UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2023
OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission file number: 1-32167

VAALCO Energy, Inc.
(Exact name of registrant as specified on its charter)

Delaware	**76-0274813**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

9800 Richmond Avenue
Suite 700
Houston , Texas 77042
(Address of principal executive offices) (Zip Code)

(Registrant's telephone number, including area code): (713) 623-0801

Securities registered under Section 12(b) of the Exchange Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, par value $0.10	EGY	New York Stock Exchange
Common Stock, par value $0.10	EGY	London Stock Exchange

Securities registered under Section 12(g) of the Exchange Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15d of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,”, “smaller reporting company” and “emerging growth company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☒	Non-accelerated filer ☐	Smaller reporting company ☐

Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management’s assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant’s executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes☐ No ☒

As of June 30, 2023, the aggregate market value of the voting and non-voting common equity of the registrant held by non-affiliates was approximately $396.6 million based on a closing price of $3.76 on June 30, 2023.

As of March 8, 2024, there were outstanding 103,274,173 shares of common stock, $0.10 par value per share, of the registrant.

Documents incorporated by reference: Portions of the definitive Proxy Statement of VAALCO Energy, Inc. relating to the Annual Meeting of Stockholders to be filed within 120 days after the end of the fiscal year covered by this Form 10-K, which are incorporated into Part III of this Form 10-K.

VAALCO ENERGY, INC.

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Glossary of Certain Crude Oil, Natural Gas and Natural Gas Liquid ("NGL") Terms

Terms used to describe quantities of crude oil, natural gas and NGLs

- *Bbl* — One stock tank barrel, or 42 United States ("U.S.") gallons liquid volume, of crude oil or other liquid hydrocarbons.
- *Bbl/d* — Barrels per day
- *Bcf* — One billion cubic feet
- *Boe* — Barrel of oil equivalent. Volumes of natural gas converted to barrels of oil using a conversion factor of 6,000 cubic feet of natural gas to one barrel of oil.
- *BOEPD* — One Boe per day
- *BOPD* — One Bbl per day.
- *Km^2* — Square Kilometers
- *M^3* — Cubic Meters
- *MBbl* — One thousand Bbls.
- *MMBbl* — One million Bbls
- *MBoe* — One thousand Boes.
- *MMBoe* — One million Boes.
- *MBopd* — One thousand Bbls per day.
- *MBOEPD* – One thousand Boes per day.
- *MCF* — One thousand cubic feet.
- *MCFD* — One thousand cubic feet per day.
- *MMBTU* – One million British Thermal Units.
- *MMcf* — One million cubic feet.
- *NGLs* — Natural Gas Liquids.
- *NRI* — working interest volumes less royalty volumes, where applicable.
- *WI* — working interest volumes.

Terms used to describe legal ownership of crude oil, natural gas and NGLs properties, and other terms applicable to our operations

- *Arta* — The Arta field in the West Gharib concession in the Egyptian Eastern Desert.
- *BWE Consortium* — A consortium of the Company, BW Energy and Panoro Energy provisionally awarded two blocks, G12-13 and H12-13, in the 12th Offshore Licensing Round in Gabon.
- *C$* — means Canadian dollars.
- *Cardium* — The Cardium formation that spans a large area from southwest Alberta to northeast British Columbia, with the producing area concentrated along the eastern slopes of the Rocky Mountains to the northwest of Calgary.
- *Carried interest* — Working Interest (as defined below) where the carried interest owner's share of costs is paid by the non-carried working interest owners. The carried costs are repaid to the non-carried working interest owners from the revenues of the carried working interest owner.
- *Crown Royalty* — The payments to be made to the Province of Alberta pursuant to the Alberta Crown Agreement or under the generic crown royalty scheme.
- *EGPC* — Egyptian General Petroleum Corporation.
- *Egypt* — Arab Republic of Egypt.
- *Gabon* — Republic of Gabon.
- *Etame Consortium* — A consortium of four companies granted rights and obligations in the Etame Marin block offshore Gabon under the Etame PSC.
- *Merged Concession* — The modernized concession that merged the West Bakr, West Gharib and NW Gharib concessions.
- *Merged Concession Agreement* — The agreement with EGPC for the Merged Concession signed by the Ministry of Petroleum at an official signing ceremony on January 19, 2022.
- *PSC* — A production sharing contract.
- *FPSO* — A floating, production, storage and offloading vessel.
- *FSO* – A floating storage and offloading vessel.
- *NW Gharib* — The North West Gharib Concession area in Egypt.
- *NW Sitra* — The North West Sitra Concession area in Egypt.

- *Participating Interest* — Working Interest (as defined below) attributable to a non-carried interest owner adjusted to include its relative share of the benefits and obligations attributable to carried working interest owners.

  RBL — Reserved based lending facility
- *Royalty interest* — A real property interest entitling the owner to receive a specified portion of the gross proceeds of the sale of crude oil and, natural gas and NGLs production or, if the conveyance creating the interest provides, a specific portion of crude oil and, natural gas and NGLs produced, without any deduction for the costs to explore for, develop or produce the crude oil and, natural gas and NGLs.
- *South Alamain* — The South Alamain Concession area in Egypt.
- *West Bakr* — The West Bakr Concession area in Egypt.
- *West Gharib* — The West Gharib Concession area in Egypt.
- *Working Interest* — A real property interest entitling the owner to receive a specified percentage of the proceeds of the sale of crude oil, natural gas and NGLs production or a percentage of the production, but requiring the owner of the working interest to bear the cost to explore for, develop and produce such crude oil, natural gas and NGLs. A working interest owner who owns a portion of the working interest may participate either as operator or by voting his percentage interest to approve or disapprove the appointment of an operator and drilling and other major activities in connection with the development and operation of a property.
- *$* — means U.S. dollars.
- *Yusr* — The Yusr reservoirs in the West Bakr concession in the Egyptian Eastern Desert.

Terms used to describe interests in wells and acreage

- *Gross crude oil and, natural gas and NGLs wells or acres* — Gross wells or gross acres represent the total number of wells or acres in which a working interest is owned, before consideration of the ownership percentage.
- *Net crude oil and, natural gas and NGLs wells or acres* — Determined by multiplying "gross" wells or acres by the owned working interest.

Terms used to classify reserve quantities

- *Proved developed crude oil and, natural gas and NGLs reserves* — Developed crude oil and, natural gas and NGLs reserves are reserves of any category that can be expected to be recovered:
  (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

  (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.
- *Proved crude oil and, natural gas and NGLs reserves* — Proved crude oil and, natural gas and NGLs reserves are those quantities of crude oil and, natural gas and NGLs, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible (from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations) prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

  (i) The area of the reservoir considered as proved includes:

    (A) The area identified by drilling and limited by fluid contacts, if any, and

    (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible crude oil or natural gas on the basis of available geoscience and engineering data.

  (ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

  (iii) Where direct observation from well penetrations has defined a highest known crude oil (HKO) elevation and the potential exists for an associated natural gas cap, proved crude oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

  (iv) Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection), are included in the proved classification when:

    (A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

    (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

  (v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first day of the month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.
- *Reserves* — Reserves are estimated remaining quantities of crude oil, natural gas, NGLs and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering crude oil, natural gas, NGLs or related substances to market, and all permits and financing required to implement the project.

- *Proved undeveloped crude oil and, natural gas reserve and NGLs reserves, PUDs* — Proved undeveloped crude oil and, natural gas and NGLs reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

  (i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

  (ii) Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

  (iii) Under no circumstances shall estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.
- *Unproved properties* — Properties with no proved reserves.

Terms used to assign a present value to reserves

- *Standardized measure* — The standardized measure of discounted future net cash flows ("standardized measure") is the present value, discounted at an annual rate of 10%, of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC"), using the 12-month unweighted average of first-day-of-the-month Brent prices adjusted for historical marketing differentials, (the "12-month average"), without giving effect to non–property related expenses such as certain general and administrative expenses, debt service, derivatives or to depreciation, depletion and amortization.

Terms used to describe seismic operations

- *Seismic data* — crude oil, natural gas and NGLs companies use seismic data as their principal source of information to locate crude oil, natural gas and NGLs deposits, both to aid in exploration for new deposits and to manage or enhance production from known reservoirs. To gather seismic data, an energy source is used to send sound waves into the subsurface strata. These waves are reflected back to the surface by underground formations, where they are detected by geophones that digitize and record the reflected waves. Computers are then used to process the raw data to develop an image of underground formations.
- *3-D seismic data* — 3-D seismic data is collected using a grid of energy sources, which are generally spread over several miles. A 3-D survey produces a three-dimensional image of the subsurface geology by collecting seismic data along parallel lines and creating a cube of information that can be divided into various planes, thus improving visualization. Consequently, 3-D seismic data is a more reliable indicator of potential crude oil, natural gas and NGLs reservoirs in the area evaluated.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (this "Annual Report") includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), which are intended to be covered by the safe harbors created by those laws. We have based these forward-looking statements on our current expectations and projections about future events. These forward-looking statements include information about possible or assumed future results of our operations. All statements, other than statements of historical facts, included in this Annual Report that address activities, events or developments that we expect or anticipate may occur in the future, including without limitation, statements regarding our financial position, operating performance and results, reserve quantities and net present values, market prices, business strategy, derivative activities, the amount and nature of capital expenditures, payment of dividends and plans and objectives of management for future operations are forward-looking statements. When we use words such as "anticipate," "believe," "estimate," "expect," "intend," "forecast," "outlook," "aim," "target," "will," "could," "should," "may," "likely," "plan," and "probably" or the negative of such terms or similar expressions, we are making forward-looking statements. Many risks and uncertainties that could affect our future results and could cause results to differ materially from those expressed in our forward-looking statements include, but are not limited to:

- volatility of, and declines and weaknesses in crude oil and, natural gas and NGLs prices, as well as our ability to offset volatility in prices through the use of hedging transactions;
- the discovery, acquisition, development and replacement of crude oil, natural gas and NGLs reserves;
- impairments in the value of our crude oil, natural gas and NGLs assets;
- future capital requirements;
- our ability to maintain sufficient liquidity in order to fully implement our business plan;
- our ability to generate cash flows that, along with our cash on hand, will be sufficient to support our operations and cash requirements;
- the ability of the BWE Consortium to successfully execute its business plan;
- our ability to attract capital or obtain debt financing arrangements;
- our ability to pay the expenditures required in order to develop certain of our properties;
- operating hazards inherent in the exploration for and production of crude oil, natural gas and NGLs;
- difficulties encountered during the exploration for and production of crude oil, natural gas and NGLs;

- the impact of competition;
- our ability to identify and complete complementary opportunistic acquisitions;
- our ability to effectively integrate assets and properties that we acquire into our operations;
- weather conditions;
- the uncertainty of estimates of crude oil, natural gas reserves and NGLs;
- currency exchange rates and regulations;
- unanticipated issues and liabilities arising from non-compliance with environmental regulations;
- the ultimate resolution of our abandonment funding obligations with the government of Gabon and the audit of our operations in Gabon currently being conducted by the government of Gabon;
- the ultimate resolution of our negotiations with EGPC relating to the Effective Date Adjustment (as defined below);
- the availability and cost of seismic, drilling and other equipment;
- difficulties encountered in measuring, transporting and delivering crude oil, natural gas, and NGLs to commercial markets;
- timing and amount of future production of crude oil and, natural gas and NGLs;
- hedging decisions, including whether or not to enter into derivative financial instruments;
- general economic conditions, including any future economic downturn, the impact of inflation, disruption in financial of credit;
- our ability to enter into new customer contracts;
- changes in customer demand and producers' supply;
- actions by the governments of and events occurring in the countries in which we operate;
- actions by our joint venture owners;
- compliance with, or the effect of changes in, governmental regulations regarding our exploration, production, and well completion operations including those related to climate change;
- the outcome of any governmental audit; and
- actions of operators of our crude oil and, natural gas and NGLs properties.

