presented in thousands of barrels (10^3bbl) for oil and condensate, millions of cubic feet (10^6ft^3) for sales gas, and thousands of barrels of oil equivalent (10^3boe) for oil, condensate, and sales gas. Sales gas quantities were converted to barrels of oil equivalent (boe) using energy equivalencies. Sales gas was converted to boe using a factor of 5,800 cubic feet per boe.

Estimates of the gross and net proved, probable, and possible oil, condensate, and sales gas reserves attributable to certain interests owned by IGas in the fields located in the United Kingdom evaluated herein, as of July 31, 2016, 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	9,020	4,134	4,906	2,505	1,524	1,829	9,453	4,397	5,221
Net	8,934	4,084	4,869	2,505	1,524	1,829	9,367	4,347	5,184

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

Revenue

Revenue values in this report have been prepared using initial prices and costs provided by IGas. Future price 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 are 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 for 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 for the probable or possible reserves comparable to the values for the proved reserves.

Estimated future net revenue and present worth at 10 percent of the future net revenue attributable to the interests evaluated herein for the proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves and quantities, as of July 31, 2016, 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	346,913	195,979	576,385	277,169	883,470	353,050
Low Case	208,836	120,864	359,623	178,970	559,278	234,561
High Case	493,591	270,896	806,067	375,021	1,225,316	471,542

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 are 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 pricing and cost assumptions are presented under the Valuation of Reserves heading of this report.

Contingent and Prospective Resources

Estimated contingent resources are presented in 10^3bbl for oil and condensate, 10^6ft^3 for sales gas, and 10^3boe for oil, condensate, and sales gas. Sales gas quantities were converted to boe using energy equivalencies. Sales gas was converted to boe using a factor of 5,800 cubic feet per boe.

Estimates of the gross and net 1C, 2C, and 3C contingent resources attributable to IGas for the fields evaluated herein, as of July 31, 2016, 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	10,738	28,431	15,640	9,715	24,860	14,000
2C	16,827	46,182	24,789	14,975	39,775	21,833
3C	26,880	68,559	38,701	23,891	58,760	34,023

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. 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 ultimate chance of commerciality.
4. Sales gas has been converted to oil equivalent using an energy equivalent factor of 5,800 cubic feet per boe.

The estimated gross and working interest P_g-adjusted prospective resources, as of July 31, 2016, in the IGas prospects evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl) and millions of cubic feet (10^6ft^3):

Prospect	Area/Basin	License	Gross Prospective Oil Resources Summary Low Estimate (10^3bbl)	Best Estimate (10^3bbl)	High Estimate (10^3bbl)	Mean Estimate (10^3bbl)	Probability of Geologic Success, P_g (decimal)	P_g-adjusted Mean Estimate (10^3bbl)
Eartham	Weald	PEDL326	587	1,837	5,710	2,601	0.400	1,041
Lea	East Midlands	PEDL316	606	1,638	3,931	2,048	0.180	369
Statistical Aggregate			**1,539**	**3,883**	**9,124**	**4,649**	**0.303**	**1,409**
Arithmetic Summation			1,193	3,475	9,641	4,649	0.303	1,409

Notes:
1. Low, best, high, and mean estimates follow the PRMS guidelines for prospective resources.
2. Low, best, high, and mean estimates in this table are P90, P50, P10, and mean respectively.
3. Pg is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. Pg has been rounded for presentation purposes. Multiplication using this presented Pg may yield imprecise results. Dividing the Pg-adjusted mean estimate by the mean estimate yields the precise Pg.
5. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of probabilistic estimates is presented in this table in compliance with PRMS guidelines.
8. Summations may vary from those shown here due to rounding.
9. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

Ownership and Infrastructure

IGas has represented that it owns 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
Beckering	PEDL337	100.00	7/20/2046
Beckingham	ML4	100.00	3/31/2040
Bletchingley	ML18	100.00	1/11/2017
Bletchingley	ML21	100.00	4/1/2017
Bothamsall	ML6	100.00	3/31/2040
Cold Hanworth	PEDL6	100.00	4/4/2027
Corringham	ML4	100.00	3/31/2040
Dunholme	AL009	100.00	4/7/2025
Eartham	PEDL326	100.00	7/20/2046
East Glentworth	PL179	100.00	11/16/2034
Egmanton	ML3	100.00	12/30/2033
Gainsborough	ML4	100.00	3/31/2040
Glentworth	ML4	100.00	3/31/2040
Godley Bridge	PEDL235	100.00	6/30/2039
Goodworth	PEDL21	100.00	4/3/2027
Hemswell	PEDL6	100.00	4/4/2027
Hemswell	PEDL210	75.00	6/30/2039
Hemswell	PEDL317	100.00	7/20/2046
Horndean	PL211	90.00	4/4/2036
Lea	PEDL316	35.00	7/20/2046
Lingfield	PEDL257	100.00	7/20/2046
Long Clawson	PL220	100.00	8/8/2016
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	8/8/2016
Scampton North	PL179	100.00	11/16/2034
Scampton South	PL179	100.00	11/16/2034
Singleton	PL240	100.00	12/1/2017
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	10/27/2017
Stockbridge	PL249	100.00	12/1/2017
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.

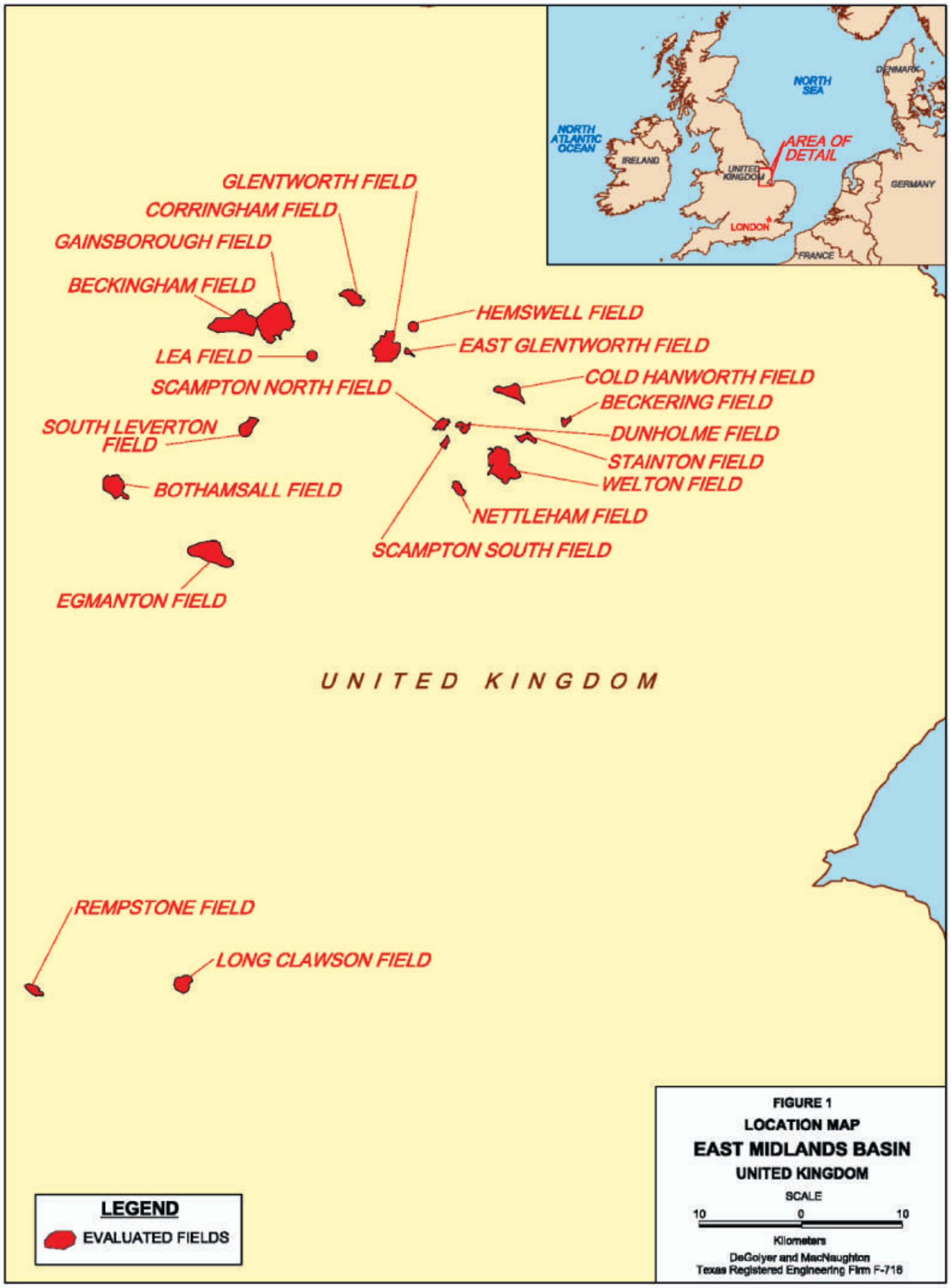

FIGURE 1
LOCATION MAP
EAST MIDLANDS BASIN
UNITED KINGDOM


NORTH ATLANTIC OCEAN
NORTH SEA
AREA OF DETAIL
LONDON
UNITED KINGDOM
PALMERS WOOD FIELD
BLETCHINGLEY FIELD
ALBURY FIELD
LINGFIELD FIELD
GOODWORTH FIELD
STOCKBRIDGE FIELD
GODLEY BRIDGE FIELD
AVINGTON FIELD
BAXTERS COPSE FIELD
STORRINGTON FIELD
SINGLETON FIELD
HORNDEAN FIELD
EARTHAM FIELD
LEGEND
EVALUATED FIELDS
FIGURE 2
LOCATION MAP
WEALD BASIN
UNITED KINGDOM
SCALE
10
0
10
Kilometers
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AREA OF DETAIL
NORTH SEA
NORTH ATLANTIC OCEAN
LONDON
UNITED KINGDOM
LYBSTER FIELD
NORTH SEA
LEGEND
EVALUATED FIELD
FIGURE 3
LOCATION MAP
LYBSTER FIELD
OFFSHORE UNITED KINGDOM
SCALE
2
0
2
Kilometers
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716

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 July 31, 2016, have been considered to be valid for their stated terms, as represented by IGas.

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

Environmental Consideration

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

Definition of Reserves

The proved, probable, and possible reserves presented in this report have been prepared in accordance with the PRMS approved in March 2007 by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum Evaluation 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 further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation 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 – Proved Reserves are those quantities of petroleum which, 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-percent probability that the quantities actually recovered will equal or exceed the estimate.

Unproved Reserves – Unproved Reserves are based on geoscience and/or engineering data similar to that used in estimates of Proved Reserves, but technical or other uncertainties preclude such reserves being classified as Proved. Unproved Reserves may be further categorized as Probable Reserves and Possible Reserves.

Probable Reserves – 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-percent probability that the actual quantities recovered will equal or exceed the 2P estimate.

Possible Reserves – Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest 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 Reserves (3P), which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10-percent probability that the actual quantities recovered will equal or exceed the 3P estimate.

Reserves Status Categories – Reserves status categories define the development and producing status of wells and reservoirs.

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

Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which 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 which will require additional completion work or future recompletion prior to the start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Undeveloped Reserves – Undeveloped Reserves are quantities expected to be recovered through future investments: (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.

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 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 July 31, 2016, 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 to June 2016. Where applicable, estimated cumulative production, as of July 31, 2016, was deducted from the gross ultimate recovery to determine the estimated gross reserves. This report takes into account all relevant information provided to us by IGas.

Gas quantities estimated herein are sales gas expressed at a pressure base of 14.7 pounds per square inch absolute (psia) and a temperature base of 60 degrees Fahrenheit (°F) and are reported in 10^6ft^3. Sales gas has been converted to oil equivalent using an energy equivalent factor of 5,800 cubic feet per boe. Sales gas is the quantity of gas to be delivered into a gas pipeline for sale after reduction for fuel. Oil and condensate reserves reported herein are to be recovered by conventional field operations. The estimates of oil and condensate are reported in 10^3bbl, where 1 barrel equals 42 United States gallons.

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.

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 July 31, 2016, are considered to be valid for their stated terms, as represented by IGas.

Procedure and Methodology

IGas has represented that it owns an interest in multiple fields, discoveries, and prospects in the United Kingdom, which have been evaluated in this report. Twenty-four 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 Avington field, located in license PEDL70, was discovered in 1960 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 is producing from two wells. Porosity ranged from 14 to 23 percent, water saturation from 46 to 57 percent, and permeability from 0.08 to 0.1 millidarcy. 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.

