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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

January 31, 2024

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, 2023, 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 0contingent resources associated with certain conventional 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 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 "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, 2023. 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.$1.25 per U.K.£1.00. All monetary values in this report are expressed in U.S.$. 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, 2023. 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, 2023. 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 29 discovered fields in the United Kingdom. This report includes evaluations of 6 fields that contain reserves only, 6 fields that contain contingent resources only, 11 fields that contain reserves and contingent resources, and 6 fields that contain no reserves or contingent resources. This evaluation also includes prospective resources for one conventional 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, 2023, 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. 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, 2023, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

Reserves Summary

	Oil and Condensate			Sales Gas			Oil Equivalent		
	Proved (10^3bbl)	Probable (10^3bbl)	Possible (10^3bbl)	Proved (10^6ft^3)	Probable (10^6ft^3)	Possible (10^6ft^3)	Proved (10^3boe)	Probable (10^3boe)	Possible (10^3boe)
Gross	10,813	4,864	4,139	5,766	5,231	6,840	11,807	5,766	5,318
Net	10,720	4,851	4,126	5,766	5,231	6,840	11,714	5,753	5,305

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

Revenue

Revenue values in this report were estimated using initial prices, expenses, and costs provided by 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.

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, 2023, 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	329,264	143,471	738,261	234,744	1,123,987	305,885
Low Case	234,089	100,312	587,990	181,463	921,174	243,986
High Case	427,443	184,367	891,658	286,742	1,328,741	366,604

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 17 fields and do not include any unconventional assets. Sales gas contingent resources were converted to boe using an energy equivalent factor of 5,800 cubic feet of gas per 1 boe.

The estimated gross and net 1C, 2C, and 3C contingent resources, as of December 31, 2023, 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	7,864	10,782	9,724	7,553	10,757	9,409
2C	13,879	31,079	19,237	13,270	30,854	18,589
3C	23,433	70,488	35,588	22,249	69,698	34,267

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 conventional prospect have been evaluated in the PEDL 316 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 prospective resources, as of December 31, 2023, of the prospects evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl):

Prospect	Gross Oil Prospective Resources Summary 1U (Low) Estimate (10^3bbl)	2U (Best) Estimate (10^3bbl)	3U (High) Estimate (10^3bbl)	Mean Estimate (10^3bbl)	Working Interest Oil Prospective Resources Summary 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 prospects evaluated in this report were aggregated by the arithmetic summation method, as required by the PRMS, and are presented in the prospective resources tables in this report.
7. Summations may vary from those shown here due to rounding.
8. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

The gross and working interest statistical aggregate Pg-adjusted mean estimate prospective resources, as of December 31, 2023, of the prospects evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl):

	Mean Estimate
Gross P_g-Adjusted Oil Prospective Resources, 10^3bbl	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 prospects evaluated in this report were aggregated by the arithmetic summation method, as required by the PRMS, and are presented in the prospective resources tables in this report.
7. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

Ownership and Infrastructure

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

Field/Discovery/Prospect	License	Working Interest (percent)	License Expiration
Albury	DL4	100.00	11/16/2027
Avington	PEDL70	53.67	9/8/2031
Beckingham	ML4	100.00	3/31/2040
Bletchingley	ML18	100.00	1/11/2027
Bletchingley	ML21	100.00	4/1/2027
Bothamsall	ML6	100.00	3/31/2040
Cold Hanworth	PEDL6	100.00	4/4/2027
Corringham	ML4	100.00	3/31/2040
Dunholme	AL009	100.00	4/7/2025
East Glentworth	PL179	100.00	11/16/2034
Egmanton	ML3	100.00	12/30/2033
Gainsborough	ML4	100.00	3/31/2040
Glentworth	ML4	100.00	3/31/2040
Godley Bridge	PEDL235	100.00	6/30/2039
Goodworth	PEDL21	100.00	4/3/2027
Hemswell	PEDL6	100.00	6/30/2039
Hemswell	PEDL210	75.00	6/30/2039
Horndean	PL211	90.00	4/4/2036
Lea	PED316	35.00	7/20/2046
Long Clawson	PL220	100.00	8/8/2026
Lybster	P1270	100.00	12/21/2031
Nettleham	PL179	100.00	11/16/2034
Nettleham	PL199	100.00	10/31/2045
Palmers Wood	PL182	100.00	11/16/2034
Rempstone	PL220	100.00	8/8/2026
Scampton North	PL179	100.00	11/16/2034
Scampton South	PL179	100.00	11/16/2034
Singleton	PL240	100.00	12/1/2037
South Leverton	ML7	100.00	3/31/2040
Stainton	PL179b	100.00	11/16/2034
Stockbridge	DL2	100.00	12/31/2030
Stockbridge	PL233	100.00	10/26/2030
Stockbridge	PL249	100.00	11/30/2030
Storrington	PL205	100.00	2/13/2036
Welton	PL179b	100.00	11/16/2034

Note: Lea is the prospect evaluated herein.

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.

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, 2023, have been considered to be valid for their stated terms, as represented by Star Energy.