The information contained in this Annual Report, including the information set forth under the heading "Item 1A. Risk Factors," identifies additional factors that could cause our results or performance to differ materially from those we express in forward-looking statements. Although we believe that the assumptions underlying our forward-looking statements are reasonable, any of these assumptions and therefore also the forward-looking statements based on these assumptions, could themselves prove to be inaccurate. In light of the significant uncertainties inherent in the forward-looking statements that are included in this Annual Report, our inclusion of this information is not a representation by us or any other person that our objectives and plans will be achieved. When you consider our forward-looking statements, you should keep in mind these risk factors and the other cautionary statements in this Annual Report.

Our forward-looking statements speak only as of the date the statements are made and reflect our best judgment about future events and trends based on the information currently available to us. Our results of operations can be affected by inaccurate assumptions we make or by risks and uncertainties known or unknown to us. Therefore, we cannot guarantee the accuracy of the forward-looking statements. Actual events and results of operations may vary materially from our current expectations and assumptions. Our forward-looking statements, express or implied, are expressly qualified by this "Cautionary Statement Regarding Forward-Looking Statements," which constitute cautionary statements. These cautionary statements should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances occurring after the date of this Annual Report.

Risk Factor Summary

Below is a summary of our risk factors. The risks below are those that we believe are the material risks that we currently face but are not the only risks facing us and our business. If any of these risks actually occur, our business, financial condition and results of operations could be materially adversely affected. See "Risk Factors" beginning on page 27 and the other information included elsewhere or incorporated by reference in this annual report for a discussion of factors you should carefully consider before deciding to invest in our common stock.

- Our business requires significant capital expenditures, and we may not be able to obtain needed capital or financing to fund our exploration and development activities or potential acquisitions on satisfactory terms or at all.
- Unless we are able to replace the proved reserve quantities that we have produced through acquiring or developing additional reserves, our cash flows and production will decrease over time.
- We may not enter into definitive agreements with the BWE Consortium to explore and exploit new properties, and we may not be in a position to control the timing of development efforts, the associated costs or the rate of production of the reserves operated by the BWE Consortium or from any non-operated properties in which we have an interest.
- Our offshore operations involve special risks that could adversely affect our results of operations.
- Acquisitions and divestitures of properties and businesses may subject us to additional risks and uncertainties, including that acquired assets may not produce as projected, may subject us to additional liabilities and may not be successfully integrated with our business. In addition, any sales or divestments of properties we make may result in certain liabilities that we are required to retain under the terms of such sales or divestments.

- The proposed acquisition of Svenska (as defined below) may not be consummated and if consummated, we may not realize the anticipated benefits expected from the acquisition.
- Our reserve information represents estimates that may turn out to be incorrect if the assumptions on which these estimates are based are inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present values of our reserves.
- If our assumptions underlying accruals for abandonment/decommissioning costs are too low, we could be required to expend greater amounts than expected.
- We may not generate sufficient cash to satisfy our payment obligations under the Merged Concession Agreement or be able to collect some or all of our receivables from the EGPC, which could negatively affect our operating results and financial condition.
- The Egyptian PSCs contain assignment provisions which, if triggered or deemed to be triggered, could adversely affect our business.
- We could lose our interest in Block P if we do not meet our commitments under the production sharing contract.
- Commodity derivative transactions that we enter into may fail to protect us from declines in commodity prices and could result in financial losses or reduce our income.
- We are exposed to the credit risks of the third parties with whom we contract.
- Our business could be materially and adversely affected by security threats, including cybersecurity threats, and other disruptions.
- Current and future geopolitical events outside of our control could adversely impact our business, results of operations, cash flows, financial condition and liquidity.
- Production cuts mandated by the government of Gabon, a member of OPEC, could adversely affect our revenues, cash flow and results of operations.
- We have less control over our investments in foreign properties than we would have with respect to domestic investments.
- Our operations may be adversely affected by political and economic circumstances in the countries in which we operate.
- Inflation could adversely impact our ability to control costs, including operating expenses and capital costs.
- Our results of operations, financial condition and cash flows could be adversely affected by changes in currency exchange rates.
- We operate in international jurisdictions, and we could be adversely affected by violations of the U.S. Foreign Corrupt Practices Act and similar worldwide anti-corruption laws.
- There are inherent limitations in all control systems, and misstatements due to error or fraud that could seriously harm our business may occur and not be detected.
- We may not have enough insurance to cover all of the risks we face.
- Our business could suffer if we lose the services of, or fail to attract, key personnel.
- We may be exposed to the risk of earthquakes in Alberta, Canada.
- We may be adversely affected by changes in currency regulations.
- We may be adversely affected by changes to interest rates.
- The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced.
- There may be valid challenges to title or legislative changes which affect our title to the oil, natural gas and NGLs properties we control in Canada.
- Crude oil, natural gas and NGLs prices are highly volatile and a depressed price regime, if prolonged, may negatively affect our financial results.
- Exploring for, developing, or acquiring reserves is capital intensive and uncertain.
- Competitive industry conditions may negatively affect our ability to conduct operations.
- Weather, unexpected subsurface conditions and other unforeseen operating hazards may adversely impact our crude oil, natural gas and NGLs activities, including but not limited to, earthquakes in Alberta and risks related to hydraulic fracking.
- An increased societal and governmental focus on ESG and climate change issues may adversely impact our business, impact our access to investors and financing, and decrease demand for our product.
- We face various risks associated with increased opposition to and activism against crude oil, natural gas and NGLs exploration and development activities.
- Our operations are subject to risks associated with climate change and potential regulatory programs meant to address climate change; these programs may impact or limit our business plans, result in significant expenditures or reduce demand for our product.
- Compliance with applicable laws, environmental and other government regulations could be costly and could negatively impact production.
- A significant level of indebtedness incurred under the Facility may limit our ability to borrow additional funds or capitalize on acquisition or other business opportunities in the future. In addition, the covenants in the Facility impose restrictions that may limit our ability and the ability of our subsidiaries to take certain actions. Our failure to comply with these covenants could result in the acceleration of any future outstanding indebtedness under the Facility.
- If we experience in the future a continued period of low commodity prices, our ability to comply with applicable debt covenants may be impacted.
- The borrowing base under the Facility may be reduced pursuant to the terms of the Facility Agreement, which may limit our available funding for exploration and development. We may have difficulty obtaining additional credit, which could adversely affect our operations and financial position.
- Restrictive debt covenants could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

PART I

Item 1. Business

OVERVIEW

As used in this Annual Report, the terms, “we,” “us,” “our,” the “Company” and “VAALCO” refer to VAALCO Energy, Inc. and its consolidated subsidiaries, unless the context otherwise requires.

We are a Houston, Texas-based, African-focused independent energy company with strong production and reserve portfolio of assets in Gabon, Egypt, Equatorial Guinea and Canada, currently engaged in the acquisition, exploration, development and production of crude oil, natural gas and NGLs.

We own a working interest in, and are the operator of, the Etame PSC related to the Etame Marin block located offshore Gabon in West Africa. The Etame Marin block covers an area of approximately 46,200 gross acres located 20 miles offshore in water depths of approximately 250 feet. Currently, our working interest in the Etame Marin block is 58.8%, and we are designated as the operator on behalf of the Etame Consortium. The block is subject to a 7.5% back-in carried interest by the government of Gabon, which they have assigned to a third party. Our working interest will decrease to 57.2% in June 2026 when the back-in carried interest increases to 10%.

We are also a member of a consortium with BW Energy and Panoro Energy (the “BWE Consortium”). The BWE Consortium has been provisionally awarded two blocks in the 12th Offshore Licensing Round in Gabon. Negotiations to finalize the commercial terms were held in 2023, however they were halted late in the year due to the presidential elections. The negotiations were started again at the request of the Gabonese Government in early February 2024, where the consortium and the government came to an agreement on the fiscal terms on February 9, 2024. The next step is concluding the terms of PSCs with the Gabonese government. BW Energy will be the operator with a 37.5% working interest, with VAALCO (37.5% working interest) and Panoro Energy (25% working interest) as non-operating joint owners. The two blocks, G12-13 and H12-13 are adjacent to our Etame PSC as well as BW Energy and Panoro’s Dussafu PSC offshore Southern Gabon and cover an area of 2,989 square kilometers and 1,929 square kilometers, respectively.

As a result of the business combination transaction with TransGlobe Energy Corporation (“TransGlobe”) in 2022 (the “Arrangement”), we own a 100% working interest in PSCs covering two regions: the Eastern Desert, which contains the West Gharib, West Bakr and North West Gharib merged concessions (45,067 acres) and the Western Desert which contains the South Ghazalat concession (7,340 acres). We also acquired TransGlobe’s production and working interests in Cardium light oil and Mannville liquids-rich gas assets located in Harmattan, Canada (47,400 gross acers developed).

On February 29, 2024, VAALCO Energy (Holdings), LLC (“Buyer”), a Delaware limited liability company and wholly-owned subsidiary of us, and Petroswede AB, a company incorporated in Sweden (“Seller”), entered into a Share Purchase Agreement (the “Share Purchase Agreement”) pursuant to which the Buyer will purchase all of the issued shares in the capital of Svenska Petroleum Exploration Aktiebolag, a company incorporated in Sweden (“Svenska”) for $66.5 million in cash (the “Purchase Price”), subject to adjustment as described in the Share Purchase Agreement. Pursuant to the terms and subject to the conditions of the Share Purchase Agreement, upon closing of the Acquisition (the “Closing”), Buyer will acquire Svenska and, as a result, Svenska’s primary asset: a 27.39% non-operated working interest in the deepwater producing Baobab field in Block CI-40, offshore Cote d’Ivoire in West Africa. Buyer will also acquire a 21.05% non-operated working interest in OML 145, a non-producing discovery located offshore of Nigeria that is not expected to be developed at this time. The Purchase Price will be funded by a combination of a dividend of cash on Svenska’s balance sheet to the Seller immediately prior to the consummation of the Acquisition and a portion of VAALCO’s cash-on-hand. VAALCO estimates that cash due from VAALCO at Closing will be in the range of approximately $30 to $40 million.

At December 31, 2023, net proved reserves related to Gabon were 9.1 MBoe, net proved reserves related to Egypt were 10.6 MBoe and net proved reserves related to Canada were 9.0 MBoe.

We also currently own an interest in an undeveloped block offshore Equatorial Guinea, West Africa.

STRATEGY

We own crude oil, natural gas and NGLs producing properties and conduct operating activities in Egypt, Canada, and offshore Gabon, with a focus on maximizing the value of our current resources and expanding into new development opportunities across Africa. Our financial results are heavily dependent upon the margins between prices received for our crude oil, natural gas and NGLs production and the costs to find and produce such crude oil, natural gas and NGLs.

We intend to increase stockholder value by accretively growing production and value through organic drilling in a capital efficient manner to unlock the inherent value of our assets and making disciplined strategic acquisitions that meet our strategic and financial objectives. Specifically, we seek to:

- Focus on maintaining production and lowering costs to increase margins and preserve optionality to capitalize on an increase in crude oil, natural gas and NGLs prices;
- Manage capital expenditures related to our drilling programs so that expenditures can be funded by cash on hand and cash from operations;
- Continue our focus on operating safely and complying with internationally accepted environmental operating standards;
- Optimize production through careful management of wells and infrastructure;
- Maximize our cash flow and income generation;
- Continue planning for additional development at Etame, Egypt, and Canada as well as future activity in Equatorial Guinea;
- Preserve a strong balance sheet by maintaining conservative leverage ratios and exhibiting financial discipline;
- Opportunistically hedge against exposures to changes in crude oil, natural gas or NGLs prices; and
- Actively pursue strategic, value-accretive mergers and acquisitions of similar properties to diversify our portfolio of producing assets.

We believe that we have strong management and technical expertise specific to the markets in which we operate, and that our strengths include:

- Our reputation as a safe and efficient operator in Africa and Canada;
- Our history of establishing favorable operating relationships with host governments and local joint venture owners;
- Our subsurface knowledge of key plays and risks in the broader regional framework of discoveries and fields;
- Our operational capacity to take on new development projects;
- Our familiarity with local practices and infrastructure; and
- Our market intelligence to provide early insight into available opportunities.

