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DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

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

February 14, 2025

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

Ladies and Gentlemen:

Pursuant to your request, we have prepared estimates, as of December 31, 2024, of the extent of the proved, probable, and possible oil, condensate, and sales gas reserves, estimates of the value of the proved, proved-plus-probable, and proved plus-probable-plus-possible reserves, and estimates of the extent of the 1C, 2C, and 3C contingent resources associated with certain properties in and offshore the United Kingdom in which Star Energy Group PLC (Star Energy) has represented it holds an interest. This report also presents estimates of the extent of the prospective resources of the Lea prospect located in the PEDL 316 onshore license block in which Star Energy has represented it holds an interest.

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

This report is compliant with the Competent Person's Report requirements as published in the United Kingdom Financial Conduct Authority Primary Market Technical Note TN/619.1 entitled "Guidelines on Disclosure Requirements under the Prospectus Regulation and Guidance on Specialist Issuers" dated May 2022 (FCA TN /619.1). PRMS is a referenced standard therein.

Reserves estimated in this report are expressed as gross reserves and net reserves. Gross reserves are defined as the total estimated petroleum remaining to be produced from the fields after December 31, 2024. Net reserves are defined as that portion of the gross reserves attributable to the interests held by Star Energy after deducting all interests held by others.

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

This report presents values for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves that were estimated using initial prices, expenses, and costs provided by Star Energy and forecast prices, expenses, and costs as described herein. Prices, expenses, and costs were provided in United Kingdom pounds sterling (U.K.£). For the purposes of this report, U.K.£ were converted to United States dollars (U.S.$) using an exchange rate of U.S.$1.27 per U.K.£1.00. All monetary values in this report are expressed in U.S.$. An explanation of the forecast price, expense, and cost assumptions is included under the Valuation of Reserves heading of this report.

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

Contingent resources estimated in this report are expressed as gross contingent resources and net contingent resources. Gross contingent resources are defined as the total estimated petroleum that is potentially recoverable from known accumulations after December 31, 2024. Net contingent resources are defined as that portion of the gross contingent resources attributable to the interests held by Star Energy after deducting all interests held by others.

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

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

Prospective resources estimated in this report are expressed as gross prospective resources and working interest prospective resources. Gross prospective resources are defined as the total estimated petroleum that is potentially recoverable from undiscovered accumulations after December 31, 2024. Working interest prospective resources are defined as the product of the gross prospective resources and Star Energy' working interest in the leasehold or concession associated with a given prospect.

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

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

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

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

Executive Summary

Star Energy has represented that it holds interests in properties that include 27 discovered fields in and offshore the United Kingdom. This report includes evaluations of 5 fields that contain reserves only, 7 fields that contain contingent resources only, 11 fields that contain reserves and contingent resources, and 4 fields that contain no reserves or contingent resources. This evaluation also includes prospective resources for one prospect.

For this report, technical and commercial uncertainties have been considered in each case exclusive of ongoing political events in a given venue. All contracts, regulations, and agreements in place on December 31, 2024, have been considered to be valid for their stated terms, as represented by Star Energy.

Reserves

Oil, condensate, and sales gas reserves were estimated herein for 20 fields and do not include any assets with resources derived from unconventional reservoirs. Sales gas reserves were converted to barrels of oil equivalent (boe) using an energy equivalent factor of 5,800 cubic feet of gas per 1 boe.

The estimated gross and net proved, probable, and possible reserves, as of December 31, 2024, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

Reserves Summary

	Oil and Condensate			**Sales Gas**			**Oil Equivalent**		
	Proved (10^3bbl)	**Probable (10^3bbl)**	**Possible (10^3bbl)**	**Proved (10^6ft^3)**	**Probable (10^6ft^3)**	**Possible (10^6ft^3)**	**Proved (10^3boe)**	**Probable (10^3boe)**	**Possible (10^3boe)**
Gross	9,513	4,352	2,699	4,662	4,645	5,864	10,317	5,153	3,710
Net	9,363	4,338	2,682	4,662	4,645	5,864	10,167	5,139	3,693

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

Revenue

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

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

The estimated future net revenue and present worth of the future net revenue discounted at 10 percent to be derived from the production and sale of the proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves and quantities, as of December 31, 2024, of the properties evaluated under the three economic scenarios described herein are summarized as follows, expressed in thousands of United States dollars (10^3U.S.$):

Valuation Summary

	Proved		**Proved plus Probable**		**Proved plus Probable plus Possible**	
	Future Net Revenue (10^3U.S.$)	**Present Worth at 10 Percent (10^3U.S.$)**	**Future Net Revenue (10^3U.S.$)**	**Present Worth at 10 Percent (10^3U.S.$)**	**Future Net Revenue (10^3U.S.$)**	**Present Worth at 10 Percent (10^3U.S.$)**
Base Case	279,349	113,408	661,179	188,006	922,914	233,814
Low Case	193,188	74,482	522,106	140,128	746,661	180,599
High Case	367,091	150,558	801,557	234,390	1,101,635	285,331

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

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

Contingent Resources

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

The estimated gross and net 1C, 2C, and 3C contingent resources, as of December 31, 2024, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

Contingent Resources Summary

	Gross Contingent Resources			**Net Contingent Resources**		
	Oil and Condensate (10^3bbl)	**Sales Gas (10^6ft^3)**	**Oil Equivalent (10^3boe)**	**Oil and Condensate (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Oil Equivalent (10^3boe)**
1C	9,166	4,263	9,902	8,889	4,263	9,625
2C	15,289	8,404	16,738	14,841	8,404	16,290
3C	22,554	12,508	24,711	21,927	12,508	24,084

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

Prospective Resources

Estimates of prospective resources were prepared by the use of standard geological and engineering methods generally accepted by the petroleum industry. Prospective resources in one prospect have been evaluated in the PEDL 316 onshore license block in the United Kingdom and do not include any potential accumulations with resources derived from unconventional reservoirs. The prospective resources estimates presented below were based on a statistical aggregation method.

The estimated gross and working interest prospective resources, as of December 31, 2024, of the prospect evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl):

	Gross Oil Prospective Resources Summary				Working Interest Oil Prospective Resources Summary			
Prospect	**1U (Low) Estimate (10^3bbl)**	**2U (Best) Estimate (10^3bbl)**	**3U (High) Estimate (10^3bbl)**	**Mean Estimate (10^3bbl)**	**1U (Low) Estimate (10^3bbl)**	**2U (Best) Estimate (10^3bbl)**	**3U (High) Estimate (10^3bbl)**	**Mean Estimate (10^3bbl)**
Lea	606	1,638	3,931	2,048	212	573	1,376	717
Statistical Aggregate	606	1,638	3,931	2,048	212	573	1,376	717

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

The gross and working interest statistical aggregate Pg-adjusted mean estimate prospective resources, as of December 31, 2024, of the prospect evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl):

	Mean Estimate
Gross P_g-Adjusted Oil Prospective Resources, 10^3bbl	369
Working Interest P_g-Adjusted Oil Prospective Resources, 10^3bbl	129

Notes:
1. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
2. Recovery efficiency was applied to prospective resources in this table.
3. The prospective resources presented above were based on the statistical aggregation method.
4. P_g is predicated and correlated to the minimum case prospective resources gross recoverable volume(s). The P_g is not linked to economically viable volumes, economic flow rates, or economic field size assumptions.
5. The range in probability of occurrence for the statistical aggregate P_g-adjusted mean oil estimate is 0.07 to 0.10.
6. The prospective resources quantities for the prospect evaluated in this report were aggregated by the arithmetic summation method, as required by the PRMS, and are presented in the prospective resources tables in this report.
7. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

Ownership and Infrastructure

Star Energy has represented that it holds interests in certain licenses for exploration, production, and development in and offshore the United Kingdom. The fields are located in the East Midlands Basin, the Weald Basin, and offshore. The specific properties evaluated herein are shown in the following list and on Figures 1 through 3.

Field/Discovery/Prospect	License	Working Interest (percent)	License Expiration
Albury	DL4	100.00	11/16/2027
Avington	PEDL70	53.67	9/8/2031
Beckingham	ML4	100.00	3/31/2040
Bletchingley	ML18	100.00	1/11/2034
Bletchingley	ML21	100.00	4/1/2034
Bothamsall	ML6	100.00	3/31/2040
Cold Hanworth	PEDL6	100.00	4/4/2027
Corringham	ML4	100.00	3/31/2040
Dunholme	AL009	100.00	4/7/2025
East Glentworth	PL179	100.00	11/16/2034
Egmanton	ML3	100.00	12/30/2033
Gainsborough	ML4	100.00	3/31/2040
Glentworth	ML4	100.00	3/31/2040
Goodworth	PEDL21	100.00	4/3/2027
Horndean	PL211	90.00	4/4/2026
Lea	PED316	35.00	7/20/2046
Long Clawson	PL220	100.00	8/8/2026
Lybster	P1270	100.00	12/21/2031
Nettleham	PL179	100.00	11/16/2034
Palmers Wood	PL182	100.00	11/16/2034
Rempstone	PL220	100.00	8/8/2026
Scampton North	PL179	100.00	11/16/2034
Scampton South	PL179	100.00	11/16/2034
Singleton	PL240	100.00	12/1/2037
South Leverton	ML7	100.00	3/31/2040
Stainton	PL179b	100.00	11/16/2034
Stockbridge	DL2	100.00	12/31/2030
Stockbridge	PL233	100.00	10/26/2030
Stockbridge	PL249	100.00	11/30/2030
Storrington	PL205	100.00	2/13/2036
Welton	PL179b	100.00	11/16/2034

Notes:
1. Lea is the prospect evaluated herein.
2. The license expiration dates shown are those currently in place before the application of any likely extensions.

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

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

For this report, technical and commercial uncertainties have been considered in each case exclusive of ongoing political events in a given venue. All contracts, regulations, and agreements in place on December 31, 2024, have been considered to be valid for their stated terms, as represented by Star Energy.

There are 17 fields and 1 prospect evaluated herein located in the East Midlands Basin, as shown on Figure 1.