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

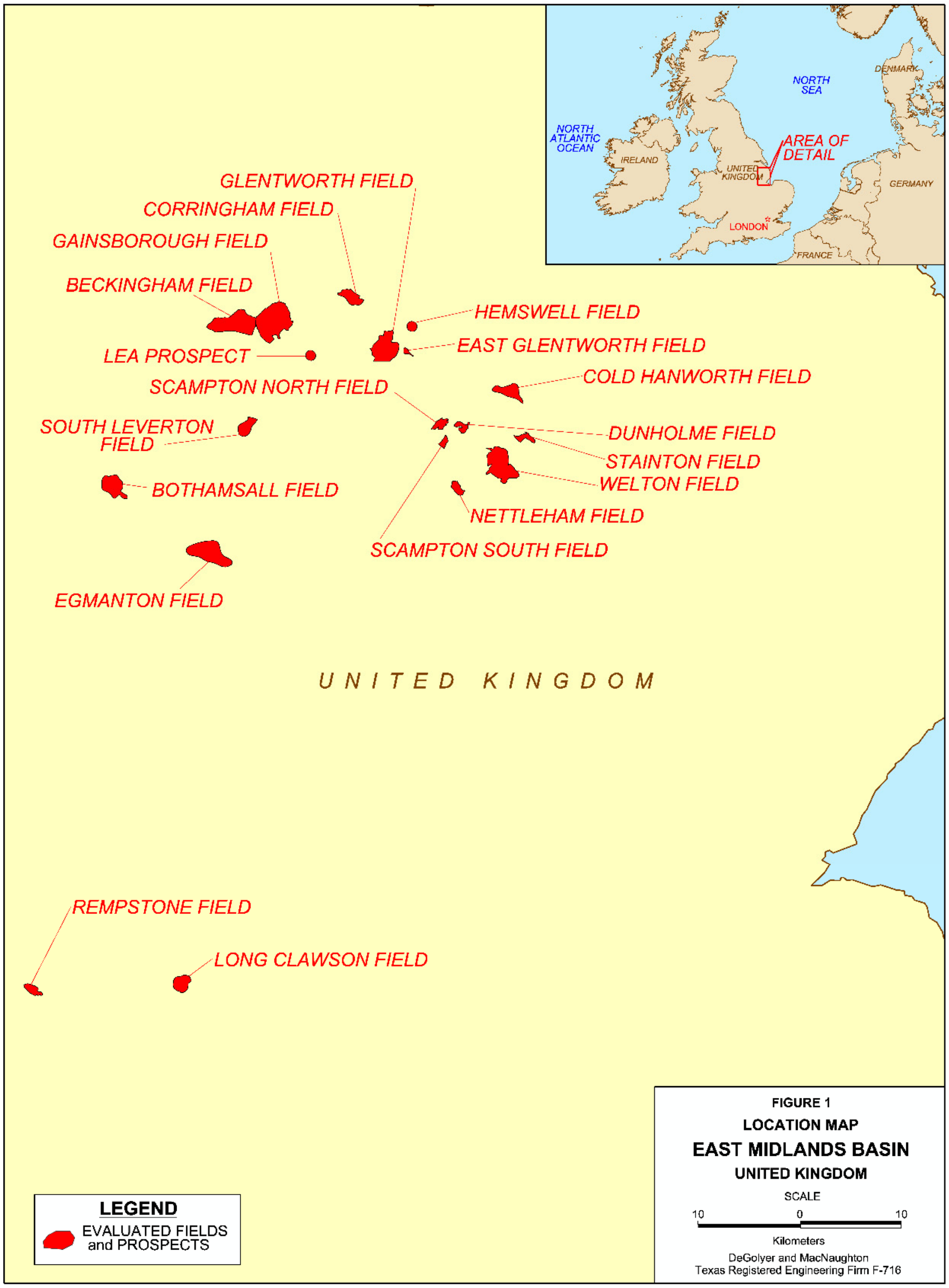

FIGURE 1
LOCATION MAP
EAST MIDLANDS BASIN
UNITED KINGDOM

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

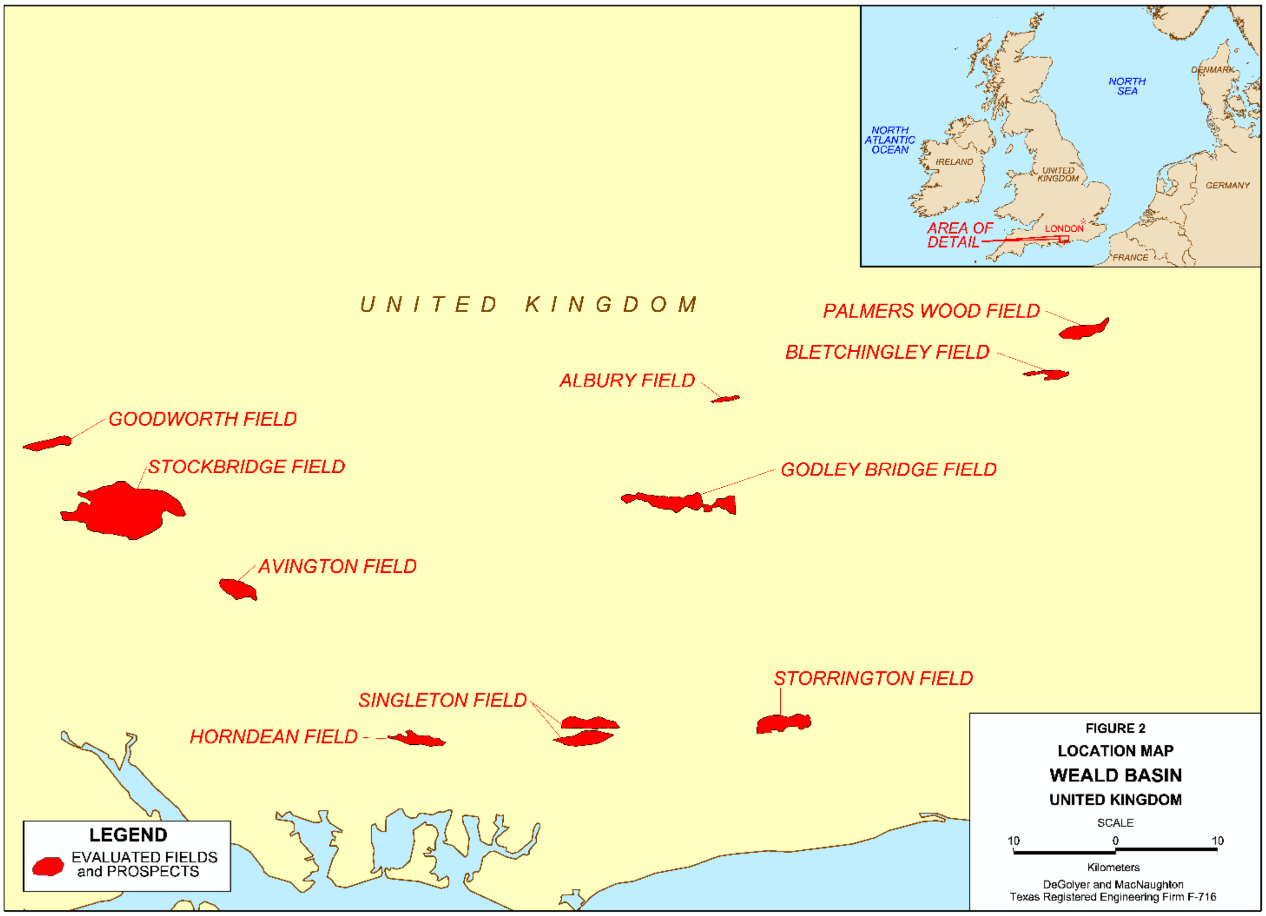

FIGURE 2
LOCATION MAP
WEALD BASIN
UNITED KINGDOM

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, 2023, 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 2023. Where applicable, estimated cumulative production, as of December 31, 2023, was deducted from the gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 3 months.

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

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

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

At the request of 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 20 of those fields. The fields produce from various reservoirs in the East Midlands and Weald Basins (Figures 4 and 5).

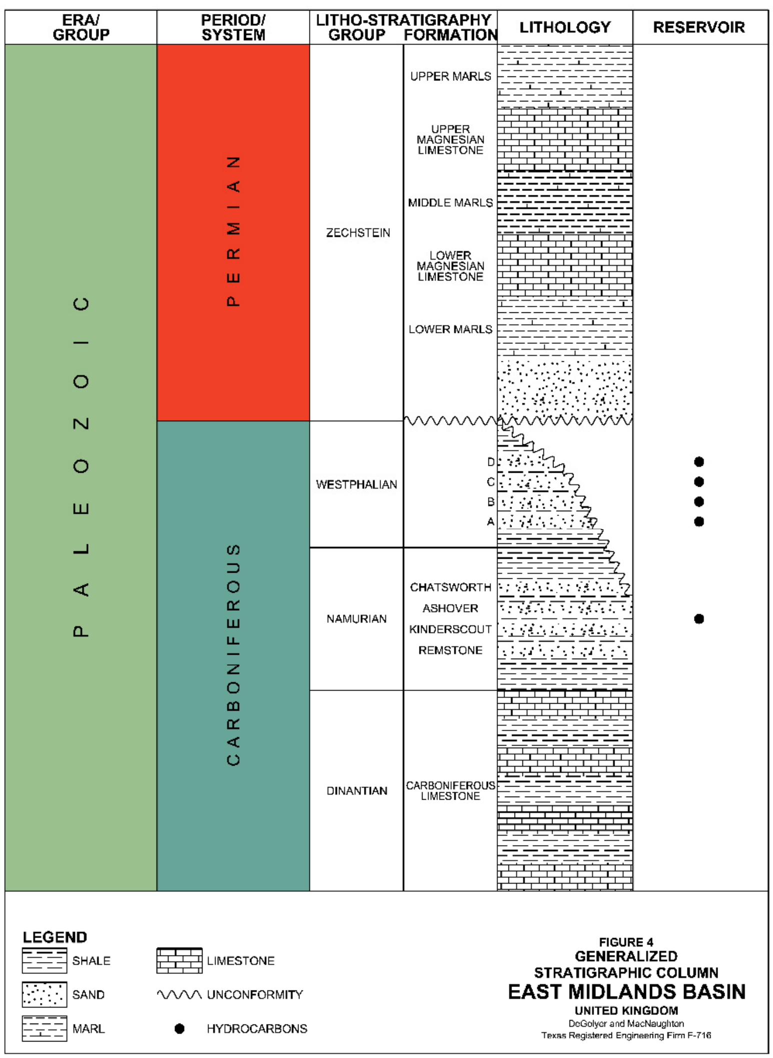


FIGURE 4
GENERALIZED
STRATIGRAPHIC COLUMN
EAST MIDLANDS BASIN
UNITED KINGDOM
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716

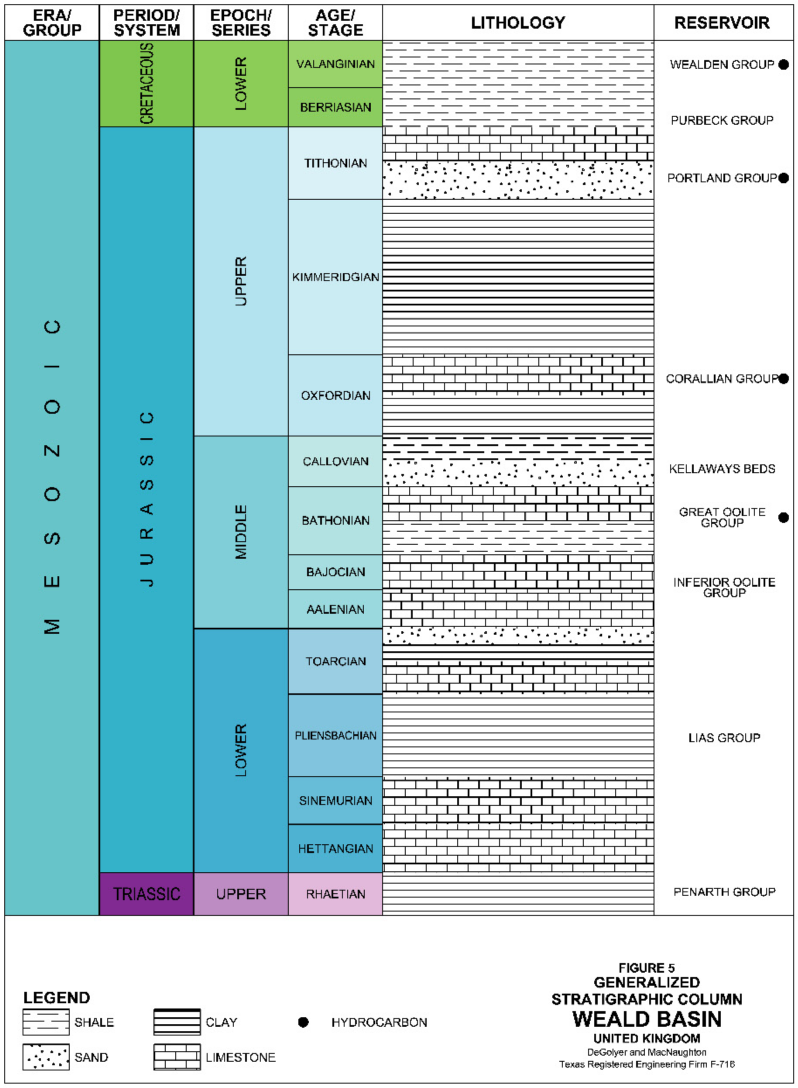


FIGURE 5
GENERALIZED
STRATIGRAPHIC COLUMN
WEALD BASIN
UNITED KINGDOM
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716

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. The recovery factors were estimated to range from 70 to 79 percent. Proved developed producing reserves were estimated based on the performance data from producing wells. 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 current plan is 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 2029. For the purposes of this report, abandonment was scheduled for 2029.

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 52 10^3boe based on the performance of four existing wells and are associated with workovers to remove wax in three wells and repair casing integrity 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 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. Proved undeveloped reserves were estimated to be 356 10^3boe based on volumetric analysis of a workover in a currently shut-in well. Estimates of probable and possible reserves account for the potential for better performance than proved reserves. Undeveloped reserves estimates for the field also include a “gas-to-wire” project to support the building of a 6-megawatt generator. 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 260 10^3boe based on individual-well performance. Estimates of probable and possible reserves account for the potential for better performance than proved reserves. Undeveloped reserves estimates for the field include a new producer in the Silkstone reservoir, the CR13 well. 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 produces oil from the Upper Namurian and Lower Westphalian reservoirs through two wells. The field is located in license ML3, southwest of the Gainsborough trough. Porosity was estimated to range from 13 to 17 percent, S_w was estimated to range from 45 to 55 percent, and permeability was estimated to range from 1 to 100 millidarcys. Performance analysis was completed on this field. After economic evaluation, recoverable quantities were determined to be uneconomic. As such, reserves for this field were estimated to be zero. The field will be abandoned, with site restorations, in 2024. For the purposes of this report, abandonment was scheduled for 2024.

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 2028.