SEGMENT AND GEOGRAPHIC INFORMATION

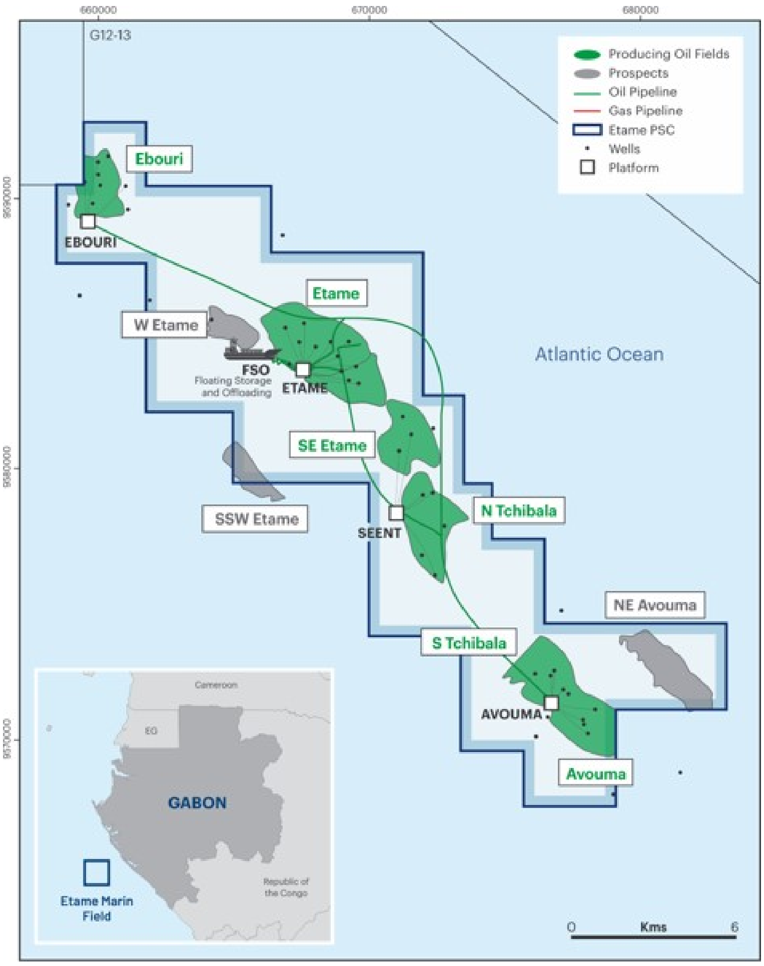
For operating segment and geographic financial information, see Note 5 to the Consolidated Financial Statements. Our reportable operating segments are Gabon, Egypt, Canada and Equatorial Guinea.

Gabon Segment

Offshore – Etame Marin Block

The Etame PSC related to the Etame Marin block is located offshore Gabon. The Etame Marin block covers an area of approximately 46,200 gross acres located 20 miles offshore in water depths of approximately 250 feet. Currently, our working interest in the Etame Marin block is 58.8%, and we are designated as the operator on behalf of the Etame Consortium. The block is subject to a 7.5% back-in carried interest by the government of Gabon, which they have assigned to a third party. Our working interest will decrease to 57.2% in June 2026 when the back-in carried interest increases to 10%. The terms of the Etame PSC include provisions for payments to the government of Gabon for: royalties based on 13% of production at the published price and a shared portion of "Profit Oil" determined based on daily production rates, as well as a gross carried working interest of 7.5% (increasing to 10% beginning June 20, 2026) for all costs. The term of the Etame PSC with Gabon related to the Etame Marin block located offshore Gabon extends through 2028 with two five-year options to extend the PSC ("PSC Extension"). The PSC Extension provides us with the extended time horizon necessary to pursue developing the resources we have identified at Etame. Prior to February 1, 2018, the government of Gabon did not take any of its share of Profit Oil in-kind. Beginning February 1, 2018, the government of Gabon elected to, and has continued to, take its Profit Oil in-kind.

As of December 31, 2023, our core areas in Gabon are illustrated below:



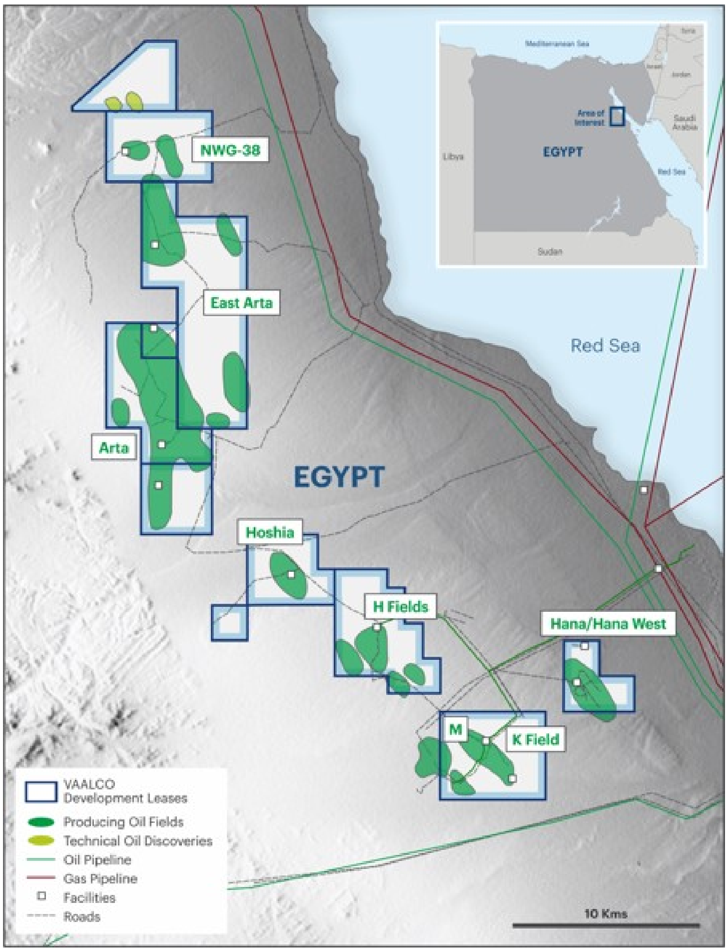
Egypt Segment

In Egypt, as of December 31, 2023, our interests are spread across two regions: the Eastern Desert, which contains the West Gharib, West Bakr and North West Gharib merged concessions, and the Western Desert, which contains the South Ghazalat concession. The Eastern Desert merged concession is approximately 45,067 acres and the Western Desert, South Ghazalat concession, is approximately 7,340 acres. Both of our Egyptian blocks are PSCs with the Egyptian General Petroleum Corporation ("EGPC"), the Egyptian government and VAALCO. We have an equal ownership interest, with EGPC owning the other portion, in the joint venture that has a 100% working interest in both PSCs. Our oil entitlement is the sum of cost oil, profit oil and excess cost oil, if any. The government takes their share of production based on the terms and conditions of the respective contracts. Our share of royalties is paid out of the government's share of production. Taxes are captured in the Egyptian government's net entitlement oil due and therefore there is no additional tax burden to us.

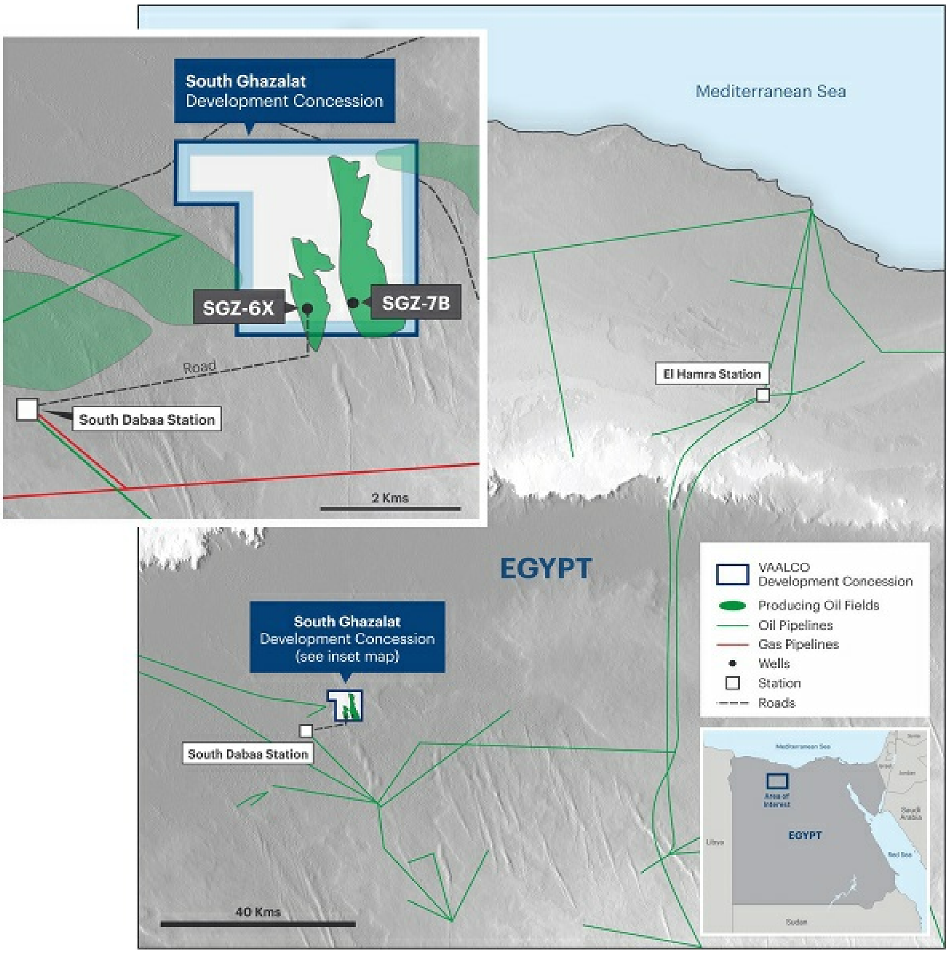
On January 20, 2022, prior to the consummation of the Arrangement, TransGlobe announced a fully executed Merged Concession Agreement with EGPC that merged the three existing Eastern Desert concessions with a 15-year primary term and improved economics. In advance of the Minister of Petroleum and Mineral Resources of the Arab Republic of Egypt (the "Minister") executing the Merged Concession Agreement, TransGlobe paid the first modernization payment of $15.0 million and signature bonus of $1.0 million as part of the conditions precedent to the official signing ceremony on January 19, 2022. On February 1, 2022, TransGlobe paid the second modernization payment of $10.0 million. In accordance with the Merged Concession Agreement, we agreed to substitute the 2023 and 2024 payment and issue two $10.0 million credits against receivables owed from EGPC. We will make two further annual modernization payments of $10.0 million each beginning February 1, 2025 until February 1, 2026. We also have minimum financial work commitments of $50.0 million per each five-year period of the primary development term, commencing on February 1, 2020 (the "Merged Concession Effective Date"). As of December 31, 2023, the $50 million of financial work commitments had been delivered to EGPC. As the Merger Concession Agreement is effective as of February 1, 2020, there will be an effective date adjustment owed to us for the difference in the historic commercial terms and the revised commercial terms applied against the production since the Merged Concession Effective Date. The cumulative amount of the effective date adjustment was estimated at $67.5 million. However, the cumulative amount to be received as a result of the effective date adjustment is currently being finalized with EGPC and could result in a range of outcomes based on the final price per barrel negotiated. At December 31, 2023, we had received $17.2 million of the receivable and the remaining $50.3 million is recorded on our consolidated balance sheet in Receivables-Other, net.

The Egyptian PSCs provide for the government to receive a percentage gross royalty on the gross production. The remaining oil production, after deducting the gross royalty, if any, is split between cost sharing oil and production sharing oil. Cost sharing oil is up to a maximum percentage as defined in the specific PSC. Cost oil is assigned to recover approved operating and capital costs spent on the specific project. Unutilized cost sharing oil or excess cost oil (maximum cost recovery less actual cost recovery) is shared between the government and the contractor as defined in the specific PSCs. Each PSC is treated individually in respect of cost recovery and production sharing purposes. The remaining production sharing oil (total production less cost oil) is shared between the government and the contractor as defined in the specific PSC. The Egyptian PSCs do not contain minimum production or sales requirements, and there are no restrictions with respect to pricing of the contractor's sales volumes. Except as otherwise disclosed, all crude oil sales are priced at current market rates at the time of sale.