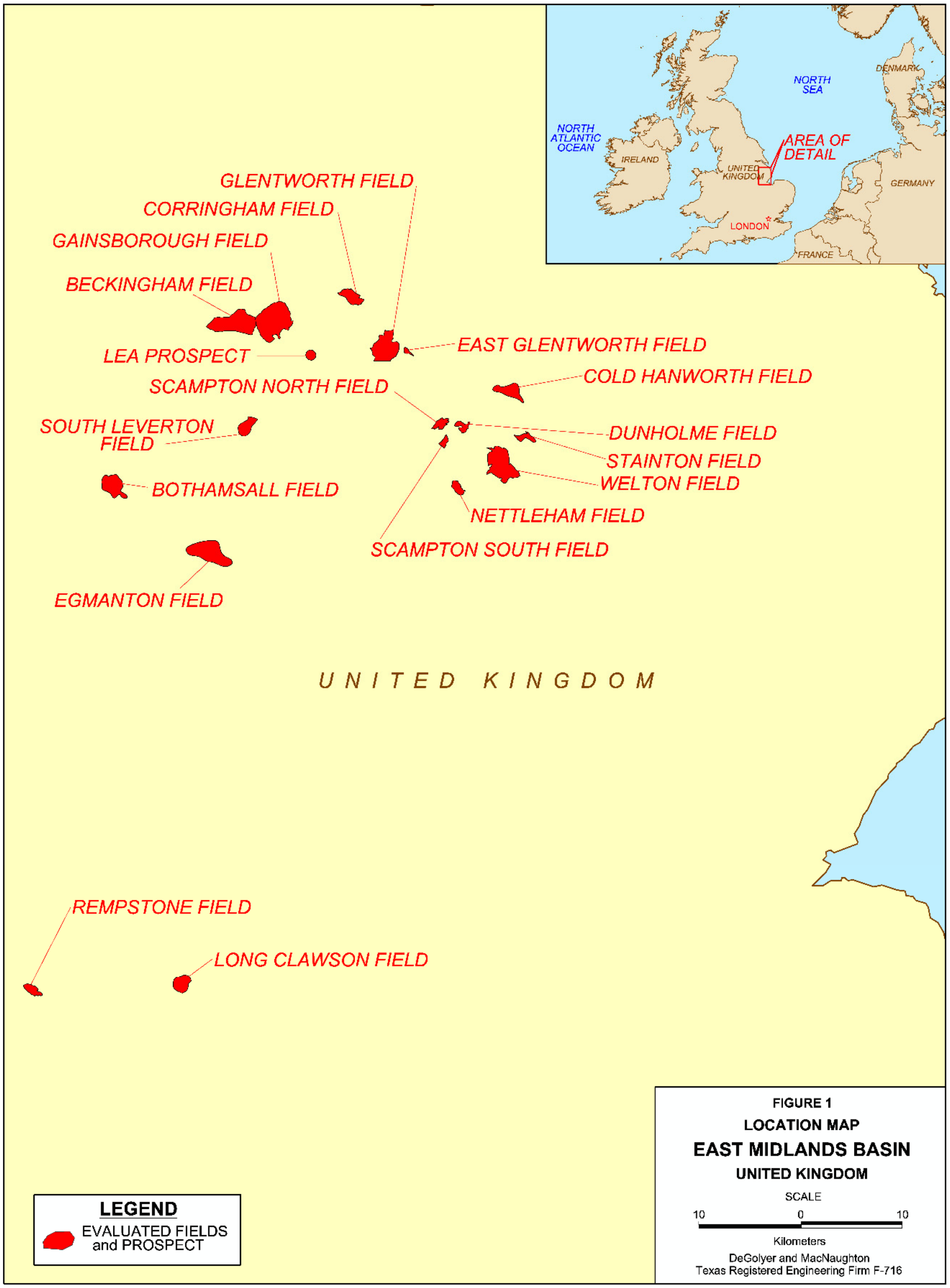

FIGURE 1
LOCATION MAP
EAST MIDLANDS BASIN
UNITED KINGDOM

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

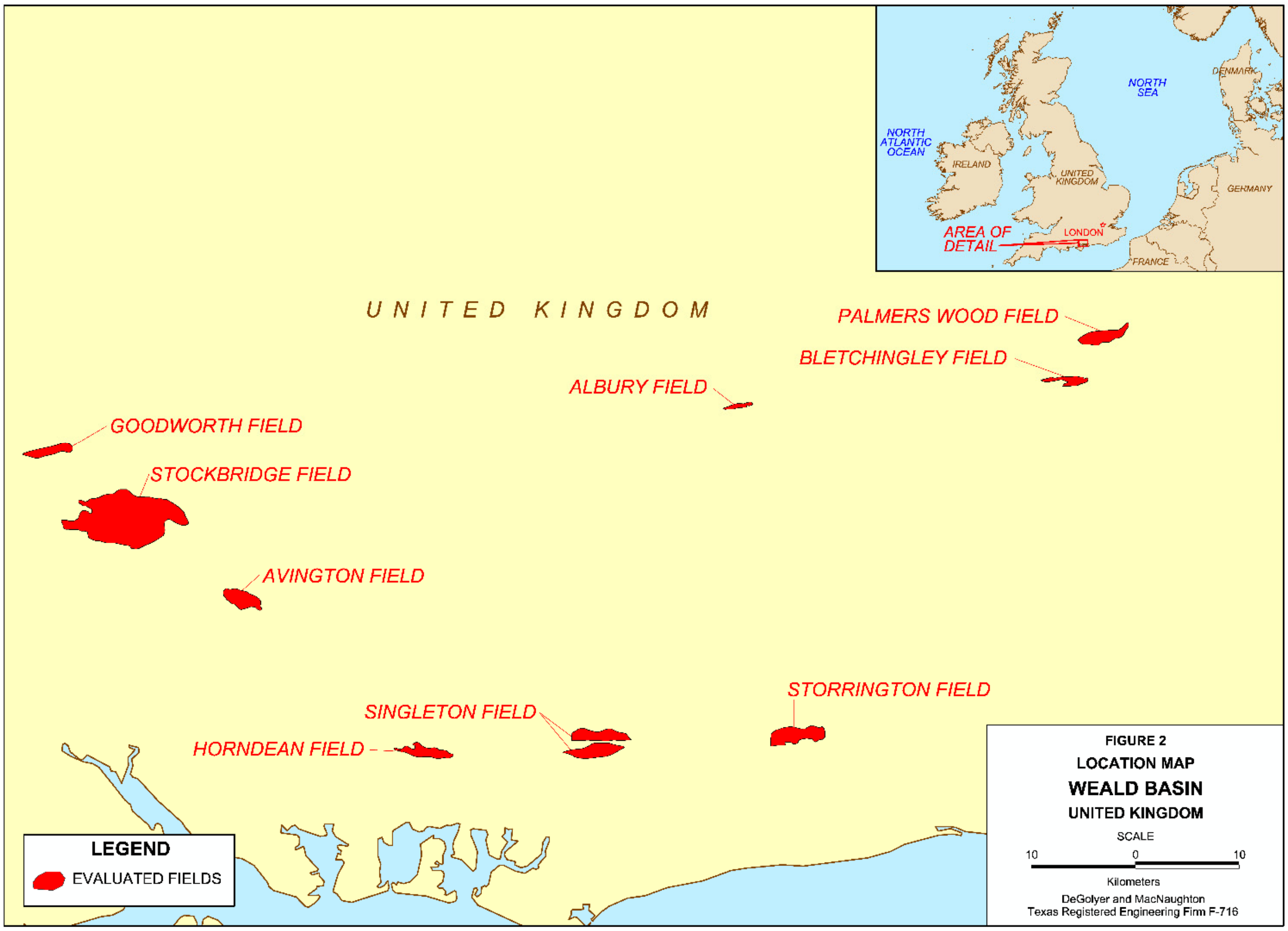

FIGURE 2
LOCATION MAP
WEALD BASIN
UNITED KINGDOM

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

FIGURE 3
LOCATION MAP
LYBSTER FIELD
OFFSHORE UNITED KINGDOM

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

Environmental Consideration

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

Definition of Reserves

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

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

> *Proved Reserves* are those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating

methods, and government regulations. If deterministic methods are used, the term “reasonable certainty” is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate.

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability [P50] that the actual quantities recovered will equal or exceed the 2P estimate.

Possible Reserves are those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate.

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

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

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

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

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

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

Estimation of Reserves

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

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

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

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

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

Where applicable, estimates of ultimate recovery were obtained after applying recovery factors to OOIP and OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories.

When applicable, material balance and other engineering methods were used to estimate recovery factors based on an analysis of reservoir performance, including production rate, reservoir pressure, and reservoir fluid properties.

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

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

Reserves estimates presented herein were based on data available through December 31, 2024, and were supported by details regarding 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 available only through September 2024. Where applicable, estimated cumulative production, as of December 31, 2024, was deducted from the gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 3 months.

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

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

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

At the request of Star Energy, sales gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 5,800 cubic feet of gas per 1 boe.

Procedure and Methodology

Star Energy has represented that it holds an interest in multiple fields in the United Kingdom that have been evaluated in this report. Reserves were estimated in this report for 16 of those fields. The fields produce from various reservoirs in the East Midlands and Weald Basins (Figures 4 and 5).

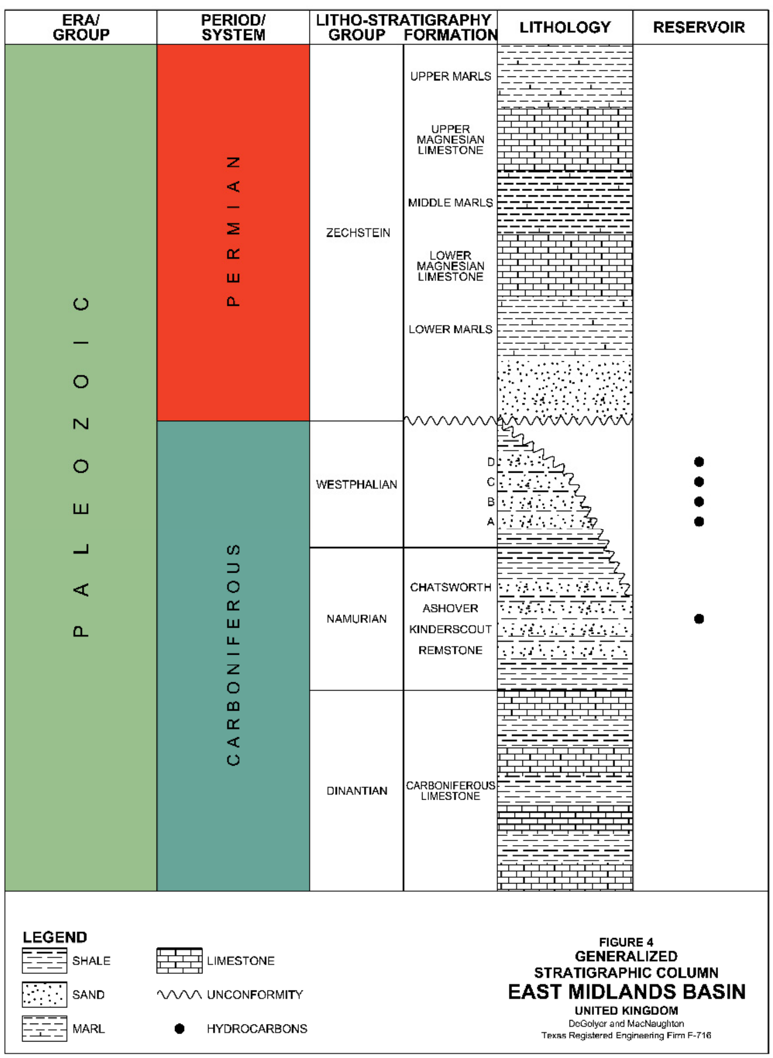
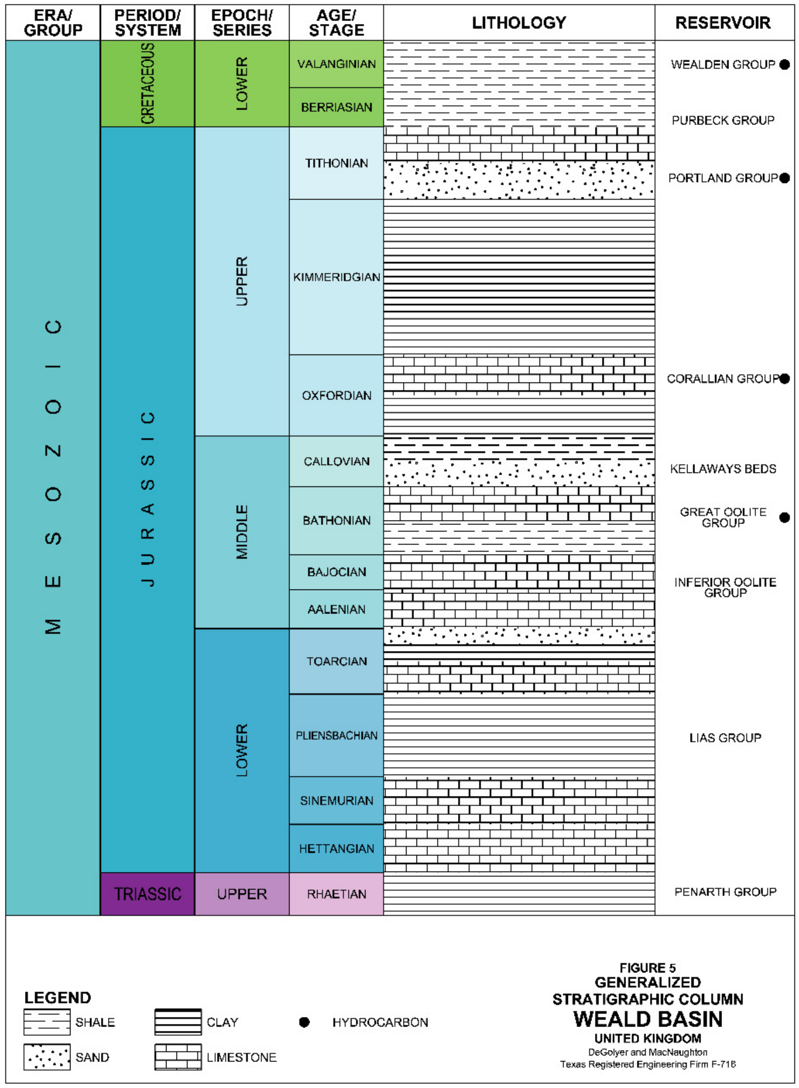


FIGURE 4
GENERALIZED
STRATIGRAPHIC COLUMN
EAST MIDLANDS BASIN
UNITED KINGDOM
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716



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

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

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

The Avington field, located in license PEDL70, was discovered in 1987 with oil shows in the Cornbrash and Great Oolite reservoirs. Development of the field occurred in 1987 with the Avington-1 well drilled into the upthrown side of a fault defining the field. The field stopped producing from two wells at the end of 2017 due to high operating costs. Porosity was estimated to range from 14 to 23 percent, S_w was estimated to range from 46 to 57 percent, and permeability was estimated to range from 0.08 to 0.1 millidarcys. In this fractured reservoir, the effective permeability can be much higher. The plan was to bring one well, AV3z, back to production in 2024 by disposing the produced water offsite and reducing operating costs. After economic evaluation, recoverable quantities were determined to be uneconomic. As such, reserves for this field were estimated to be zero. The field will be abandoned, with site restorations, in 2030. For the purposes of this report, abandonment was scheduled for 2030.