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 a new producer 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. Proved developed non-producing reserves were estimated to be 13 10^3boe based on performance of one of the existing wells, which will require replacement of the surface unit equipment. 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 Nettleham field, located in licenses PL179 and PL199, was discovered in 1983 and is located approximately 5 kilometers northeast of the city of Lincoln. The primary reservoir is the Basal Westphalian. The field is not currently producing. Porosity was estimated to range from 19 to 22 percent, S_w was estimated to range from 30 to 60 percent, and permeability was estimated to range from 6 to 1,000 millidarcys. Production was stopped in February 2016 due to high water cut. No plans were presented to bring this field back on production; as such, reserves for this field were estimated to be zero. For the purposes of this report, abandonment was scheduled for 2027.

The Palmers Wood field was discovered in 1983 and is located 5 kilometers east of Redhill within license PL182. The Palmers Wood field currently produces through four wells from the Upper Jurassic Corallian Sandstone. In addition, there has been an active waterflood 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. 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 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. 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 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. Proved developed non-producing reserves were estimated to be 82 10^3boe based on the expected performance of three planned workovers on existing wells that will require site upgrades to restore production. 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 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 2032.

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 768 10^3boe based on performance of existing wells and include a north block development of one new producer, the conversion of one existing shut-in well to a water injector, and deepening one existing well for oil production. Estimates of probable and possible reserves account for the potential for better performance from existing and future wells than proved reserves. The current plan is to install a new 4-megawatt generator by 2026, which may allow the recovery of proved, probable, and possible gas reserves in the future. 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 2029.

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 2027.

The Stockbridge field was discovered in 1984. This field is located within the DL2, PL233, and PL249 licenses, in the northwest portion of the Weald Basin. The field produces from the Great Oolite reservoir. Water injection began in 1998 after converting the STK-16 well to a water injector. The field is currently producing from six wells. 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 102 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 2031.

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 392 10^3boe based on the expected performance of three planned workovers on existing wells to restart production. The planned workovers were 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, 2023, 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	853	231	229	147	40	39
Avington	0	0	0	0	0	0	0	0	0
Beckingham	351	87	105	0	0	0	351	87	105
Bletchingley	196	40	86	2,067	3,438	5,092	552	633	964
Bothamsall	29	16	24	0	0	0	29	16	24
Cold Hanworth	222	80	79	0	0	0	222	80	79
Corringham	542	132	118	0	0	0	542	132	118
Dunholme	0	0	0	0	0	0	0	0	0
East Glentworth	99	29	38	0	0	0	99	29	38
Egmanton	0	0	0	0	0	0	0	0	0
Gainsborough	0	0	0	0	0	0	0	0	0
Glentworth	1,231	626	480	0	0	0	1,231	626	480
Godley Bridge	0	0	0	0	0	0	0	0	0
Goodworth	37	7	33	0	0	0	37	7	33
Hemswell (PEDL6)	0	0	0	0	0	0	0	0	0
Hemswell (PEDL210)	0	0	0	0	0	0	0	0	0
Horndean	929	135	123	0	0	0	929	135	123
Long Clawson	241	44	69	0	0	0	241	44	69
Lybster	0	0	0	0	0	0	0	0	0
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	280	64	104	0	0	0	280	64	104
Rempstone	5	0	0	0	0	0	5	0	0
Scampton North	567	125	292	0	0	0	567	125	292
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	2,656	1,218	1,226	2,846	1,562	1,519	3,147	1,487	1,488
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	897	318	291	0	0	0	897	318	291
Storrington	0	0	0	0	0	0	0	0	0
Welton	2,531	1,943	1,071	0	0	0	2,531	1,943	1,071
Total	**10,813**	**4,864**	**4,139**	**5,766**	**5,231**	**6,840**	**11,807**	**5,766**	**5,318**

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, total gross proved developed producing reserves were estimated to be 9,180 10^3boe, total gross proved developed non-producing reserves were estimated to be 249 10^3boe, and total gross proved undeveloped reserves were estimated to be 2,378 10^3boe.

The estimated net proved, probable, and possible reserves, as of December 31, 2023, 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	853	231	229	147	40	39
Avington	0	0	0	0	0	0	0	0	0
Beckingham	351	87	105	0	0	0	351	87	105
Bletchingley	196	40	86	2,067	3,438	5,092	552	633	964
Bothamsall	29	16	24	0	0	0	29	16	24
Cold Hanworth	222	80	79	0	0	0	222	80	79
Corringham	542	132	118	0	0	0	542	132	118
Dunholme	0	0	0	0	0	0	0	0	0
East Glentworth	99	29	38	0	0	0	99	29	38
Egmanton	0	0	0	0	0	0	0	0	0
Gainsborough	0	0	0	0	0	0	0	0	0
Glentworth	1,231	626	480	0	0	0	1,231	626	480
Godley Bridge	0	0	0	0	0	0	0	0	0
Goodworth	37	7	33	0	0	0	37	7	33
Hemswell (PEDL6)	0	0	0	0	0	0	0	0	0
Hemswell (PEDL210)	0	0	0	0	0	0	0	0	0
Horndean	836	122	110	0	0	0	836	122	110
Long Clawson	241	44	69	0	0	0	241	44	69
Lybster	0	0	0	0	0	0	0	0	0
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	280	64	104	0	0	0	280	64	104
Rempstone	5	0	0	0	0	0	5	0	0
Scampton North	567	125	292	0	0	0	567	125	292
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	2,656	1,218	1,226	2,846	1,562	1,519	3,147	1,487	1,488
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	897	318	291	0	0	0	897	318	291
Storrington	0	0	0	0	0	0	0	0	0
Welton	2,531	1,943	1,071	0	0	0	2,531	1,943	1,071
Total	**10,720**	**4,851**	**4,126**	**5,766**	**5,231**	**6,840**	**11,714**	**5,753**	**5,305**

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, total net proved developed producing reserves were estimated to be 9,087 10^3boe, total net proved developed non-producing reserves were estimated to be 249 10^3boe, and total net proved undeveloped reserves were estimated to be 2,378 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 2023, 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 2023. 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)
2024	76.84	69.16	12.11	11.96
2025	73.70	66.33	12.02	11.88
2026	71.40	64.26	10.57	10.44
2027	69.48	62.53	9.09	8.98
2028	70.98	63.88	9.27	9.16
2029	72.52	65.27	9.46	9.34
2030	74.09	66.68	9.65	9.53
2031	75.69	68.12	9.84	9.72
2032	77.32	69.59	10.04	9.92
2033	79.00	71.10	10.24	10.11
2034	81.54	73.38	10.44	10.32
2035	84.15	75.74	10.65	10.52
2036	86.84	78.15	10.86	10.73
2037	89.60	80.64	11.08	10.95
2038	92.43	83.19	11.30	11.17
2039	95.34	85.81	11.53	11.39
2040	98.33	88.50	11.76	11.62
2041	101.41	91.26	11.99	11.85
2042	104.56	94.11	12.23	12.09
2043	107.80	97.02	12.48	12.33
2044	109.96	98.96	12.73	12.57
2045	112.16	100.94	12.98	12.83
2046	114.40	102.96	13.24	13.08
2047	116.69	105.02	13.51	13.34
2048	119.02	107.12	13.78	13.61
2049	121.40	109.26	14.05	13.88
2050	123.83	111.45	14.33	14.16

Note: From 2050 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.$1.25 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, 2023, of the properties evaluated under the Base Case economic conditions 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	981,654	1,533,731	2,047,122
Operating Expenses	484,155	622,963	747,170
Abandonment and Capital Costs	168,235	172,507	175,965
Future Net Revenue	329,264	738,261	1,123,987
Present Worth at 10 Percent	143,471	234,744	305,885

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, 2023, of the properties evaluated under the Low Case and High Case economic conditions 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	865,381	1,362,949	1,828,898	1,079,833	1,687,128	2,251,876
Operating Expenses	465,247	604,575	732,938	484,155	622,963	747,170
Abandonment and Capital Costs	166,045	170,384	174,786	168,235	172,507	175,965
Future Net Revenue	234,089	587,990	921,174	427,443	891,658	1,328,741
Present Worth at 10 Percent	100,312	181,463	243,986	184,367	286,742	366,604

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, 2023. The development and economic status represents the status applicable on December 31, 2023.

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.

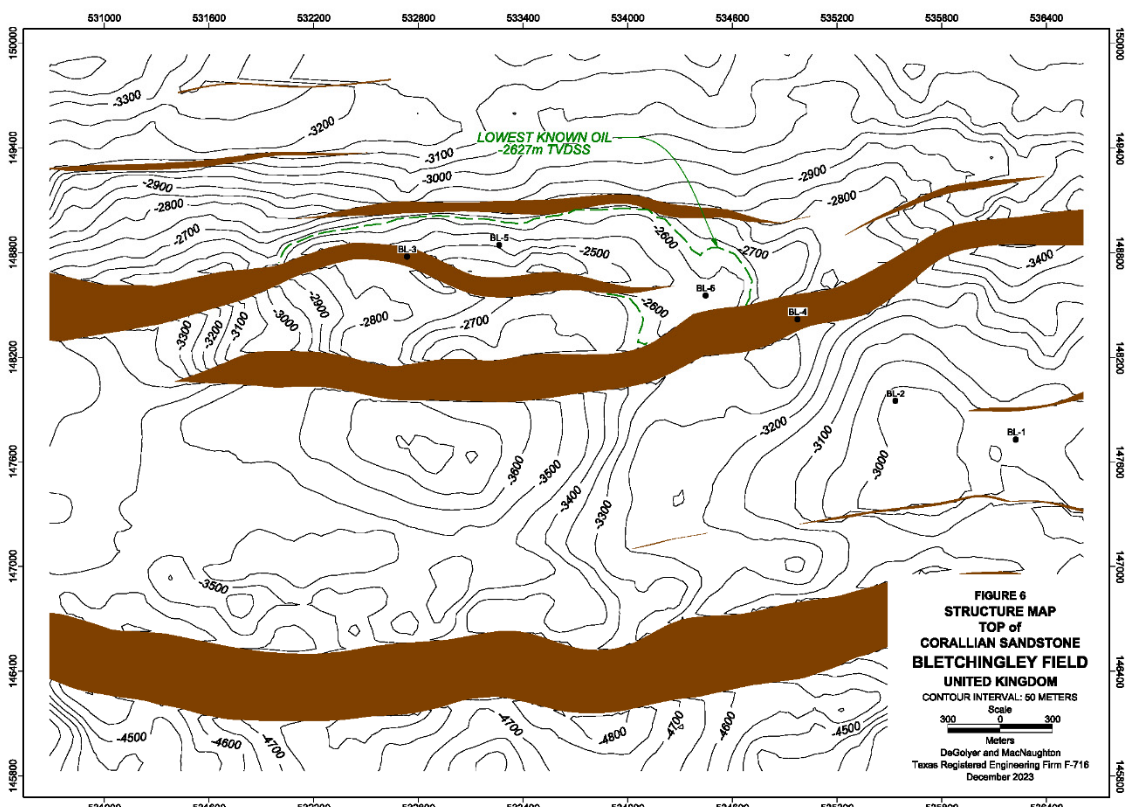
After a review of the data available for the fields evaluated herein, 17 fields located in the United Kingdom were estimated to contain contingent resources: Avington, Beckingham, Bletchingley, Corringham, Dunholme, Gainsborough, Glentworth, Godley Bridge, Hemswell, Horndean, Long Clawson, Lybster, Palmers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