The following illustrates our Merged Concession in the Eastern Desert:



The following illustrates our concession, South Ghazalat, in the Western Desert:



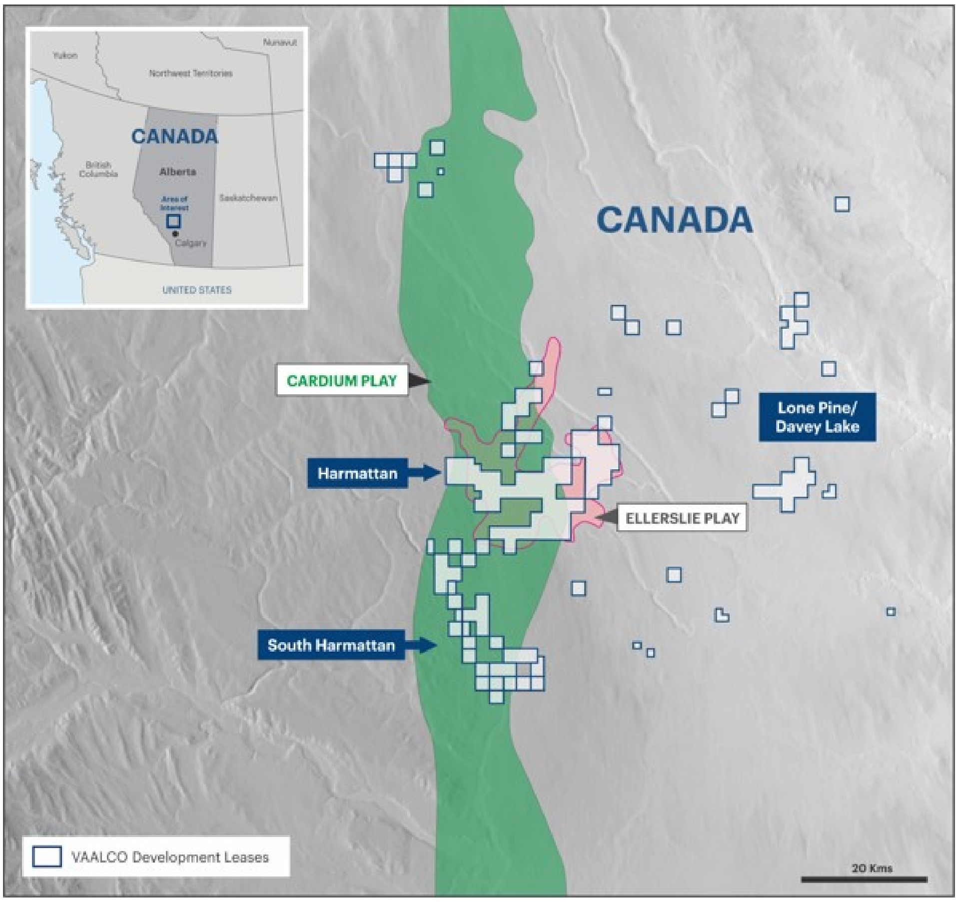
Canada Segment

In Harmattan, Canada, we own production and working interests in Cardium light oil and Mannville liquids-rich gas assets. Harmattan is located approximately 80 kilometers north of Calgary, Alberta. This property produces oil and associated natural gas from the Cardium zone and liquids-rich natural gas from zones in the Lower Mannville and Rock Creek formations at vertical depths of 1,200 to 2,600 meters. The Harmattan property covers 47,400 gross acres of developed land and 28,700 gross acres of undeveloped land. We also own a 100% working interest in a large oil battery and a compressor station where a majority of oil volumes are handled. All gas is delivered to a third party non-operated gas plant for processing.

Under the Modernized Royalty Framework (the "MRF") in Alberta, producers initially pay a flat royalty of 5% on production revenue from each producing well until payout, which is the point at which cumulative gross revenues from the well equals the applicable drilling and completion cost allowance. After payout, producers pay an increased royalty of up to 40% that will vary depending on the nature of the resource and market prices. Once the rate of production from a well is too low to sustain the full royalty burden, its royalty rate is gradually adjusted downward as production declines, eventually reaching a floor of 5%. The MRF applies to the hydrocarbons produced by wells spud or re-entered on or after January 1, 2017. The Royalty Guarantee Act (Alberta) came into effect in July 2019, amending the Mines and Minerals Act (Alberta) and guaranteeing no major changes to the oil and gas royalty structure for a period of 10 years.

Royalty rates for the production of privately owned oil and natural gas are negotiated between the producer and the resource owner. The Government of Alberta levies annual freehold mineral taxes for production from freehold mineral lands. On average, the tax levied in Alberta is 4% of revenues reported from freehold mineral title properties and is payable by the registered owner of the mineral rights.

Below is an illustration of our Canadian assets:



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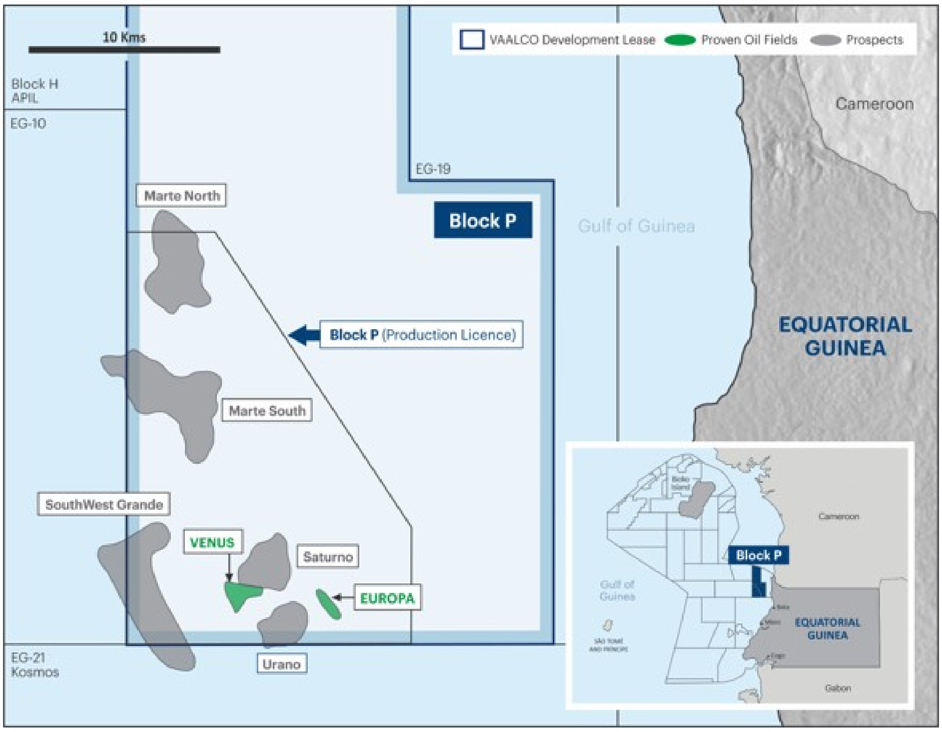
Equatorial Guinea Segment

We acquired a 31% working interest in an undeveloped portion of a block ("Block P") offshore Equatorial Guinea in 2012. The Equatorial Guinea Ministry of Mines and Hydrocarbons ("EG MMH") approved our appointment as the operator of Block P on November 12, 2019. We acquired an additional working interest of 12% from Atlas Petroleum, thereby increasing our working interest to 43% in 2020, in exchange for a potential future payment of $3.1 million to Compania Nacional de Petroles de Guinea Equitoria, ("GEPetrol") in the event that there is commercial production from Block P. On August 27, 2020, the amendment to the production sharing contract to ratify our increased working interest and appointment as operator was approved by the EG MMH. In April 2021, Crown Energy, who held a 5% working interest, elected to default on its obligations from Block P. On April 12, 2021, the majority of non-defaulting parties assigned the defaulting party's interest to the non defaulting parties. As a result, our working interest increased to 45.9% with the approval of a fourth amendment to the production sharing contract by the EG MMH. On July 15, 2022, VAALCO, on behalf of itself and Guinea Ecuatorial de Petroleós ("GEPetrol"), submitted to the EG MMH a plan of development for the Venus development in Block P. On September 26, 2022, the EG MMH approved the submitted plan of development. Final documents to effect the plan of development are subject to EG MMH approval. The Block P production sharing contract provides for a development and production period of 25 years from the date of approval of a development and production plan for the area associated with the Venus development. The 2023 budget for the plan was delivered on October 12, 2022 to the MMH and was approved effective November 16, 2022.

In February of 2023, we acquired an additional 14.1% participating interest, increasing our participating interest in the Block to 60.0%. In March 2023, Atlas voted to participate in the Venus Development. Amendment 5 of the PSC was approved by all parties in March 2023 with this updated participating interest, and execution of the Venus development plan has been initiated. This increase of 14.1% participating interest increases our future payment to GEPetrol to $6.80 million at first commercial production of the Block. The Third Amendment to the Joint Operating Agreement ("JOA") was approved by GEPetrol and Atlas on Feb 18, 2024 and was further approved by the MMH on Feb 27, 2024. With the approval of the JOA, the work could commence on the engineering for the Venus Development to enable a Final Investment Decision ("FID") on the Venus Development.

As of December 31, 2023, our Block P license in Equatorial Guinea is illustrated below:



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DRILLING ACTIVITY

In Gabon, we commenced the 2021/2022 drilling campaign in December 2021. The following table sets forth the total number of completed exploratory and development wells in 2023, 2022 and 2021 on a gross and net basis:

	Gabon					
	Gross			Net		
	2023	2022	2021	2023	2022	2021
Exploratory wells						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
In progress	—	—	—	—	—	—
Development wells						
Productive	**—**	4	—	**—**	2.4	—
Dry	—	—	—	—	—	—
In progress	**—**	—	1	**—**	—	0.6
Total wells	**—**	4	1	**—**	2.4	0.6

In December 2021, we began drilling the ETAME 8H-ST development well that was completed in February 2022. In 2022, we completed the Etame 8H-ST, North Tchibala 2H-ST, South Tchibala-1HB-ST2 and Avouma 3H-ST development wells.

The following table sets forth the total number of exploratory and development wells from the TransGlobe acquisition date in 2022 and 2023 in Egypt on a gross and net basis:

	Egypt			
	Gross		Net	
	2023	2022	2023	2022
Exploratory wells				
Productive	**—**	—	—	—
Dry	**2**	2	**2**	2
In progress	**—**	—	—	—
Development wells				
Productive	**16**	2	**16**	2
Dry	—	—	—	—
In progress	—	1	—	1
Total wells	**18**	5	**18**	5

The 18 wells drilled in 2023 along with the spud date for each were the EastArta-53 - January 15, 2023, the K-81 - February 2, 2023, the K-79 - February 21, 2023, the Arta-80 - March 10, 2023, the Arta-81 - March 21, 2023, the HE-5 Injector - April 16, 2023, the HE-3 - May 10, 2023, the Arta-82 - May 25, 2023, the Arta-84 - June 6, 2023, the NEG-5C1 - June 16, 2023, the K-80 - June 30, 2023, the K-84 - July 16, 2023, the K-85 - July 31, 2023, the M-24 - August 14, 2023, the Arta-91 - September 1, 2023, the EA-54 - September 12, 2023 and the EA-55 - October 4, 2023. The two dry hole wells were the NWG-SC1 and the EA-54 which were abandoned during 2023.
The wells drilled in 2022 included the M-17 Development well which was spud on September 28, 2022 and rig released on October 17, 2022, the NWG-2INJ-1A planned as injector well but encountered oil and came online December 23, 2022 and the Arta-77Hz well in progress which came online in the first quarter of 2023.