The Beckingham field, located in license ML4, was discovered in 1964 and is located on the Lincolnshire-Nottingham border, 40 kilometers east of the city of Sheffield. The main producing reservoirs are the Eagle, Donald, and Condor Sandstones, which produce from three separate blocks in the Beckingham field. The Beckingham field also has the potential to produce nonassociated gas from the Mexborough/Alexander Formations; however, this development potential has not been considered in this evaluation. In the producing reservoirs, porosity was estimated to range from 8 to 20 percent, S_w was estimated to range from 40 to 70 percent, and permeability was estimated to range from 0.01 to 30 millidarcys. The field produces light oil with a gravity of approximately 38 degrees API (°API). Proved developed producing reserves were estimated based on the performance of existing wells. Proved developed non-producing reserves were estimated to be 38 10^3boe based on the performance of five existing wells and are associated with workovers to remove wax in five wells. Estimates of probable and possible reserves account for the potential for better performance than proved reserves. Proved undeveloped reserves were estimated to be zero for this field.

The Bletchingley field, located in licenses ML18 and ML21, was discovered in 1966. Oil was found in the Corallian Sandstone and the field is currently producing from two wells. Porosity was estimated to range from 5 to 25 percent, S_w was estimated to range from 40 to 70 percent, and permeability was estimated to range from 0.2 to 1,000 millidarcys. Proved developed producing reserves were estimated based on individual-well performance. Estimates of probable and possible reserves account for the potential for better performance than proved reserves. Proved undeveloped reserves were estimated to be 356 10^3boe based on gas sales associated with a "gas-to-wire" project to support the building of a 6-megawatt generator. Proved developed non-producing reserves were estimated to be zero for this field.

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

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

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

27 percent, S_w was estimated to range from 37 to 44 percent, and permeability was estimated to range from 160 to 500 millidarcys. Proved developed producing reserves were estimated based on the performance of existing wells. Proved undeveloped reserves were estimated to be 264 10^3boe and are associated with a new producer in the Silkstone reservoir, the CR13 well. Estimates of probable and possible reserves account for the potential for better performance than proved reserves. Proved developed non-producing reserves were estimated to be zero for this field.

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

The Egmanton field was discovered in 1955 and produced oil from the Upper Namurian and Lower Westphalian reservoirs through two wells. The field is located in license ML3, southwest of the Gainsborough trough. Porosity was estimated to range from 13 to 17 percent, S_w was estimated to range from 45 to 55 percent, and permeability was estimated to range from 1 to 100 millidarcys. Performance analysis was completed on this field. After economic evaluation, recoverable quantities were determined to be uneconomic. As such, reserves for this field were estimated to be zero. The field will be abandoned, with site restorations, in 2027. For the purposes of this report, abandonment was scheduled for 2027.

The Gainsborough field, located in license ML4, was discovered in 1959 and is located on the Lincolnshire-Nottingham border, 25 miles east of Sheffield. The main producing reservoirs are the Eagle, Donald, and Condor Sandstones. Porosity was estimated to range from 8 to 20 percent, S_w was estimated to range from 40 to 70 percent, and permeability was estimated to range from 0.01 to 30 millidarcys. The field produces light oil with a gravity of approximately 38 °API. Performance analysis was completed on this field. After economic evaluation, recoverable quantities were determined to be uneconomic. As such, reserves for this field were estimated to be zero. For the purposes of this report, abandonment was scheduled for 2037.

The Glentworth field was discovered in 1961 and is located in license ML4 in Lincolnshire. The field is a four-way dip closure and produces from the Mexborough Formation. The field was shut in from 1965 to 1971 and is currently producing low-shrinkage oil from four wells. Porosity was estimated to range from 16 to 20 percent, S_w was estimated to range from 50 to 65 percent, and permeability was estimated to range from 0.1 to 30 millidarcys. Proved developed producing reserves were estimated based on the performance of existing wells. Proved undeveloped reserves for this field were estimated to be 600 10^3boe assuming that a new producer will be drilled in the Mexborough Rock reservoir. Estimates of probable and possible reserves account for the potential for better performance than proved reserves. Proved developed non-producing reserves were estimated to be zero for this field.

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

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

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

The Nettleham field, located in license PL179, was discovered in 1983 and is located approximately 5 kilometers northeast of the city of Lincoln. The primary reservoir is the Basal Westphalian. The field is not currently producing. Porosity was estimated to range from 19 to 22 percent, S_w was estimated to range from 30 to 60 percent, and permeability was estimated to range from 6 to 1,000 millidarcys. Production was stopped in February 2016 due to high water cut. No plans were presented to bring this field back on production; as such, reserves for this field were estimated to be zero. For the purposes of this report, abandonment was scheduled for 2029.

The Palmers Wood field was discovered in 1983 and is located 5 kilometers east of Redhill within license PL182. The Palmers Wood field currently produces through four wells from the Upper Jurassic Corallian Sandstone. In addition, there has been an active waterflood conducted through three injectors since the beginning of production. Porosity was estimated to range from 16 to 20 percent, S_w was estimated to range from 40 to 60 percent, and permeability was estimated to range from 0.5 to 50 millidarcys. Proved developed producing reserves were estimated based on the performance of existing wells. Proved developed non-producing reserves were estimated to be 26 10^3boe based on analogy and are associated with a workover to remove wax in one well. Estimates of probable and possible reserves account for the potential for better performance than proved reserves. Proved undeveloped reserves were estimated to be zero for this field.

The Rempstone field was discovered in 1985. The primary reservoir is the Lower Namurian; gas is produced from the H-Sandstone and oil is produced from the C-Sandstone. The field is located in license PL220 and is currently producing from one well. Porosity was estimated to range from 16 to 19 percent, S_w was estimated to range from 40 to 50 percent, and permeability was estimated to range from 0.1 to 20 millidarcys. Performance analysis was completed on this field. After economic evaluation, recoverable quantities were determined to be uneconomic. For the purposes of this report, abandonment was scheduled for 2031.

The Scampton North field was discovered in 1985 by well SNA1. The field is located within license PL179 in Lincolnshire. The Scampton North field produces light oil with a gravity of approximately 35 °API through five wells from the Basal Succession Sandstone. Porosity was estimated to range from 12 to 18 percent, S_w was estimated to range from 30 to 50 percent, and permeability was estimated to range from 0.5 to 400 millidarcys. Proved developed producing reserves were estimated based on the performance of existing wells and a waterflood injector that is being optimized to improve the injection rate. Estimates of probable and possible reserves account for the potential for better performance than proved reserves and improved injection and sweep water efficiency in the injector. Proved developed non-producing and proved undeveloped reserves were estimated to be zero for this field.

The Scampton South field is located in license PL179 in Lincolnshire, to the northwest of the Welton field. The field was discovered in 1985, but development was delayed due to consideration of high sulfur levels. The field is not currently producing and was shut in due to high water production. Porosity was estimated to range from 10 to 16 percent, S_w was estimated to range from 26 to 40 percent, and permeability was estimated to range from 5 to 500 millidarcys. No plans were presented to bring this field back on production; as such, reserves for this field were estimated to be zero. For the purposes of this report, abandonment was scheduled for 2029.

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 with a gravity of approximately 39 °API through six wells from the Great Oolite Formation. Porosity was estimated to range from 13 to 16 percent, S_w was estimated to range from 30 to 62 percent, and permeability was estimated to range from 0.1 to 10 millidarcys. Proved developed producing reserves were estimated based on the performance of existing wells. Proved undeveloped reserves were estimated to be 297 10^3boe and are based on gas sales associated with the construction of a new 4-megawatt generator by 2026. Estimates of probable and possible reserves account for the potential for better performance than proved reserves. Proved developed non-producing reserves were estimated to be zero for this field.

The South Leverton field, located in license ML7, was discovered in 1960. The field is not currently producing because all wells are shut in. Porosity was estimated to range from 9 to 13 percent, S_w was estimated to range from 22 to 27 percent, and permeability was estimated to range from 0.2 to 10 millidarcys. Reserves for this field were estimated to be zero. For the purposes of this report, abandonment was scheduled for 2028.

The Stainton field was discovered in 1984 by the Stainton-1 well. The field is located within license PL179b, 10 kilometers northeast of Lincoln. The field currently produces low-shrinkage oil through one well from the Basal Sandstone Formation. Porosity was estimated to range from 12 to 16 percent, S_w was estimated to range from 30 to 50 percent, and permeability was estimated to range from 0.4 to 50 millidarcys. Performance analysis was completed on this field. After economic evaluation, recoverable quantities were determined to be uneconomic. As such, reserves for this field were estimated to be zero. For the purposes of this report, abandonment was scheduled for 2029.

The Stockbridge field was discovered in 1984. This field is located within the DL2, PL233, and PL249 licenses, in the northwest portion of the Weald Basin. The field produces from the Great Oolite reservoir. Water injection began in 1998 after converting the STK-16 well to a water injector. The field is currently producing from six wells. Porosity was estimated to range from 12 to 24 percent, S_w was estimated to range from 66 to 79 percent, and permeability was estimated to range from 0.1 to 5 millidarcys. Proved developed producing reserves were estimated based on individual-well performance. Proved developed non-producing reserves were estimated to be 62 10^3boe based on the expected performance of one planned workover on an existing well that will require split tubing repair prior to resuming production. Estimates of probable and possible reserves account for the potential for better performance than proved reserves. Proved undeveloped reserves were estimated to be zero for this field.

The Storrington field has been producing from the Great Oolite Formation since 1998. The field is located in license PL205 in West Sussex County. Porosity was estimated to range from 10 to 17 percent, S_w was estimated to range from 45 to 60 percent, and permeability was estimated to range from 0.01 to 50 millidarcys. Performance analysis was completed on this field. After economic evaluation, recoverable quantities were determined to be uneconomic. As such, reserves for this field were estimated to be zero. For the purposes of this report, abandonment was scheduled for 2030.

The Welton field was discovered in 1981. The field is located 7 kilometers northeast of Lincoln in license PL179b. The field has produced from several formations, including the Basal Succession and the Upper Succession. Porosity was estimated to range from 12 to 20 percent, S_w was estimated to range from 20 to 40 percent, and permeability was estimated to range from 10 to 1,000 millidarcys. Proved developed producing reserves were estimated based on individual-well performance and a waterflood injector that is now injecting. Proved undeveloped reserves were estimated to be 54 10^3boe based on the expected performance of one planned workover on an existing well to restart production. The planned workover was classified as proved undeveloped because of relatively high capital costs. Proved developed non-producing reserves were estimated to be zero for this field. Estimates of probable and possible reserves account for the potential for better performance than proved reserves and improved injection and sweep water efficiency in the injector.

The estimated gross proved, probable, and possible reserves, as of December 31, 2024, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

	Gross Reserves								
	Oil and Condensate			Sales Gas			Oil Equivalent		
Field	**Proved (10^3bbl)**	**Probable (10^3bbl)**	**Possible (10^3bbl)**	**Proved (10^6ft^3)**	**Probable (10^6ft^3)**	**Possible (10^6ft^3)**	**Proved (10^3boe)**	**Probable (10^3boe)**	**Possible (10^3boe)**
Albury	0	0	0	68	0	0	12	0	0
Avington	0	0	0	0	0	0	0	0	0
Beckingham	205	56	119	0	0	0	205	56	119
Bletchingley	193	37	82	2,067	3,438	5,092	549	630	960
Bothamsall	41	18	20	0	0	0	41	18	20
Cold Hanworth	196	82	98	0	0	0	196	82	98
Corringham	469	124	109	0	0	0	469	124	109
Dunholme	0	0	0	0	0	0	0	0	0
East Glentworth	73	26	30	0	0	0	73	26	30
Egmanton	0	0	0	0	0	0	0	0	0
Gainsborough	0	0	0	0	0	0	0	0	0
Glentworth	1,351	591	482	0	0	0	1,351	591	482
Goodworth	36	13	30	0	0	0	36	13	30
Horndean	1,502	148	171	0	0	0	1,502	148	171
Long Clawson	224	45	74	0	0	0	224	45	74
Lybster	0	0	0	0	0	0	0	0	0
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	301	77	121	0	0	0	301	77	121
Rempstone	0	0	0	0	0	0	0	0	0
Scampton North	542	130	133	0	0	0	542	130	133
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	1,629	785	317	2,527	1,207	772	2,065	993	450
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	742	324	314	0	0	0	742	324	314
Storrington	0	0	0	0	0	0	0	0	0
Welton	2,009	1,896	599	0	0	0	2,009	1,896	599
Total	**9,513**	**4,352**	**2,699**	**4,662**	**4,645**	**5,864**	**10,317**	**5,153**	**3,710**

Notes:

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

For the fields evaluated in this report, gross total proved developed producing reserves were estimated to be 8,620 10^3boe, gross total proved developed non-producing reserves were estimated to be 126 10^3boe, and gross total proved undeveloped reserves were estimated to be 1,571 10^3boe.