The contingent resources estimated for the fields evaluated herein are those quantities of petroleum that are potentially recoverable from discovered accumulations but which are not currently considered to be commercially recoverable because of one or more contingencies, including 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

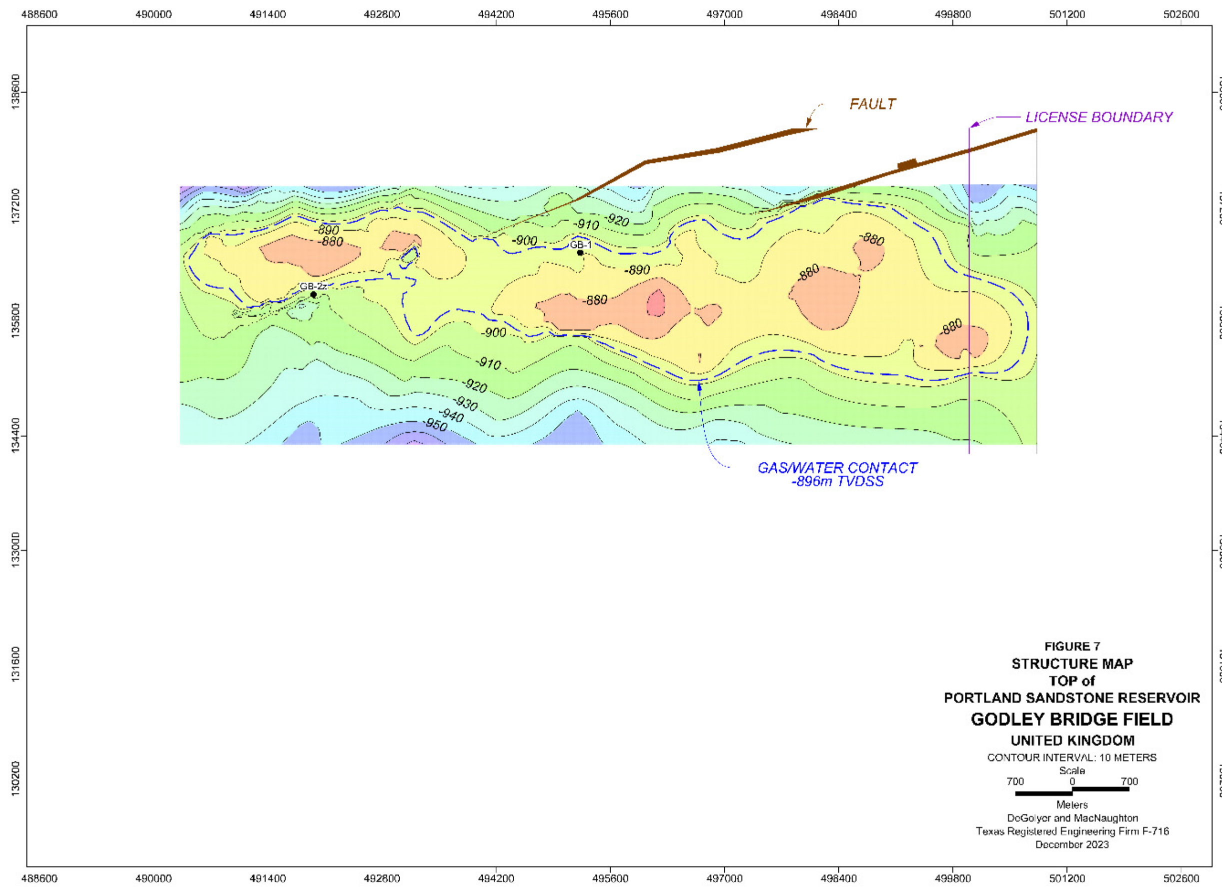
The Bletchingley field, located in licenses ML18 and ML21, was discovered in 1966. Oil was found in the Corallian Sandstone (Figure 6) and the field is currently producing from two wells. Porosity was estimated to range from 5 to 25 percent, S_w was estimated to range from 40 to 70 percent, and permeability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



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 Godley Bridge field (Figure 7), located in license PEDL235, was discovered in 1982. The field is gas bearing in the Portland Sandstone. The Godley Bridge field was evaluated volumetrically, and contingent resources were estimated using analogous recovery factors based on other, similar fields in the area. Porosity was estimated to be 13 percent, S_w was estimated to be 37 percent, and permeability was estimated to range from 0.1 to 548 millidarcys. The recovery factors were estimated to range from 71 to 84 percent. This field is considered contingent based on the lack of firm development plans. New seismic data for the Godley Bridge Portland Sandstone were incorporated into the current evaluation. The contingent resources estimated herein for the Godley Bridge field do not include the Kimmeridge Micrites reservoir.



The Lybster field (Figure 8) 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.

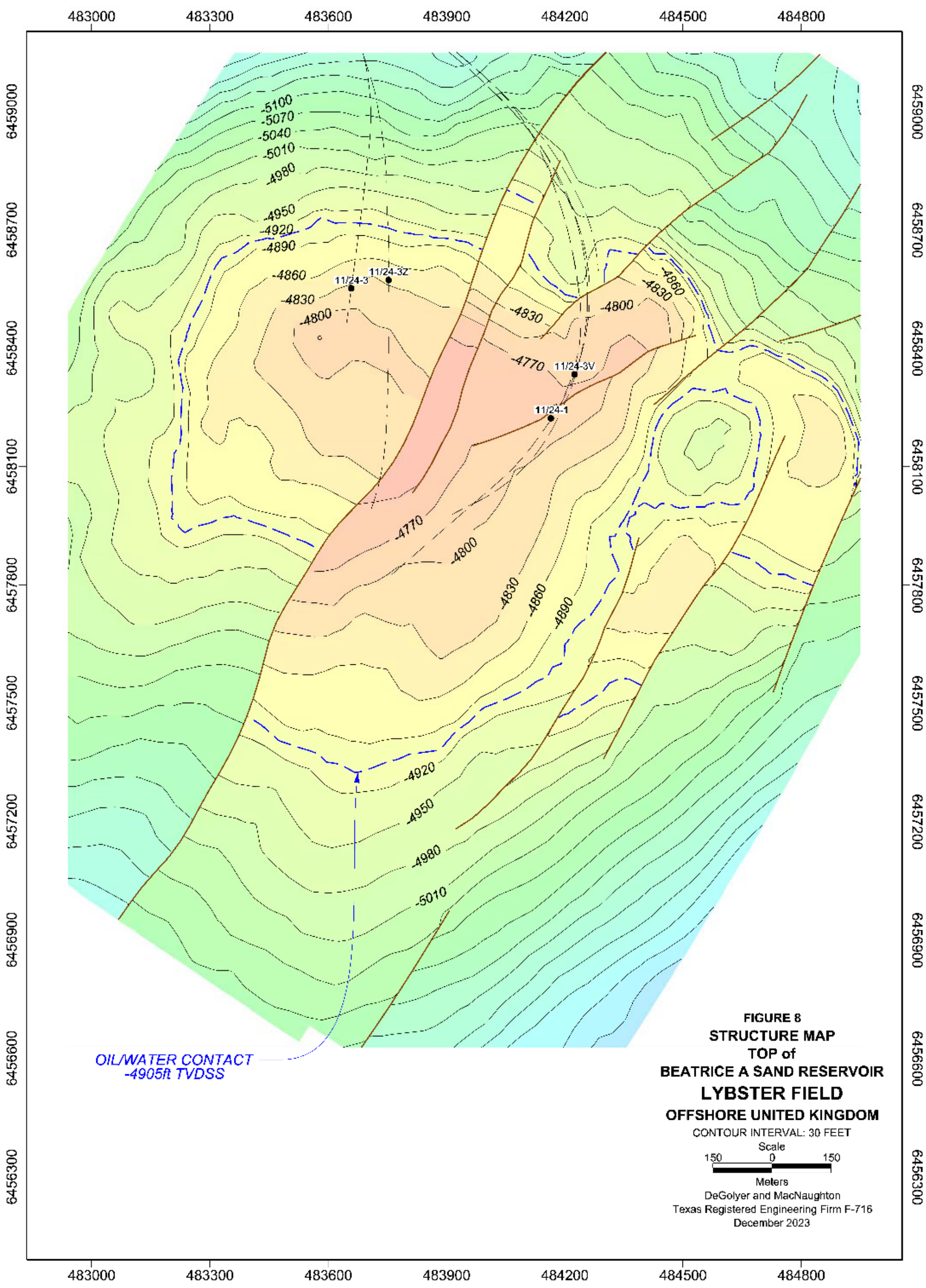


FIGURE 8
STRUCTURE MAP
TOP of
BEATRICE A SAND RESERVOIR
LYBSTER FIELD
OFFSHORE UNITED KINGDOM

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, Hemswell, Horndean, Long Clawson, Palmers Wood, Singleton, Stockbridge, and Welton fields.