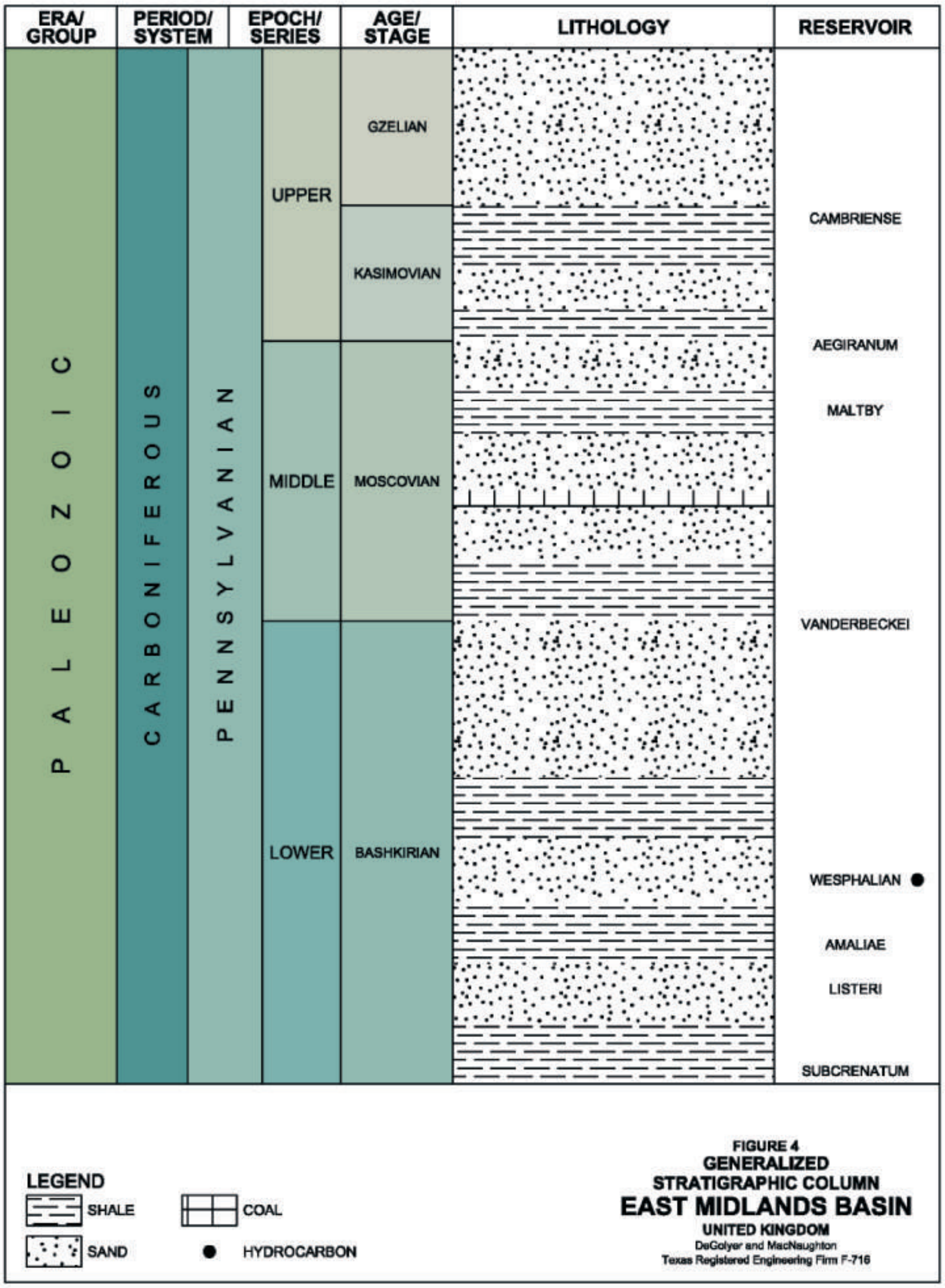

FIGURE 4
GENERALIZED
STRATIGRAPHIC COLUMN
EAST MIDLANDS BASIN
UNITED KINGDOM

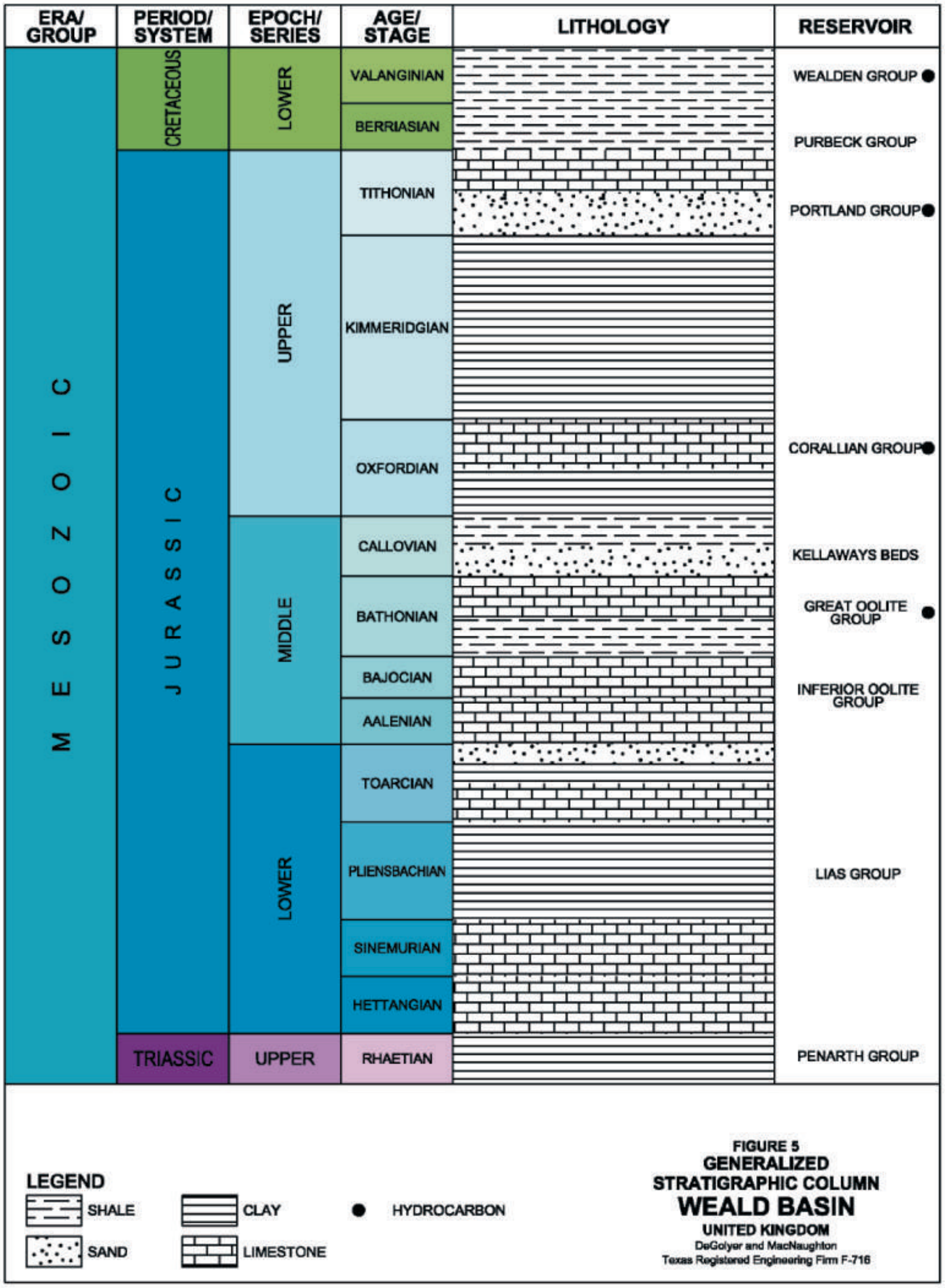

FIGURE 5
GENERALIZED
STRATIGRAPHIC COLUMN
WEALD BASIN
UNITED KINGDOM
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Texas Registered Engineering Firm F-716

The Beckingham field, located in license ML4, was discovered in 1964 and is located on the Lincolnshire-Nottingham border, 40 kilometers east of Sheffield. The main producing reservoirs are the Eagle, Donald, and Condor Sandstones, which produce from five separate blocks in the Beckingham field. The Beckingham field also produces nonassociated gas from the Mexborough/Alexander Formations. Porosity ranged from 8 to 20 percent, water saturation 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, water saturation from 40 to 70 percent, and permeability from 0.2 to 1,000 millidarcys. Proved reserves were estimated based on individual well performance and includes workovers on both producing wells. 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 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, water saturation 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, including scheduled workovers. 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 Gainsborough. The field is producing from two wells. Porosity ranged from 7 to 16 percent, water saturation 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 and includes a workover on the CH-5z well. 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, water saturation from 37 to 44 percent, and permeability from 160 to 500 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 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, water saturation 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, water saturation 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, water saturation 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, water saturation from 50 to 65 percent, and permeability from 0.1 to 30 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 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, water saturation from 50 to 70 percent, and permeability from 0.1 to 5 millidarcys. Performance analysis was completed on this field and after economic evaluation, quantities were determined to be uneconomic. As a result, reserves for this field were estimated to be zero.

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, water saturation from 70 to 80 percent, and permeability from 0.01 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 Long Clawson field was discovered in 1986. The field is located in license PL220 in Leicestershire and is currently producing from four wells. Porosity ranged from 13 to 18 percent, water saturation 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 Nettleham field, located in licenses PL179 and PL199, was discovered in 1983 and is located approximately 5 kilometers northeast of Lincoln. The primary reservoir is the Basal Westphalian. The field is not currently producing. Porosity ranged from 19 to 22 percent, water saturation from 30 to 60 percent, and permeability from 6 to 1,000 millidarcys. No reserves were estimated due to production stopping in February 2016, and the projections that might have allowed the field to come back online 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, water saturation 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, water saturation 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, and 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 PL179 in Lincolnshire. Scampton North produces light oil of approximately 35°API through four wells from the Basal Succession Sandstone. Porosity ranged from 12 to 18 percent, water saturation from 30 to 50 percent, and permeability from 0.5 to 400 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 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, water saturation 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, water saturation from 30 to 62 percent, and permeability from 0.1 to 10 millidarcys. Proved reserves were estimated based on performance of existing wells, including scheduled drilling. 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 not currently producing due to the existing wells watering out. Porosity ranged from 9 to 13 percent, water saturation from 22 to 27 percent, and permeability from 0.2 to 10 millidarcys. 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, water saturation 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 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, water saturation from 66 to 79 percent, and permeability from 0.1 to 5 millidarcys. Proved reserves were estimated based on individual well performance and includes 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, water saturation 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 and is currently producing from 26 wells. Porosity ranged from 12 to 20 percent, water saturation 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.

Estimates of the gross proved, probable, and possible oil, condensate, and sales gas reserves for the properties located in the United Kingdom evaluated herein, as of July 31, 2016, 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), where sales gas is converted to boe using a factor of 5,800 cubic feet per boe:

	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)
Avington	18	18	27	0	0	0	18	18	27
Beckingham	253	219	292	0	0	0	253	219	292
Bletchingley	88	64	85	0	0	0	88	64	85
Bothamsall	84	37	62	0	0	0	84	37	62
Cold Hanworth	92	45	69	0	0	0	92	45	69
Corringham	219	42	42	0	0	0	219	42	42
East Glentworth	40	17	10	0	0	0	40	17	10
Egmanton	0	0	0	0	0	0	0	0	0
Gainsborough	186	168	203	978	882	1,066	355	320	387
Glentworth	440	113	230	0	0	0	440	113	230
Goodworth	0	0	0	0	0	0	0	0	0
Horndean	774	406	245	0	0	0	774	406	245
Long Clawson	82	28	27	0	0	0	82	28	27
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	193	102	81	0	0	0	193	102	81
Rempstone	0	0	0	0	0	0	0	0	0
Scampton North	510	233	304	0	0	0	510	233	304
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	2,208	990	1,204	1,170	394	507	2,410	1,058	1,291
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	1,028	454	338	0	0	0	1,028	454	338
Storrington	103	26	26	0	0	0	103	26	26
Welton	2,702	1,172	1,661	357	248	256	2,764	1,215	1,705
Total	**9,020**	**4,134**	**4,906**	**2,505**	**1,524**	**1,829**	**9,453**	**4,397**	**5,221**

Notes:

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

Estimates of the net proved, probable, and possible oil, condensate, and sales gas reserves attributable to certain interests owned by IGas in the fields located in the United Kingdom evaluated herein, as of July 31, 2016, 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), where sales gas is converted to boe using a factor of 5,800 cubic feet per boe:

Field	Net Reserves: Oil and Condensate Proved (10³bbl)	Oil and Condensate Probable (10³bbl)	Oil and Condensate Possible (10³bbl)	Sales Gas Proved (10⁶ft³)	Sales Gas Probable (10⁶ft³)	Sales Gas Possible (10⁶ft³)	Oil Equivalent Proved (10³boe)	Oil Equivalent Probable (10³boe)	Oil Equivalent Possible (10³boe)
Avington	9	9	14	0	0	0	9	9	14
Beckingham	253	219	292	0	0	0	253	219	292
Bletchingley	88	64	85	0	0	0	88	64	85
Bothamsall	84	37	62	0	0	0	84	37	62
Cold Hanworth	92	45	69	0	0	0	92	45	69
Corringham	219	42	42	0	0	0	219	42	42
East Glentworth	40	17	10	0	0	0	40	17	10
Egmanton	0	0	0	0	0	0	0	0	0
Gainsborough	186	168	203	978	882	1,066	355	320	387
Glentworth	440	113	230	0	0	0	440	113	230
Goodworth	0	0	0	0	0	0	0	0	0
Horndean	697	365	221	0	0	0	697	365	221
Long Clawson	82	28	27	0	0	0	82	28	27
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	193	102	81	0	0	0	193	102	81
Rempstone	0	0	0	0	0	0	0	0	0
Scampton North	510	233	304	0	0	0	510	233	304
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	2,208	990	1,204	1,170	394	507	2,410	1,058	1,291
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	1,028	454	338	0	0	0	1,028	454	338
Storrington	103	26	26	0	0	0	103	26	26
Welton	2,702	1,172	1,661	357	248	256	2,764	1,215	1,705
Total	**8,934**	**4,084**	**4,869**	**2,505**	**1,524**	**1,829**	**9,367**	**4,347**	**5,184**

Notes:

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

Valuation of Reserves

This report has been prepared using initial prices and costs provided by IGas and certain future price and cost assumptions as described below. Three economic scenario cases (Base, Low, High) were evaluated, with future prices and costs as described below. Gross and net reserves estimated herein are based on the Base Case price and cost estimations. The Low and High sensitivity cases are 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 are 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 for 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 for the probable or possible reserves comparable to the values for the proved reserves.

Revenue values of the proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves were established 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 provided by IGas.

The future net revenue attributable to the fields evaluated herein has been estimated using assumptions described as follows:

Oil and Gas Prices

Base Case Price Assumptions

Oil prices for the Base Case were based on the dated Brent oil price per barrel of U.S.$51.20 in 2016, U.S.$57.30 in 2017, U.S.$63.62 in 2018, U.S.$70.18 in 2019, U.S.$76.99 in 2020, U.S.$80.74 in 2021, and were escalated 2.0 percent per year each year thereafter. Revenue from gas was based on sales gas quantities. Initial sales gas prices were based on current sales gas prices in the fields evaluated herein. Base Case sales gas prices per thousand cubic feet (10^3ft^3) were U.S.$5.25 in 2016, U.S.$5.40 in 2017, U.S.$5.55 in 2018, U.S.$5.70 in 2019, U.S.$5.81 in 2020, and were escalated 2.0 percent per year each year thereafter.

Low Case Price Assumptions

Oil prices for the Low Case were based on the dated Brent oil price per barrel of U.S.$40.96 in 2016, U.S.$45.84 in 2017, U.S.$50.90 in 2018, U.S.$56.14 in 2019, U.S.$61.59 in 2020, U.S.$64.59 in 2021, and were escalated 2.0 percent per year each year thereafter. Revenue from gas was based on sales gas quantities. Sales gas prices per 10^3ft^3 were U.S.$4.20 in 2016, U.S.$4.32 in 2017, U.S.$4.44 in 2018, U.S.$4.56 in 2019, U.S.$4.65 in 2020, and were escalated 2.0 percent per year each year thereafter.