The estimated net proved, probable, and possible reserves, as of December 31, 2024, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

	Net Reserves								
	Oil and Condensate			Sales Gas			Oil Equivalent		
Field	Proved (10^3bbl)	Probable (10^3bbl)	Possible (10^3bbl)	Proved (10^6ft^3)	Probable (10^6ft^3)	Possible (10^6ft^3)	Proved (10^3boe)	Probable (10^3boe)	Possible (10^3boe)
Albury	0	0	0	68	0	0	12	0	0
Avington	0	0	0	0	0	0	0	0	0
Beckingham	205	56	119	0	0	0	205	56	119
Bletchingley	193	37	82	2,067	3,438	5,092	549	630	960
Bothamsall	41	18	20	0	0	0	41	18	20
Cold Hanworth	196	82	98	0	0	0	196	82	98
Corringham	469	124	109	0	0	0	469	124	109
Dunholme	0	0	0	0	0	0	0	0	0
East Glentworth	73	26	30	0	0	0	73	26	30
Egmanton	0	0	0	0	0	0	0	0	0
Gainsborough	0	0	0	0	0	0	0	0	0
Glentworth	1,351	591	482	0	0	0	1,351	591	482
Goodworth	36	13	30	0	0	0	36	13	30
Horndean	1,352	134	154	0	0	0	1,352	134	154
Long Clawson	224	45	74	0	0	0	224	45	74
Lybster	0	0	0	0	0	0	0	0	0
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	301	77	121	0	0	0	301	77	121
Rempstone	0	0	0	0	0	0	0	0	0
Scampton North	542	130	133	0	0	0	542	130	133
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	1,629	785	317	2,527	1,207	772	2,065	993	450
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	742	324	314	0	0	0	742	324	314
Storrington	0	0	0	0	0	0	0	0	0
Welton	2,009	1,896	599	0	0	0	2,009	1,896	599
Total	**9,363**	**4,338**	**2,682**	**4,662**	**4,645**	**5,864**	**10,167**	**5,139**	**3,693**

Notes:

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

For the fields evaluated in this report, net total proved developed producing reserves were estimated to be 8,470 10^3boe, net total proved developed non-producing reserves were estimated to be 126 10^3boe, and net total proved undeveloped reserves were estimated to be 1,571 10^3boe.

Valuation of Reserves

This report has been prepared using initial prices, expenses, and costs provided by Star Energy and certain forecast price, expense, and cost assumptions as described herein. Three economic cases were evaluated in this report: Base Case, Low Case, and High Case. The sensitivity cases were evaluated in this report to present alternative outcomes to the future revenue estimates for estimated reserves. Projections of gross and net reserves summarized herein were based on the Base Case, and quantities in the sensitivity cases are those included prior to the limit of projected production under the Base Case or when an annual economic limit for each case is reached, whichever occurs first. Only the prices were varied in each economic scenario. Unless noted otherwise, all other components of the evaluation for the sensitivity cases are the same as those stated for the Base Case herein.

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

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

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

Oil, Condensate, and Gas Prices

Base Case

Oil prices for the Base Case were anchored at the prevailing Brent oil price at the end of 2024, followed by price changes that match historical price levels. The condensate price was assumed to be 90 percent of the oil price. The oil and condensate prices are shown in the table below, expressed in United States dollars per barrel (U.S.$/bbl).

Gas sales prices for the Base Case were based on the United Kingdom National Balancing Point (NBP) forecast at the end of 2024. Star Energy has represented that its produced gas is sold in two outlets: through direct sales to the United Kingdom national gas grid and "gas to power." Gas to power is a portion of produced gas that receives a net price related to the amount of electricity it produces through generation. The gas prices used in the Base Case are shown in the table below, expressed in United States dollars per thousand cubic feet (U.S.$/$10^3$ft^3).

	Base Case Prices			
Year	Oil (U.S.$/bbl)	Condensate (U.S.$/bbl)	Gas Export (U.S.$/$10^3$ft^3)	Gas to Power (U.S.$/$10^3$ft^3)
2025	74.33	66.90	13.56	13.40
2026	72.12	64.91	10.91	10.78
2027	70.72	63.65	10.35	10.23
2028	69.83	62.85	9.95	9.83
2029	71.85	64.66	10.15	10.03
2030	73.92	66.53	10.35	10.23
2031	76.04	68.44	10.56	10.43
2032	78.22	70.40	10.77	10.64
2033	80.46	72.41	10.99	10.85
2034	82.75	74.48	11.21	11.07
2035	85.19	76.67	11.43	11.29
2036	87.69	78.92	11.66	11.52
2037	90.26	81.24	11.89	11.75
2038	92.90	83.61	12.13	11.98
2039	95.61	86.05	12.37	12.22
2040	98.38	88.55	12.62	12.47
2041	101.23	91.11	12.87	12.72
2042	104.16	93.74	13.13	12.97
2043	107.16	96.45	13.39	13.23
2044	110.24	99.22	13.66	13.50
2045	112.45	101.20	13.93	13.77
2046	114.70	103.23	14.21	14.04
2047	116.99	105.29	14.50	14.32
2048	119.33	107.40	14.79	14.61
2049	121.72	109.54	15.08	14.90
2050	124.15	111.74	15.38	15.20
2051	126.63	113.97	15.69	15.50
2052	129.17	116.25	16.00	15.81
2053	131.75	118.57	16.32	16.13
2054	134.38	120.95	16.65	16.45

Note: From 2054 forward, all prices were held flat.

Low Case

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

High Case

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

Operating Expenses, Capital Costs, and Abandonment Costs

Current operating expenses and operating expense forecasts provided by Star Energy 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 Star Energy. A 2-percent per year cost escalation was applied to any expenses or costs estimated herein. Generally, abandonment costs, which are those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment, were assigned the year after cessation of production, except where other anticipated abandonment dates were represented by Star Energy. At the request of Star Energy, abandonment costs were applied for all properties evaluated herein, even if reserves were estimated to be zero. Economic limits for each field have been estimated based on annual operating expenses with no consideration of taxes.

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

Royalty

No royalty was considered for these United Kingdom fields.

Exchange Rate

Where applicable, an exchange rate of U.S.$1.27 per U.K.£1.00 was used for this report.

Host Country Taxes

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

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

The estimated future revenue to be derived from the production and sale of the net proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves, as of December 31, 2024, of the properties evaluated under the Base Case economic assumptions described herein is summarized as follows, expressed in thousands of United States dollars (10^3U.S.$):

Valuation of Reserves Summary
Base Case

	Proved (10^3U.S.$)	Proved plus Probable (10^3U.S.$)	Proved plus Probable plus Possible (10^3U.S.$)
Future Gross Revenue	881,059	1,413,083	1,788,530
Operating Expenses	463,766	610,973	720,195
Abandonment and Capital Costs	137,944	140,931	145,421
Future Net Revenue	279,349	661,179	922,914
Present Worth at 10 Percent	113,408	188,006	233,814

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

The estimated future revenue to be derived from the production and sale of the proved, proved-plus-probable, and proved-plus-probable-plus-possible quantities, as of December 31, 2024, of the properties evaluated under the Low Case and High Case economic assumptions described herein is summarized as follows, expressed in thousands of United States dollars (10^3U.S.$):

Valuation of Quantities Summary – Sensitivity Cases

	Low Case			High Case		
	Proved (10^3U.S.$)	**Proved plus Probable (10^3U.S.$)**	**Proved plus Probable Plus Possible (10^3U.S.$)**	**Proved (10^3U.S.$)**	**Proved plus Probable (10^3U.S.$)**	**Proved plus Probable Plus Possible (10^3U.S.$)**
Future Gross Revenue	773,025	1,254,018	1,589,573	983,368	1,566,206	1,973,581
Operating Expenses	443,797	593,241	699,796	477,281	622,078	726,068
Abandonment and Capital Costs	136,040	138,671	143,116	138,996	142,571	145,878
Future Net Revenue	193,188	522,106	746,661	367,091	801,557	1,101,635
Present Worth at 10 Percent	74,482	140,128	180,599	150,558	234,390	285,331

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

The estimated future net revenue of all fields for the Base, Low, and High Cases is shown in Tables A-1 through A-12 in the appendix to this report.

Definition of Contingent Resources

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

> *Contingent Resources* are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently

considered to be commercially recoverable owing to one or more contingencies.

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

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

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

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

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

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

Estimation of Contingent Resources

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

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

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

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

The contingent resources estimates presented herein were generally based on consideration of drilling results, analyses of available geological data, well-test results, pressures, and other data available through December 31, 2024. The development and economic status represents the status applicable on December 31, 2024.

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

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

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

At the request of Star Energy, sales gas contingent resources estimated herein were converted to oil equivalent using an energy equivalent factor of 5,800 cubic feet of gas per 1 boe.

After a review of the data available for the fields evaluated herein, 18 fields located in the United Kingdom were estimated to contain contingent resources: Avington, Beckingham, Bletchingley, Corringham, Dunholme, Gainsborough, Glentworth, Horndean, Long Clawson, Lybster, Palmers Wood, Rempstone, Scampton North, Singleton, Stainton, Stockbridge, Storrington, 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 a lack of internal Star Energy approval or partner agreement for commitment to develop and produce the associated quantities.

Because of the uncertainty of commerciality, the contingent resources estimated herein are not classified as reserves. At the request of Star Energy, the contingent resources estimated herein are reported as having an economic status of undetermined, since the evaluation of these contingent resources is at a stage such that it is premature to clearly define the associated cash flows.

Procedure and Methodology

The Bletchingley field, located in licenses ML18 and ML21, was discovered in 1966. Oil was found in the Corallian Sandstone (Figure 6) and the field is currently producing from two wells. Porosity was estimated to range from 5 to 25 percent, S_w was estimated to range from 40 to 70 percent, and permeability was estimated to range from 0.2 to 1,000 millidarcys. Contingent resources were estimated for the drilling of two wells in the reservoir and are considered contingent due to the lack of a firm development plan.