The estimated gross 1C, 2C, and 3C contingent resources, as of December 31, 2023, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (106ft3), 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	65	218	103	232	317	287	301	387	368
Bletchingley	435	15	438	608	23	612	843	32	849
Bothamsall	0	0	0	0	0	0	0	0	0
Cold Hanworth	0	0	0	0	0	0	0	0	0
Corringham	687	0	687	959	0	959	1,048	0	1,048
Dunholme	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	83	39	90	272	141	296	509	183	541
Glentworth	2,130	0	2,130	2,922	0	2,922	3,096	0	3,096
Godley Bridge	0	7,823	1,349	0	23,193	3,999	0	53,366	9,201
Goodworth	0	0	0	0	0	0	0	0	0
Hemswell (PEDL6)	0	0	0	44	64	55	2,002	2,872	2,497
Hemswell (PEDL210)	69	99	86	627	900	782	2,202	3,159	2,747
Horndean	349	0	349	798	0	798	1,296	0	1,296
Long Clawson	690	0	690	950	0	950	1,360	0	1,360
Lybster	154	770	287	221	1,108	412	267	1,336	497
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	299	147	324	392	188	424	532	247	575
Rempstone	0	0	0	0	0	0	0	0	0
Scampton North	350	0	350	539	0	539	653	0	653
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	947	1,671	1,235	2,566	5,145	3,453	3,777	8,906	5,313
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	577	0	577	707	0	707	877	0	877
Storrington	0	0	0	0	0	0	0	0	0
Welton	457	0	457	1,047	0	1,047	3,157	0	3,157
Total	**7,864**	**10,782**	**9,724**	**13,879**	**31,079**	**19,237**	**23,433**	**70,488**	**35,588**

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, 2023, 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	65	218	103	232	317	287	301	387	368
Bletchingley	435	15	438	608	23	612	843	32	849
Bothamsall	0	0	0	0	0	0	0	0	0
Cold Hanworth	0	0	0	0	0	0	0	0	0
Corringham	687	0	687	959	0	959	1,048	0	1,048
Dunholme	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	83	39	90	272	141	296	509	183	541
Glentworth	2,130	0	2,130	2,922	0	2,922	3,096	0	3,096
Godley Bridge	0	7,823	1,349	0	23,193	3,999	0	53,366	9,201
Goodworth	0	0	0	0	0	0	0	0	0
Hemswell (PEDL6)	0	0	0	44	64	55	2,002	2,872	2,497
Hemswell (PEDL210)	52	74	65	471	675	587	1,652	2,369	2,060
Horndean	314	0	314	719	0	719	1,166	0	1,166
Long Clawson	690	0	690	950	0	950	1,360	0	1,360
Lybster	154	770	287	221	1,108	412	267	1,336	497
Nettleham	0	0	0	0	0	0	0	0	0
Palmers Wood	299	147	324	392	188	424	532	247	575
Rempstone	0	0	0	0	0	0	0	0	0
Scampton North	350	0	350	539	0	539	653	0	653
Scampton South	0	0	0	0	0	0	0	0	0
Singleton	947	1,671	1,235	2,566	5,145	3,453	3,777	8,906	5,313
South Leverton	0	0	0	0	0	0	0	0	0
Stainton	0	0	0	0	0	0	0	0	0
Stockbridge	577	0	577	707	0	707	877	0	877
Storrington	0	0	0	0	0	0	0	0	0
Welton	457	0	457	1,047	0	1,047	3,157	0	3,157
Total	**7,553**	**10,757**	**9,409**	**13,270**	**30,854**	**18,589**	**22,249**	**69,698**	**34,267**

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, 2023, 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 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, 2023, of the prospects evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl):

Prospect	Gross Oil Prospective Resources Summary 1U (Low) Estimate (10^3bbl)	2U (Best) Estimate (10^3bbl)	3U (High) Estimate (10^3bbl)	Mean Estimate (10^3bbl)	Working Interest Oil Prospective Resources Summary 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 prospects evaluated in this report were aggregated by the arithmetic summation method, as required by the PRMS, and are presented in the prospective resources tables in this report.
7. Summations may vary from those shown here due to rounding.
8. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

The gross and working interest statistical aggregate P_g-adjusted mean estimate oil prospective resources, as of December 31, 2023, of the prospects evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl):

	Mean Estimate
Gross P_g-Adjusted Oil Prospective Resources, 10^3bbl	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 prospects evaluated in this report were aggregated by the arithmetic summation method, as required by the PRMS, and are presented in the prospective resources tables in this report.
7. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.

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

Professional Qualifications

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

The evaluation has been supervised by Mr. Regnald A. Boles, an Executive Vice President 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 40 years of oil and gas industry experience.

Submitted,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

Regnald A. Boles

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

TABLE A-1
SUMMARY PROJECTION of PROVED DEVELOPED RESERVES and REVENUE
as of
DECEMBER 31, 2023
attributable to
STAR ENERGY GROUP PLC
UNITED KINGDOM

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

Base Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2024	712	0	146	120	58,038	29,322	4,569	24,147	22,888
2025	685	0	121	121	53,105	29,068	3,308	20,729	17,786
2026	626	0	79	266	48,369	28,220	3,375	16,774	13,027
2027	576	0	47	329	43,467	27,327	2,505	13,635	9,587
2028	527	0	21	328	40,563	25,553	7,022	7,988	5,085
2029	480	0	1	309	37,625	20,388	6,737	10,500	6,051
2030	437	0	0	215	34,485	18,585	1,560	14,340	7,480
2031	404	0	0	196	32,584	18,184	1,724	12,676	5,984
2032	379	0	0	180	30,899	15,950	2,371	12,578	5,374
2033	344	0	0	163	29,168	15,360	0	13,808	5,341
2034	324	0	0	148	27,654	14,779	0	12,875	4,509
2035	292	0	0	134	26,164	14,227	0	11,937	3,784
2036	272	0	0	122	24,810	13,732	0	11,078	3,179
2037	229	0	0	110	21,757	11,436	10,310	11	1
2038	215	0	0	99	20,892	11,162	0	9,730	2,289
2039	194	0	0	89	19,578	10,416	1,390	7,772	1,654
2040	182	0	0	80	18,846	10,189	0	8,657	1,668
2041	171	0	0	71	18,048	9,952	0	8,096	1,411
2042	158	0	0	64	17,406	9,780	0	7,626	1,204
2043	150	0	0	55	16,797	9,623	0	7,174	1,024
2044	139	0	0	26	15,750	9,385	0	6,365	825
2045	118	0	0	18	13,403	7,680	27,291	(21,568)	(2,526)
2046	109	0	0	15	12,707	7,526	0	5,181	548
2047	100	0	0	12	11,707	6,961	3,551	1,195	115
2048	91	0	0	7	11,091	6,812	0	4,279	372
Subtotal	**7,914**	**0**	**415**	**3,277**	**684,913**	**381,617**	**75,713**	**227,583**	**118,660**
Remaining	784	0	0	7	96,909	71,975	49,875	(24,941)	(23)
Total	**8,698**	**0**	**415**	**3,284**	**781,822**	**453,592**	**125,588**	**202,642**	**118,637**

Present Worth at (10^3U.S.$)	
8 Percent	131,922
12 Percent	107,438
15 Percent	93,841

TABLE A-2
SUMMARY PROJECTION of TOTAL PROVED RESERVES and REVENUE
as of
DECEMBER 31, 2023
attributable to
STAR ENERGY GROUP PLC
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

Base Case

	Net								
Year	Oil (10^3bbl)	Condensate (10^3bbl)	Sales Gas Export (10^6ft^3)	Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2024	712	0	146	120	58,038	29,322	28,265	451	427
2025	713	0	121	121	55,139	29,244	12,440	13,455	11,544
2026	732	0	79	671	60,157	29,786	13,194	17,177	13,340
2027	729	0	47	734	57,799	29,243	2,505	26,051	18,318
2028	669	0	21	733	54,327	27,426	7,022	19,879	12,654
2029	610	0	1	714	50,833	22,216	6,737	21,880	12,607
2030	556	0	0	620	47,201	20,376	1,560	25,265	13,176
2031	515	0	0	238	41,301	19,072	1,724	20,505	9,678
2032	480	0	0	180	38,710	16,691	2,371	19,648	8,397
2033	436	0	0	163	36,498	16,052	0	20,446	7,908
2034	409	0	0	148	34,614	15,430	0	19,184	6,718
2035	371	0	0	134	32,763	14,837	0	17,926	5,683
2036	344	0	0	122	31,083	14,304	0	16,779	4,815
2037	296	0	0	110	27,699	11,972	10,310	5,417	1,405
2038	275	0	0	99	26,539	11,665	0	14,874	3,497
2039	250	0	0	89	24,932	10,889	1,390	12,653	2,692
2040	234	0	0	80	23,934	10,634	0	13,300	2,565
2041	219	0	0	71	22,869	10,367	0	12,502	2,178
2042	202	0	0	64	21,987	10,171	0	11,816	1,864
2043	189	0	0	55	21,137	9,989	0	11,148	1,594
2044	177	0	0	26	19,834	9,731	0	10,103	1,308
2045	152	0	0	18	17,232	8,003	27,291	(18,062)	(2,115)
2046	141	0	0	15	16,308	7,831	0	8,477	897
2047	129	0	0	12	15,086	7,245	3,551	4,290	412
2048	118	0	0	7	14,210	7,077	0	7,133	619
Subtotal	**9,658**	**0**	**415**	**5,344**	**850,230**	**399,573**	**118,360**	**332,297**	**142,181**
Remaining	1,062	0	0	7	131,424	84,582	49,875	(3,033)	1,290
Total	**10,720**	**0**	**415**	**5,351**	**981,654**	**484,155**	**168,235**	**329,264**	**143,471**

Present Worth at (10^3U.S.$)	
8 Percent	166,828
12 Percent	124,504
15 Percent	102,237

TABLE A-3
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE RESERVES and REVENUE
as of
DECEMBER 31, 2023
attributable to
STAR ENERGY GROUP PLC
UNITED KINGDOM