High Case Price Assumptions

Oil prices for the High Case were based on the dated Brent oil price per barrel of U.S.$61.44 in 2016, U.S.$68.76 in 2017, U.S.$76.34 in 2018, U.S.$84.22 in 2019, U.S.$92.39 in 2020, U.S.$96.89 in 2021, and were escalated 2.0 percent per year each year thereafter. Revenue from gas was based on sales gas quantities. Sales gas prices per 10^3ft^3 were U.S.$6.30 in 2016, U.S.$6.48 in 2017, U.S.$6.66 in 2018, U.S.$6.84 in 2019, U.S.$6.97 in 2020, and were escalated 2.0 percent per year each year thereafter.

Operating Expenses, Tariffs, 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 2.5-percent cost escalation per year was applied for 2017 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.$1.33 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 contingencies and timing delays where reasonable.

Estimated Base Case future revenue and costs attributable to the interests evaluated herein for the proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves, as of July 31, 2016, 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	733,396	1,148,422	1,709,239
Tariff Paid and Operating Expenses	327,512	505,027	747,060
Abandonment and Capital Costs	58,971	67,010	78,709
Future Net Revenue	346,913	576,385	883,470
Present Worth at 10 Percent	195,979	277,169	353,050

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

For the sensitivity case economic scenarios, estimates of future revenue and costs attributable to the interests evaluated herein for the proved, proved-plus-probable, and proved-plus-probable-plus-possible quantities, as of July 31, 2016, 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	536,928	839,000	1,264,973	880,074	1,378,104	2,051,085
Tariff Paid and Operating Expenses	272,114	416,996	632,628	327,512	505,027	747,060
Abandonment and Capital Costs	55,978	62,381	73,067	58,971	67,010	78,709
Future Net Revenue	208,836	359,623	559,278	493,591	806,067	1,225,316
Present Worth at 10 Percent	120,864	178,970	234,561	270,896	375,021	471,542

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

Estimated future net revenue of all fields for the Base, Low, and High Cases are shown in Tables 1 through 9.

Definition of Contingent Resources

Petroleum resources included in this report are classified as contingent resources and have been prepared in accordance with the PRMS approved in March 2007 by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers. Because of the lack of commerciality or sufficient development drilling, the contingent resources estimated herein cannot be classified as reserves. The petroleum resources are classified as follows:

> *Contingent Resources* – Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.
>
> Based on assumptions regarding future conditions and their impact on ultimate economic viability, projects currently classified as Contingent Resources may be broadly divided into three economic status groups:
>
>> *Marginal Contingent Resources* – Those quantities associated with technically feasible projects that are either currently economic or projected to be economic under reasonably forecasted improvements in commercial conditions but are not

committed for development because of one or more contingencies.

Sub-Marginal Contingent Resources – Those quantities associated with discoveries for which analysis indicates that technically feasible development projects would not be economic and/or other contingencies would not be satisfied under current or reasonably forecasted improvements in commercial conditions. These projects nonetheless should be retained in the inventory of discovered resources pending unforeseen major changes in commercial conditions.

Undetermined Contingent Resources – Where evaluations are incomplete such that it is premature to clearly define ultimate chance of commerciality, it is acceptable to note that project economic status is "undetermined."

The estimation of resources quantities for an accumulation 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 volumes. 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 petroleum 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 water saturation.

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, the 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 are generally based on consideration of drilling results, analyses of available geological data, well-test results, pressures, and other data available through July 31, 2016. The development and economic status represents the status applicable on July 31, 2016.

Gas quantity estimates reported herein are sales gas expressed at a pressure base of 14.7 psia and a temperature base of 60 ºF and are reported in 10^6ft^3. Sales gas has been converted to oil equivalent using an energy equivalent factor of 5,800 cubic feet per boe. Sales gas contingent resources are defined as the total gas produced from the reservoir after reduction for shrinkage resulting from field separation, processing, flare, fuel usage, and other losses.

Oil and condensate contingent resources reported herein are to be recovered by normal field separation. The estimates of oil and condensate are reported in 10^3bbl, where 1 barrel equals 42 United States gallons.

After a review of the data available for the fields evaluated herein, 20 fields located in the United Kingdom were estimated to contain contingent resources: Albury, Avington, Baxters Copse, Beckering, Beckingham, Bletchingley, Corringham, Dunholme, Gainsborough, Glentworth, Godley Bridge, Hemswell, Horndean, Lingfield, Long Clawson, Lybster, 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 ultimate chance of commerciality.

Procedure and Methodology

The Albury field, located in license DL4, was discovered in 1987. The following ranges were estimated: porosity from 12 to 25 percent, water saturation from 21 to 60 percent, and permeability from 0.1 to 100 millidarcys. The field is gas bearing in the Purbeck and Corallian Sandstones. The Albury 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 range from 55 to 80 percent. This field is contingent based on lack of a firm development plan.

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 6), with the Cornbrash Formation being non-reservoir. The following ranges were estimated: porosity from 3 to 15 percent, water saturation from 60 to 67 percent, and permeability from 0.1 to 10 millidarcys. The oil has a gravity of 37 °API. Estimated recovery factors range from 10 to 15 percent. This field is contingent based on lack of a firm development plan.

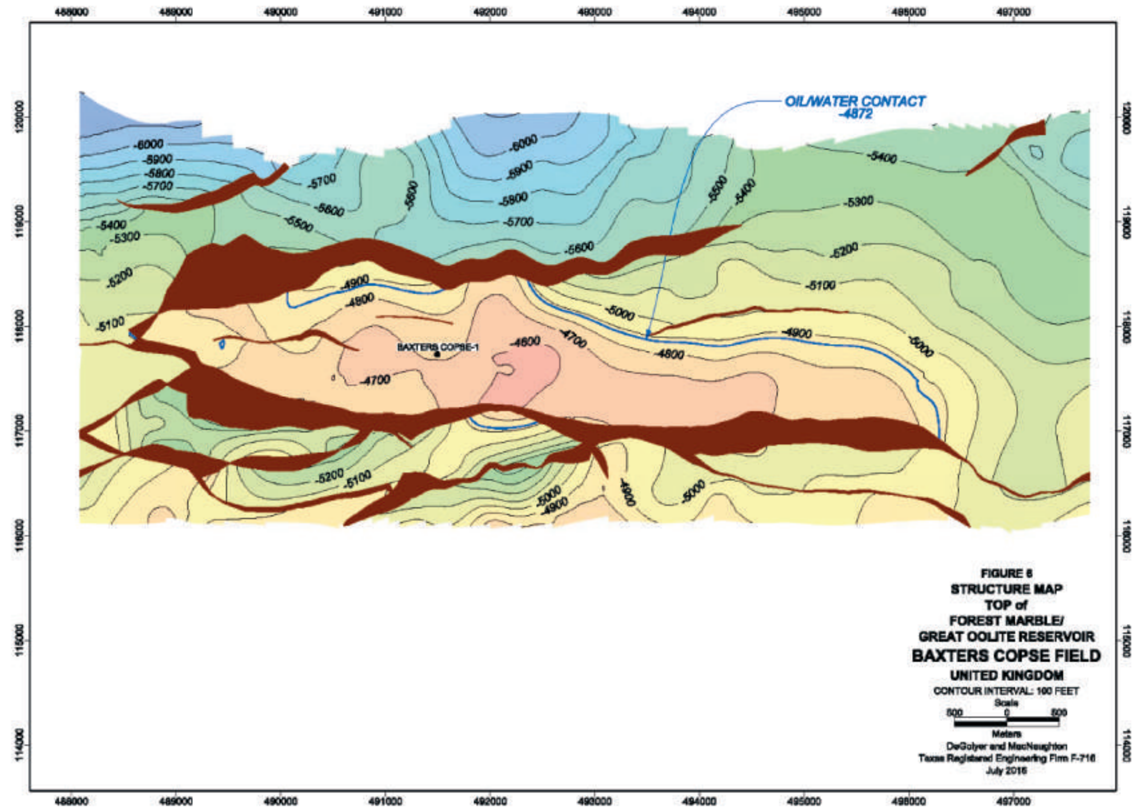


FIGURE 8
STRUCTURE MAP
TOP of
FOREST MARBLE/
GREAT OOLITE RESERVOIR
BAXTERS COPSE FIELD
UNITED KINGDOM
CONTOUR INTERVAL: 100 FEET

The Beckering field (Figure 7) was discovered in 1990 by the Beckering-1 well. The discovery is located in the United Kingdom in the East Midlands Platform in license PEDL337. The following ranges were estimated: porosity at 10.7 percent, water saturation from 15 to 60 percent, and permeability from 1 to 250 millidarcys. The field has produced oil from the Carboniferous Wesphalian A Sub-Alton Sandstone. The Beckering field was evaluated volumetrically and contingent resources were estimated using analogous recovery factors based on other, similar fields in the area. Estimated recovery factors used range from 25 to 35 percent.

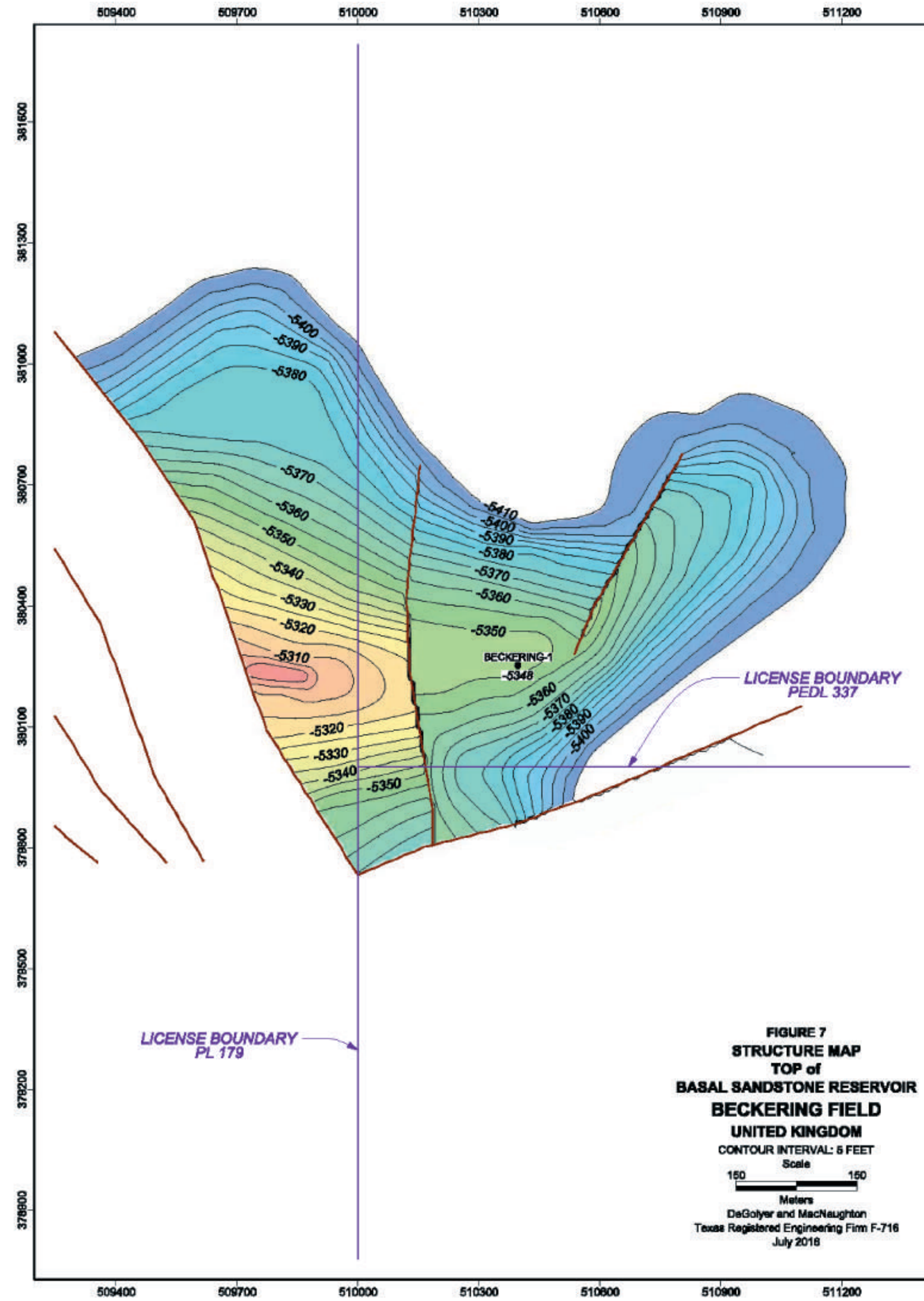
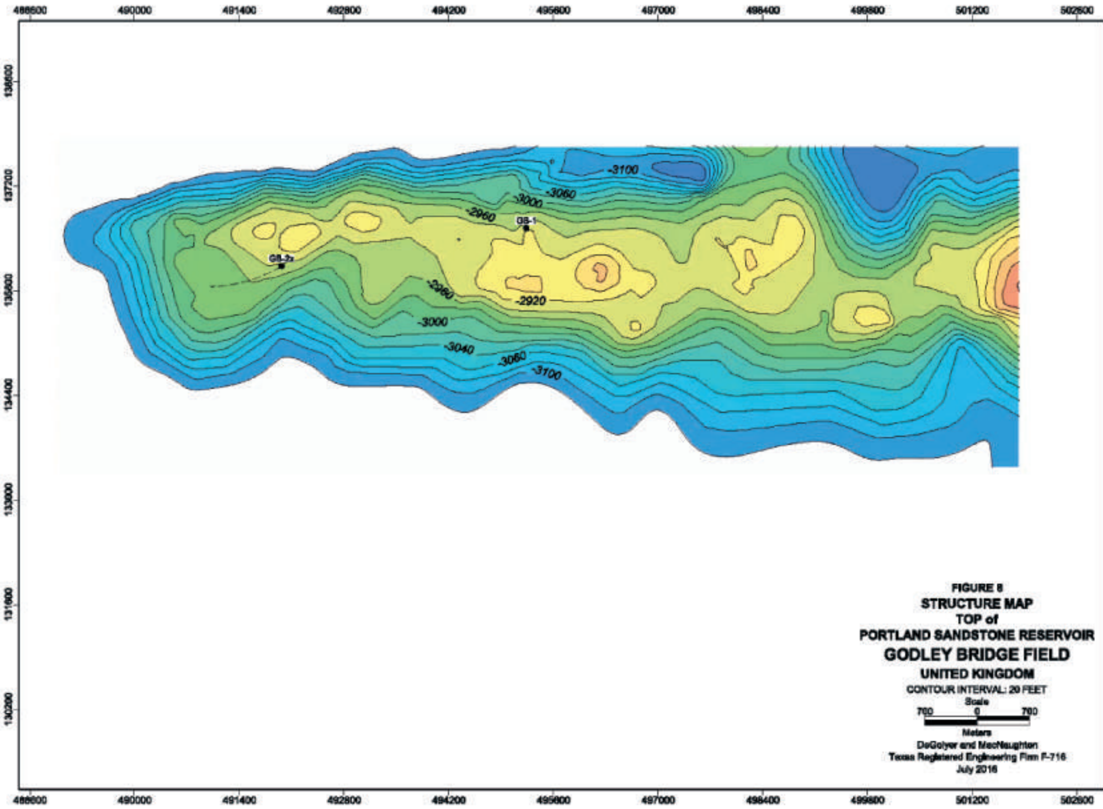


FIGURE 7
STRUCTURE MAP
TOP of
BASAL SANDSTONE RESERVOIR
BECKERING FIELD
UNITED KINGDOM

The Dunholme field was discovered in 1983 by British Petroleum with the Dunholme-1 well. The field is located in the United Kingdom in the East Midlands Platform in license AL009. The following ranges were estimated: porosity at 19.8 percent, water saturation at 58 percent, and permeability from 5 to 400 millidarcys. The Dunholme-1 well encountered a thin oil column in the Carboniferous Westphalian-age Basal Sand reservoir. The well is interpreted to have intersected the oil column very near the oil/water contact, and additional original oil in place quantities have been estimated updip of the Dunholm-1 well. The Dunholme field was evaluated volumetrically and contingent resources were estimated using analogous recovery factors based on other, similar fields in the area. Estimated recovery factors used range from 5 to 15 percent. The field has no established development plan.