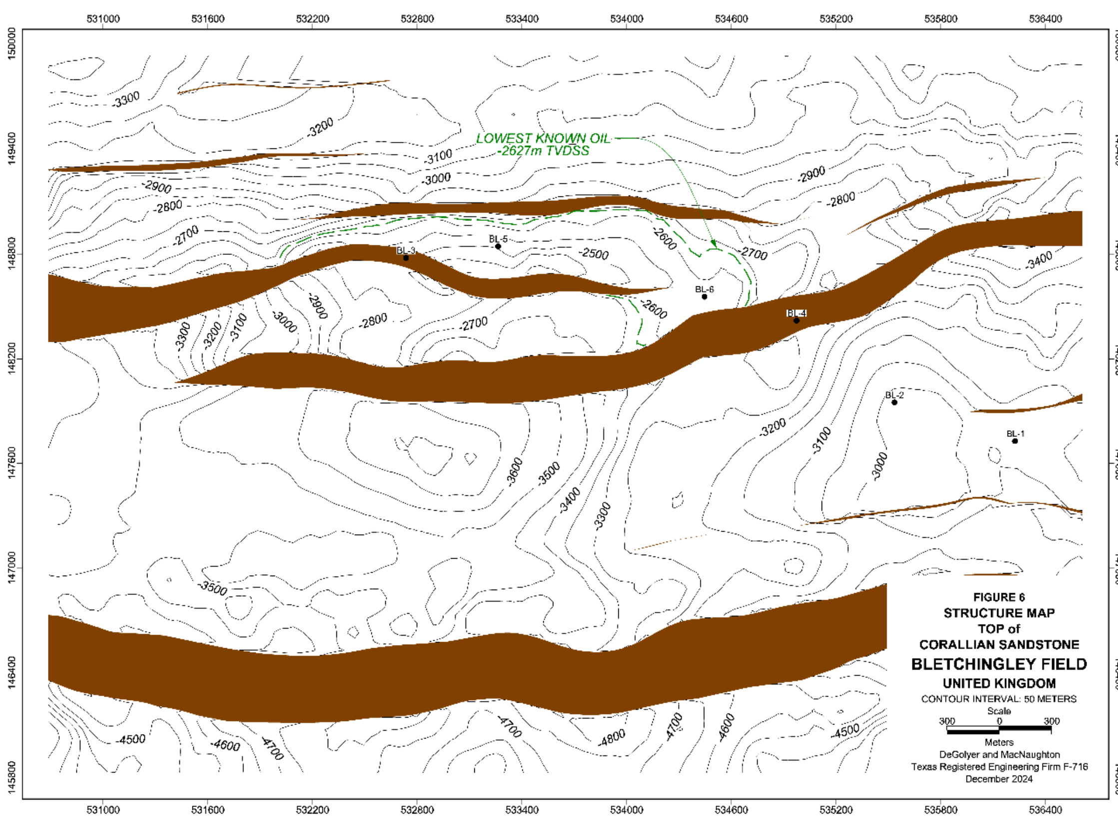


FIGURE 6
STRUCTURE MAP
TOP of
CORALLIAN SANDSTONE
BLETCHINGLEY FIELD
UNITED KINGDOM

The Dunholme field was discovered in 1983 by British Petroleum with the Dunholme-1 well. The field is located in the United Kingdom in the East Midlands Platform in license AL009. The Dunholme-1 well encountered a thin oil column in the Carboniferous Westphalian-age Basal Sand reservoir. The well is interpreted to have intersected the oil column very near the oil/water contact, and additional OOIP quantities were estimated updip of the Dunholme-1 well. Porosity was estimated to be 19.8 percent, Sw was estimated to be 58 percent, and permeability was estimated to range from 5 to 100 millidarcys. The Dunholme field was evaluated volumetrically, and contingent resources were estimated using analogous recovery factors based on other, similar fields in the area. Recovery factors were estimated to range from 5 to 15 percent. The field is considered contingent because it does not have an approved development plan.

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

The Lybster field (Figure 7) was discovered in 1996 by well 11/24-1 and is located offshore the Caithness coast in license P1270. Well 11/24-3V2 was drilled and produced in the field. 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. Recovery factors were estimated to range from 55 to 80 percent. Porosity was estimated to be 12 percent, S_w was estimated to range from 35 to 45 percent, and permeability was estimated to range from 90 to 1,115 millidarcys. Well 11/24-3V2 stopped producing at the end of 2014 due to a high gas-oil ratio (GOR), and the notional plan is to restore production in 2027. The tentative development plan includes well site upgrades, well recompletion with 3.5-inch tubing, installation of an electric submersible pump, onsite processing, and compression of the produced gas as part of a compressed natural gas (CNG) monetization scheme. The field is considered contingent based on the lack of firm development plans.

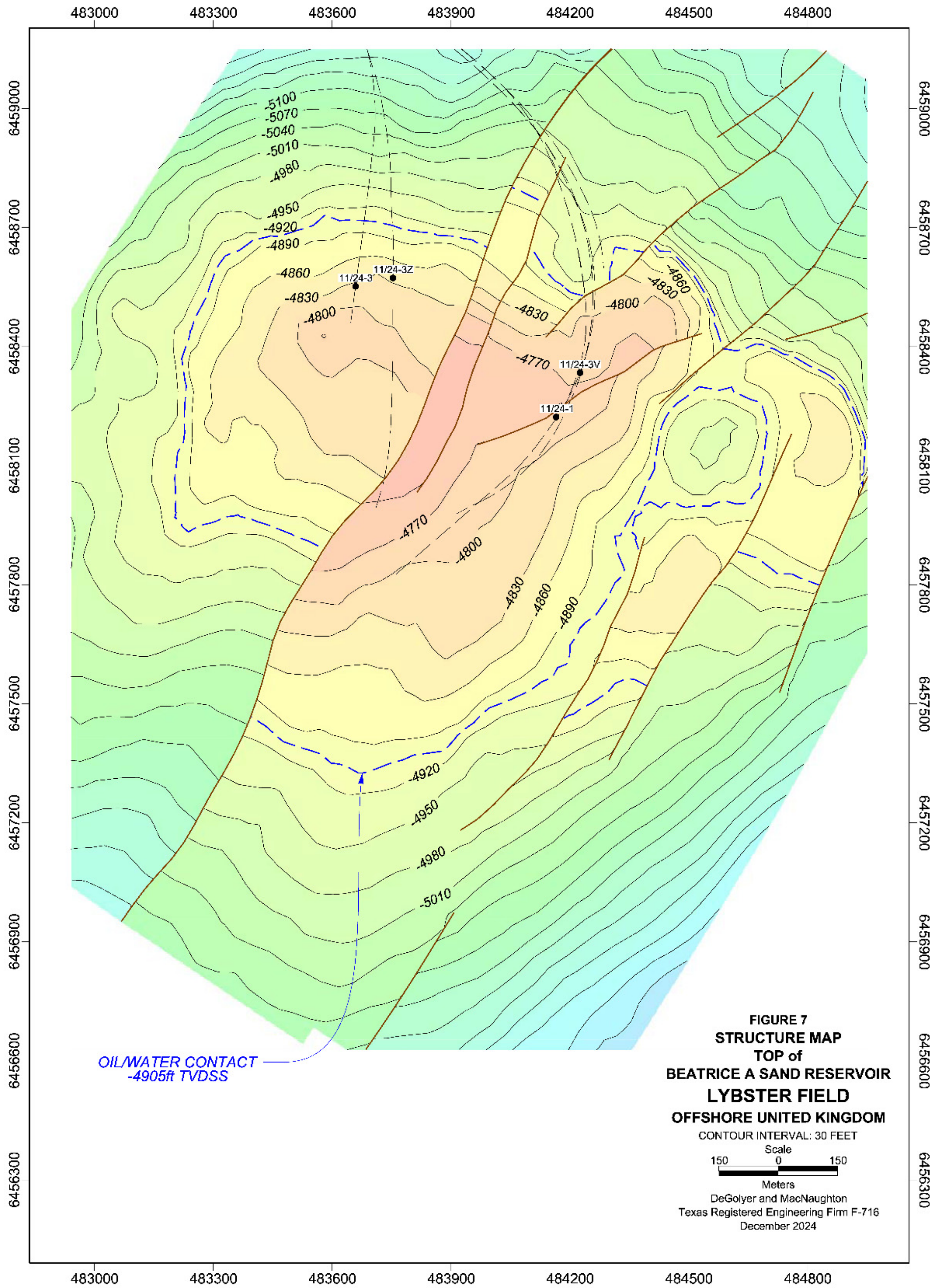


FIGURE 7
STRUCTURE MAP
TOP of
BEATRICE A SAND RESERVOIR
LYBSTER FIELD
OFFSHORE UNITED KINGDOM
CONTOUR INTERVAL: 30 FEET

The Scampton North field was discovered in 1985 by the SNA-1 well. The field is located within license PL179 in Lincolnshire. The Scampton North field produces light oil with a gravity of approximately 35 °API through five wells from the Basal Succession Sandstone. Porosity was estimated to range from 12 to 18 percent, S_w was estimated to range from 30 to 50 percent, and permeability was estimated to range from 0.5 to 400 millidarcys. Contingent resources were estimated for drilling a well to an undrained eastern target of the reservoir as well as for reperforation of the existing SCN-C3 well. The volumes associated with the additional drilling in the field to the eastern target and reperforation of the existing SCN-C3 well are considered contingent based on a lack of firm development plans.

Several of the producing fields also include contingent resources for certain projects that currently do not have firm development plans. These include the Avington, Beckingham, Corringham, Gainsborough, Horndean, Long Clawson, Palmers Wood, Singleton, Stockbridge, and Welton fields.

The estimated gross 1C, 2C, and 3C contingent resources, as of December 31, 2024, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

	Gross Contingent Resources								
	1C			2C			3C		
Field	**Oil and Condensate (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Oil Equivalent (10^3boe)**	**Oil and Condensate (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Oil Equivalent (10^3boe)**	**Oil and Condensate (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Oil Equivalent (10^3boe)**
Albury	0	0	0	0	0	0	0	0	0
Avington	560	0	560	807	0	807	1,087	0	1,087
Beckingham	66	218	104	232	317	287	303	389	370
Bletchingley	435	15	438	608	23	612	843	32	849
Bothamsall	0	0	0	0	0	0	0	0	0
Cold Hanworth	0	0	0	0	0	0	0	0	0
Corringham	618	0	618	863	0	863	943	0	943
Dunholme	12	0	12	188	0	188	426	0	426
East Glentworth	0	0	0	0	0	0	0	0	0
Egmanton	0	0	0	0	0	0	0	0	0
Gainsborough	458	446	535	784	935	945	1,100	1,175	1,303
Glentworth	2,130	0	2,130	2,922	0	2,922	3,096	0	3,096
Goodworth	0	0	0	0	0	0	0	0	0
Horndean	175	0	175	741	0	741	1,230	0	1,230
Long Clawson	690	0	690	950	0	950	1,360	0	1,360
Lybster	154	770	287	221	1,108	412	267	1,336	497
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	267	134	290	347	171	376	475	226	514
Rempstone	26	0	26	32	0	32	41	0	41
Scampton North	350	0	350	539	0	539	653	0	653
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	1,678	2,680	2,140	3,519	5,850	4,528	5,566	9,350	7,178
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	5	0	5	7	0	7	11	0	11
Stockbridge	577	0	577	707	0	707	877	0	877
Storrington	137	0	137	213	0	213	250	0	250
Welton	828	0	828	1,609	0	1,609	4,026	0	4,026
Total	**9,166**	**4,263**	**9,902**	**15,289**	**8,404**	**16,738**	**22,554**	**12,508**	**24,711**

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

The estimated net 1C, 2C, and 3C contingent resources, as of December 31, 2024, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

	Net Contingent Resources								
	1C			2C			3C		
Field	Oil and Condensate (10^3bbl)	Sales Gas (10^6ft^3)	Oil Equivalent (10^3boe)	Oil and Condensate (10^3bbl)	Sales Gas (10^6ft^3)	Oil Equivalent (10^3boe)	Oil and Condensate (10^3bbl)	Sales Gas (10^6ft^3)	Oil Equivalent (10^3boe)
Albury	0	0	0	0	0	0	0	0	0
Avington	301	0	301	433	0	433	583	0	583
Beckingham	66	218	104	232	317	287	303	389	370
Bletchingley	435	15	438	608	23	612	843	32	849
Bothamsall	0	0	0	0	0	0	0	0	0
Cold Hanworth	0	0	0	0	0	0	0	0	0
Corringham	618	0	618	863	0	863	943	0	943
Dunholme	12	0	12	188	0	188	426	0	426
East Glentworth	0	0	0	0	0	0	0	0	0
Egmanton	0	0	0	0	0	0	0	0	0
Gainsborough	458	446	535	784	935	945	1,100	1,175	1,303
Glentworth	2,130	0	2,130	2,922	0	2,922	3,096	0	3,096
Goodworth	0	0	0	0	0	0	0	0	0
Horndean	157	0	157	667	0	667	1,107	0	1,107
Long Clawson	690	0	690	950	0	950	1,360	0	1,360
Lybster	154	770	287	221	1,108	412	267	1,336	497
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	267	134	290	347	171	376	475	226	514
Rempstone	26	0	26	32	0	32	41	0	41
Scampton North	350	0	350	539	0	539	653	0	653
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	1,678	2,680	2,140	3,519	5,850	4,528	5,566	9,350	7,178
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	5	0	5	7	0	7	11	0	11
Stockbridge	577	0	577	707	0	707	877	0	877
Storrington	137	0	137	213	0	213	250	0	250
Welton	828	0	828	1,609	0	1,609	4,026	0	4,026
Total	**8,889**	**4,263**	**9,625**	**14,841**	**8,404**	**16,290**	**21,927**	**12,508**	**24,084**

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

Definition of Prospective Resources

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

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

The estimation of petroleum 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 quantities. In all cases, the range of uncertainty is dependent on the amount and quality of both technical and commercial data that are available and may change as more data become available.