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

Base Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2024	745	0	146	120	60,660	30,061	28,265	2,334	2,212
2025	772	0	146	121	59,785	30,008	12,440	17,337	14,879
2026	830	0	122	721	68,077	31,106	13,194	23,777	18,467
2027	856	0	81	734	66,926	30,702	2,505	33,719	23,705
2028	814	0	50	733	64,797	29,224	7,022	28,551	18,169
2029	752	0	24	734	61,793	24,240	1,876	35,677	20,556
2030	711	0	4	733	59,572	23,467	0	36,105	18,830
2031	659	0	0	660	56,374	22,030	3,315	31,029	14,649
2032	618	0	0	661	54,243	19,487	7,530	27,226	11,637
2033	575	0	0	651	52,291	18,902	0	33,389	12,911
2034	548	0	0	633	50,970	18,436	0	32,534	11,394
2035	511	0	0	617	49,667	17,986	0	31,681	10,042
2036	488	0	0	604	48,561	17,586	0	30,975	8,886
2037	450	0	0	589	46,810	16,988	0	29,822	7,747
2038	423	0	0	576	45,595	16,602	0	28,993	6,815
2039	396	0	0	399	42,533	15,781	0	26,752	5,693
2040	375	0	0	148	38,557	14,721	0	23,836	4,589
2041	353	0	0	137	37,091	14,312	0	22,779	3,975
2042	310	0	0	127	34,106	12,042	11,383	10,681	1,685
2043	291	0	0	116	32,790	11,376	1,504	19,910	2,845
2044	275	0	0	110	31,752	11,184	0	20,568	2,661
2045	261	0	0	99	30,599	10,967	0	19,632	2,299
2046	249	0	0	57	29,091	10,656	0	18,435	1,953
2047	239	0	0	49	28,071	10,515	0	17,556	1,686
2048	222	0	0	43	27,214	10,348	0	16,866	1,465
Subtotal	**12,723**	**0**	**573**	**10,172**	**1,177,925**	**468,727**	**89,034**	**620,164**	**229,750**
Remaining	2,848	0	0	252	355,806	154,236	83,473	118,097	4,994
Total	**15,571**	**0**	**573**	**10,424**	**1,533,731**	**622,963**	**172,507**	**738,261**	**234,744**

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	281,714
12 Percent	198,765
15 Percent	158,732

TABLE A-4
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE RESERVES and REVENUE
as of
DECEMBER 31, 2023
attributable to
STAR ENERGY GROUP PLC
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

Base Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2024	755	0	146	120	61,445	30,282	28,265	2,898	2,743
2025	800	0	146	121	61,913	30,394	12,440	19,079	16,375
2026	896	0	146	733	73,108	31,944	13,194	27,970	21,720
2027	983	0	122	734	76,000	32,090	2,505	41,405	29,117
2028	933	0	83	733	73,827	30,628	7,022	36,177	23,023
2029	884	0	52	734	71,408	25,936	1,876	43,596	25,113
2030	828	0	27	733	68,526	24,894	0	43,632	22,759
2031	783	0	7	733	66,391	24,492	1,724	40,175	18,961
2032	740	0	0	661	63,958	21,622	3,225	39,111	16,716
2033	699	0	0	662	62,042	21,065	0	40,977	15,851
2034	667	0	0	659	60,746	20,554	0	40,192	14,076
2035	623	0	0	660	59,699	20,174	0	39,525	12,526
2036	596	0	0	661	58,535	19,510	5,584	33,441	9,592
2037	561	0	0	661	57,499	19,154	0	38,345	9,962
2038	527	0	0	660	56,278	18,521	866	36,891	8,673
2039	502	0	0	647	55,251	18,203	0	37,048	7,885
2040	478	0	0	632	54,370	17,915	0	36,455	7,023
2041	452	0	0	618	52,984	17,468	0	35,516	6,191
2042	422	0	0	604	51,720	17,087	0	34,633	5,470
2043	405	0	0	590	50,823	16,857	0	33,966	4,850
2044	382	0	0	581	49,652	16,654	0	32,998	4,270
2045	363	0	0	567	47,902	16,253	0	31,649	3,707
2046	325	0	0	558	44,500	13,842	12,322	18,336	1,943
2047	317	0	0	547	43,477	13,705	0	29,772	2,856
2048	295	0	0	491	41,962	13,389	0	28,573	2,481
Subtotal	**15,216**	**0**	**729**	**15,100**	**1,464,016**	**532,633**	**89,023**	**842,360**	**293,883**
Remaining	4,481	0	0	2,008	583,106	214,537	86,942	281,627	12,002
Total	**19,697**	**0**	**729**	**17,108**	**2,047,122**	**747,170**	**175,965**	**1,123,987**	**305,885**

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	373,904
12 Percent	255,255
15 Percent	200,495

TABLE A-5
SUMMARY PROJECTION of PROVED DEVELOPED RESERVES and REVENUE
as of
DECEMBER 31, 2023
attributable to
STAR ENERGY GROUP PLC
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

Low Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2024	712	0	146	120	52,237	29,322	4,569	18,346	17,391
2025	679	0	121	121	47,381	28,720	7,799	10,862	9,320
2026	620	0	79	266	43,170	27,880	3,375	11,915	9,250
2027	571	0	47	329	38,789	26,994	2,505	9,290	6,533
2028	522	0	21	328	36,198	25,224	7,022	3,952	2,520
2029	480	0	0	236	33,246	19,702	2,681	10,863	6,256
2030	437	0	0	215	31,037	18,585	739	11,713	6,109
2031	404	0	0	196	29,325	18,184	1,724	9,417	4,446
2032	379	0	0	180	27,805	15,950	2,371	9,484	4,053
2033	344	0	0	163	26,253	15,360	0	10,893	4,214
2034	324	0	0	148	24,886	14,779	0	10,107	3,538
2035	292	0	0	134	23,549	14,227	0	9,322	2,956
2036	240	0	0	122	19,889	11,207	11,418	(2,736)	(783)
2037	222	0	0	110	19,074	10,905	0	8,169	2,121
2038	210	0	0	99	18,332	10,652	0	7,680	1,804
2039	194	0	0	89	17,623	10,416	0	7,207	1,534
2040	182	0	0	80	16,961	10,189	0	6,772	1,306
2041	171	0	0	71	16,244	9,952	0	6,292	1,096
2042	150	0	0	64	14,900	8,995	17,986	(12,081)	(1,908)
2043	137	0	0	55	13,839	8,297	6,071	(529)	(73)
2044	124	0	0	26	12,747	7,850	1,851	3,046	393
2045	114	0	0	18	11,595	7,204	3,412	979	113
2046	104	0	0	15	10,993	7,049	0	3,944	419
2047	100	0	0	12	10,536	6,961	0	3,575	342
2048	91	0	0	7	9,982	6,812	0	3,170	275
Subtotal	**7,803**	**0**	**414**	**3,204**	**606,591**	**371,416**	**73,523**	**161,652**	**83,225**
Remaining	659	0	0	7	73,281	57,249	49,875	(33,843)	(865)
Total	**8,462**	**0**	**414**	**3,211**	**679,872**	**428,665**	**123,398**	**127,809**	**82,360**

Present Worth at (10^3U.S.$)	
8 Percent	91,090
12 Percent	74,800
15 Percent	65,431

TABLE A-6
SUMMARY PROJECTION of TOTAL PROVED RESERVES and REVENUE
as of
DECEMBER 31, 2023
attributable to
STAR ENERGY GROUP PLC
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

Low Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2024	712	0	146	120	52,237	29,322	28,265	(5,350)	(5,068)
2025	707	0	121	121	49,213	28,896	16,931	3,386	2,903
2026	726	0	79	671	53,778	29,446	13,194	11,138	8,648
2027	724	0	47	734	51,689	28,910	2,505	20,274	14,254
2028	664	0	21	733	48,584	27,097	7,022	14,465	9,213
2029	610	0	0	641	45,133	21,530	2,681	20,922	12,051
2030	556	0	0	620	42,483	20,376	739	21,368	11,144
2031	515	0	0	238	37,168	19,072	1,724	16,372	7,728
2032	480	0	0	180	34,839	16,691	2,371	15,777	6,742
2033	436	0	0	163	32,848	16,052	0	16,796	6,498
2034	409	0	0	148	31,151	15,430	0	15,721	5,503
2035	371	0	0	134	29,487	14,837	0	14,650	4,644
2036	312	0	0	122	25,536	11,779	11,418	2,339	674
2037	289	0	0	110	24,421	11,442	0	12,979	3,371
2038	270	0	0	99	23,414	11,154	0	12,260	2,881
2039	250	0	0	89	22,441	10,889	0	11,552	2,459
2040	234	0	0	80	21,541	10,634	0	10,907	2,102
2041	219	0	0	71	20,583	10,367	0	10,216	1,781
2042	194	0	0	64	19,021	9,386	17,986	(8,351)	(1,320)
2043	176	0	0	55	17,748	8,663	6,071	3,014	434
2044	162	0	0	26	16,421	8,196	1,851	6,374	822
2045	148	0	0	18	15,040	7,527	3,412	4,101	479
2046	136	0	0	15	14,235	7,354	0	6,881	730
2047	129	0	0	12	13,575	7,245	0	6,330	606
2048	118	0	0	7	12,791	7,077	0	5,714	498
Subtotal	**9,547**	**0**	**414**	**5,271**	**755,377**	**389,372**	**116,170**	**249,835**	**99,777**
Remaining	988	0	0	7	110,004	75,875	49,875	(15,746)	535
Total	**10,535**	**0**	**414**	**5,278**	**865,381**	**465,247**	**166,045**	**234,089**	**100,312**

Present Worth at (10^3U.S.$)	
8 Percent	118,005
12 Percent	85,862
15 Percent	68,855

TABLE A-7
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE RESERVES and REVENUE
as of
DECEMBER 31, 2023
attributable to
STAR ENERGY GROUP PLC
UNITED KINGDOM