The Godley Bridge field (Figure 8), located in license PEDL235, was discovered in 1982. The field is gas bearing in the Portland Sandstone. The Godley Bridge field was evaluated volumetrically and contingent resources were estimated using analogous recovery factors based on other, similar fields in the area. The following ranges were estimated: porosity from 11 to 18 percent, water saturation from 50 to 80 percent, and permeability from 0.1 to 0.3 millidarcy. The recovery factors used range from 55 to 80 percent. This field is contingent based on lack of firm development plans.



The Hemswell field was discovered in 1983 by British Petroleum with the Hemswell-1 well. The field is located in the United Kingdom in the East Midlands Platform in licenses PEDL6, PEDL210, and PEDL317. The following ranges were estimated: porosity from 11 to 15 percent, water saturation from 38 to 48 percent, and permeability from 0.84 to 1.63 millidarcys. The Hemswell-1 well tested oil from the Carboniferous Westphalian age Deep Hard Rock sandstone reservoir. The Hemswell-2 well was drilled in 1994 to appraise the extent of the Hemswell discovery, but the well was junked and abandoned and no logs were available. The Hemswell 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 range from 5 to 15 percent. No development plan is yet established.

The Lingfield field (Figure 9) was discovered in 1999 by the Lingfield-1 well. The discovery is located in the United Kingdom in license PEDL257, near the 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. The following ranges were estimated: porosity at 18.2 percent and water saturation at 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 range from 50 to 60 percent.

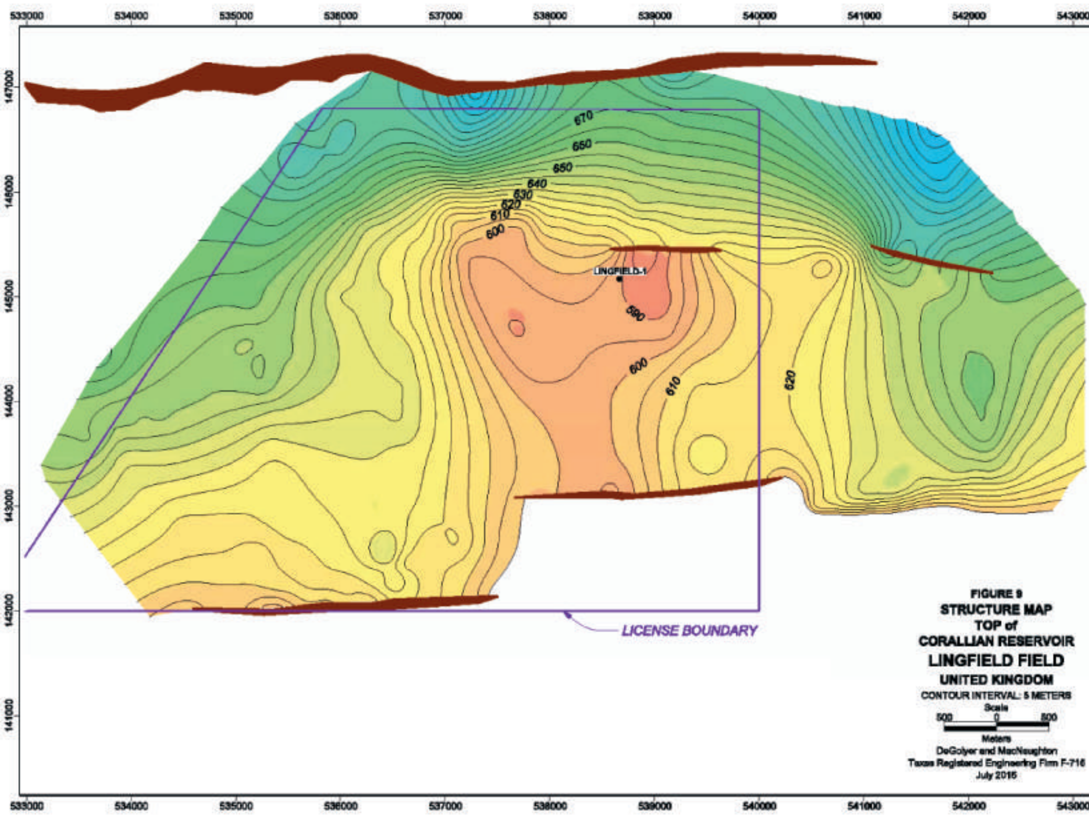
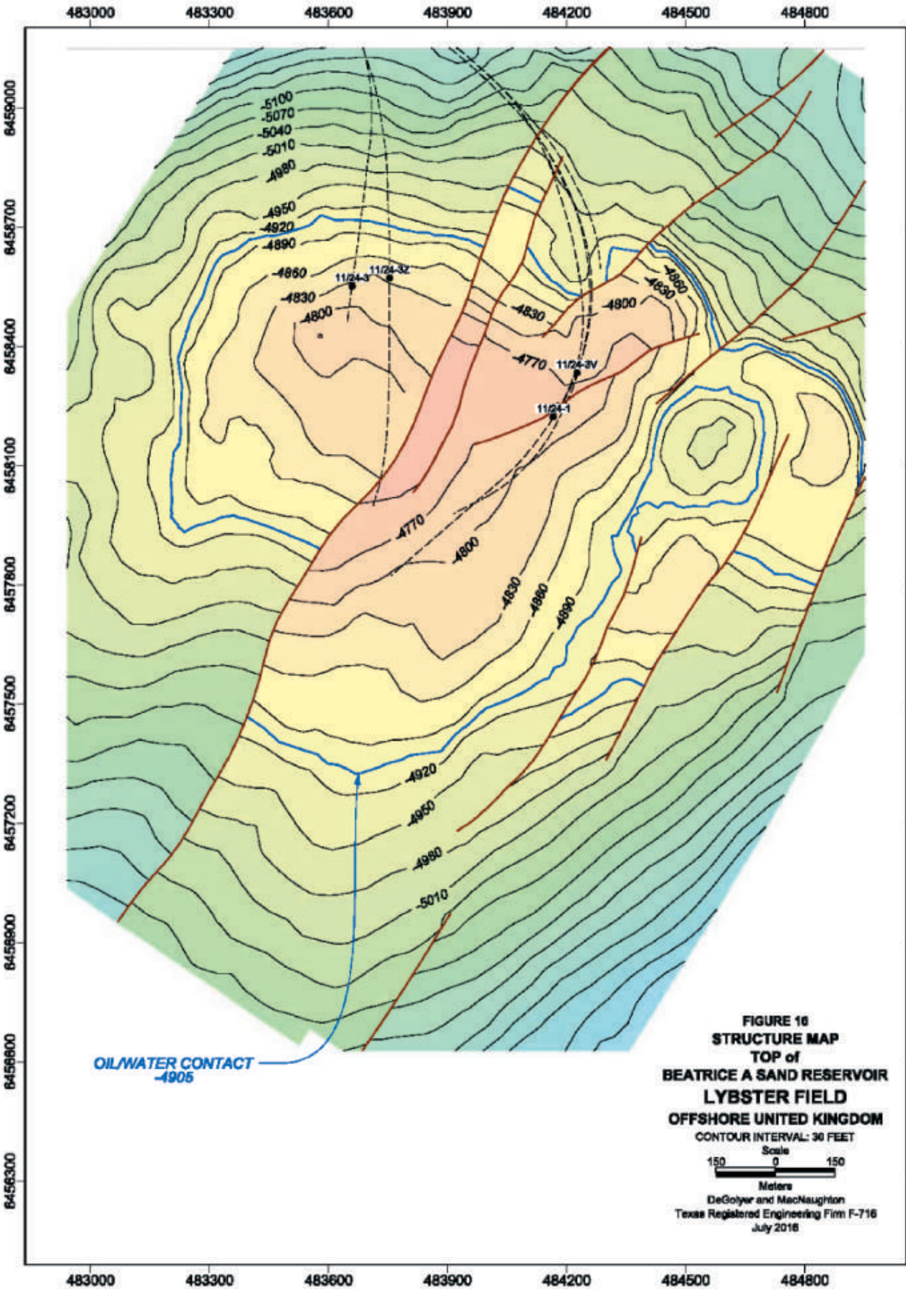


FIGURE 9
STRUCTURE MAP
TOP of
CORALLIAN RESERVOIR
LINGFIELD FIELD
UNITED KINGDOM
CONTOUR INTERVAL: 5 METERS
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716
July 2016

The Lybster field (Figure 10) was discovered in 1996 by well 11/24-1 and is located offshore from the Caithness coast in license P1270. The following ranges were estimated: porosity at 12 percent, water saturation from 35 to 45 percent, and permeability from 90 to 1,115 millidarcys. The field is gas bearing in the Beatrice sandstone. The Lybster 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 range from 55 to 80 percent. This field is contingent based on lack of established development plans.



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

Estimated contingent resources are presented in 10^3bbl for oil and condensate, 10^6ft^3 for sales gas, and 10^3boe for oil, condensate, and sales gas. Sales gas quantities were converted to boe using energy equivalencies. Sales gas was converted to boe using a factor of 5,800 cubic feet per boe.

Estimates of the gross 1C, 2C, and 3C oil, condensate, and sales gas contingent resources for the properties located in the United Kingdom evaluated herein, as of July 31, 2016, 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), where sales gas is converted to boe using a factor of 5,800 cubic feet per boe:

	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	2,992	516	0	3,264	563	0	4,080	703
Avington	510	0	510	742	0	742	1,005	0	1,005
Baxters Copse	1,433	7,091	2,656	2,488	12,314	4,611	3,615	17,894	6,700
Beckering	8	0	8	14	0	14	190	0	190
Beckingham	65	0	65	232	0	232	302	0	302
Bletchingley	435	724	560	608	1,673	896	843	2,887	1,341
Corringham	115	447	192	274	1,067	458	480	1,871	803
Dunholme	12	0	12	188	0	188	426	0	426
Gainsborough	83	434	158	272	1,425	518	512	2,686	975
Glentworth	314	0	314	555	0	555	648	0	648
Godley Bridge	0	5,160	890	0	10,409	1,795	0	13,500	2,328
Hemswell (PEDL6)	0	0	0	44	67	56	2,002	3,023	2,523
Hemswell (PEDL210)	69	104	87	627	947	790	2,202	3,325	2,775
Hemswell (PEDL317)	0	0	0	55	82	69	909	1,373	1,146
Horndean	349	0	349	798	128	820	1,296	207	1,332
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	122	453	200	189	535	281	301	658	414
Scampton North	135	0	135	397	0	397	756	155	783
Singleton	3,467	6,839	4,646	4,833	9,619	6,491	5,594	11,744	7,619
Stockbridge	598	0	598	731	0	731	904	0	904
Welton	2,333	420	2,405	2,830	509	2,918	3,535	636	3,645
Total	**10,738**	**28,431**	**15,640**	**16,827**	**46,182**	**24,789**	**26,880**	**68,559**	**38,701**

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. 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 ultimate chance of commerciality.
4. Sales gas has been converted to oil equivalent using an energy equivalent factor of 5,800 cubic feet per boe.

Estimates of the net 1C, 2C, and 3C oil, condensate, and sales gas contingent resources attributable to certain interests owned by IGas in the fields located in the United Kingdom evaluated herein, as of July 31, 2016, 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), where sales gas is converted to boe using a factor of 5,800 cubic feet per boe:

	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	2,992	516	0	3,264	563	0	4,080	703
Avington	255	0	255	371	0	371	503	0	503
Baxters Copse	717	3,546	1,328	1,244	6,157	2,306	1,808	8,947	3,351
Beckering	8	0	8	14	0	14	190	0	190
Beckingham	65	0	65	232	0	232	302	0	302
Bletchingley	435	724	560	608	1,673	896	843	2,887	1,341
Corringham	115	447	192	274	1,067	458	480	1,871	803
Dunholme	12	0	12	188	0	188	426	0	426
Gainsborough	83	434	158	272	1,425	518	512	2,686	975
Glentworth	314	0	314	555	0	555	648	0	648
Godley Bridge	0	5,160	890	0	10,409	1,795	0	13,500	2,328
Hemswell (PEDL6)	0	0	0	44	67	56	2,002	3,023	2,523
Hemswell (PEDL210)	52	78	65	470	710	592	1,652	2,494	2,082
Hemswell (PEDL317)	0	0	0	55	82	69	909	1,373	1,146
Horndean	314	0	314	718	115	738	1,166	186	1,198
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	122	453	200	189	535	281	301	658	414
Scampton North	135	0	135	397	0	397	756	155	783
Singleton	3,467	6,839	4,646	4,833	9,619	6,491	5,594	11,744	7,619
Stockbridge	598	0	598	731	0	731	904	0	904
Welton	2,333	420	2,405	2,830	509	2,918	3,535	636	3,645
Total	**9,715**	**24,860**	**14,000**	**14,975**	**39,775**	**21,833**	**23,891**	**58,760**	**34,023**

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. 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 ultimate chance of commerciality.
4. Sales gas has been converted to oil equivalent using an energy equivalent factor of 5,800 cubic feet per boe.

All of the contingent resources in this report have an economic status of Undetermined, since the evaluation of those contingent resources is at a stage such that it is premature to clearly define the ultimate chance of commerciality.