The following table sets forth the total number of exploratory and development wells from the TransGlobe acquisition date in 2022 and all of 2023 in Canada on a gross and net basis:

	Canada			
	Gross		Net	
	2023	2022	2023	2022
Exploratory wells				
Productive	—	—	—	—
Dry	—	—	—	—
In progress	—	—	—	—
Development wells				
Productive	2	3	2	3
Dry	—	—	—	—
In progress	—	—	—	—
Total wells	2	3	2	3

The two wells drilled in 2023 were the 12-12-030-04W5/0 and the 16-30-029-03W5/0 with a spud date of January 28, 2023 and February 22, 2023, respectively.
The three wells drilled in 2022 were the 4-10-29-3W5, the 4-18-29-3W5 and the 4-24-29-4W5 well with a spud date of July 4, 2022, June 11, 2022 and June 23, 2022, respectively.

ACREAGE AND PRODUCTIVE WELLS

Below is the total acreage under lease or covered by the Etame PSC, Egypt PSCs, Canada PSCs and Block P and the total number of productive crude oil, natural gas and NGLs wells as of December 31, 2023:

	Developed		Undeveloped(2)		Total	
Acreage in thousands	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Gabon	6.9	4.1	39.4	23.1	46.3	27.2
Canada	47.4	41.7	28.7	25.3	76.1	67.0
Egypt	29.2	29.2	23.3	23.3	52.5	52.5
Equatorial Guinea	—	—	57.3	26.3	57.3	26.3
Total acreage	83.5	75.0	148.7	97.9	232.2	173.0

Productive crude oil wells	**Gross**	**Net**
Gabon	15 (1)	8.8
Canada	63	59.5
Egypt	123	123.0
Total Productive crude oil wells	201	191.3

Productive natural gas wells	**Gross**	**Net**
Gabon	—	—
Canada	40	37.6
Egypt	—	—
Total productive natural gas wells	40	37.6

(1) Excludes three wells shut-in due to the presence of high levels of H_2S.

(2) The expiration dates for undeveloped acreage associated with each region is as follows:

a. For Gabon the undeveloped acres expire at the end of the license contract; currently 2028 with two five-year options to extend the license contract.

b. For Egypt the undeveloped acres expire at the end of the license contracts; currently 2035 with one five-year option to extend the license contract for the West Gharib, West Bakr and North West Gharib areas and 2039 with one 5 year extension for South Ghazlat area.

c. For Canada the undeveloped acres are generally held by production by areas that are producing reserves. At December 31, 2023 approximately 82% of Canada's net undeveloped acreage has no expiration risk. Approximately 4.3 acres have risk of expiration from 2024 through 2027.

RESERVE INFORMATION

Estimated Reserves and Estimated Future Net Revenues

Reserve Data

In accordance with the current SEC guidelines, estimates of future net cash flow from our properties and the present value thereof are made using the average of the first-day-of-the-month price for each of the twelve months of the year adjusted for quality, transportation fees and market differentials. Such prices are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. For 2023, the average of such prices used for our reserve estimate was $83.22 per Bbl for crude oil for Gabon. Prices were $64.59 per Bbl for crude oil from Egypt and $71.67 per Bbl for crude oil from Canada. For 2022, the average of such prices used for our reserve estimates was $100.35 per Bbl for crude oil from Gabon. Prices were between $84.76 and $85.65 per Bbl for crude oil from Egypt and $89.61 per Bbl for crude oil from Canada. For Gabon, this compares to the average of such price used for 2021 of $69.10 per Bbl.

For 2023, the adjusted average price for our reserves associated with natural gas was $1.91 per MCF, $5.20 per Bbl for Ethane, $20.18 per Bbl for propane, $36.69 per Bbl for butane and $74.76 per Bbl for condensates. For 2022, the adjusted average price for our reserves associated with natural gas was $4.13 per MCF, $12.77 per Bbl for Ethane, $40.27 per Bbl for propane, $43.85 per Bbl for butane and $91.57 per Bbl for condensates.

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Reserves reported below consist of net proved reserves related to the Etame Marin block located offshore Gabon in West Africa, the eastern desert and western area of Egypt and Harmattan area of west central Alberta, Canada. The tables below sets forth our estimated net proved reserve quantities for the years ended December 31, 2023, 2022 and 2021. The Gabon and Egypt information was prepared by the independent petroleum engineering firm, Netherland, Sewell & Associates, Inc. ("NSAI"). Canada information was prepared by the independent firm, GLJ Ltd. ("GLJ"). The 2021 information includes the Sasol interest in the Etame Marin block as we acquired Sasol's interest on February 25, 2021.

	As of December 31, 2023			
	Crude Oil (MBbls)	**Natural Gas (MMcf)**	**NGLs (MBbls)**	**Total (MBoe) (1)**
Proved developed reserves				
Gabon	**8,053**	**—**	**—**	**8,053**
Egypt	**10,141**	**—**	**—**	**10,141**
Canada	**1,310**	**9,011**	**1,449**	**4,260**
Total proved developed reserves	**19,504**	**9,011**	**1,449**	**22,454**
Proved undeveloped reserves				
Gabon	**1,011**	**—**	**—**	**1,011**
Egypt	**451**	**—**	**—**	**451**
Canada	**2,122**	**7,921**	**1,289**	**4,731**
Total proved undeveloped reserves	**3,584**	**7,921**	**1,289**	**6,193**
Total proved reserves	**23,088**	**16,932**	**2,738**	**28,647**

(1) To convert Natural Gas to MBoe, MMcf is divided by 6.

Standardized Measure and Changes in Proved Reserves

The following table shows changes in total proved Gabon reserves for all presented years:

Proved Reserves	As of December 31,		
(MBoe)	**2023**	**2022**	**2021**
Proved reserves, beginning of year	**10,219**	11,218	3,216
Production	**(3,197)**	(2,971)	(2,599)
Revisions of previous estimates	**2,042**	1,972	7,968
Extensions and discoveries	**—**	—	—
Purchase of reserves	**—**	—	2,633
Proved reserves, end of year	**9,064**	10,219	11,218

In February 2021, we completed the acquisition of Sasol's interest in the Etame Marin block. The reserves associated with the acquisition is included in the purchase of reserves category of the December 2021 balance. In 2022, we drilled four wells that were previously included in the proved undeveloped category of the 2021 reserves.

In comparing the net proved reserves of 9.1 MMBoes at December 31, 2023 to the 10.2 MMBoes at December 31, 2022, we added 2.0 MMBoes of reserves through positive revisions of previous estimates. 2.8 MMBoes of the positive revisions were due to performance offset by 0.8 MMBoes of negative revisions through price. The decrease of 17% in the average of the first-day-of-the-month prices for each of the years, adjusted for quality, transportation fees and market differentials required by SEC rules to determine reserves, was $83.22 for 2023 down from $100.35 for 2022.

The following table shows changes in total proved Egypt reserves for the year ended December 31, 2023 and the period October 14, 2022 through December 31, 2022:

Proved Reserves	As of December 31,		
(MBoe)	**2023**	**2022**	**2021**
Proved reserves, beginning of year	**8,577**	—	—
Production	**(2,771)**	(639)	—
Revisions of previous estimates	**4,693**	—	—
Extensions and discoveries	**93**	—	—
Purchase of reserves	**—**	9,216	—
Proved reserves, end of year	**10,592**	8,577	—

In 2023, eighteen wells were drilled in Egypt as part of the 2023 drilling campaign. Two of these wells were exploratory that resulted in dry hole wells.

In comparing the net proved reserves of 10.6 MMBoes at December 31, 2023 to the 8.6 MMBoes at December 31, 2022, we added 4.7 MMBoes of reserves through positive revisions of previous estimates. 5.3 MMBoes of the positive revisions were due to performance offset by 0.6 MMBoes of negative revisions through price. The decrease of 20% in the average of the first-day-of-the-month prices for each of the years, adjusted for quality, transportation fees and market differentials required by SEC rules to determine reserves, was $64.59 for 2023 down from $85.02 for 2022.

The following table shows changes in total proved Canada reserves for the year ended December 31, 2023 and the period October 14, 2022 through December 31, 2022:

Proved Reserves *(MBoe)*	As of December 31, 2023	 2022	 2021
Proved reserves, beginning of year	**9,161**	—	—
Production	**(859)**	(247)	—
Revisions of previous estimates	**(1,163)**	—	—
Extensions and discoveries	**1,852**	—	—
Purchase of reserves	**—**	9,408	—
Proved reserves, end of year	**8,991**	9,161	—

In comparing the net proved reserves of 9.0 MMBoes at December 31, 2023 to the 9.2 MMBoes at December 31, 2022, 1.2 MMBoes of reserves were removed through negative revisions of previous estimates. 0.9 MMBoes of the negative revisions were due to performance and 0.3 MMBoes of negative revisions were through price. The decrease of 28% in the average of the first-day-of-the-month prices for the composite MBoe equivalent each of the years, adjusted for quality, transportation fees and market differentials required by SEC rules to determine reserves, was $39.63 per Boe for 2023 down from $55.30 per Boe for 2022..

The following table sets forth the standardized measure of discounted future net cash flows:

	As of December 31, 2023	 2022 *(in thousands)*	 2021
Gabon	**$ 107,824**	$ 244,427	$ 99,258
Egypt	**161,747**	226,888	—
Canada	**72,363**	153,150	—
Standardized measure of discounted future net cash flows	**$ 341,934**	$ 624,465	$ 99,258

The information set forth in the tables includes revisions for certain reserve estimates attributable to proved properties included in preceding years' estimates. Such revisions are the result of additional information from subsequent completions and production history from the properties involved or the result of an increase or decrease in the projected economic life of such properties resulting from changes in product prices, estimated operating costs and other factors. Crude oil amounts shown for Gabon are recoverable under the Etame PSC, and the reserves in place at the end of the contract remain the property of the Gabon government. Crude oil amounts shown for Egypt are recoverable under the Merged Concession and the western desert South Ghazalat concession, and the reserves in place at the end of those concessions remain the property of the Egyptian government. The reserves at the end of the contract, including extensions, are not included in the table above.

We do not reflect proved reserves on discoveries in our reserve estimates until such time as a development plan has been prepared and approved by our joint venture owners and the government, where applicable.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. Reserve engineering is a subjective process of estimating underground accumulations of crude oil, natural gas and NGLs that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of crude oil, natural gas and NGLs that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future crude oil, natural gas and NGLs sales prices may all differ from those assumed in these estimates. The standardized measure of discounted future net cash flows should not be construed as the current market value of the estimated crude oil, natural gas and NGLs reserves attributable to our properties.

Proved undeveloped reserves

Historically, we have reviewed on an annual basis all of our PUDs to ensure an appropriate plan for development exists.

The following table discloses our estimated proved undeveloped ("PUD") reserve activities:

	Proved Undeveloped Reserves (MBoe)	**Future Development Costs (in thousands)**
Beginning proved undeveloped reserves at December 31, 2022	4,322	$ 72,142
Undeveloped reserves converted to developed reserves	(602)	(11,212)
Revisions	891	34,570
Extensions and discoveries	1,582	23,607
Ending proved undeveloped reserves at December 31, 2023	6,193	$ 119,107

Our PUD reserves at December 31, 2023 increased by 1.9 MMBoe, primarily due to:

Extensions and Discoveries — Extensions and discoveries of 1.6 MMBoe are primarily due to our Canada segment where the wells drilled in 2023 proved up areas surrounding the drilling locations and future drilling locations were added in that area.

Revisions of Previous Estimates — Revision of 0.9 MMBoe are primarily due to our Gabon segment where a well future well locations was added.

Conversion to Proved Developed — Conversions of 0.6 MMBoe are attributable to our Egypt segment where five wells that were previously classified ad PUDs were converted to PDP as part of the 2023 drilling program.