DeGOLYER AND MacNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

Low Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2024	745	0	146	120	54,596	30,061	28,265	(3,730)	(3,534)
2025	772	0	146	121	53,808	30,008	12,440	11,360	9,748
2026	830	0	122	721	61,273	31,106	13,194	16,973	13,181
2027	856	0	81	734	60,227	30,702	2,505	27,020	18,999
2028	814	0	50	733	58,312	29,224	7,022	22,066	14,045
2029	748	0	24	734	55,295	23,909	6,737	24,649	14,199
2030	706	0	0	660	52,650	22,427	821	29,402	15,334
2031	655	0	0	660	50,446	21,705	2,478	26,263	12,399
2032	618	0	0	661	48,811	19,487	2,371	26,953	11,519
2033	575	0	0	651	47,062	18,902	0	28,160	10,892
2034	548	0	0	633	45,869	18,436	0	27,433	9,604
2035	511	0	0	617	44,702	17,986	0	26,716	8,469
2036	488	0	0	604	43,700	17,586	0	26,114	7,494
2037	450	0	0	589	42,129	16,988	0	25,141	6,529
2038	423	0	0	576	41,037	16,602	0	24,435	5,743
2039	396	0	0	399	38,279	15,781	0	22,498	4,790
2040	375	0	0	148	34,702	14,721	0	19,981	3,847
2041	327	0	0	137	31,022	11,788	12,606	6,628	1,157
2042	305	0	0	127	30,260	11,573	0	18,687	2,949
2043	291	0	0	116	29,508	11,376	0	18,132	2,592
2044	275	0	0	110	28,579	11,184	0	17,395	2,251
2045	261	0	0	99	27,536	10,967	0	16,569	1,939
2046	240	0	0	57	25,328	9,799	19,468	(3,939)	(418)
2047	231	0	0	49	24,448	9,663	0	14,785	1,419
2048	207	0	0	43	22,914	8,671	8,707	5,536	481
Subtotal	**12,647**	**0**	**569**	**10,099**	**1,052,493**	**460,652**	**116,614**	**475,227**	**175,628**
Remaining	2,763	0	0	252	310,456	143,923	53,770	112,763	5,835
Total	**15,410**	**0**	**569**	**10,351**	**1,362,949**	**604,575**	**170,384**	**587,990**	**181,463**

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	219,673
12 Percent	152,217
15 Percent	119,742

TABLE A-8
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE RESERVES and REVENUE
as of
DECEMBER 31, 2023
attributable to
STAR ENERGY GROUP PLC
UNITED KINGDOM

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

Low Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2024	755	0	146	120	55,301	30,282	28,265	(3,246)	(3,076)
2025	800	0	146	121	55,725	30,394	12,440	12,891	11,061
2026	896	0	146	733	65,797	31,944	13,194	20,659	16,047
2027	983	0	122	734	68,398	32,090	2,505	33,803	23,767
2028	933	0	83	733	66,443	30,628	7,022	28,793	18,322
2029	884	0	52	734	64,267	25,936	1,876	36,455	21,003
2030	828	0	27	733	61,677	24,894	0	36,783	19,184
2031	783	0	0	660	59,050	23,749	2,561	32,740	15,455
2032	736	0	0	661	57,225	21,289	7,530	28,406	12,141
2033	695	0	0	662	55,521	20,734	0	34,787	13,454
2034	658	0	0	659	54,061	19,902	800	33,359	11,682
2035	615	0	0	660	53,132	19,516	0	33,616	10,655
2036	592	0	0	661	52,369	19,173	0	33,196	9,524
2037	557	0	0	661	51,423	18,810	0	32,613	8,469
2038	527	0	0	660	50,651	18,521	0	32,130	7,555
2039	502	0	0	647	49,722	18,203	0	31,519	6,710
2040	478	0	0	632	48,939	17,915	0	31,024	5,975
2041	452	0	0	618	47,678	17,468	0	30,210	5,269
2042	422	0	0	604	46,550	17,087	0	29,463	4,650
2043	405	0	0	590	45,742	16,857	0	28,885	4,127
2044	382	0	0	581	44,691	16,654	0	28,037	3,628
2045	342	0	0	567	40,956	14,018	12,080	14,858	1,739
2046	325	0	0	558	40,050	13,842	0	26,208	2,779
2047	317	0	0	547	39,127	13,705	0	25,422	2,437
2048	295	0	0	491	37,771	13,389	0	24,382	2,119
Subtotal	**15,162**	**0**	**722**	**15,027**	**1,312,266**	**527,000**	**88,273**	**696,993**	**234,676**
Remaining	4,406	0	0	2,008	516,632	205,938	86,513	224,181	9,310
Total	**19,568**	**0**	**722**	**17,035**	**1,828,898**	**732,938**	**174,786**	**921,174**	**243,986**

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	300,439
12 Percent	201,998
15 Percent	156,676

TABLE A-9
SUMMARY PROJECTION of PROVED DEVELOPED RESERVES and REVENUE
as of
DECEMBER 31, 2023
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)	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.$)
2024	712	0	146	120	63,834	29,322	4,569	29,943	28,385
2025	685	0	121	121	58,418	29,068	3,308	26,042	22,343
2026	626	0	79	266	53,210	28,220	3,375	21,615	16,787
2027	576	0	47	329	47,812	27,327	2,505	17,980	12,643
2028	527	0	21	328	44,624	25,553	7,022	12,049	7,671
2029	480	0	1	309	41,390	20,388	6,737	14,265	8,215
2030	437	0	0	215	37,930	18,585	1,560	17,785	9,279
2031	404	0	0	196	35,842	18,184	1,724	15,934	7,522
2032	379	0	0	180	33,990	15,950	2,371	15,669	6,695
2033	344	0	0	163	32,086	15,360	0	16,726	6,470
2034	324	0	0	148	30,416	14,779	0	15,637	5,475
2035	292	0	0	134	28,783	14,227	0	14,556	4,614
2036	272	0	0	122	27,291	13,732	0	13,559	3,890
2037	229	0	0	110	23,928	11,436	10,310	2,182	566
2038	215	0	0	99	22,979	11,162	0	11,817	2,780
2039	194	0	0	89	21,539	10,416	1,390	9,733	2,070
2040	182	0	0	80	20,731	10,189	0	10,542	2,031
2041	171	0	0	71	19,852	9,952	0	9,900	1,725
2042	158	0	0	64	19,149	9,780	0	9,369	1,481
2043	150	0	0	55	18,473	9,623	0	8,850	1,265
2044	139	0	0	26	17,328	9,385	0	7,943	1,026
2045	118	0	0	18	14,744	7,680	27,291	(20,227)	(2,366)
2046	109	0	0	15	13,980	7,526	0	6,454	684
2047	100	0	0	12	12,876	6,961	3,551	2,364	226
2048	91	0	0	7	12,199	6,812	0	5,387	468
Subtotal	**7,914**	**0**	**415**	**3,277**	**753,404**	**381,617**	**75,713**	**296,074**	**151,945**
Remaining	784	0	0	7	106,607	71,975	49,875	(15,243)	454
Total	**8,698**	**0**	**415**	**3,284**	**860,011**	**453,592**	**125,588**	**280,831**	**152,399**

Present Worth at (10^3U.S.$)	
8 Percent	170,180
12 Percent	137,644
15 Percent	119,936

TABLE A-10
SUMMARY PROJECTION of TOTAL PROVED RESERVES and REVENUE
as of
DECEMBER 31, 2023
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)	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.$)
2024	712	0	146	120	63,834	29,322	28,265	6,247	5,926
2025	713	0	121	121	60,656	29,244	12,440	18,972	16,275
2026	732	0	79	671	66,177	29,786	13,194	23,197	18,018
2027	729	0	47	734	63,581	29,243	2,505	31,833	22,380
2028	669	0	21	733	59,768	27,426	7,022	25,320	16,117
2029	610	0	1	714	55,919	22,216	6,737	26,966	15,533
2030	556	0	0	620	51,914	20,376	1,560	29,978	15,638
2031	515	0	0	238	45,430	19,072	1,724	24,634	11,627
2032	480	0	0	180	42,586	16,691	2,371	23,524	10,052
2033	436	0	0	163	40,145	16,052	0	24,093	9,321
2034	409	0	0	148	38,072	15,430	0	22,642	7,928
2035	371	0	0	134	36,043	14,837	0	21,206	6,721
2036	344	0	0	122	34,191	14,304	0	19,887	5,707
2037	296	0	0	110	30,466	11,972	10,310	8,184	2,123
2038	275	0	0	99	29,191	11,665	0	17,526	4,122
2039	250	0	0	89	27,427	10,889	1,390	15,148	3,225
2040	234	0	0	80	26,327	10,634	0	15,693	3,023
2041	219	0	0	71	25,156	10,367	0	14,789	2,579
2042	202	0	0	64	24,187	10,171	0	14,016	2,212
2043	189	0	0	55	23,251	9,989	0	13,262	1,896
2044	177	0	0	26	21,819	9,731	0	12,088	1,562
2045	152	0	0	18	18,956	8,003	27,291	(16,338)	(1,912)
2046	141	0	0	15	17,939	7,831	0	10,108	1,072
2047	129	0	0	12	16,591	7,245	3,551	5,795	555
2048	118	0	0	7	15,633	7,077	0	8,556	744
Subtotal	**9,658**	**0**	**415**	**5,344**	**935,259**	**399,573**	**118,360**	**417,326**	**182,444**
Remaining	1,062	0	0	7	144,574	84,582	49,875	10,117	1,923
Total	**10,720**	**0**	**415**	**5,351**	**1,079,833**	**484,155**	**168,235**	**427,443**	**184,367**

Present Worth at (10^3U.S.$)	
8 Percent	213,460
12 Percent	160,871
15 Percent	133,378