Definition of Prospective Resources

Petroleum resources included in this report are classified as prospective resources and have been prepared in accordance with the PRMS approved in March 2007 by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum

Evaluation Engineers. Because of the lack of commerciality or sufficient development drilling, the prospective resources estimated herein cannot be classified as contingent resources or reserves. The petroleum resources are classified as follows:

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

The estimation of resources quantities for a prospect 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 volumes. 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.

> *Low, Best, High, and Mean Estimates* – Estimates of petroleum resources in this report are expressed using the terms low estimate, best estimate, high estimate, and mean estimate to reflect the range of uncertainty.

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

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

Probability of Geologic Success – P_g is defined as the probability of discovering reservoirs that flow petroleum at a measurable rate. P_g is estimated by quantifying the probability of each of the following individual geologic factors: trap, source, reservoir, and migration. The product of these four probabilities or chance factors is computed as P_g.

In this report estimates of prospective resources are presented both before and after adjustment for P_g. Total prospective resources estimates are based on the probabilistic summation of the volumes for the total inventory of prospects.

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

Predictability versus Portfolio Size – The accuracy of forecasts of the number of discoveries that are likely to be made is constrained by the number of prospects in the exploration portfolio. The size of the portfolio and P_g together are helpful in gauging the limits on the reliability of these forecasts. A high P_g, which indicates a high chance of discovering measurable petroleum, may not require a large portfolio to ensure that at least one discovery will be made (assuming the P_g does not change during drilling of some of the prospects). By contrast, a low P_g, which indicates a low chance of discovering measurable petroleum, could require a large number of prospects to ensure a high confidence level of making even a single discovery. The relationship between portfolio size, P_g, and the probability of a fully unsuccessful drilling program that results in a series of wells not encountering measurable hydrocarbons is referred to herein as the predictability versus portfolio size relationship* (PPS). It is critical to be aware of PPS, because an unsuccessful drilling program, which results in a series of wells that do no encounter measurable hydrocarbons, can adversely affect any exploration effort, resulting in a negative present worth.

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

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

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

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

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

<u>Estimation of Prospective Resources</u>

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

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

Standard probabilistic methods were used in the uncertainty analysis. Probability distributions were estimated from representations of rock volume, porosity, hydrocarbon saturation, recovery efficiency, and formation volume factor for each prospect. These representations were prepared based on known data, analogy, and other standard estimation methods including experience. Statistical measures describing the probability distributions of these representations were identified and input to a Monte Carlo simulation to produce low estimate (P90), best estimate (P50), high estimate (P10), and mean estimate prospective resources for each prospect.

Estimates of recovery efficiency presented in this report are based on analog data and global experience and reflect the potential range in recovery for the potential reservoirs considered in each prospect. Recovery efficiency estimates do not incorporate development or economic input and are subject to change upon selection of specific development options and costs, economic parameters, and product price scenarios. In this report, two potential accumulations (Eartham and Lea) are referred to as prospects to reflect the current stage of technical evaluation.

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

Volumetrics, Quantitative Risk Assessment, and the Application of P_g

Minimum, low, modal, best, mean, high, and maximum representations of potential productive area were interpreted from maps, available seismic data, and/or analogy. Representations for the petrophysical parameters (porosity, hydrocarbon saturation, and net hydrocarbon thickness) and engineering parameters (recovery efficiency and fluid properties) were also estimated based on available well data, regional data, analog field data, and global experience. Individual probability distributions for rock volume and petrophysical and engineering parameters were estimated from these representations and are summarized in Table 10.

The distributions for the variables were derived from (1) scenario-based interpretations, (2) the geologic, geophysical, petrophysical, and engineering data available, (3) local, regional, and global knowledge, and (4) field and case studies in the literature. The parameters used to model the recoverable quantities were potential productive area, net hydrocarbon thickness, geometric correction factor, porosity, hydrocarbon saturation, formation volume factor, and recovery efficiency. Minimum, mean, and maximum representations were used to statistically model and shape the input P90, P50, and P10 parameters. Potential productive area, net hydrocarbon thickness, and recovery efficiency were modeled using truncated lognormal distributions. Truncated normal distributions were used to model geometric correction factor, formation volume factor, porosity, and hydrocarbon saturation. Latin hypercube sampling was used to better represent the tails of the distributions.

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

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

Estimates of gross and working interest prospective resources and the P_g estimates, as of July 31, 2016, evaluated herein are shown in Tables 11 and 12. The P_g-adjusted mean estimate of the prospective resources was then made by the probabilistic product of P_g and the resources distributions for the prospect. These results were then stochastically summed (zero dependency) to produce the statistical aggregate P_g-adjusted mean estimate prospective resources.

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

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

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

IGas provided a designated list of prospects; only those prospects listed below were evaluated in this report.

Discovery	License	Working Interest (percent)	License Expiration
Eartham	PEDL326	100.00	7/20/2046
Lea	PEDL316	35.00	7/20/2046

The estimated gross and working interest P_g-adjusted prospective resources, as of July 31, 2016, in the IGas prospects evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl) and millions of cubic feet (10^6ft^3):

			Gross Prospective Oil Resources Summary					
Prospect	**Area/Basin**	**License**	**Low Estimate (10^3bbl)**	**Best Estimate (10^3bbl)**	**High Estimate (10^3bbl)**	**Mean Estimate (10^3bbl)**	**Probability of Geologic Success, P_g (decimal)**	**P_g-adjusted Mean Estimate (10^3bbl)**
Eartham	Weald	PEDL326	587	1,837	5,710	2,601	0.400	1,041
Lea	East Midlands	PEDL316	606	1,638	3,931	2,048	0.180	369
Statistical Aggregate			**1,539**	**3,883**	**9,124**	**4,649**	**0.303**	**1,409**
Arithmetic Summation			1,193	3,475	9,641	4,649	0.303	1,409

Notes:
1. Low, best, high, and mean estimates follow the PRMS guidelines for prospective resources.
2. Low, best, high, and mean estimates in this table are P90, P50, P10, and mean respectively.
3. Pg is defined as the probability of discovering reservoirs which flow petroleum at a measurable rate.
4. Pg has been rounded for presentation purposes. Multiplication using this presented Pg may yield imprecise results. Dividing the Pg-adjusted mean estimate by the mean estimate yields the precise Pg.
5. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of probabilistic estimates is presented in this table in compliance with PRMS guidelines.
8. Summations may vary from those shown here due to rounding.
9. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

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, and a member of the International Society of Petroleum Engineers. He has over 33 years of oil and gas industry experience.

Submitted,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

Regnald A. Boles

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

Glossary of Probabilistic Terms

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

Best Estimate – In accordance with SPE definitions, the best estimate is the probability-weighted average, which typically has a probability in the P_{45} to P_{15} range, depending on the variance of prospective resources volume or associated value. Therefore, the probability of a prospect or accumulation containing the probability weighted average volume or greater is usually between 45 and 15 percent. The best estimate is the preferred probabilistic estimate of prospective resources.

Contingent Resources – Those quantities of petroleum that are estimated, on a given date, to be potentially recoverable from known (drilled) or discovered accumulations, but which are not currently considered to be commercially recoverable or for which the degree of commitment is not such that the accumulation is expected to be developed and placed on production within a reasonable time frame. Contingent resources include accumulations for which there is currently no viable market, or where commercial recovery is dependent on the development of new technology, or where evaluation of the accumulation is still at an early stage.

Expected Value – The expected value (EV) is the probability-weighted average of the parameter being estimated, where probability values from the probability distribution are used as the weighting factors. Parameter values (abscissa) and probabilities (ordinate) are the Cartesian pairs (e.g., gross recoverable volumes and P_{90}), which define the probability distribution. These parameters are probability-weighted and summed to yield the resulting expected value. The equation for computing the expected value is as follows:

$$EV = \sum_{i=1}^{n} (P_i)(V_i)$$

where:
- P = probability from probability distribution, ordinate
- V = parameter value, abscissa
- i = a specific value in an ordered sequence of values
- n = the total number of samples

The expected value is the algebraic sum of all of the products obtained by multiplying the parameter quantity and its associated probability of occurrence. The expected value is sometimes called the mean, best estimate, or the statistical mean. In a probabilistic analysis, the expected value is the only quantity that can be treated arithmetically (by addition, subtraction, multiplication, or division). All other quantities, such as median (P_{50}), mode, P_{90}, and P_{10}, require probabilistic techniques for scaling or aggregation.

The probability associated with the statistical mean depends on the variance of the distribution from which the mean is calculated. The best estimate is the statistical mean (the probability-weighted average), which typically has a probability in the P_{45} to P_{15} range. Therefore, if a successful discovery occurs, the probability of the accumulation containing the statistical mean volume or greater is usually between 45 and 15 percent.

The expected value is the preferred quantity to use for the best estimate in probabilistic estimates of prospective resources. The P_{90} and P_{10} quantity is often used for the low and high estimates, respectively, of prospective resources. Aggregation or scaling of P_{90}, P_{50}, and P_{10} quantities should be done probabilistically, not arithmetically.

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

High Estimate – In accordance with SPE definitions, the low estimate is the P_{10} quantity. P_{10} means there is a 10-percent chance that an estimated quantity, such as a prospective resources volume or associated value, will be equaled or exceeded.

Immature Prospect – An immature prospect is less well defined and requires additional data and/or evaluation to be classified as a mature prospect. An example would be a poorly defined closure mapped using sparse regional seismic data in a basin containing favorable source and reservoir(s). An immature prospect may or may not be elevated to mature prospect status depending on the results of additional technical work. An immature prospect must have a P_g equal to or less than 0.05 to reflect the inherent technical uncertainty.

Low Estimate – In accordance with SPE definitions, the low estimate is the P_{90} quantity. P_{90} means there is a 90-percent chance that an estimated quantity, such as a prospective resources volume or associated value, will be equaled or exceeded.

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

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

The median is an acceptable, but not preferred, quantity to use for the best estimate in probabilistic estimations of prospective resources. Aggregation or scaling of P_{50} quantities should be done probabilistically, not arithmetically.

Median Estimate – In accordance with SPE definitions, the median estimate is the P_{50} quantity. P_{50} means there is a 50-percent chance that an estimated quantity, such as a prospective resources volume or associated value, will be equaled or exceeded.

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

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

The mode is an acceptable, but not preferred, quantity to use for the best estimate in probabilistic estimations of prospective resources.

P_e-Adjusted Best Estimate – The P_e-adjusted best estimate, or "economic risk-adjusted best estimate," is a probability-weighted average of the hydrocarbon quantities potentially recoverable if a prospect portfolio were drilled, or if a family of similar prospects were drilled. The P_e-adjusted best estimate is a "blended" quantity. It is a mean estimation of volumetric uncertainty, geologic (P_g), and economic risk (chance). This statistical measure considers and quantifies the economic success and economic failure outcomes. Consequently, it represents the average or mean "economic" volumes resulting from economically viable drilling and exploration. The P_e-adjusted best estimate is calculated as follows:

$$P_e\text{-adjusted best estimate} = P_e \times \text{best estimate}$$

P_g-Adjusted Best Estimate – The P_g-adjusted best estimate, or "geologic risk-adjusted best estimate," is a probability-weighted average of the hydrocarbon quantities potentially recoverable if a prospect portfolio were drilled, or if a family of similar prospects were drilled. The P_g-adjusted best estimate is a "blended" quantity. It is a mean estimation of both volumetric uncertainty and geological risk (chance). This statistical measure considers and quantifies the geological success and geological failure outcomes. Consequently, it represents the average or mean "geologic" outcome of a drilling and exploration program. The P_g-adjusted best estimate is calculated as follows:

$$P_g\text{-adjusted best estimate} = P_g \times \text{best estimate}$$

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

Potential Present Worth – Potential present worth (PPW) is defined as potential future net revenue discounted at 10 percent compounded monthly over the expected period of realization. The estimation is probabilistically modeled using distributions (except NRI, a constant) in the following equation:

$$PPW_{10} = \left[\left(P_e \times EV_t \times NRI \times \frac{PW}{BOE}\right) - \left(P_e \times CWCE \times NRI\right)\right] - \left(P_f \times DHC \times NRI\right)$$

where:	PPW_{10}	=	potential present worth at 10 percent
	P_e	=	probability of economic success
	EV_t	=	best estimate, potential gross recoverable volume, truncated, TEFS-adjusted
	NRI	=	net revenue interest
	PW/BOE	=	present worth at 10 percent per barrel of oil equivalent
	CWCE	=	completed well cost estimate
	P_f	=	probability of economic failure
	DHC	=	dry hole cost estimate

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

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

$$C_x^{\ n} = \frac{n!}{x!(n-x)!}$$

where: P_x^n = the probability of x successes in n trials

C_x^n = the number of mutually exclusive ways that x successes can be arranged in n trials

p = the probability of success for a given trial (for petroleum exploration, this is P_g)

x = the number of successes (e.g., the number of discoveries)

n = the number of trials (e.g., the number of wells to be drilled)

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

Probability of Economic Success – The probability of economic success (P_e) is defined as the probability that a given discovery will be economically viable. It takes into account P_g, P_{TEFS}, TEFS, capital costs, operating expenses, the proposed development plan, the economic model (discounted cash flow analyses), and other business and economic factors. P_e is calculated as follows:

$$P_e = P_g \times P_{TEFS}$$

Probability of Geologic Success – The probability of geologic success (P_g) is defined as the probability of discovering reservoirs that flow petroleum at a measurable rate. P_g is estimated by quantifying with a probability each of the following individual geologic chance factors: trap, source, reservoir, and migration. The product of the probabilities of these four chance factors is P_g.

Probability of TEFS – The probability of threshold economic field size (P_{TEFS}) is defined as the probability of discovering an accumulation that is large enough to be economically viable. P_{TEFS} is estimated by using the prospective resources recoverable volumes distribution in conjunction with the TEFS. The probability associated with the TEFS can be determined graphically from the prospective gross recoverable volumes distribution.

Prospective Resources – Those quantities of petroleum that are estimated, on a given date, to be potentially recoverable from undiscovered (undrilled) accumulations.