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

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

This means that there is at least a 10-percent probability that, assuming the prospect is discovered and developed, the quantities actually recovered will equal or exceed the high estimate. The expected value* (EV), an outcome of the probabilistic analysis, is the mean estimate.

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

> *Probability of Geologic Success* – The probability of geologic success (P_g) is defined as the estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum. The P_g is estimated by quantifying with a probability each of the following individual geologic chance factors: trap, source, reservoir, and migration. The product of the probabilities of these four chance factors is P_g. P_g is predicated and correlated to the minimum case prospective resources gross recoverable volume(s). Consequently, the P_g is not linked to economically viable volumes, economic flow rates, or economic field size assumptions.
>
> In this report, estimates of prospective resources are presented both before and after adjustment for P_g. Total prospective resources estimates are based on the probabilistic summation (statistical aggregate) of the quantities for the total inventory of prospects. The statistical aggregate P_g-adjusted mean estimate, or “aggregated geologic chance-adjusted mean estimate,” is a probability-weighted average geologic success case expectation (average) of the hydrocarbon quantities potentially recoverable if all of the prospects in a portfolio were drilled. The P_g-adjusted mean estimate is a “blended” quantity; it is a product of the statistically aggregated mean volume estimate and the portfolio’s probability of geologic success. This statistical measure considers and stochastically quantifies the geological success and geological failure outcomes. Consequently, it represents the average or mean “geologic success case” volume outcome of drilling all of the prospects in the exploration program.

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

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

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

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

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

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

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

Estimation of Prospective Resources

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

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

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

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

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

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

Volumetrics, Quantitative Risk Assessment, and the Application of P_g

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

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

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

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

Estimates of gross and working interest prospective resources and the P_g estimates, as of December 31, 2024, are evaluated herein. The P_g-adjusted mean estimate of the prospective resources was then made by the probabilistic product of P_g and the resources distributions for the prospect. These results were then stochastically summed (zero dependency) to produce the statistical aggregate P_g-adjusted mean estimate prospective resources. The range in probability of the mean occurrence (P_{MEAN})* for the prospective resources volumes were estimated as defined in the glossary of this report. The range in P_{MEAN} for the statistical aggregate P_g-adjusted mean oil estimate is 0.07 to 0.10.

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

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

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

Prospective resources in one prospect have been evaluated in the PEDL 316 onshore license block in the United Kingdom. The prospective resources estimates presented below were based on a statistical aggregation method. The estimated gross and working interest unrisked prospective resources, as of December 31, 2024, of the prospect evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl):

	Gross Oil Prospective Resources Summary				Working Interest Oil Prospective Resources Summary			
Prospect	**1U (Low) Estimate (10^3bbl)**	**2U (Best) Estimate (10^3bbl)**	**3U (High) Estimate (10^3bbl)**	**Mean Estimate (10^3bbl)**	**1U (Low) Estimate (10^3bbl)**	**2U (Best) Estimate (10^3bbl)**	**3U (High) Estimate (10^3bbl)**	**Mean Estimate (10^3bbl)**
Lea	606	1,638	3,931	2,048	212	573	1,376	717
Statistical Aggregate	606	1,638	3,931	2,048	212	573	1,376	717

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

The gross and working interest statistical aggregate P_g-adjusted mean estimate oil prospective resources, as of December 31, 2024, of the prospect evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl):

	Mean Estimate
Gross P_g-Adjusted Oil Prospective Resources, 10^3bbl	369
Working Interest P_g-Adjusted Oil Prospective Resources, 10^3bbl	129

Notes:
1. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
2. Recovery efficiency was applied to prospective resources in this table.
3. The prospective resources presented above were based on the statistical aggregation method.
4. P_g is predicated and correlated to the minimum case prospective resources gross recoverable volume(s). The P_g is not linked to economically viable volumes, economic flow rates, or economic field size assumptions.
5. The range in probability of occurrence for the statistical aggregate P_g-adjusted mean oil estimate is 0.07 to 0.10.
6. The prospective resources quantities for the prospect evaluated in this report were aggregated by the arithmetic summation method, as required by the PRMS, and are presented in the prospective resources tables in this report.
7. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

The prospect evaluated in this report is shown in Tables A-13 through A-16 in the appendix bound with this report.

Professional Qualifications

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

The evaluation has been supervised by Mr. Regnald A. Boles, an Executive Vice President and Division Manager with DeGolyer and MacNaughton, a Registered Professional Engineer in the State of Texas, and a member of the Society of Petroleum Engineers, the Society of Petroleum Evaluation Engineers, and the European Association of Geoscientists & Engineers. He has over 41 years of oil and gas industry experience.

Submitted,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

STATE OF TEXAS
REGNALD A. BOLES
65092
LICENSED
PROFESSIONAL ENGINEER

Regnald A. Boles

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

PROSPECTIVE RESOURCES GLOSSARY

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

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

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

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

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

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

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

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

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

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

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

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

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

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

P_g-adjusted mean estimate = P_g × mean estimate (mean geologic success case volume)

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

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

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

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

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

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

where:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

TABLE A-1
SUMMARY PROJECTION of PROVED DEVELOPED RESERVES and REVENUE
as of
DECEMBER 31, 2024
attributable to
STAR ENERGY GROUP PLC
UNITED KINGDOM

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

Base Case

	Net				Star Energy				
Year	**Oil (10^3bbl)**	**Condensate (10^3bbl)**	**Sales Gas Export (10^6ft^3)**	**Sales Gas to Power (10^6ft^3)**	**Future Gross Revenue (10^3U.S.$)**	**Operating Expenses (10^3U.S.$)**	**Abandonment and Capital Costs (10^3U.S.$)**	**Future Net Revenue (10^3U.S.$)**	**Present Worth at 10 Percent (10^3U.S.$)**
2025	684	0	0	115	52,388	29,731	406	22,251	21,091
2026	641	0	0	48	46,639	29,308	413	16,918	14,516
2027	585	0	0	47	42,118	28,381	1,196	12,541	9,744
2028	544	0	0	48	38,315	25,791	3,991	8,533	5,998
2029	500	0	0	47	36,312	25,147	0	11,165	7,103
2030	460	0	0	48	34,400	17,948	7,825	8,627	4,973
2031	419	0	0	47	32,492	17,040	4,902	10,550	5,498
2032	384	0	0	48	30,551	16,119	6,631	7,801	3,682
2033	354	0	0	47	28,905	15,523	0	13,382	5,721
2034	324	0	0	48	27,581	15,043	2,985	9,553	3,694
2035	304	0	0	47	26,265	14,545	6,089	5,631	1,974
2036	281	0	0	47	25,188	14,178	0	11,010	3,488
2037	239	0	0	43	22,147	11,812	7,321	3,014	865
2038	219	0	0	37	20,473	10,663	12,566	(2,756)	(716)
2039	199	0	0	34	19,684	10,411	0	9,273	2,179
2040	190	0	0	30	19,017	10,217	0	8,800	1,874
2041	173	0	0	25	17,854	9,543	1,298	7,013	1,350
2042	161	0	0	23	17,234	9,370	0	7,864	1,371
2043	148	0	0	19	16,141	8,676	2,543	4,922	779
2044	137	0	0	17	15,401	8,281	1,327	5,793	827
2045	124	0	0	9	14,048	7,467	4,128	2,453	316
2046	118	0	0	1	13,416	7,329	0	6,087	714
2047	109	0	0	0	12,929	7,235	0	5,694	604
2048	105	0	0	0	12,513	7,162	0	5,351	513
2049	100	0	0	0	12,042	7,076	0	4,966	432
Subtotal	**7,502**	**0**	**0**	**875**	**634,053**	**363,996**	**63,621**	**206,436**	**98,590**
Remaining	943	0	0	0	124,375	82,662	40,613	1,100	722
Total	**8,445**	**0**	**0**	**875**	**758,428**	**446,658**	**104,234**	**207,536**	**99,312**

Present Worth at (10^3U.S.$)	
8 Percent	111,780
12 Percent	89,330
15 Percent	77,716

TABLE A-2
SUMMARY PROJECTION of TOTAL PROVED RESERVES and REVENUE
as of
DECEMBER 31, 2024
attributable to
STAR ENERGY GROUP PLC
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

Base Case

	Net				Star Energy				
Year	Oil (10^3bbl)	Condensate (10^3bbl)	Sales Gas Export (10^6ft^3)	Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2025	689	0	0	115	52,733	29,903	9,296	13,534	12,828
2026	645	0	0	208	48,673	29,681	4,299	14,693	12,606
2027	617	0	0	206	45,992	28,940	22,130	(5,078)	(3,941)
2028	624	0	0	613	49,476	27,602	3,991	17,883	12,574
2029	572	0	0	612	47,216	26,942	0	20,274	12,901
2030	527	0	0	610	45,065	19,728	7,825	17,512	10,090
2031	480	0	0	591	42,761	18,769	4,902	19,090	9,952
2032	439	0	0	576	40,480	17,803	6,631	16,046	7,573
2033	404	0	0	194	34,539	16,262	0	18,277	7,813
2034	370	0	0	139	32,363	15,620	2,985	13,758	5,321
2035	345	0	0	124	30,678	15,066	6,089	9,523	3,337
2036	319	0	0	112	29,265	14,649	0	14,616	4,632
2037	274	0	0	100	25,943	12,245	7,321	6,377	1,828
2038	251	0	0	89	24,013	11,062	12,566	385	101
2039	227	0	0	80	22,984	10,779	0	12,205	2,868
2040	216	0	0	70	22,101	10,555	0	11,546	2,457
2041	197	0	0	60	20,715	9,854	1,298	9,563	1,842
2042	182	0	0	54	19,898	9,655	0	10,243	1,787
2043	168	0	0	46	18,614	8,935	2,543	7,136	1,129
2044	156	0	0	39	17,705	8,519	1,327	7,859	1,120
2045	140	0	0	22	16,022	7,658	4,128	4,236	549
2046	132	0	0	2	15,025	7,463	0	7,562	886
2047	121	0	0	0	14,412	7,362	0	7,050	746
2048	117	0	0	0	13,893	7,278	0	6,615	634
2049	111	0	0	0	13,322	7,184	0	6,138	534
Subtotal	**8,323**	**0**	**0**	**4,662**	**743,888**	**379,514**	**97,331**	**267,043**	**112,167**
Remaining	1,040	0	0	0	137,171	84,252	40,613	12,306	1,241
Total	**9,363**	**0**	**0**	**4,662**	**881,059**	**463,766**	**137,944**	**279,349**	**113,408**

Present Worth at (10^3U.S.$)	
8 Percent	131,697
12 Percent	98,892
15 Percent	82,181

TABLE A-3
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE RESERVES and REVENUE
as of
DECEMBER 31, 2024
attributable to
STAR ENERGY GROUP PLC
UNITED KINGDOM

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

Base Case

	Net				Star Energy				
Year	Oil (10^3bbl)	Condensate (10^3bbl)	Sales Gas Export (10^6ft^3)	Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2025	714	0	0	115	54,553	30,502	9,296	14,755	13,986
2026	682	0	0	208	51,335	30,310	4,299	16,726	14,350
2027	677	0	0	206	50,372	29,856	22,130	(1,614)	(1,253)
2028	719	0	0	613	56,030	28,823	3,991	23,216	16,324
2029	677	0	0	612	54,652	28,309	0	26,343	16,766
2030	636	0	0	612	53,205	21,217	7,825	24,163	13,919
2031	594	0	0	612	51,753	20,650	4,280	26,823	13,987
2032	565	0	0	613	50,602	20,210	0	30,392	14,346
2033	523	0	0	611	48,801	19,339	647	28,815	12,313
2034	485	0	0	608	47,238	18,743	2,985	25,510	9,868
2035	457	0	0	594	45,459	17,778	13,126	14,555	5,098
2036	432	0	0	582	44,505	17,447	0	27,058	8,576
2037	408	0	0	570	43,379	17,074	0	26,305	7,546
2038	389	0	0	560	42,403	16,759	0	25,644	6,661
2039	360	0	0	549	41,475	16,466	0	25,009	5,880
2040	343	0	0	540	40,767	16,252	0	24,515	5,220
2041	319	0	0	364	36,753	14,552	13,335	8,866	1,706
2042	279	0	0	116	30,620	11,405	8,083	11,132	1,942
2043	265	0	0	108	29,904	11,209	0	18,695	2,952
2044	254	0	0	100	29,315	11,051	0	18,264	2,607
2045	238	0	0	92	27,905	10,423	1,405	16,077	2,079
2046	225	0	0	85	27,010	10,265	0	16,745	1,963
2047	210	0	0	62	25,658	10,047	0	15,611	1,655
2048	200	0	0	32	24,379	9,589	1,437	13,353	1,281
2049	194	0	0	29	23,634	9,464	0	14,170	1,230
Subtotal	**10,845**	**0**	**0**	**9,193**	**1,031,707**	**447,740**	**92,839**	**491,128**	**181,002**
Remaining	2,856	0	0	114	381,376	163,233	48,092	170,051	7,004
Total	**13,701**	**0**	**0**	**9,307**	**1,413,083**	**610,973**	**140,931**	**661,179**	**188,006**