TABLE A-11
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE RESERVES and REVENUE
as of
DECEMBER 31, 2023
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)	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.$)
2024	745	0	146	120	66,721	30,061	28,265	8,395	7,959
2025	772	0	146	121	65,767	30,008	12,440	23,319	20,008
2026	830	0	122	721	74,888	31,106	13,194	30,588	23,759
2027	856	0	81	734	73,618	30,702	2,505	40,411	28,413
2028	814	0	50	733	71,282	29,224	7,022	35,036	22,297
2029	752	0	24	734	67,976	24,240	1,876	41,860	24,116
2030	711	0	4	733	65,523	23,467	0	42,056	21,934
2031	659	0	0	660	62,012	22,030	3,315	36,667	17,308
2032	618	0	0	661	59,669	19,487	7,530	32,652	13,955
2033	575	0	0	651	57,518	18,902	0	38,616	14,935
2034	548	0	0	633	56,066	18,436	0	37,630	13,175
2035	511	0	0	617	54,634	17,986	0	36,648	11,618
2036	488	0	0	604	53,417	17,586	0	35,831	10,280
2037	450	0	0	589	51,485	16,988	0	34,497	8,960
2038	423	0	0	576	50,149	16,602	0	33,547	7,887
2039	396	0	0	399	46,788	15,781	0	31,007	6,597
2040	375	0	0	148	42,416	14,721	0	27,695	5,336
2041	353	0	0	137	40,799	14,312	0	26,487	4,620
2042	310	0	0	127	37,518	12,042	11,383	14,093	2,223
2043	291	0	0	116	36,070	11,376	1,504	23,190	3,315
2044	275	0	0	110	34,928	11,184	0	23,744	3,070
2045	261	0	0	99	33,660	10,967	0	22,693	2,659
2046	249	0	0	57	32,001	10,656	0	21,345	2,262
2047	239	0	0	49	30,880	10,515	0	20,365	1,955
2048	222	0	0	43	29,933	10,348	0	19,585	1,699
Subtotal	**12,723**	**0**	**573**	**10,172**	**1,295,718**	**468,727**	**89,034**	**737,957**	**280,340**
Remaining	2,848	0	0	252	391,410	154,236	83,473	153,701	6,402
Total	**15,571**	**0**	**573**	**10,424**	**1,687,128**	**622,963**	**172,507**	**891,658**	**286,742**

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	342,445
12 Percent	244,114
15 Percent	196,666

TABLE A-12
SUMMARY PROJECTION of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE RESERVES and REVENUE
as of
DECEMBER 31, 2023
attributable to
STAR ENERGY GROUP PLC
UNITED KINGDOM

DeGolyer and MacNaughton
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TEXAS REGISTERED ENGINEERING FIRM

High Case

Year	Net Oil (10^3bbl)	Net Condensate (10^3bbl)	Net Sales Gas Export (10^6ft^3)	Net Sales Gas to Power (10^6ft^3)	Future Gross Revenue (10^3U.S.$)	Operating Expenses (10^3U.S.$)	Abandonment and Capital Costs (10^3U.S.$)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)
2024	755	0	146	120	67,583	30,282	28,265	9,036	8,563
2025	800	0	146	121	68,106	30,394	12,440	25,272	21,688
2026	896	0	146	733	80,425	31,944	13,194	35,287	27,404
2027	983	0	122	734	83,603	32,090	2,505	49,008	34,459
2028	933	0	83	733	81,217	30,628	7,022	43,567	27,726
2029	884	0	52	734	78,547	25,936	1,876	50,735	29,229
2030	828	0	27	733	75,373	24,894	0	50,479	26,328
2031	783	0	7	733	73,024	24,492	1,724	46,808	22,097
2032	740	0	0	661	70,360	21,622	3,225	45,513	19,447
2033	699	0	0	662	68,248	21,065	0	47,183	18,251
2034	667	0	0	659	66,815	20,554	0	46,261	16,200
2035	623	0	0	660	65,671	20,174	0	45,497	14,419
2036	596	0	0	661	64,393	19,510	5,584	39,299	11,277
2037	561	0	0	661	63,239	19,154	0	44,085	11,450
2038	527	0	0	660	61,897	18,521	866	42,510	9,992
2039	502	0	0	647	60,777	18,203	0	42,574	9,062
2040	478	0	0	632	59,813	17,915	0	41,898	8,072
2041	452	0	0	618	58,277	17,468	0	40,809	7,117
2042	422	0	0	604	56,896	17,087	0	39,809	6,285
2043	405	0	0	590	55,904	16,857	0	39,047	5,579
2044	382	0	0	581	54,620	16,654	0	37,966	4,910
2045	363	0	0	567	52,694	16,253	0	36,441	4,266
2046	325	0	0	558	48,950	13,842	12,322	22,786	2,416
2047	317	0	0	547	47,824	13,705	0	34,119	3,274
2048	295	0	0	491	46,165	13,389	0	32,776	2,845
Subtotal	**15,216**	**0**	**729**	**15,100**	**1,610,421**	**532,633**	**89,023**	**988,765**	**352,356**
Remaining	4,481	0	0	2,008	641,455	214,537	86,942	339,976	14,248
Total	**19,697**	**0**	**729**	**17,108**	**2,251,876**	**747,170**	**175,965**	**1,328,741**	**366,604**

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	446,054
12 Percent	307,474
15 Percent	243,463

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TABLE A-13
PROSPECT PORTFOLIO SUMMARY
as of
DECEMBER 31, 2023
for
STAR ENERGY GROUP PLC
in the
LEA PROSPECT
PEDL 316 BLOCK
UNITED KINGDOM

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

TABLE A-14
ESTIMATE of the GROSS PROSPECTIVE OIL RESOURCES
as of
DECEMBER 31, 2023
for
STAR ENERGY GROUP PLC
in the
LEA PROSPECT
PEDL 316 BLOCK
UNITED KINGDOM

DeGolyer and MacNaughton
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				Gross Prospective Oil Resources Summary					
Prospect	**Country**	**Area/Basin**	**License/Block**	**1U (Low) Estimate (10^3bbl)**	**2U (Best) Estimate (10^3bbl)**	**3U (High) Estimate (10^3bbl)**	**Mean Estimate (10^3bbl)**	**Probability of Geologic Success, P_g (decimal)**	**P_g-Adjusted Mean Estimate (10^3bbl)**
Lea	United Kingdom	East Midlands	PEDL 316	606	1,638	3,931	2,048	0.180	369
Statistical Aggregate				**606**	**1,638**	**3,931**	**2,048**	**0.180**	**369**
Arithmetic Summation				606	1,638	3,931	2,048	0.180	369

Notes:
1. 1U (Low), 2U (Best), 3U (High), and mean estimates follow the PRMS guidelines for prospective resources.
2. 1U (Low), 2U (Best), 3U (High), and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean respectively.
3. P_g is defined as the probability of discovering reservoirs which exceed the minimum case prospective resources recoverable volume(s). P_g is not linked to economically viable volumes, economic flow rates, or economic field size assumptions.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of probabilistic estimates is presented in this table in compliance with PRMS guidelines.
8. Summations may vary from those shown here due to rounding.
9. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.
10. The range in P_{mean} for the statistical aggregate P_g-adjusted mean estimate is 0.07 to 0.10.

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TABLE A-15
ESTIMATE of the WORKING INTEREST PROSPECTIVE OIL RESOURCES
as of
DECEMBER 31, 2023
for
STAR ENERGY GROUP PLC
in the
LEA PROSPECT
PEDL 316 BLOCK
UNITED KINGDOM

				Working Interest Prospective Oil Resources Summary					
Prospect	**Country**	**Area/Basin**	**License/Block**	**1U (Low) Estimate (10^3bbl)**	**2U (Best) Estimate (10^3bbl)**	**3U (High) Estimate (10^3bbl)**	**Mean Estimate (10^3bbl)**	**Probability of Geologic Success, P_g (decimal)**	**P_g-Adjusted Mean Estimate (10^3bbl)**
Lea	United Kingdom	East Midlands	PEDL 316	212	573	1,376	717	0.180	129
Statistical Aggregate				**212**	**573**	**1,376**	**717**	**0.180**	**129**
Arithmetic Summation				212	573	1,376	717	0.180	129

Notes:

1. 1U (Low), 2U (Best), 3U (High), and mean estimates follow the PRMS guidelines for prospective resources.
2. 1U (Low), 2U (Best), 3U (High), and mean estimates in this table are P_{90}, P_{50}, P_{10}, and mean respectively.
3. P_g is defined as the probability of discovering reservoirs which exceed the minimum case prospective resources recoverable volume(s). P_g is not linked to economically viable volumes, economic flow rates, or economic field size assumptions.
4. P_g has been rounded for presentation purposes. Multiplication using this presented P_g may yield imprecise results. Dividing the P_g-adjusted mean estimate by the mean estimate yields the precise P_g.
5. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.
6. Recovery efficiency is applied to prospective resources in this table.
7. Arithmetic summation of probabilistic estimates produces invalid results except for the mean estimate. Arithmetic summation of probabilistic estimates is presented in this table in compliance with PRMS guidelines.
8. Summations may vary from those shown here due to rounding.
9. There is no certainty that any portion of the prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources evaluated.
10. The range in P_{mean} for the statistical aggregate P_g-adjusted mean estimate is 0.07 to 0.10.

TABLE A-16
PROBABILITY DISTRIBUTIONS
for
MONTE CARLO SIMULATION
as of
DECEMBER 31, 2023
for
STAR ENERGY GROUP PLC
in the
LEA PROSPECT
PEDL 316 BLOCK
UNITED KINGDOM

DeGolyer and MacNaughton
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TEXAS REGISTERED ENGINEERING FIRM

Prospect	Potential Target	Parameter	P_{100}	P_{90}	P_{50}	P_{10}	P_0	Mean
Lea	Westphalian Eagle Sandstone	Productive area, acres	107	193	301	464	671	316
		Net hydrocarbon thickness, feet	16.42	31.00	56.28	101.84	181.38	62.30
		Porosity, decimal	0.090	0.110	0.140	0.170	0.190	0.140
		Oil saturation, decimal	0.401	0.461	0.550	0.639	0.699	0.550
		Formation volume factor, Bo	1.315	1.223	1.150	1.076	0.986	1.150
		Recovery efficiency, decimal	0.050	0.109	0.191	0.306	0.393	0.200
		Prospective OOIP, barrels	1,135,875	3,768,624	8,652,833	19,613,361	50,696,615	10,240,423
		Prospective gross ultimate recovery, barrels	144,919	606,284	1,637,952	3,931,267	14,711,688	2,048,085

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.