Controls over Reserve Estimates

Our policies and practices regarding internal controls over the recording of reserves are structured to objectively and accurately estimate our crude oil, natural gas, and NGLs reserves quantities and present values in compliance with SEC regulations and generally accepted accounting principles in the U.S. ("GAAP"). Compliance with these rules and regulations with respect to our reserves is the responsibility of our Technical Reserve Committee and our reservoir engineer, who is our principal engineer. Our principal engineer has over 30 years of experience in the crude oil and natural gas industry, including over 10 years as a reserve evaluator and trainer, and is a qualified reserves estimator, as defined by the Society of Petroleum Engineers' standards. Further professional qualifications include a Master's degree in petroleum engineering and Texas Professional Engineering (PE) certification, extensive internal and external reserve training, and asset evaluation and management. In addition, the principal engineer is an active participant in industry reserve seminars, professional industry groups and is a member of the Society of Petroleum Engineers. The Technical Reserve Committee of the Board of Directors meets periodically with management to discuss matters and policies related to reserves.

Our controls over reserve estimation include engaging and retaining qualified independent petroleum and geological firms with respect to reserves information. We provide information to our independent reserve engineers about our crude oil, natural gas and NGLs properties in Gabon, Egypt and Canada which includes, but is not limited to, production profiles, ownership and production sharing rights, prices, costs and future drilling plans. Our independent reserve engineers prepare their own estimates of the reserves attributable to our properties. The reserves estimates for our Gabon, Egypt and Canada assets shown herein have been independently evaluated by NSAI (Gabon and Egypt), GLJ (Canada) and our Technical Reserve Committee.

NET VOLUMES SOLD, PRICES, AND PRODUCTION COSTS

Net volumes sold, average sales prices per unit, and production costs per unit for our 2023, 2022 and 2021 operations are shown in the tables below.

	Production Volumes (2)			Sales Volumes (2)			Average Sales Price (2)			Average Production Cost (2)
	Crude Oil (MBbl)	Natural Gas (MMcf)	NGLs (MBbl)	Crude Oil (MBbl)	Natural Gas (MMcf)	NGLs (MBbl)	Crude Oil (Per Bbl)	Natural Gas (per Mcf)	NGLs (Per Bbl)	Total (per BoE)
Year Ended December 31, 2023										
Gabon	3,197	—	—	3,196	—	—	$ 79.80	$ —	$ —	$ 27.26
Egypt(1)	2,771	—	—	2,771	—	—	58.11	—	—	19.77
Canada(1)	334	1,528	270	334	1,528	270	71.88	1.93	26.58	11.02
Total	6,302	1,528	270	6,301	1,528	270	$ 69.84	$ 1.93	$ 26.58	$ 22.16
Year Ended December 31, 2022										
Gabon	2,971	—	—	2,919	—	—	$ 103.09	$ —	$ —	$ 33.18
Egypt(1)	547	—	—	547	—	—	69.00	—	—	21.84
Canada(1)	72	396	73	93	335	63	79.56	4.00	36.12	9.33
Total	3,590	396	73	3,559	335	63	$ 97.24	$ 4.00	$ 36.12	$ 30.12
Year Ended December 31, 2021										
Gabon	2,599	—	—	2,711	—	—	$ 70.66	—	—	$ 29.97

(1) Reflects sales and production costs after the acquisition date, October 13, 2022
(2) The sales volumes and per Boe information are reported on NRI basis
(3) All of the Company's production volumes in Gabon are from the Etame Marin block, all of the Company's production volumes in Egypt are from the Petrobakr concession and substantially all of the Company's production volumes in Canada are from the Harmattan area.

AVAILABLE INFORMATION

VAALCO Energy, Inc. is a Delaware corporation, incorporated in 1985 and headquartered at 9800 Richmond Avenue, Suite 700, Houston, Texas 77042. Our telephone number is (713) 623-0801 and our website address is www.vaalco.com. We make available, free of charge on our website, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports, at https://www.vaalco.com/investors/sec-filings as soon as reasonably practicable after such reports are electronically filed with or furnished to the SEC. These reports and other information are also available on the SEC's website at https://www.sec.gov. Information contained on our website and the SEC's website is not incorporated by reference into this Annual Report. We have placed on our website copies of charters for our Audit Committee, Compensation Committee and Environmental, Social and Governance Committee as well as our Code of Business Conduct and Ethics ("Code of Ethics"), Corporate Governance Principles and Code of Ethics for the CEO and Senior Financial Officers. Stockholders may request a printed copy of these governance materials by writing to the Company Secretary, VAALCO Energy, Inc., 9800 Richmond Avenue, Suite 700, Houston, Texas 77042. We intend to disclose updates or amendments to our Code of Ethics and Code of Ethics for the CEO and Senior Financial Officers on our website within four business days following the date of such update or amendment.

CUSTOMERS

Gabon

For the years ended December 31, 2023, 2022 and 2021, we sold our crude oil production from Gabon under a term contract with pricing in the month of lifting, adjusted for location and market factors. For the period of August 2022 through December 2022, revenues in Gabon were concentrated in one customer that constituted 100% of revenues in Gabon. For the year ended December 31, 2023, revenues in Gabon were concentrated in one customer that constituted 100% of revenues in Gabon.

Egypt

For the period of October 14, 2022 through December 31, 2022, revenues in Egypt were concentrated with one customer that constituted 100% of revenues in Egypt. For the year ended December 31, 2023, revenues in Egypt were concentrated in two separate customers that constituted approximately 62% and 38% of revenues in Egypt.

Canada

For the period of October 14, 2022 through December 31, 2022, revenues in Canada were concentrated in three separate customers that constituted approximately 54%, 32% and 14% of revenues in Canada. For the year ended December 31, 2023, revenues in Canada were concentrated in three separate customers that constituted approximately 52%, 37% and 7% of revenues in Canada

EMPLOYEES AND HUMAN CAPITAL RESOURCE MANAGEMENT

We operate on the fundamental philosophy that people are our most valuable asset as every person who works for us has the potential to impact our success. Identifying quality talent is at the core of everything we do and our success is dependent upon our ability to attract, develop and retain highly qualified employees. Our core values include honesty/integrity, treating people fairly, high performance, efficient and effective processes, open communication and being respected in our local communities. These values establish the foundation on which the culture is built and represent the key expectations we have of our employees. We believe our culture and commitment to our employees creates an environment that allows us to attract and retain our qualified talent, while simultaneously providing significant value to us and our stockholders by helping our employees attain their highest level of creativity and efficiency.

As part of our sustainability effort, we plan to conduct and publish the results of an all-employee engagement survey in 2024.

Demographics

As of December 31, 2023, we had 189 full-time employees, 91 of whom were located in Gabon, 34 in Egypt, 9 in Canada and 55 in Houston. Likewise, there are 42 contractors in Gabon, 16 contractors in Egypt, 1 contractor in Canada and 21 contractors in Houston. We are not subject to any collective bargaining agreements, although some of the national employees in Gabon are members of the NEOP (National Organization of Petroleum Workers) union. We believe relations with our employees are satisfactory.

Diversity and Inclusion

We value building diverse teams, embracing different perspectives and fostering an inclusive, empowering work environment for our employees. We have a long-standing commitment to equal employment opportunity as evidenced by our Equal Employment Opportunity policy. Approximately 16% of our management team are female employees, 96% of our Gabon workforce is Gabonese and 92% of our Egypt workforce is Egyptian.

Compensation and Benefits

Critical to our success is identifying, recruiting, retaining, and incentivizing our existing and future employees. We strive to attract and retain the most talented employees in the industry by offering competitive compensation and benefits. Our pay-for-performance compensation philosophy is based on rewarding each employee's individual contributions and striving to achieve equal pay for equal work regardless of gender, race or ethnicity. We use a combination of fixed and variable pay including base salary, bonus, and merit increases, which vary across the business. In addition, as part of our long-term incentive plan for executives and certain employees, we provide share-based compensation to foster our pay-for-performance culture and to attract, retain and motivate our key leaders.

As the success of our business is fundamentally connected to the well-being of our people, we offer benefits that support their physical, financial and emotional well-being. We provide our employees with access to flexible and convenient medical programs intended to meet their needs and the needs of their families. In addition to this medical coverage, we offer eligible employees dental and vision coverage, health savings and flexible spending accounts, paid time off, employee assistance programs, voluntary short-term and long-term disability insurance and term life insurance. Additionally, we offer a 401(k) Savings Plan and Deferred Compensation Plan to certain employees. Certain employees receive additional compensation for working in foreign jurisdictions. We also plan to expand the benefit for our employees to participate in paid volunteering in company-approved activities, in certain areas of operation. As part of this global effort, we also expect to publish details about this new benefit for employees.

Workplace environment is also crucial in attracting and retaining key talent. Most of our offices offer a certain level of flexibility (i.e. work from home days and/or flexible core hours) to help meet the needs of the multigenerational workforce and the needs of the business. Our benefits and compensation packages vary by location and are designed to meet or exceed local laws and to be competitive in the marketplace.

Commitment to Values and Ethics

Along with our core values, we act in accordance with our Code of Ethics, which sets forth expectations and guidance for employees to make appropriate decisions. Our Code of Ethics covers topics such as anti-corruption, discrimination, harassment, privacy, appropriate use of company assets, protecting confidential information, and reporting Code of Ethics violations. The Code of Ethics reflects our commitment to operating in a fair, honest, responsible and ethical manner and also provides direction for reporting complaints in the event of alleged violations of our policies (including through an anonymous hotline). Our executive officers and supervisors maintain “open door” policies and any form of retaliation is strictly prohibited.

Professional Development, Safety and Training

We believe that key factors in employee retention are professional development, safety and training. We have training programs across all levels to meet the needs of various roles, specialized skill sets and departments across the Company. We provide compliance education as well as general workplace safety training to our employees and offer Occupational Safety and Health Administration training to key employees. We are committed to the security and confidentiality of our employees’ personal information and employs software tools and periodic employee training programs to promote security and information protection at all levels. We utilize certain employee turnover rates and productivity metrics in assessing our employee programs to ensure that they are structured to instill high levels of in-house employee tenure, low levels of voluntary turnover and the optimization of productivity and performance across our entire workforce. Additionally, we have a performance evaluation program which adopts a modern approach to valuing and strengthening individual performance through on-going interactive progress assessments related to established goals and objectives.

Communication and Engagement

We strongly believe that our success depends on employees understanding how their work contributes to our overall strategy. To this end, we communicate with our workforce through a variety of channels and encourage open and direct communication, including: (i) quarterly company-wide CEO updates; (ii) regular company-wide calls with management and (iii) frequent corporate email communications.

COMPETITION

The crude oil, natural gas and NGLs industry is highly competitive. Competition is particularly intense from other independent operators and from major crude oil, natural gas and NGLs companies with respect to acquisitions and development of desirable crude oil, natural gas and NGLs properties and licenses, and contracting for drilling equipment. There is also competition for the hiring of experienced personnel. In addition, the drilling, producing, processing and marketing of crude oil, natural gas and NGLs is affected by a number of factors beyond our control, which may delay drilling, increase prices and have other adverse effects, which cannot be accurately predicted.

Our competition for acquisitions, exploration, development and production includes the major crude oil, natural gas and NGLs companies in addition to numerous independent crude oil companies, individual proprietors, investors and others. We also compete against companies developing alternatives to petroleum-based products, including those that are developing renewable fuels. Many of these competitors have financial and technical resources and staff that are substantially larger than ours. As a result, our competitors may be able to pay more for desirable crude oil, natural gas and NGLs assets, or to evaluate, bid for and purchase a greater number of properties and licenses than our financial or personnel resources will permit. Furthermore, these companies may also be better able to withstand the financial pressures of lower commodity prices, unsuccessful wells, volatility in financial markets and generally adverse global and industry-wide economic conditions. These companies may also be better able to absorb the burdens resulting from changes in relevant laws and regulations, which may adversely affect our competitive position. Our ability to generate reserves in the future will depend on our ability to select and acquire suitable producing properties and/or develop prospects for future drilling and exploration.