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

Present Worth at (10^3U.S.$)	
8 Percent	227,510
12 Percent	158,492
15 Percent	126,397

TABLE A-4
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE
RESERVES and REVENUE
as of
DECEMBER 31, 2024
attributable to
STAR ENERGY GROUP PLC
UNITED KINGDOM

Base Case

	Net				Star Energy				
Year	Oil (10^3bbl)	Condensate (10^3bbl)	Sales Gas Export (10^6ft^3)	Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2025	725	0	0	115	55,449	30,827	9,296	15,326	14,527
2026	701	0	0	208	52,715	30,690	4,299	17,726	15,208
2027	711	0	0	206	52,895	30,436	22,130	329	256
2028	794	0	0	613	61,071	29,782	3,991	27,298	19,196
2029	747	0	0	612	59,745	29,287	0	30,458	19,382
2030	708	0	0	612	58,506	22,276	7,825	28,405	16,365
2031	666	0	0	612	57,268	21,783	4,280	31,205	16,273
2032	639	0	0	613	56,237	21,373	0	34,864	16,457
2033	600	0	0	611	55,034	20,931	0	34,103	14,572
2034	563	0	0	613	53,796	20,445	2,985	30,366	11,748
2035	542	0	0	612	52,880	19,984	6,089	26,807	9,386
2036	516	0	0	612	52,126	19,697	0	32,429	10,279
2037	480	0	0	601	50,323	19,055	0	31,268	8,972
2038	456	0	0	592	48,935	18,366	7,467	23,102	6,000
2039	421	0	0	580	47,715	17,723	729	29,263	6,878
2040	404	0	0	572	47,103	17,531	0	29,572	6,295
2041	388	0	0	561	46,199	17,254	0	28,945	5,574
2042	369	0	0	553	45,541	17,076	0	28,465	4,964
2043	348	0	0	545	44,807	16,862	0	27,945	4,413
2044	336	0	0	537	44,203	16,693	0	27,510	3,929
2045	321	0	0	529	43,218	16,531	0	26,687	3,454
2046	306	0	0	521	42,379	16,405	0	25,974	3,039
2047	270	0	0	515	39,194	13,891	8,924	16,379	1,738
2048	261	0	0	507	38,515	13,786	0	24,729	2,374
2049	242	0	0	482	36,433	12,543	15,624	8,266	718
Subtotal	**12,514**	**0**	**0**	**13,134**	**1,242,287**	**511,227**	**93,639**	**637,421**	**221,997**
Remaining	3,869	0	0	2,037	546,243	208,968	51,782	285,493	11,817
Total	**16,383**	**0**	**0**	**15,171**	**1,788,530**	**720,195**	**145,421**	**922,914**	**233,814**

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

Present Worth at (10^3U.S.$)	
8 Percent	287,667
12 Percent	194,362
15 Percent	152,368

TABLE A-5
SUMMARY PROJECTION of PROVED DEVELOPED RESERVES and REVENUE
as of
DECEMBER 31, 2024
attributable to
STAR ENERGY GROUP PLC
UNITED KINGDOM

Low Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Star Energy Future Gross Revenue (10^3U.S.$)	Star Energy Operating Expenses (10^3U.S.$)	Star Energy Abandonment and Capital Costs (10^3U.S.$)	Star Energy Future Net Revenue (10^3U.S.$)	Star Energy Present Worth at 10 Percent (10^3U.S.$)
2025	684	0	0	47	46,331	29,731	406	16,194	15,350
2026	641	0	0	48	41,975	29,308	413	12,254	10,514
2027	585	0	0	47	37,911	28,381	1,196	8,334	6,475
2028	544	0	0	48	34,485	25,791	3,991	4,703	3,304
2029	495	0	0	47	32,352	24,816	598	6,938	4,415
2030	450	0	0	48	30,313	17,279	14,198	(1,164)	(671)
2031	415	0	0	47	28,942	16,710	4,280	7,952	4,145
2032	384	0	0	48	27,499	16,119	0	11,380	5,371
2033	354	0	0	47	26,015	15,523	0	10,492	4,484
2034	312	0	0	48	23,929	14,119	14,594	(4,784)	(1,848)
2035	265	0	0	47	20,600	11,471	13,126	(3,997)	(1,399)
2036	246	0	0	47	19,929	11,211	0	8,718	2,764
2037	229	0	0	43	19,124	10,914	0	8,210	2,354
2038	219	0	0	37	18,424	10,663	0	7,761	2,018
2039	194	0	0	34	17,250	9,928	1,248	6,074	1,427
2040	185	0	0	30	16,683	9,748	0	6,935	1,476
2041	172	0	0	25	15,942	9,409	862	5,671	1,093
2042	150	0	0	23	14,324	8,134	5,504	686	121
2043	139	0	0	19	13,621	7,731	1,301	4,589	723
2044	131	0	0	17	13,253	7,616	0	5,637	805
2045	124	0	0	9	12,642	7,467	0	5,175	670
2046	118	0	0	1	12,074	7,329	0	4,745	555
2047	109	0	0	0	11,638	7,235	0	4,403	468
2048	105	0	0	0	11,262	7,162	0	4,100	392
2049	100	0	0	0	10,837	7,076	0	3,761	326
Subtotal	**7,350**	**0**	**0**	**807**	**557,355**	**350,871**	**61,717**	**144,767**	**65,332**
Remaining	883	0	0	0	104,916	75,414	40,613	(11,111)	1
Total	**8,233**	**0**	**0**	**807**	**662,271**	**426,285**	**102,330**	**133,656**	**65,333**

Present Worth at (10^3U.S.$)	
8 Percent	73,617
12 Percent	58,721
15 Percent	51,097

TABLE A-6
SUMMARY PROJECTION of TOTAL PROVED RESERVES and REVENUE
as of
DECEMBER 31, 2024
attributable to
STAR ENERGY GROUP PLC
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

Low Case

Year	Net				Star Energy				
	Oil (10^3bbl)	Condensate (10^3bbl)	Sales Gas Export (10^6ft^3)	Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2025	689	0	0	47	46,641	29,903	9,296	7,442	7,055
2026	645	0	0	208	43,806	29,681	4,299	9,826	8,430
2027	617	0	0	206	41,395	28,940	22,130	(9,675)	(7,514)
2028	624	0	0	613	44,532	27,602	3,991	12,939	9,096
2029	567	0	0	612	42,163	26,611	598	14,954	9,517
2030	517	0	0	610	39,906	19,059	14,198	6,649	3,830
2031	476	0	0	591	38,189	18,439	4,280	15,470	8,065
2032	439	0	0	576	36,435	17,803	0	18,632	8,794
2033	404	0	0	194	31,085	16,262	0	14,823	6,336
2034	358	0	0	139	28,232	14,696	14,594	(1,058)	(405)
2035	306	0	0	124	24,573	11,992	13,126	(545)	(193)
2036	284	0	0	112	23,600	11,682	0	11,918	3,778
2037	264	0	0	100	22,540	11,347	0	11,193	3,210
2038	251	0	0	89	21,611	11,062	0	10,549	2,742
2039	222	0	0	80	20,219	10,296	1,248	8,675	2,039
2040	211	0	0	70	19,460	10,086	0	9,374	1,996
2041	196	0	0	60	18,517	9,720	862	7,935	1,529
2042	171	0	0	54	16,721	8,419	5,504	2,798	488
2043	159	0	0	46	15,848	7,990	1,301	6,557	1,035
2044	150	0	0	39	15,327	7,854	0	7,473	1,066
2045	140	0	0	22	14,418	7,658	0	6,760	876
2046	132	0	0	2	13,521	7,463	0	6,058	708
2047	121	0	0	0	12,972	7,362	0	5,610	596
2048	117	0	0	0	12,503	7,278	0	5,225	502
2049	111	0	0	0	11,989	7,184	0	4,805	416
Subtotal	**8,171**	**0**	**0**	**4,594**	**656,203**	**366,389**	**95,427**	**194,387**	**73,992**
Remaining	983	0	0	0	116,822	77,408	40,613	(1,199)	490
Total	**9,154**	**0**	**0**	**4,594**	**773,025**	**443,797**	**136,040**	**193,188**	**74,482**

Present Worth at (10^3U.S.$)	
8 Percent	87,811
12 Percent	63,965
15 Percent	51,990

TABLE A-7
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE RESERVES and REVENUE
as of
DECEMBER 31, 2024
attributable to
STAR ENERGY GROUP PLC
UNITED KINGDOM

Low Case

	Net				Star Energy				
Year	Oil (10^3bbl)	Condensate (10^3bbl)	Sales Gas Export (10^6ft^3)	Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2025	714	0	0	47	48,281	30,502	9,296	8,483	8,041
2026	682	0	0	208	46,202	30,310	4,299	11,593	9,945
2027	677	0	0	206	45,332	29,856	22,130	(6,654)	(5,165)
2028	719	0	0	613	50,432	28,823	3,991	17,618	12,388
2029	677	0	0	612	49,181	28,309	0	20,872	13,280
2030	631	0	0	612	47,547	20,880	8,435	18,232	10,504
2031	589	0	0	612	46,240	20,307	4,280	21,653	11,291
2032	555	0	0	613	44,859	19,521	6,631	18,707	8,832
2033	519	0	0	611	43,607	19,003	0	24,604	10,515
2034	481	0	0	608	42,211	18,408	2,985	20,818	8,052
2035	457	0	0	594	40,912	17,778	6,089	17,045	5,968
2036	432	0	0	582	40,055	17,447	0	22,608	7,165
2037	396	0	0	570	38,064	16,094	12,319	9,651	2,770
2038	378	0	0	560	37,250	15,801	0	21,449	5,571
2039	350	0	0	549	36,467	15,532	0	20,935	4,921
2040	308	0	0	540	33,523	13,010	7,769	12,744	2,713
2041	296	0	0	364	30,969	12,313	0	18,656	3,594
2042	274	0	0	116	27,098	10,944	1,324	14,830	2,587
2043	260	0	0	108	26,485	10,760	0	15,725	2,481
2044	250	0	0	100	25,979	10,610	0	15,369	2,195
2045	238	0	0	92	25,113	10,423	0	14,690	1,901
2046	225	0	0	85	24,308	10,265	0	14,043	1,648
2047	201	0	0	62	22,096	9,015	5,703	7,378	778
2048	187	0	0	32	20,642	8,231	2,807	9,604	922
2049	183	0	0	29	20,035	8,118	0	11,917	1,035
Subtotal	**10,679**	**0**	**0**	**9,125**	**912,888**	**432,260**	**98,058**	**382,570**	**133,932**
Remaining	2,837	0	0	114	341,130	160,981	40,613	139,536	6,196
Total	**13,516**	**0**	**0**	**9,239**	**1,254,018**	**593,241**	**138,671**	**522,106**	**140,128**

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

Present Worth at (10^3U.S.$)	
8 Percent	171,832
12 Percent	116,609
15 Percent	91,282

TABLE A-8
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE
RESERVES and REVENUE
as of
DECEMBER 31, 2024
attributable to
STAR ENERGY GROUP PLC
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