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

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

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

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

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

Threshold Economic Field Size – The threshold economic field size (TEFS) is the minimum amount of producible petroleum required to recover the total capital expenditure used to establish the prospect as having a positive potential present worth greater than zero. These investments include expenditures required to establish and prove profitable production and to conduct delineation or confirmation drilling. All geologic, geophysical, lease and/or contract-area acquisition costs and other anticipated field delineation costs are included in the estimation of TEFS as well. The potential present worth per resources volume methodology is a standard industry practice used to estimate prospective resources value. This methodology is directly formulated from the discounted cash flow analysis, which is fundamental to the potential present worth estimation. Accordingly, where the potential present worth per barrel methodology is being employed to estimate TEFS, no additional provision should be made for field development costs.

$$\text{TEFS} = \frac{\text{Geology} + \text{Geophysics} + \text{Drilling} + \text{Land} + \text{Transportation} + \text{Overhead}}{\text{Potential Present Worth per Barrel}}$$

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

Truncated Best Estimate – The truncated best estimate is the resulting expected value calculated from the truncation of the resources distribution by the threshold economic field size. This truncated distribution produces a new set of statistical metrics.

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

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

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

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TEXAS REGISTERED ENGINEERING FIRM

TABLE 1
SUMMARY PROJECTION of NET TOTAL PROVED RESERVES and FUTURE NET REVENUE – BASE CASE
as of
JULY 31, 2016
attributable to
IGAS
for
CERTAIN PROPERTIES
in the
UNITED KINGDOM

	Gross			Net			Product Prices			Future Gross Revenue	Tariff Paid and Operating Expenses	Abandonment and Capital Costs	Future Net Revenue	Present Worth at 10 Percent
Year	Oil (10^3bbl)	Cond (10^3bbl)	Sales Gas (10^6ft^3)	Oil (10^3bbl)	Cond (10^3bbl)	Sales Gas (10^6ft^3)	Oil (U.S.$/bbl)	Cond (U.S.$/bbl)	Sales Gas (U.S.$/$10^3$ft^3)	(10^3 U.S.$)	(10^3 U.S.$)	(10^3 U.S.$)	(10^3 U.S.$)	(10^3 U.S.$)
2016 (5 months)	389	0	114	384	0	114	51.20	0.00	5.25	20,260	14,643	2,128	3,489	3,405
2017	957	0	240	946	0	240	57.30	0.00	5.40	55,502	22,809	6,230	26,463	24,064
2018	889	0	221	884	0	221	63.62	0.00	5.55	57,467	21,970	6,707	28,790	23,698
2019	829	0	207	825	0	207	70.18	0.00	5.70	59,079	21,392	0	37,687	28,083
2020	743	0	194	739	0	194	76.99	0.00	5.81	58,025	20,686	0	37,339	25,185
2021	653	0	176	649	0	176	80.74	0.00	5.93	53,442	19,522	602	33,318	20,342
2022	579	0	168	575	0	168	82.36	0.00	6.05	48,374	18,249	925	29,200	16,139
2023	524	0	155	520	0	155	84.00	0.00	6.17	44,636	17,867	0	26,769	13,393
2024	465	0	144	462	0	144	85.68	0.00	6.29	40,490	16,883	1,944	21,663	9,810
2025	397	0	63	394	0	63	87.40	0.00	6.42	34,841	14,074	4,651	16,116	6,605
2026	352	0	62	349	0	62	89.15	0.00	6.55	31,521	13,285	1,022	17,214	6,389
2027	308	0	60	305	0	60	90.93	0.00	6.68	28,134	12,159	1,745	14,230	4,781
2028	246	0	59	243	0	59	92.75	0.00	6.81	22,940	9,464	3,935	9,541	2,901
2029	212	0	58	209	0	58	94.60	0.00	6.95	20,174	8,287	4,767	7,120	1,960
2030	194	0	57	192	0	57	96.50	0.00	7.09	18,933	8,238	0	10,695	2,665
2031	177	0	56	175	0	56	98.43	0.00	7.23	17,631	8,214	0	9,417	2,124
2032	162	0	56	160	0	56	100.39	0.00	7.37	16,474	8,191	0	8,283	1,691
2033	148	0	55	146	0	55	102.40	0.00	7.52	15,364	8,185	0	7,179	1,327
2034	135	0	54	133	0	54	104.45	0.00	7.67	14,306	8,188	0	6,118	1,025
2035	122	0	52	120	0	52	106.54	0.00	7.82	13,191	8,189	0	5,002	758
2036	106	0	46	104	0	46	108.67	0.00	7.98	11,669	7,426	2,179	2,064	282
2037	96	0	42	94	0	42	110.84	0.00	8.14	10,761	7,476	0	3,285	407
2038	84	0	38	82	0	38	113.06	0.00	8.30	9,587	7,182	916	1,489	167
2039	78	0	35	77	0	35	115.32	0.00	8.47	9,175	7,266	0	1,909	194
2040	44	0	27	43	0	27	117.63	0.00	8.64	5,291	3,853	13,953	(12,515)	(1,151)
Subtotal	**8,889**	**0**	**2,439**	**8,810**	**0**	**2,439**				**717,267**	**313,698**	**51,704**	**351,865**	**196,244**
Remaining	131	0	66	124	0	66				16,129	13,814	7,267	(4,952)	(265)
Total	**9,020**	**0**	**2,505**	**8,934**	**0**	**2,505**				**733,396**	**327,512**	**58,971**	**346,913**	**195,979**

Present Worth at	(10^3 U.S.$)
8 Percent	217,279
12 Percent	177,695
15 Percent	154,827

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

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TABLE 2
SUMMARY PROJECTION of NET PROVED-PLUS-PROBABLE RESERVES and FUTURE NET REVENUE – BASE CASE
as of
JULY 31, 2016
attributable to
IGAS
for
CERTAIN PROPERTIES
in the
UNITED KINGDOM

	Gross			Net			Product Prices			Future	Tariff Paid	Abandonment	Future	Present
Year	Oil (10^3bbl)	Cond (10^3bbl)	Sales Gas (10^6ft^3)	Oil (10^3bbl)	Cond (10^3bbl)	Sales Gas (10^6ft^3)	Oil (U.S.$/bbl)	Cond (U.S.$/bbl)	Sales Gas (U.S.$/$10^3$ft^3)	Gross Revenue (10^3 U.S.$)	and Operating Expenses (10^3 U.S.$)	and Capital Costs (10^3 U.S.$)	Net Revenue (10^3 U.S.$)	Worth at 10 Percent (10^3 U.S.$)
2016 (5 months)	425	0	144	420	0	144	51.20	0.00	5.25	22,261	15,251	2,128	4,882	4,762
2017	1,049	0	278	1,038	0	278	57.30	0.00	5.40	60,979	24,177	6,230	30,572	27,800
2018	1,017	0	265	1,007	0	265	63.62	0.00	5.55	65,536	23,903	6,428	35,205	28,982
2019	975	0	251	966	0	251	70.18	0.00	5.70	69,228	23,538	0	45,690	34,045
2020	890	0	237	885	0	237	76.99	0.00	5.81	69,516	22,795	294	46,427	31,314
2021	816	0	224	811	0	224	80.74	0.00	5.93	66,808	22,274	0	44,534	27,190
2022	753	0	216	748	0	216	82.36	0.00	6.05	62,911	21,903	0	41,008	22,664
2023	691	0	203	687	0	203	84.00	0.00	6.17	58,960	21,519	0	37,441	18,733
2024	627	0	196	623	0	196	85.68	0.00	6.29	54,611	20,308	972	33,331	15,095
2025	573	0	183	569	0	183	87.40	0.00	6.42	50,905	19,559	664	30,682	12,577
2026	523	0	176	519	0	176	89.15	0.00	6.55	47,420	18,866	1,362	27,192	10,091
2027	474	0	169	470	0	169	90.93	0.00	6.68	43,867	17,716	1,047	25,104	8,433
2028	441	0	162	437	0	162	92.75	0.00	6.81	41,636	17,611	0	24,025	7,305
2029	408	0	155	405	0	155	94.60	0.00	6.95	39,389	17,505	0	21,884	6,024
2030	373	0	148	370	0	148	96.50	0.00	7.09	36,756	16,845	1,128	18,783	4,680
2031	330	0	63	327	0	63	98.43	0.00	7.23	32,642	14,662	5,008	12,972	2,924
2032	297	0	62	294	0	62	100.39	0.00	7.37	29,972	13,580	1,974	14,418	2,943
2033	274	0	61	271	0	61	102.40	0.00	7.52	28,210	13,534	0	14,676	2,711
2034	230	0	60	227	0	60	104.45	0.00	7.67	24,172	10,744	4,564	8,864	1,483
2035	202	0	59	199	0	59	106.54	0.00	7.82	21,663	9,455	5,528	6,680	1,013
2036	190	0	58	187	0	58	108.67	0.00	7.98	20,784	9,490	0	11,294	1,547
2037	176	0	57	174	0	57	110.84	0.00	8.14	19,750	9,508	0	10,242	1,271
2038	164	0	57	162	0	57	113.06	0.00	8.30	18,789	9,553	0	9,236	1,036
2039	153	0	56	151	0	56	115.32	0.00	8.47	17,888	9,595	0	8,293	843
2040	144	0	55	142	0	55	117.63	0.00	8.64	17,179	9,672	0	7,507	692
Subtotal	**12,195**	**0**	**3,595**	**12,089**	**0**	**3,595**				**1,021,832**	**413,563**	**37,327**	**570,942**	**276,158**
Remaining	959	0	434	929	0	434				126,590	91,464	29,683	5,443	1,011
Total	**13,154**	**0**	**4,029**	**13,018**	**0**	**4,029**				**1,148,422**	**505,027**	**67,010**	**576,385**	**277,169**

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

Present Worth at	(10^3 U.S.$)
8 Percent	314,115
12 Percent	246,724
15 Percent	210,174

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TABLE 3
SUMMARY PROJECTION of NET PROVED-PLUS-PROBABLE-PLUS-POSSIBLE RESERVES and FUTURE NET REVENUE – BASE CASE
as of
JULY 31, 2016
attributable to
IGAS
for
CERTAIN PROPERTIES
in the
UNITED KINGDOM

	Gross			Net			Product Prices			Future Gross	Tariff Paid and Operating	Abandonment and	Future Net	Present Worth at
Year	Oil (10^3bbl)	Cond (10^3bbl)	Sales Gas (10^6ft^3)	Oil (10^3bbl)	Cond (10^3bbl)	Sales Gas (10^6ft^3)	Oil (U.S.$/bbl)	Cond (U.S.$/bbl)	Sales Gas (U.S.$/$10^3$ft^3)	Revenue (10^3 U.S.$)	Expenses (10^3 U.S.$)	Capital Costs (10^3 U.S.$)	Revenue (10^3 U.S.$)	10 Percent (10^3 U.S.$)
2016 (5 months)	439	0	149	434	0	149	51.20	0.00	5.25	23,004	15,470	2,128	5,406	5,274
2017	1,104	0	297	1,092	0	297	57.30	0.00	5.40	64,176	25,021	6,230	32,925	29,939
2018	1,104	0	285	1,092	0	285	63.62	0.00	5.55	71,055	25,151	6,428	39,476	32,495
2019	1,082	0	277	1,071	0	277	70.18	0.00	5.70	76,742	25,067	0	51,675	38,505
2020	1,015	0	264	1,006	0	264	76.99	0.00	5.81	78,989	24,728	0	54,261	36,599
2021	945	0	256	936	0	256	80.74	0.00	5.93	77,092	24,296	0	52,796	32,234
2022	880	0	249	875	0	249	82.36	0.00	6.05	73,570	23,793	308	49,469	27,343
2023	826	0	235	821	0	235	84.00	0.00	6.17	70,414	23,572	0	46,842	23,435
2024	775	0	228	770	0	228	85.68	0.00	6.29	67,408	23,364	0	44,044	19,947
2025	725	0	221	720	0	221	87.40	0.00	6.42	64,347	23,136	0	41,211	16,895
2026	670	0	214	666	0	214	89.15	0.00	6.55	60,776	22,043	1,022	37,711	13,993
2027	630	0	207	626	0	207	90.93	0.00	6.68	58,303	21,935	0	36,368	12,218
2028	590	0	200	586	0	200	92.75	0.00	6.81	55,715	21,393	1,431	32,891	10,000
2029	537	0	194	533	0	194	94.60	0.00	6.95	51,770	19,700	1,833	30,237	8,322
2030	509	0	187	505	0	187	96.50	0.00	7.09	50,061	19,724	0	30,337	7,557
2031	479	0	180	475	0	180	98.43	0.00	7.23	48,054	19,704	0	28,350	6,394
2032	453	0	174	449	0	174	100.39	0.00	7.37	46,357	19,696	0	26,661	5,443
2033	427	0	172	424	0	172	102.40	0.00	7.52	44,712	19,719	0	24,993	4,620
2034	404	0	166	401	0	166	104.45	0.00	7.67	43,157	19,782	0	23,375	3,910
2035	382	0	160	379	0	160	106.54	0.00	7.82	41,631	19,846	0	21,785	3,300
2036	353	0	153	350	0	153	108.67	0.00	7.98	39,256	18,802	2,179	18,275	2,506
2037	325	0	152	322	0	152	110.84	0.00	8.14	36,928	18,109	1,340	17,479	2,171
2038	265	0	62	262	0	62	113.06	0.00	8.30	30,136	12,556	10,990	6,590	741
2039	250	0	62	247	0	62	115.32	0.00	8.47	29,009	12,592	0	16,417	1,670
2040	239	0	61	236	0	61	117.63	0.00	8.64	28,287	12,716	0	15,571	1,433
Subtotal	**15,408**	**0**	**4,805**	**15,278**	**0**	**4,805**				**1,330,949**	**511,915**	**33,889**	**785,145**	**346,944**
Remaining	2,652	0	1,053	2,609	0	1,053				378,290	235,145	44,820	98,325	6,106
Total	**18,060**	**0**	**5,858**	**17,887**	**0**	**5,858**				**1,709,239**	**747,060**	**78,709**	**883,470**	**353,050**

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

Present Worth at	(10^3 U.S.$)
8 Percent	409,142
12 Percent	308,654
15 Percent	257,443

TABLE 4
SUMMARY PROJECTION of NET TOTAL PROVED RESERVES and FUTURE NET REVENUE – LOW CASE
as of
JULY 31, 2016
attributable to
IGAS
for
CERTAIN PROPERTIES
in the
UNITED KINGDOM