INSURANCE

For protection against financial loss resulting from various operating hazards, we maintain insurance coverage, including insurance coverage for certain physical damage, blowout/control of a well, comprehensive general liability, worker’s compensation and employer’s liability. We maintain insurance at levels we believe to be customary in the industry to limit our financial exposure in the event of a substantial environmental claim resulting from sudden, unanticipated and accidental discharges of certain prohibited substances into the environment. Such insurance might not cover the complete claim amount and would not cover fines or penalties for a violation of environmental law. We are not fully insured against all risks associated with our business either because such insurance is unavailable or because premium costs are considered uneconomic. A material loss not fully covered by insurance could have an adverse effect on our financial position, results of operations or cash flows.

REGULATORY

Question - is our practice to obtain any updates on country-specific regulations from local counsel? Also, there was an issue with us not filing to be regulated locally for emissions, verses federally, in Canada. Consider if that merits a mention somewhere.

General

Our operations and our ability to finance and fund our operations and growth are affected by political developments and laws and regulations in the areas in which we operate. In particular, crude oil, natural gas and NGLs production operations and economics are affected by:

- change in governments;
- civil unrest;
- price and currency controls;
- limitations on crude oil, natural gas and NGLs production;
- tax, environmental, safety and other laws relating to the petroleum industry;
- changes in laws relating to the petroleum industry;
- changes in administrative regulations and the interpretation and application of administrative rules and regulations; and
- changes in contract interpretation and policies of contract adherence.

In any country in which we may do business, the crude oil, natural gas and NGLs industry legislation and agency regulation are periodically changed, sometimes retroactively, for a variety of political, economic, environmental and other reasons. Numerous governmental departments and agencies issue rules and regulations binding on the crude oil, natural gas and NGLs industry, some of which carry substantial penalties for the failure to comply. The regulatory burden on the crude oil, natural gas and NGLs industry increases our cost of doing business and our potential for economic loss.

Gabon

Our exploration and production activities offshore Gabon are subject to Gabonese regulations. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that could substantially increase our costs or affect our operations. In recent years, there have been indications that authorities were working or planned to work on a Gas Code and new Hydrocarbons Law. Also, following the coup d'état of August 30, 2023, Gabon established a Transition Committee for the Restoration of Institutions, swore in General Brice Oligui Nguema as the President and appointed a Transition Government and tentatively plans to hold national, presidential and local elections in 2025. Accordingly, the risk of legislation having a significant impact on petroleum operations being adopted during the Transition Period cannot be discarded. The following is a summary of certain applicable regulatory frameworks in Gabon.

2014 Hydrocarbons Law - Up until 2014, the fiscal and regulatory framework governing the exploration and production of hydrocarbons in Gabon was notably unregulated. Successive model contracts issued by the State of Gabon acted as guidelines; all fiscal aspects of each contract were negotiable between the State of Gabon and exploratory parties, including work commitments and exploration costs for each PSC.

In September 2014, Law No. 11/2014, of August 28, 2014, came into force in Gabon ("2014 Hydrocarbons Law"). The 2014 Hydrocarbons Law was not exhaustive; it sought to provide a framework of governing principles and rules, applicable to both the exploratory and extracting industry of hydrocarbons, as well as the downstream sector, to be complemented by implementing regulations.

Under the Gabonese Civil Code ("Civil Code"), laws will not have retroactive effects unless they expressly or tacitly provide otherwise. The Civil Code further provides that former laws continue to govern the effects of existing contracts, save in case of express or tacit derogation by the legislator and that, in any event, the application of a new law to existing contracts cannot modify the effects already produced by existing contracts under a former law, except via express derogation by the legislator.

The 2014 Hydrocarbons Law explicitly provided that establishment conventions, petroleum contracts, petroleum titles, mining concessions and exploitation permits concluded or granted by the State of Gabon prior to the date of its publication remained in force until their expiration date.

However, the 2014 Hydrocarbons Law further provided that unless such arrangements became consistent with the requirements of the 2014 Hydrocarbons Law, establishment conventions, mining concessions and exploitation permits in effect could not be extended or renewed. Furthermore, the 2014 Hydrocarbons Law prohibited establishment conventions and mining concessions, and provided that the exploitation of new discoveries in areas covered by existing conventions and concessions would be required to be made in accordance with the 2014 Hydrocarbons Law.

2019 Hydrocarbons Law - The 2014 Hydrocarbons Law was repealed in its entirety by Law No. 002/2019, of 16 July 2019, published on 22 July 2019 ("2019 Hydrocarbons Law"). As with the 2014 Hydrocarbons Law, the 2019 Hydrocarbons Law contains provisions applicable to both the upstream and downstream segments. However, despite the publication of the 2019 Hydrocarbons Law, there are various issues and matters yet to be fully enacted by implementing regulations.

Under the transitory provision contained in the 2019 Hydrocarbons Law, existing PSCs and other petroleum contracts, permits and authorizations remain in full force and effect until their expiration.

However, any renewal or extension of those instruments are subject to the provisions of the 2019 Hydrocarbons Law, and its implementing regulations.

The 2019 Hydrocarbons Law also provides for obligations for immediate application, irrespective of the date of signature of existing PSCs or petroleum contracts and/or granting of petroleum permits and authorizations. These include (i) the requirement for foreign producers and explorers applying for an exclusive development and production authorization to conduct their operations in Gabon through a company incorporated in Gabon rather than through branches of entities incorporated in other jurisdictions; and (ii) the obligation for all companies undertaking hydrocarbon activities to domicile their site rehabilitation funds with the Bank of Central African States, which is the Central African Economic and Monetary Community ("CEMAC") or a Gabonese bank or financial institution subject to the Central Africa Banking Commission, which supervises banks and financial institutions licensed to operate in CEMAC countries, within one year after the entry into force of the 2019 Hydrocarbons Law.

PSCs entered into between independent contractors and the State of Gabon since the implementation of the 2019 Hydrocarbons Law must include a clause providing that participation by the State of Gabon cannot exceed a 10% participating interest in the operations, to be carried by the contractor.

Under the 2019 Hydrocarbons Law, the direct or indirect assignment of a Contractor's rights or obligations to third parties (non affiliates) under the PSC is subject to approval of the Minister of Petroleum. The State and the national operator have preemption rights, that the State must exercise within 60 days and the national operator must exercise within 45 days if the State does not exercise its rights within the 60 days. The preemption right of the State and the national operator also applies in change of control situations. In February 2024, the State/national operator exercised its preemption right in a share transaction involving a number of PSCs and concessions already in effect prior to 2014.

The 2019 Hydrocarbons Law also entitles the National operator to acquire a maximum 15% stake at market value in all PSCs as of the date of signature.

In addition, the 2019 Hydrocarbons Law provides that the State of Gabon may acquire an equity stake of up to 10%, at market value, in an operator applying for or already holding an exclusive development and production authorization.

Canada

In Harmattan, Canada, we now own production and working interests in certain facilities in the Cardium light oil and Mannville liquids-rich gas assets. Harmattan is located approximately 80 kilometers north of Calgary, Alberta. This property produces oil and associated natural gas from the Cardium and liquids-rich natural gas from zones in the Lower Mannville and Rock Creek formations at vertical depths of 1,200 to 2,600 meters. The Harmattan property covers 46,100 gross acres of developed land and 29,300 gross acres of undeveloped land. We also own a 100% working interest in a large oil battery and a compressor station where a majority of oil volumes are handled. All gas is delivered to a third party non-operated gas plant for processing.

Our exploration and production activities in Canada are subject to Canadian federal and provincial regulations. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that could substantially increase our costs or affect our operations. The following is a summary of certain applicable regulatory frameworks in Canada.

With the exception of the province of Manitoba, each provincial government in Western Canada owns most of the mineral rights to the oil and natural gas located within their respective provincial borders. The Government of Alberta grants rights to explore for and produce oil and natural gas based on conditions set out in provincial legislation and regulations in exchange for a Crown Royalty share as set out in the Alberta Modernized Royalty Framework Guidelines, 2017 (as amended in 2023). To develop oil and gas resources, producers must also have access rights to the surface lands required to conduct operations. For private lands in Alberta, producers must either obtain consent of the private landowner or, where an agreement cannot be reached, a right of entry order issued under the Surface Rights Act (Alberta). In addition to obtaining mineral and surface rights in Canada, producers may need to engage extensively with Indigenous groups. Canadian federal and provincial governments have a constitutional duty to consult and, in some cases, accommodate Indigenous groups where a project might adversely impact a potential Indigenous rights and title claim. The procedural aspects of the duty to consult are often delegated to project proponents.

Pursuant to The Constitution Act, 1867 (Canada), the Canadian federal government has primary jurisdiction over interprovincial oil and gas pipelines, import and export trade in oil and gas, and offshore oil and gas exploration and production. Proposed interprovincial pipeline projects require a regulatory review by the Canada Energy Regulator under the Canadian Energy Regulator Act (Canada) to proceed. An impact assessment by the Impact Assessment Agency and a determination by Cabinet that a pipeline project is in the public interest will also likely be required under the Impact Assessment Act (Canada)("IAA"). Certain oil and gas projects were subject to federal environmental assessments prior to the Supreme Court of Canada finding the "designated projects" component of the IAA to be unconstitutional in a judgement released on October 13, 2023. The federal government has yet to introduce legislative changes to the IAA clarifying the scope of federal environmental assessments following the Supreme Court of Canada's ruling.

The Alberta Energy Regulator ("AER") is the primary regulator of resource development in Alberta. It derives its authority from the Responsible Energy Development Act (Alberta) and several related statutes. AER regulatory approval is required for all oil and natural gas projects or activities in Alberta. An environmental impact assessment under the Environmental Protection and Enhancement Act (Alberta) will also likely be required.

In addition to conducting project approvals, the AER regulates the lifecycle of projects and performs ongoing monitoring of oil and gas projects to ensure compliance with standards and conditions set out in the licenses and approvals it issues and in the AER directives and regulations. The AER also oversees project closure obligations. For example, the AER administers the Licensee Liability Management Rating Program, which is currently being phased out with implementation of the AER's new Liability Management Framework ("LMF"), to ensure adequate security is available for a project to be decommissioned safely, with no harm to the public or the environment.

Canada also has extensive climate change regulations at both the federal and provincial level mandating greenhouse gas ("GHG") emission reductions by oil and natural gas producers. The federal government enacted the Greenhouse Gas Pollution Pricing Act (Canada) (the "GGPPA"), which came into force on January 1, 2019. One component of this regime is an emissions trading system for large industry. The GGPPA allows provinces to either develop their own carbon pollution pricing systems that meet the minimum federal benchmark, failing which the federal carbon pollution pricing system applies. Alberta's Technology Innovation and Emissions Reduction Regulation ("TIER"), which came into effect on January 1, 2020, regulates emissions of heavy industry in line with federal standards. On December 14, 2022, the Government of Alberta introduced several amendments to TIER which became effective January 1, 2023, broadening the scope of "large emitters" subject to TIER and strengthening facility specific benchmarks, among other things. The Government of Alberta also enacted the Methane Emission Reduction Regulation (Alberta) on January 1, 2020, which, in line with AER Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting ("AER Directive 060") and AER Directive 017: Measurement Requirements for Oil and Gas Operations sets vent gas limits for methane per month, which are monitored through the collection of representative measuring data.

In Canada, there is a general presumption against the retroactive application of legislation absent an express statutory statement to the contrary. Significant changes to oil and gas regulations impacting existing projects are also often implemented through a prospective phase-in approach. For example, in 2019 the Royalty Guarantee Act (Alberta) came into effect and provides that no major changes will be made to the current oil and gas royalty structure for a period of at least 10 years. AER Directive 060 was updated in April 2022 and sets more stringent vent gas limits for equipment installed after January 1, 2022, with a phased in approach for equipment installed prior to that date.

Egypt

Laws and Regulations

The Egyptian Ministry of Petroleum and Mineral Resources ("MOP") is the ministerial governmental authority responsible for the regulation and development of the oil and gas industry in Egypt. Certain government agencies, including EGPC, the Egyptian Natural Gas Holding Company ("EGAS") and the Ganoube El-Wadi Petroleum Holding Company ("GANOPE") (each the "government entity") have been set up to help the MOP achieve its objectives.