Low Case

	Net				Star Energy				
Year	Oil (10^3bbl)	Condensate (10^3bbl)	Sales Gas Export (10^6ft^3)	Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2025	725	0	0	47	49,085	30,827	9,296	8,962	8,497
2026	701	0	0	208	47,446	30,690	4,299	12,457	10,685
2027	711	0	0	206	47,604	30,436	22,130	(4,962)	(3,854)
2028	794	0	0	613	54,969	29,782	3,991	21,196	14,907
2029	747	0	0	612	53,764	29,287	0	24,477	15,574
2030	708	0	0	612	52,651	22,276	7,825	22,550	12,993
2031	666	0	0	612	51,547	21,783	4,280	25,484	13,288
2032	639	0	0	613	50,616	21,373	0	29,243	13,805
2033	600	0	0	611	49,531	20,931	0	28,600	12,220
2034	563	0	0	613	48,415	20,445	2,985	24,985	9,667
2035	534	0	0	612	46,944	19,300	13,799	13,845	4,846
2036	508	0	0	612	46,268	19,006	0	27,262	8,641
2037	471	0	0	601	44,644	18,358	0	26,286	7,540
2038	452	0	0	592	43,711	18,006	0	25,705	6,680
2039	421	0	0	580	42,945	17,723	0	25,222	5,929
2040	404	0	0	572	42,396	17,531	0	24,865	5,291
2041	388	0	0	561	41,578	17,254	0	24,324	4,688
2042	369	0	0	553	40,985	17,076	0	23,909	4,168
2043	348	0	0	545	40,331	16,862	0	23,469	3,702
2044	326	0	0	537	38,789	15,661	14,151	8,977	1,284
2045	287	0	0	529	35,506	13,042	8,578	13,886	1,797
2046	274	0	0	521	34,850	12,909	0	21,941	2,569
2047	260	0	0	515	34,220	12,797	0	21,423	2,271
2048	252	0	0	507	33,703	12,720	0	20,983	2,014
2049	242	0	0	482	32,786	12,543	0	20,243	1,757
Subtotal	**12,390**	**0**	**0**	**13,066**	**1,105,284**	**498,618**	**91,334**	**515,332**	**170,959**
Remaining	3,806	0	0	2,037	484,289	201,178	51,782	231,329	9,640
Total	**16,196**	**0**	**0**	**15,103**	**1,589,573**	**699,796**	**143,116**	**746,661**	**180,599**

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

Present Worth at (10^3U.S.$)	
8 Percent	224,466
12 Percent	148,616
15 Percent	114,775

TABLE A-9
SUMMARY PROJECTION of PROVED DEVELOPED RESERVES and REVENUE
as of
DECEMBER 31, 2024
attributable to
STAR ENERGY GROUP PLC
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

High Case

	Net				Star Energy				
Year	Oil (10^3bbl)	Condensate (10^3bbl)	Sales Gas Export (10^6ft^3)	Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2025	684	0	0	115	57,624	29,731	406	27,487	26,057
2026	641	0	0	48	51,303	29,308	413	21,582	18,512
2027	585	0	0	47	46,330	28,381	1,196	16,753	13,016
2028	544	0	0	48	42,143	25,791	3,991	12,361	8,691
2029	500	0	0	47	39,940	25,147	0	14,793	9,414
2030	460	0	0	48	37,840	17,948	7,825	12,067	6,953
2031	423	0	0	47	36,075	17,354	4,280	14,441	7,529
2032	392	0	0	48	34,303	16,766	0	17,537	8,277
2033	362	0	0	47	32,475	16,176	0	16,299	6,967
2034	324	0	0	48	30,342	15,043	10,544	4,755	1,841
2035	304	0	0	47	28,893	14,545	6,089	8,259	2,891
2036	281	0	0	47	27,706	14,178	0	13,528	4,287
2037	260	0	0	43	26,458	13,812	0	12,646	3,629
2038	228	0	0	37	23,439	11,537	7,467	4,435	1,153
2039	199	0	0	34	21,652	10,411	12,817	(1,576)	(373)
2040	190	0	0	30	20,916	10,217	0	10,699	2,280
2041	177	0	0	25	20,130	9,998	0	10,132	1,947
2042	165	0	0	23	19,410	9,813	0	9,597	1,676
2043	154	0	0	19	18,343	9,220	1,351	7,772	1,227
2044	144	0	0	17	17,784	9,089	0	8,695	1,243
2045	130	0	0	9	16,153	8,119	3,999	4,035	522
2046	123	0	0	1	15,413	7,969	0	7,444	872
2047	109	0	0	0	14,222	7,235	4,295	2,692	284
2048	105	0	0	0	13,764	7,162	0	6,602	635
2049	100	0	0	0	13,247	7,076	0	6,171	534
Subtotal	**7,584**	**0**	**0**	**875**	**705,905**	**372,026**	**64,673**	**269,206**	**130,064**
Remaining	983	0	0	0	142,968	88,525	40,613	13,830	1,432
Total	**8,567**	**0**	**0**	**875**	**848,873**	**460,551**	**105,286**	**283,036**	**131,496**

Present Worth at (10^3U.S.$)	
8 Percent	148,345
12 Percent	118,054
15 Percent	102,432

TABLE A-10
SUMMARY PROJECTION of TOTAL PROVED RESERVES and REVENUE
as of
DECEMBER 31, 2024
attributable to
STAR ENERGY GROUP PLC
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

High Case

	Net				Star Energy				
Year	Oil (10^3bbl)	Condensate (10^3bbl)	Sales Gas Export (10^6ft^3)	Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2025	689	0	0	115	58,003	29,903	9,296	18,804	17,827
2026	645	0	0	208	53,542	29,681	4,299	19,562	16,778
2027	617	0	0	206	50,589	28,940	22,130	(481)	(370)
2028	624	0	0	613	54,419	27,602	3,991	22,826	16,049
2029	572	0	0	612	51,933	26,942	0	24,991	15,904
2030	527	0	0	610	49,569	19,728	7,825	22,016	12,686
2031	484	0	0	591	47,379	19,083	4,280	24,016	12,520
2032	447	0	0	576	45,225	18,450	0	26,775	12,639
2033	412	0	0	194	38,672	16,915	0	21,757	9,300
2034	370	0	0	139	35,603	15,620	10,544	9,439	3,651
2035	345	0	0	124	33,746	15,066	6,089	12,591	4,410
2036	319	0	0	112	32,192	14,649	0	17,543	5,559
2037	295	0	0	100	30,632	14,245	0	16,387	4,703
2038	260	0	0	89	27,334	11,936	7,467	7,931	2,061
2039	227	0	0	80	25,283	10,779	12,817	1,687	394
2040	216	0	0	70	24,308	10,555	0	13,753	2,929
2041	201	0	0	60	23,278	10,309	0	12,969	2,495
2042	186	0	0	54	22,339	10,099	0	12,240	2,135
2043	174	0	0	46	21,063	9,479	1,351	10,233	1,617
2044	163	0	0	39	20,320	9,327	0	10,993	1,571
2045	146	0	0	22	18,323	8,310	3,999	6,014	778
2046	137	0	0	2	17,183	8,103	0	9,080	1,063
2047	121	0	0	0	15,853	7,362	4,295	4,196	445
2048	117	0	0	0	15,282	7,278	0	8,004	767
2049	111	0	0	0	14,654	7,184	0	7,470	650
Subtotal	**8,405**	**0**	**0**	**4,662**	**826,724**	**387,545**	**98,383**	**340,796**	**148,561**
Remaining	1,078	0	0	0	156,644	89,736	40,613	26,295	1,997
Total	**9,483**	**0**	**0**	**4,662**	**983,368**	**477,281**	**138,996**	**367,091**	**150,558**

Present Worth at (10^3U.S.$)	
8 Percent	174,014
12 Percent	131,943
15 Percent	110,470

TABLE A-11
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE RESERVES and REVENUE
as of
DECEMBER 31, 2024
attributable to
STAR ENERGY GROUP PLC
UNITED KINGDOM

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

High Case

	Net				Star Energy				
Year	Oil (10^3bbl)	Condensate (10^3bbl)	Sales Gas Export (10^6ft^3)	Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2025	714	0	0	115	60,007	30,502	9,296	20,209	19,157
2026	682	0	0	208	56,466	30,310	4,299	21,857	18,752
2027	677	0	0	206	55,407	29,856	22,130	3,421	2,660
2028	719	0	0	613	61,630	28,823	3,991	28,816	20,259
2029	677	0	0	612	60,109	28,309	0	31,800	20,238
2030	636	0	0	612	58,526	21,217	7,825	29,484	16,986
2031	594	0	0	612	56,934	20,650	4,280	32,004	16,688
2032	565	0	0	613	55,664	20,210	0	35,454	16,737
2033	527	0	0	611	54,038	19,665	0	34,373	14,686
2034	489	0	0	608	52,327	19,075	2,985	30,267	11,712
2035	465	0	0	594	50,736	18,451	6,089	26,196	9,171
2036	435	0	0	582	49,297	17,781	687	30,829	9,772
2037	408	0	0	570	47,717	17,074	7,321	23,322	6,691
2038	389	0	0	560	46,647	16,759	0	29,888	7,763
2039	360	0	0	549	45,622	16,466	0	29,156	6,856
2040	343	0	0	540	44,840	16,252	0	28,588	6,082
2041	328	0	0	364	41,434	15,480	0	25,954	5,003
2042	309	0	0	116	37,070	14,539	0	22,531	3,926
2043	273	0	0	108	33,837	12,128	8,245	13,464	2,126
2044	254	0	0	100	32,249	11,051	14,151	7,047	1,009
2045	242	0	0	92	31,151	10,855	0	20,296	2,624
2046	225	0	0	85	29,709	10,265	1,434	18,010	2,107
2047	210	0	0	62	28,224	10,047	0	18,177	1,927
2048	203	0	0	32	27,119	9,874	0	17,245	1,655
2049	194	0	0	29	25,997	9,464	1,465	15,068	1,308
Subtotal	**10,918**	**0**	**0**	**9,193**	**1,142,757**	**455,103**	**94,198**	**593,456**	**225,895**
Remaining	2,883	0	0	114	423,449	166,975	48,373	208,101	8,495
Total	**13,801**	**0**	**0**	**9,307**	**1,566,206**	**622,078**	**142,571**	**801,557**	**234,390**

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

Present Worth at (10^3U.S.$)	
8 Percent	281,861
12 Percent	198,803
15 Percent	159,928

TABLE A-12
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE
RESERVES and REVENUE
as of
DECEMBER 31, 2024
attributable to
STAR ENERGY GROUP PLC
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

High Case

Year	Net: Oil (10^3bbl)	Net: Condensate (10^3bbl)	Net: Sales Gas Export (10^6ft^3)	Net: Sales Gas to Power (10^6ft^3)	Star Energy: Future Gross Revenue (10^3U.S.$)	Star Energy: Operating Expenses (10^3U.S.$)	Star Energy: Abandonment and Capital Costs (10^3U.S.$)	Star Energy: Future Net Revenue (10^3U.S.$)	Star Energy: Present Worth at 10 Percent (10^3U.S.$)
2025	725	0	0	115	60,990	30,827	9,296	20,867	19,781
2026	701	0	0	208	57,985	30,690	4,299	22,996	19,730
2027	711	0	0	206	58,183	30,436	22,130	5,617	4,361
2028	794	0	0	613	67,175	29,782	3,991	33,402	23,487
2029	747	0	0	612	65,714	29,287	0	36,427	23,184
2030	708	0	0	612	64,353	22,276	7,825	34,252	19,733
2031	666	0	0	612	63,002	21,783	4,280	36,939	19,263
2032	639	0	0	613	61,864	21,373	0	40,491	19,114
2033	600	0	0	611	60,538	20,931	0	39,607	16,923
2034	563	0	0	613	59,177	20,445	2,985	35,747	13,828
2035	542	0	0	612	58,173	19,984	6,089	32,100	11,241
2036	516	0	0	612	57,336	19,697	0	37,639	11,930
2037	480	0	0	601	55,357	19,055	0	36,302	10,417
2038	459	0	0	592	54,206	18,712	0	35,494	9,220
2039	425	0	0	580	52,858	18,069	729	34,060	8,007
2040	408	0	0	572	52,165	17,878	0	34,287	7,295
2041	388	0	0	561	50,822	17,254	7,924	25,644	4,939
2042	369	0	0	553	50,097	17,076	0	33,021	5,759
2043	348	0	0	545	49,288	16,862	0	32,426	5,117
2044	336	0	0	537	48,621	16,693	0	31,928	4,563
2045	321	0	0	529	47,534	16,531	0	31,003	4,013
2046	306	0	0	521	46,617	16,405	0	30,212	3,537
2047	270	0	0	515	43,109	13,891	8,924	20,294	2,149
2048	261	0	0	507	42,370	13,786	0	28,584	2,743
2049	242	0	0	482	40,072	12,543	15,624	11,905	1,034
Subtotal	**12,525**	**0**	**0**	**13,134**	**1,367,606**	**512,266**	**94,096**	**761,244**	**271,368**
Remaining	3,902	0	0	2,037	605,975	213,802	51,782	340,391	13,963
Total	**16,427**	**0**	**0**	**15,171**	**1,973,581**	**726,068**	**145,878**	**1,101,635**	**285,331**

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

Present Worth at (10^3U.S.$)	
8 Percent	349,109
12 Percent	238,530
15 Percent	188,575