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Net			Product Prices			Future	Tariff Paid	Abandonment	Future	Present
Year	Oil (10^3bbl)	Cond (10^3bbl)	Sales Gas (10^6ft^3)	Oil (10^3bbl)	Cond (10^3bbl)	Sales Gas (10^6ft^3)	Oil (U.S.$/bbl)	Cond (U.S.$/bbl)	Sales Gas (U.S.$/$10^3$ft^3)	Gross Revenue (10^3 U.S.$)	and Operating Expenses (10^3 U.S.$)	and Capital Costs (10^3 U.S.$)	Net Revenue (10^3 U.S.$)	Worth at 10 Percent (10^3 U.S.$)
2016 (5 months)	362	0	114	360	0	114	40.96	0.00	4.20	15,226	12,761	4,256	(1,791)	(1,745)
2017	896	0	240	891	0	240	45.84	0.00	4.32	41,881	20,128	6,230	15,523	14,115
2018	845	0	221	840	0	221	50.90	0.00	4.44	43,739	19,642	6,428	17,669	14,543
2019	789	0	207	785	0	207	56.14	0.00	4.56	45,014	19,101	0	25,913	19,308
2020	709	0	194	705	0	194	61.59	0.00	4.65	44,323	18,477	0	25,846	17,433
2021	602	0	71	598	0	71	64.59	0.00	4.74	38,962	15,542	4,514	18,906	11,543
2022	541	0	68	537	0	68	65.89	0.00	4.84	35,710	15,110	0	20,600	11,384
2023	483	0	66	479	0	66	67.20	0.00	4.94	32,517	14,289	1,265	16,963	8,486
2024	434	0	65	431	0	65	68.54	0.00	5.03	29,869	13,803	648	15,418	6,983
2025	362	0	63	359	0	63	69.92	0.00	5.14	25,424	11,465	5,980	7,979	3,271
2026	327	0	62	324	0	62	71.32	0.00	5.24	23,433	11,267	0	12,166	4,515
2027	295	0	60	292	0	60	72.74	0.00	5.34	21,561	11,063	0	10,498	3,527
2028	234	0	59	231	0	59	74.20	0.00	5.45	17,461	8,367	3,935	5,159	1,569
2029	212	0	58	209	0	58	75.68	0.00	5.56	16,141	8,287	0	7,854	2,161
2030	194	0	57	192	0	57	77.20	0.00	5.67	15,146	8,238	0	6,908	1,722
2031	177	0	56	175	0	56	78.74	0.00	5.78	14,104	8,214	0	5,890	1,330
2032	162	0	56	160	0	56	80.31	0.00	5.90	13,179	8,191	0	4,988	1,018
2033	138	0	55	136	0	55	81.92	0.00	6.02	11,472	7,349	2,024	2,099	388
2034	126	0	54	124	0	54	83.56	0.00	6.14	10,694	7,359	0	3,335	558
2035	114	0	52	112	0	52	85.23	0.00	6.26	9,871	7,368	0	2,503	378
2036	106	0	46	104	0	46	86.94	0.00	6.38	9,335	7,426	0	1,909	261
2037	59	0	36	57	0	36	88.67	0.00	6.51	5,288	4,047	12,956	(11,715)	(1,454)
2038	50	0	33	48	0	33	90.45	0.00	6.64	4,560	3,728	916	(84)	(10)
2039	47	0	30	46	0	30	92.26	0.00	6.78	4,448	3,789	0	659	67
2040	44	0	27	43	0	27	94.10	0.00	6.91	4,233	3,853	0	380	36
Subtotal	**8,308**	**0**	**2,050**	**8,238**	**0**	**2,050**				**533,591**	**268,864**	**49,152**	**215,575**	**121,387**
Remaining	34	0	24	33	0	24				3,337	3,250	6,826	(6,739)	(523)
Total	**8,342**	**0**	**2,074**	**8,271**	**0**	**2,074**				**536,928**	**272,114**	**55,978**	**208,836**	**120,864**

Present Worth at (10^3 U.S.$)	
8 Percent	133,926
12 Percent	109,504
15 Percent	95,115

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

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE 5
SUMMARY PROJECTION of NET PROVED-PLUS-PROBABLE RESERVES and FUTURE NET REVENUE – LOW CASE
as of
JULY 31, 2016
attributable to
IGAS
for
CERTAIN PROPERTIES
in the
UNITED KINGDOM

Year	Gross Oil (10^3bbl)	Gross Cond (10^3bbl)	Gross Sales Gas (10^6ft^3)	Net Oil (10^3bbl)	Net Cond (10^3bbl)	Net Sales Gas (10^6ft^3)	Product Prices Oil (U.S.$/bbl)	Product Prices Cond (U.S.$/bbl)	Product Prices Sales Gas (U.S.$/$10^3$ft^3)	Future Gross Revenue (10^3 U.S.$)	Tariff Paid and Operating Expenses (10^3 U.S.$)	Abandonment and Capital Costs (10^3 U.S.$)	Future Net Revenue (10^3 U.S.$)	Present Worth at 10 Percent (10^3 U.S.$)
2016 (5 months)	407	0	144	405	0	144	40.96	0.00	4.20	17,193	14,067	3,458	(332)	(323)
2017	1,008	0	278	1,003	0	278	45.84	0.00	4.32	47,179	22,462	6,230	18,487	16,811
2018	981	0	265	976	0	265	50.90	0.00	4.44	50,856	22,256	6,428	22,172	18,250
2019	943	0	251	938	0	251	56.14	0.00	4.56	53,806	21,929	0	31,877	23,752
2020	867	0	237	862	0	237	61.59	0.00	4.65	54,194	21,421	0	32,773	22,106
2021	794	0	224	789	0	224	64.59	0.00	4.74	52,023	20,894	0	31,129	19,005
2022	719	0	216	714	0	216	65.89	0.00	4.84	48,090	19,584	925	27,581	15,243
2023	660	0	203	656	0	203	67.20	0.00	4.94	45,087	19,214	0	25,873	12,946
2024	609	0	196	605	0	196	68.54	0.00	5.03	42,452	18,940	0	23,512	10,648
2025	550	0	183	546	0	183	69.92	0.00	5.14	39,117	17,716	1,993	19,408	7,956
2026	486	0	71	482	0	71	71.32	0.00	5.24	34,750	15,430	4,427	14,893	5,526
2027	434	0	69	430	0	69	72.74	0.00	5.34	31,646	14,050	2,443	15,153	5,090
2028	403	0	67	399	0	67	74.20	0.00	5.45	29,971	13,915	0	16,056	4,882
2029	372	0	66	369	0	66	75.68	0.00	5.56	28,293	13,780	0	14,513	3,996
2030	345	0	64	342	0	64	77.20	0.00	5.67	26,766	13,707	0	13,059	3,253
2031	268	0	63	265	0	63	78.74	0.00	5.78	21,231	9,494	9,246	2,491	562
2032	250	0	62	247	0	62	80.31	0.00	5.90	20,202	9,473	0	10,729	2,190
2033	232	0	61	229	0	61	81.92	0.00	6.02	19,127	9,439	0	9,688	1,791
2034	217	0	60	214	0	60	83.56	0.00	6.14	18,250	9,441	0	8,809	1,474
2035	202	0	59	199	0	59	85.23	0.00	6.26	17,331	9,455	0	7,876	1,193
2036	190	0	58	187	0	58	86.94	0.00	6.38	16,628	9,490	0	7,138	979
2037	176	0	57	174	0	57	88.67	0.00	6.51	15,798	9,508	0	6,290	780
2038	164	0	57	162	0	57	90.45	0.00	6.64	15,032	9,553	0	5,479	615
2039	149	0	56	147	0	56	92.26	0.00	6.78	13,942	9,222	939	3,781	385
2040	140	0	55	138	0	55	94.10	0.00	6.91	13,366	9,290	0	4,076	375
Subtotal	**11,566**	**0**	**3,122**	**11,478**	**0**	**3,122**				**772,330**	**363,730**	**36,089**	**372,511**	**179,485**
Remaining	647	0	351	628	0	351				66,670	53,266	26,292	(12,888)	(515)
Total	**12,213**	**0**	**3,473**	**12,106**	**0**	**3,473**				**839,000**	**416,996**	**62,381**	**359,623**	**178,970**

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

Present Worth at	(10^3 U.S.$)
8 Percent	202,461
12 Percent	159,373
15 Percent	135,590

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE 6
SUMMARY PROJECTION of NET PROVED-PLUS-PROBABLE-PLUS-POSSIBLE RESERVES and FUTURE NET REVENUE – LOW CASE
as of
JULY 31, 2016
attributable to
IGAS
for
CERTAIN PROPERTIES
in the
UNITED KINGDOM

	Gross			Net			Product Prices			Future Gross Revenue	Tariff Paid and Operating Expenses	Abandonment and Capital Costs	Future Net Revenue	Present Worth at 10 Percent
Year	Oil (10^3bbl)	Cond (10^3bbl)	Sales Gas (10^6ft^3)	Oil (10^3bbl)	Cond (10^3bbl)	Sales Gas (10^6ft^3)	Oil (U.S.$/bbl)	Cond (U.S.$/bbl)	Sales Gas (U.S.$/$10^3$ft^3)	(10^3 U.S.$)	(10^3 U.S.$)	(10^3 U.S.$)	(10^3 U.S.$)	(10^3 U.S.$)
2016 (5 months)	432	0	149	427	0	149	40.96	0.00	4.20	18,115	14,899	2,394	822	802
2017	1,087	0	297	1,075	0	297	45.84	0.00	4.32	50,562	24,186	6,230	20,146	18,320
2018	1,088	0	285	1,076	0	285	50.90	0.00	4.44	56,033	24,320	6,428	25,285	20,813
2019	1,067	0	277	1,056	0	277	56.14	0.00	4.56	60,548	24,242	0	36,306	27,053
2020	1,001	0	264	992	0	264	61.59	0.00	4.65	62,325	23,909	0	38,416	25,913
2021	932	0	256	923	0	256	64.59	0.00	4.74	60,829	23,485	0	37,344	22,802
2022	868	0	249	863	0	249	65.89	0.00	4.84	58,067	22,990	308	34,769	19,219
2023	814	0	235	809	0	235	67.20	0.00	4.94	55,525	22,749	0	32,776	16,399
2024	750	0	228	745	0	228	68.54	0.00	5.03	52,210	21,539	972	29,699	13,451
2025	702	0	221	697	0	221	69.92	0.00	5.14	49,870	21,339	0	28,531	11,695
2026	644	0	214	640	0	214	71.32	0.00	5.24	46,767	20,073	2,384	24,310	9,023
2027	606	0	207	602	0	207	72.74	0.00	5.34	44,895	19,960	0	24,935	8,376
2028	567	0	200	563	0	200	74.20	0.00	5.45	42,866	19,368	715	22,783	6,929
2029	529	0	194	525	0	194	75.68	0.00	5.56	40,809	19,041	733	21,035	5,790
2030	501	0	187	497	0	187	77.20	0.00	5.67	39,429	19,048	0	20,381	5,078
2031	436	0	70	432	0	70	78.74	0.00	5.78	34,420	15,545	6,934	11,941	2,693
2032	413	0	69	409	0	69	80.31	0.00	5.90	33,253	15,538	0	17,715	3,618
2033	388	0	67	385	0	67	81.92	0.00	6.02	31,941	15,486	0	16,455	3,041
2034	366	0	66	363	0	66	83.56	0.00	6.14	30,738	15,485	0	15,253	2,552
2035	312	0	65	309	0	65	85.23	0.00	6.26	26,745	12,443	4,678	9,624	1,457
2036	298	0	64	295	0	64	86.94	0.00	6.38	26,056	12,515	0	13,541	1,855
2037	280	0	63	277	0	63	88.67	0.00	6.51	24,972	12,503	0	12,469	1,547
2038	248	0	62	245	0	62	90.45	0.00	6.64	22,573	10,980	0	11,593	1,303
2039	234	0	62	231	0	62	92.26	0.00	6.78	21,733	11,012	0	10,721	1,091
2040	223	0	61	220	0	61	94.10	0.00	6.91	21,124	11,097	0	10,027	923
Subtotal	**14,786**	**0**	**4,112**	**14,656**	**0**	**4,112**				**1,012,405**	**453,752**	**31,776**	**526,877**	**231,743**
Remaining	2,260	0	983	2,227	0	983				252,568	178,876	41,291	32,401	2,818
Total	**17,046**	**0**	**5,095**	**16,883**	**0**	**5,095**				**1,264,973**	**632,628**	**73,067**	**559,278**	**234,561**

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

Present Worth at	(10^3 U.S.$)
8 Percent	271,194
12 Percent	205,203
15 Percent	170,998

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE 7
SUMMARY PROJECTION of NET TOTAL PROVED RESERVES and FUTURE NET REVENUE – HIGH CASE
as of
JULY 31, 2016
attributable to
IGAS
for
CERTAIN PROPERTIES
in the
UNITED KINGDOM

	Gross			Net			Product Prices							
Year	Oil (10^3bbl)	Cond (10^3bbl)	Sales Gas (10^6ft^3)	Oil (10^3bbl)	Cond (10^3bbl)	Sales Gas (10^6ft^3)	Oil (U.S.$/bbl)	Cond (U.S.$/bbl)	Sales Gas (U.S.$/$10^3$ft^3)	Future Gross Revenue (10^3 U.S.$)	Tariff Paid and Operating Expenses (10^3 U.S.$)	Abandonment and Capital Costs (10^3 U.S.$)	Future Net Revenue (10^3 U.S.$)	Present Worth at 10 Percent (10^3 U.S.$)
2016 (5 months)	389	0	114	384	0	114	61.44	0.00	6.30	24,310	14,643	2,128	7,539	7,354
2017	957	0	240	946	0	240	68.76	0.00	6.48	66,603	22,809	6,230	37,564	34,158
2018	889	0	221	884	0	221	76.34	0.00	6.66	68,956	21,970	6,707	40,279	33,156
2019	829	0	207	825	0	207	84.22	0.00	6.84	70,900	21,392	0	49,508	36,890
2020	743	0	194	739	0	194	92.39	0.00	6.97	69,629	20,686	0	48,943	33,012
2021	653	0	176	649	0	176	96.89	0.00	7.12	64,135	19,522	602	44,011	26,869
2022	579	0	168	575	0	168	98.83	0.00	7.26	58,047	18,249	925	38,873	21,485
2023	524	0	155	520	0	155	100.80	0.00	7.40	53,561	17,867	0	35,694	17,859
2024	465	0	144	462	0	144	102.82	0.00	7.55	48,588	16,883	1,944	29,761	13,479
2025	397	0	63	394	0	63	104.88	0.00	7.70	41,808	14,074	4,651	23,083	9,463
2026	352	0	62	349	0	62	106.98	0.00	7.86	37,825	13,285	1,022	23,518	8,728
2027	308	0	60	305	0	60	109.12	0.00	8.02	33,762	12,159	1,745	19,858	6,672
2028	246	0	59	243	0	59	111.30	0.00	8.17	27,528	9,464	3,935	14,129	4,297
2029	212	0	58	209	0	58	113.52	0.00	8.34	24,209	8,287	4,767	11,155	3,071
2030	194	0	57	192	0	57	115.80	0.00	8.51	22,719	8,238	0	14,481	3,607
2031	177	0	56	175	0	56	118.12	0.00	8.68	21,158	8,214	0	12,944	2,919
2032	162	0	56	160	0	56	120.47	0.00	8.84	19,769	8,191	0	11,578	2,363
2033	148	0	55	146	0	55	122.88	0.00	9.02	18,437	8,185	0	10,252	1,896
2034	135	0	54	133	0	54	125.34	0.00	9.20	17,166	8,188	0	8,978	1,503
2035	122	0	52	120	0	52	127.85	0.00	9.38	15,830	8,189	0	7,641	1,158
2036	106	0	46	104	0	46	130.40	0.00	9.58	14,003	7,426	2,179	4,398	602
2037	96	0	42	94	0	42	133.01	0.00	9.77	12,913	7,476	0	5,437	674
2038	84	0	38	82	0	38	135.67	0.00	9.96	11,504	7,182	916	3,406	383
2039	78	0	35	77	0	35	138.38	0.00	10.16	11,011	7,266	0	3,745	381
2040	44	0	27	43	0	27	141.16	0.00	10.37	6,350	3,853	13,953	(11,456)	(1,054)
Subtotal	**8,889**	**0**	**2,439**	**8,810**	**0**	**2,439**				**860,721**	**313,698**	**51,704**	**495,319**	**270,925**
Remaining	131	0	66	124	0	66				19,353	13,814	7,267	(1,728)	(29)
Total	**9,020**	**0**	**2,505**	**8,934**	**0**	**2,505**				**880,074**	**327,512**	**58,971**	**493,591**	**270,896**

Present Worth at	(10^3 U.S.$)
8 Percent	300,987
12 Percent	245,329
15 Percent	213,655

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

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE 8
SUMMARY PROJECTION of NET PROVED-PLUS-PROBABLE RESERVES and FUTURE NET REVENUE – HIGH CASE
as of
JULY 31, 2016
attributable to
IGAS
for
CERTAIN PROPERTIES
in the
UNITED KINGDOM

Year	Gross Oil (10^3bbl)	Gross Cond (10^3bbl)	Gross Sales Gas (10^6ft^3)	Net Oil (10^3bbl)	Net Cond (10^3bbl)	Net Sales Gas (10^6ft^3)	Product Prices Oil (U.S.$/bbl)	Product Prices Cond (U.S.$/bbl)	Product Prices Sales Gas (U.S.$/$10^3$ft^3)	Future Gross Revenue (10^3 U.S.$)	Tariff Paid and Operating Expenses (10^3 U.S.$)	Abandonment and Capital Costs (10^3 U.S.$)	Future Net Revenue (10^3 U.S.$)	Present Worth at 10 Percent (10^3 U.S.$)
2016 (5 months)	425	0	144	420	0	144	61.44	0.00	6.30	26,711	15,251	2,128	9,332	9,104
2017	1,049	0	278	1,038	0	278	68.76	0.00	6.48	73,175	24,177	6,230	42,768	38,893
2018	1,017	0	265	1,007	0	265	76.34	0.00	6.66	78,640	23,903	6,428	48,309	39,765
2019	975	0	251	966	0	251	84.22	0.00	6.84	83,074	23,538	0	59,536	44,362
2020	890	0	237	885	0	237	92.39	0.00	6.97	83,418	22,795	294	60,329	40,691
2021	816	0	224	811	0	224	96.89	0.00	7.12	80,171	22,274	0	57,897	35,351
2022	753	0	216	748	0	216	98.83	0.00	7.26	75,491	21,903	0	53,588	29,620
2023	691	0	203	687	0	203	100.80	0.00	7.40	70,751	21,519	0	49,232	24,633
2024	627	0	196	623	0	196	102.82	0.00	7.55	65,538	20,308	972	44,258	20,044
2025	573	0	183	569	0	183	104.88	0.00	7.70	61,085	19,559	664	40,862	16,752
2026	523	0	176	519	0	176	106.98	0.00	7.86	56,908	18,866	1,362	36,680	13,614
2027	474	0	169	470	0	169	109.12	0.00	8.02	52,641	17,716	1,047	33,878	11,381
2028	441	0	162	437	0	162	111.30	0.00	8.17	49,962	17,611	0	32,351	9,837
2029	408	0	155	405	0	155	113.52	0.00	8.34	47,268	17,505	0	29,763	8,193
2030	373	0	148	370	0	148	115.80	0.00	8.51	44,105	16,845	1,128	26,132	6,511
2031	330	0	63	327	0	63	118.12	0.00	8.68	39,172	14,662	5,008	19,502	4,399
2032	297	0	62	294	0	62	120.47	0.00	8.84	35,966	13,580	1,974	20,412	4,167
2033	274	0	61	271	0	61	122.88	0.00	9.02	33,851	13,534	0	20,317	3,755
2034	230	0	60	227	0	60	125.34	0.00	9.20	29,004	10,744	4,564	13,696	2,292
2035	202	0	59	199	0	59	127.85	0.00	9.38	25,995	9,455	5,528	11,012	1,668
2036	190	0	58	187	0	58	130.40	0.00	9.58	24,941	9,490	0	15,451	2,117
2037	176	0	57	174	0	57	133.01	0.00	9.77	23,700	9,508	0	14,192	1,761
2038	164	0	57	162	0	57	135.67	0.00	9.96	22,547	9,553	0	12,994	1,460
2039	153	0	56	151	0	56	138.38	0.00	10.16	21,465	9,595	0	11,870	1,207
2040	144	0	55	142	0	55	141.16	0.00	10.37	20,615	9,672	0	10,943	1,007
Subtotal	**12,195**	**0**	**3,595**	**12,089**	**0**	**3,595**				**1,226,194**	**413,563**	**37,327**	**775,304**	**372,584**
Remaining	959	0	434	929	0	434				151,910	91,464	29,683	30,763	2,437
Total	**13,154**	**0**	**4,029**	**13,018**	**0**	**4,029**				**1,378,104**	**505,027**	**67,010**	**806,067**	**375,021**

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

Present Worth at	(10^3 U.S.$)
8 Percent	425,891
12 Percent	333,444
15 Percent	283,969

DEGOLYER AND MACNAUGHTON
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TEXAS REGISTERED ENGINEERING FIRM

TABLE 9
SUMMARY PROJECTION of NET PROVED-PLUS-PROBABLE-PLUS-POSSIBLE RESERVES and FUTURE NET REVENUE – HIGH CASE
as of
JULY 31, 2016
attributable to
IGAS
for
CERTAIN PROPERTIES
in the
UNITED KINGDOM

	Gross			Net			Product Prices			Future Gross	Tariff Paid and Operating	Abandonment and	Future Net	Present Worth at
Year	Oil (10^3bbl)	Cond (10^3bbl)	Sales Gas (10^6ft^3)	Oil (10^3bbl)	Cond (10^3bbl)	Sales Gas (10^6ft^3)	Oil (U.S.$/bbl)	Cond (U.S.$/bbl)	Sales Gas (U.S.$/$10^3$ft^3)	Revenue (10^3 U.S.$)	Expenses (10^3 U.S.$)	Capital Costs (10^3 U.S.$)	Revenue (10^3 U.S.$)	10 Percent (10^3 U.S.$)
2016 (5 months)	439	0	149	434	0	149	61.44	0.00	6.30	27,604	15,470	2,128	10,006	9,759
2017	1,104	0	297	1,092	0	297	68.76	0.00	6.48	77,009	25,021	6,230	45,758	41,611
2018	1,104	0	285	1,092	0	285	76.34	0.00	6.66	85,262	25,151	6,428	53,683	44,190
2019	1,082	0	277	1,071	0	277	84.22	0.00	6.84	92,093	25,067	0	67,026	49,942
2020	1,015	0	264	1,006	0	264	92.39	0.00	6.97	94,784	24,728	0	70,056	47,254
2021	945	0	256	936	0	256	96.89	0.00	7.12	92,513	24,296	0	68,217	41,652
2022	880	0	249	875	0	249	98.83	0.00	7.26	88,282	23,793	308	64,181	35,473
2023	826	0	235	821	0	235	100.80	0.00	7.40	84,497	23,572	0	60,925	30,481
2024	775	0	228	770	0	228	102.82	0.00	7.55	80,890	23,364	0	57,526	26,052
2025	725	0	221	720	0	221	104.88	0.00	7.70	77,216	23,136	0	54,080	22,171
2026	670	0	214	666	0	214	106.98	0.00	7.86	72,930	22,043	1,022	49,865	18,504
2027	630	0	207	626	0	207	109.12	0.00	8.02	69,970	21,935	0	48,035	16,135
2028	590	0	200	586	0	200	111.30	0.00	8.17	66,857	21,393	1,431	44,033	13,387
2029	537	0	194	533	0	194	113.52	0.00	8.34	62,124	19,700	1,833	40,591	11,172
2030	509	0	187	505	0	187	115.80	0.00	8.51	60,070	19,724	0	40,346	10,052
2031	479	0	180	475	0	180	118.12	0.00	8.68	57,669	19,704	0	37,965	8,564
2032	453	0	174	449	0	174	120.47	0.00	8.84	55,629	19,696	0	35,933	7,337
2033	427	0	172	424	0	172	122.88	0.00	9.02	53,653	19,719	0	33,934	6,270
2034	404	0	166	401	0	166	125.34	0.00	9.20	51,788	19,782	0	32,006	5,354
2035	382	0	160	379	0	160	127.85	0.00	9.38	49,955	19,846	0	30,109	4,560
2036	353	0	153	350	0	153	130.40	0.00	9.58	47,105	18,802	2,179	26,124	3,581
2037	325	0	152	322	0	152	133.01	0.00	9.77	44,313	18,109	1,340	24,864	3,084
2038	265	0	62	262	0	62	135.67	0.00	9.96	36,162	12,556	10,990	12,616	1,416
2039	250	0	62	247	0	62	138.38	0.00	10.16	34,810	12,592	0	22,218	2,258
2040	239	0	61	236	0	61	141.16	0.00	10.37	33,947	12,716	0	21,231	1,954
Subtotal	**15,408**	**0**	**4,805**	**15,278**	**0**	**4,805**				**1,597,132**	**511,915**	**33,889**	**1,051,328**	**462,213**
Remaining	2,652	0	1,053	2,609	0	1,053				453,953	235,145	44,820	173,988	9,329
Total	**18,060**	**0**	**5,858**	**17,887**	**0**	**5,858**				**2,051,085**	**747,060**	**78,709**	**1,225,316**	**471,542**

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

Present Worth at	(10^3 U.S.$)
8 Percent	547,496
12 Percent	411,919
15 Percent	343,614

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

DeGolyer and MacNaughton
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TEXAS REGISTERED ENGINEERING FIRM

TABLE 10
PROBABILITY DISTRIBUTIONS
for
MONTE CARLO SIMULATION
as of
JULY 31, 2016
for
IGAS
in
VARIOUS OIL PROSPECTS
VARIOUS LICENSES
UNITED KINGDOM

Prospect	Potential Target	Parameter	P_{100}	P_{90}	P_{50}	P_{10}	P_0	Mean
Eartham	Middle Jurassic Great Oolite	Productive area, acres	158	407	796	1,529	2,700	896
		Net hydrocarbon thickness, feet	16.41	27.00	48.43	86.94	145.40	53.45
		Porosity, decimal	0.055	0.075	0.105	0.135	0.155	0.105
		Oil saturation, decimal	0.251	0.311	0.400	0.489	0.549	0.400
		Formation volume factor, Bo	1.374	1.276	1.200	1.123	1.027	1.200
		Recovery efficiency, decimal	0.050	0.109	0.191	0.306	0.393	0.200
		Prospective OOIP, barrels	1,026,309	3,656,617	9,993,670	27,893,788	98,582,678	13,007,214
		Prospective gross ultimate recovery, barrels	95,041	586,906	1,837,033	5,709,873	18,969,975	2,601,443
Lea	Westphalian Eagle Sandstone	Productive area, acres	107	193	301	464	671	316
		Net hydrocarbon thickness, feet	16.42	31.00	56.28	101.84	181.38	62.30
		Porosity, decimal	0.090	0.110	0.140	0.170	0.190	0.140
		Oil saturation, decimal	0.401	0.461	0.550	0.639	0.699	0.550
		Formation volume factor, Bo	1.315	1.223	1.150	1.076	0.986	1.150
		Recovery efficiency, decimal	0.050	0.109	0.191	0.306	0.393	0.200
		Prospective OOIP, barrels	1,135,875	3,768,624	8,652,833	19,613,361	50,696,615	10,240,423
		Prospective gross ultimate recovery, barrels	144,919	606,284	1,637,952	3,931,267	14,711,688	2,048,085

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

TABLE 11
ESTIMATE of the GROSS PROSPECTIVE OIL RESOURCES
as of
JULY 31, 2016
for
IGAS
in
VARIOUS OIL PROSPECTS
VARIOUS LICENSES
UNITED KINGDOM

			Gross Prospective Oil Resources Summary					
Prospect	**Area/Basin**	**License/Block**	**Low Estimate (10^3bbl)**	**Best Estimate (10^3bbl)**	**High Estimate (10^3bbl)**	**Mean Estimate (10^3bbl)**	**Probability of Geologic Success, P_g (decimal)**	**P_g-Adjusted Mean Estimate (10^3bbl)**
Eartham	Weald	PEDL326	587	1,837	5,710	2,601	0.400	1,041
Lea	East Midlands	PEDL316	606	1,638	3,931	2,048	0.180	369
Statistical Aggregate			**1,539**	**3,883**	**9,124**	**4,649**	**0.303**	**1,409**
Arithmetic Summation			1,193	3,475	9,641	4,649	0.303	1,409

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

TABLE 12
ESTIMATE of the WORKING INTEREST PROSPECTIVE OIL RESOURCES
as of
JULY 31, 2016
for
IGAS
in
VARIOUS OIL PROSPECTS
VARIOUS LICENSES
UNITED KINGDOM

			Working Interest Prospective Oil Resources Summary					
Prospect	Area/Basin	License/Block	Low Estimate (10^3bbl)	Best Estimate (10^3bbl)	High Estimate (10^3bbl)	Mean Estimate (10^3bbl)	Probability of Geologic Success, P_g (decimal)	P_g-Adjusted Mean Estimate (10^3bbl)
Eartham	Weald	PEDL326	293	919	2,855	1,301	0.400	520
Lea	East Midlands	PEDL316	606	1,638	3,931	2,048	0.180	369
Statistical Aggregate			**1,160**	**2,857**	**6,422**	**3,349**	**0.265**	**889**
Arithmetic Summation			899	2,557	6,786	3,349	0.265	889

Notes:

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