Under the Egyptian Constitution, all oil and gas resources are under the control of the State of Egypt. Accordingly, only the State can grant rights for exploration and exploitation of oil and gas resources for interested investors. The Egyptian Constitution provides that concessions for the exploitation of such resources shall be issued by virtue of a law for a period not exceeding 30 years.

Concession Agreement

The mechanism for granting a contractor the right to carry out oil and gas exploration and development activities is the concession agreement. Concession agreements have the force and privileges of law in Egypt, meaning each agreement is an Egyptian Act of Parliament. The concession agreement overrides any contradictory Egyptian laws but not the Egyptian Constitution. In the absence of any legal rule under the relevant concession agreement, the exploration and exploitation operations will be subject to the rules of the Fuel Materials Law No. 66/1953 as amended, and its executive regulation issued by Minister of Industry Decree No. 758/1972 as amended (the "Fuel Materials Law"), and related ministerial decrees, where applicable.

Concession agreements usually follow a standard format which may be updated by the MOP and the relevant government entity from time to time, with slight variations. The commercial terms of concession agreements are open to negotiation, but each concession agreement will typically set out certain factors such as: (i) minimum work and financial commitments associated with each exploration and development program; (ii) any bonus payment(s) to be paid by the contractor to the relevant government agency upon triggering events (usually tied to certain production milestones); (iii) royalties payable to the government in cash or in kind; (iv) exploration and development periods and extensions of each; (v) rules concerning the contractor's recovery of its costs and expenses in association with exploration, development and related operations; (vi) production sharing valuations; (vii) priority right to the relevant government entity to offtake the production for domestic needs; (viii) relinquishment obligations and the associated triggering events; and (ix) requirements and procedures to convert an area to a development and to obtain a development lease, conclude sales and offtake agreement, and to dispose of the contractor's share of production.

Cost Recovery and Production Allocation

The concession agreement will set out in detail the distribution of cost recovery for the contractor, including a dedicated annex outlining the accounting procedures for treatment of costs, expenses, and taxes under the concession agreement. Typically, the contractor bears all the risks until a commercial discovery is made, and, following which, the joint operating committee ("JOC") is formed. The contractor will then be entitled to recover a certain percentage of its costs related to its previous and ongoing exploration and development activities in proportion to its working interest in the concession agreement. These costs may be recovered from the total petroleum production at a rate set out under the concession agreement on a quarterly basis. If the recoverable expenditures exceed the amount recoverable from petroleum production in any period, the unrecovered portion of the expenditures can usually be carried forward to subsequent periods. Full title to fixed and movable assets that are charged to cost recovery will usually pass from the contractor to the relevant government agency when its total costs have been recovered in accordance with the concession agreement, or at the time of relinquishment of the concession agreement with respect to all assets chargeable to the operations whether recovered or not, whichever occurs earlier.

Ownership of Assets

Under the model concession agreements, the movable and immovable assets (other than lands, which become GANOPE/EGAS/EGPC's property as of the purchase thereof) are transferred automatically and gradually from the contractor to the government entity, as they become subject to cost recovery pursuant to the cost recovery provisions of the concession. The contractor (through the JOC) only has the right to use such assets for the purpose of petroleum operations under the concession agreement.

Termination and Revocation of Concession

The concession agreement is terminated by the lapse of its term, unless terminated prematurely. In addition, the Government has the right to prematurely terminate the concession agreement in several instances set out in the concession. The Government may, among other things, terminate the concession in the event of a misrepresentation by the contractor, an assignment of the contractor's rights without obtaining the required approvals, or the contractor being declared bankrupt, or committing any material breach under the concession or the Fuel Materials Law. If the Government deems that one of these causes (other than force majeure events) exists, it will give the contractor 90 days’ written notice to remedy and remove the cause. If, at the end of the 90-day notice period, the cause has not been remedied and removed, the concession agreement may be terminated by a presidential decree.

Equatorial Guinea

Our exploration and production activities in Equatorial Guinea are subject to the applicable regulations of the country. Failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that could substantially increase our costs or affect our operations. A draft of a new Hydrocarbons Law was distributed by the Ministry of Petroleum during 2023 for comment and a new General Tax Law is being reviewed by the Parliament, but it is still not possible to determine if any changes materially affecting our operations will be approved. The following is a summary of certain currently applicable regulatory frameworks in Equatorial Guinea.

All hydrocarbons existing in Equatorial Guinea’s onshore territory, as well as in its sovereign and jurisdictional waters, are Equatorial Guinea property and part of the public domain. The monetization of such hydrocarbons is to be pursued exclusively by Equatorial Guinea under its constitution, which reserves the exploitation of mineral and hydrocarbons resources exclusively to Equatorial Guinea and the public sector. However, the constitution also provides that Equatorial Guinea can delegate to, grant a concession to or associate itself with private parties for purposes of exploration and production activities in the manner and cases set forth by law.

Private crude oil companies have been allowed to conduct petroleum operations in Equatorial Guinea through PSCs signed by the minister responsible for petroleum operations on behalf of Equatorial Guinea. PSCs are subject to ratification by the President of the Republic of Equatorial Guinea and become effective only on the date the contractor is notified of presidential ratification. The powers to sign and amend PSCs and supervise their performance belong to the ministry responsible for petroleum operations. In addition, the national oil company of Equatorial Guinea, GEPetrol, holds, manages and takes participations in petroleum activities on behalf of Equatorial Guinea.

In 2006, the Parliament of Equatorial Guinea passed a new hydrocarbons law (“2006 Hydrocarbons Law”), which superseded the previous 1981 Hydrocarbons Law, as amended in 2000, incorporating not only the regime applicable to the exploration, appraisal, development and production of hydrocarbons, but also rules on their transportation, distribution, storage, preservation, decommissioning, refining, marketing, sale and other disposal. The Hydrocarbons Law contains provisions on a number of aspects concerning exploration and production operations and contracts, such as national content obligations, unitization, transfers and abandonment. The 2006 Hydrocarbons Law grants the ministry appointed to be responsible for petroleum operations (“Appointed EG Petroleum Ministry”) significantly broad regulatory, inspective and auditing powers concerning the performance of petroleum operations. These include the powers to negotiate, sign, amend and perform all contracts entered into between the State of Equatorial Guinea and independent contractors, as well as the right to access all data and information required for the control of contractors and their activities, including free access to the locations and facilities where petroleum operations are conducted.

In addition, the Appointed EG Petroleum Ministry can also order (i) the suspension of petroleum operations; (ii) the evacuation of persons from locations; (iii) the suspension of the use of any machine or equipment; and/or (iv) any other action it deems necessary or appropriate when the Appointed EG Petroleum Ministry determines that a given petroleum operation may cause injury to or death of persons, damage properties, or harm the environment, or whenever the national interest so requires.

Until June 2016, the Appointed EG Petroleum Ministry was the Ministry of Mines, Industry and Energy, whose organization and authority were granted under Decree No. 170/2005, of 15 August 2005.

In June 2016, the President of Equatorial Guinea appointed the EG MMH and the Minister of Industry and Energy, effectively splitting the Ministry of Mines, Industry and Energy into two ministries. However, no legislation on the organization and authority of each ministry has been enacted, and, in effect, the EG MMH has been exercising the powers contained within the Hydrocarbons Law to the Appointed EG Petroleum Ministry. This situation has not changed. Also, in early 2023, Mr. Gabriel Obiang Lima, who had been the Minister in charge of petroleum matters for several years, was moved to another Ministry and Mr. Antonio Oburu, who had been the General Director of the National Oil Company (GEPetrol), became the head of the MMH. Until now no materials changes in the enforcement of petroleum legislation has been felt.

All contracts signed with the State of Equatorial Guinea for the exploration and production of hydrocarbons have taken the form of PSCs. A model PSC, approved along with the Hydrocarbons Law, must be used as the basis for any negotiation between independent contractors and the State of Equatorial Guinea. Over time, however, revised copies of the model PSC, reflecting changes made during negotiations of certain PSCs, have been used for the negotiation of subsequent PSCs.

The Hydrocarbons Law and Petroleum Regulations provide the Appointed EG Petroleum Ministry with the power to award contracts for the exploration and production of hydrocarbons and decide whether the award is made by means of competitive international public tender or direct negotiation. These contracts, however, which are to be negotiated by the Appointed EG Petroleum Ministry, shall only become effective after they have been ratified by the President of Equatorial Guinea and on the date of delivery to the contractor of a written notice of the President's ratification. In practice, however, this notification to operators has been provided by the Appointed EG Petroleum Ministry.

GEPetrol, established in 2001, is the national oil company of Equatorial Guinea and Sociedad Nacional de Gas de Guinea Equatorial ("Sonagas"), established in 2005, is the national gas company of Equatorial Guinea.

The Hydrocarbons Law provides that these national companies are exclusively owned by the State of Equatorial Guinea and must be supervised by the Appointed EG Petroleum Ministry.

Under the applicable laws, the State of Equatorial Guinea may elect to have, either directly or through a national company, a minimum interest of 20% in a PSC.

The State of Equatorial Guinea's interest (through GEPetrol or otherwise) may be, and typically is, carried. No costs are paid by the State of Equatorial Guinea or GEPetrol with respect to a carried interest. The Hydrocarbons Law provides that the State of Equatorial Guinea (through GEPetrol or otherwise) will only be required to contribute to any cost for petroleum operations that it has a carried interest in from the period where it notifies the contractor that it no longer wants its interest carried. In effect, however, the carry normally ends with the approval of the development and production of the asset subject to the PSC.

The terms and effects of the carry of an interest of the State of Equatorial Guinea (through GEPetrol or otherwise) are not clearly established in the Hydrocarbons Law or the Petroleum Regulations; the contractor that carries the State of Equatorial Guinea's interest is given the right to a percentage of the cost recovery oil pertaining to that interest, as agreed in each PSC.

ENVIRONMENTAL REGULATIONS

General

Our operations are subject to various federal, state, local and international laws and regulations, including laws and regulations in Gabon, Equatorial Guinea, Egypt and Canada, governing the discharge of materials into the environment or otherwise relating to environmental protection or pollution control. The cost of compliance could be significant. While we are currently complying in all material respects with all environmental laws and regulations, failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial and damage payment obligations, or the issuance of injunctive relief (including orders to cease operations). Environmental laws and regulations are complex and have tended to become more stringent over time. We also are subject to various environmental permit requirements. Some environmental laws and regulations may impose strict liability, which could subject us to liability for conduct that was lawful at the time it occurred or joint and several liability, which could subject us to liability for conduct or conditions caused by prior operators or third parties. To the extent laws are enacted or other governmental action is taken that prohibits or restricts drilling or imposes environmental protection requirements that result in increased costs to the crude oil, natural gas and NGLs industry in general, our business and financial results could be adversely affected. Although no assurances can be made, we believe that, absent the occurrence of an extraordinary event, compliance with existing laws, rules and regulations regulating the release of materials into the environment or otherwise relating to the protection of the environment will not have a material effect upon our capital expenditures, earnings or competitive position with respect to our existing assets and operations. We cannot predict, however, what effect future environmental regulation or legislation, enforcement policies, or claims for damages to property, employees, other persons, the environment or natural resources could have on us.

In addition, a number of governmental bodies have adopted, have introduced or are contemplating regulatory changes in response to the potential impact of climate change. Legislation, increased regulation and litigation regarding climate change could impose significant costs on us, our joint venture owners, and our suppliers, including costs related to increased energy requirements, capital equipment, environmental monitoring and reporting, and other costs to comply with such regulations. For example, in April 2016, 195 nations, including Gabon, Equatorial Guinea, Egypt, Canada and the U.S., signed and officially entered into an international climate change accord (the "Paris Agreement"). The Paris Agreement calls for signatory countries to set their own GHG emissions targets, make these emissions targets more stringent over time and be transparent about the GHG emissions reporting and the measures each country will use to achieve its GHG targets. A long-term goal of the Paris Agreement is to limit global temperature increase to well below two degrees Celsius from temperatures in the pre-industrial era. The Paris Agreement is effectively a successor agreement to the Kyoto Protocol treaty, an international treaty aimed at reducing emissions of GHG, to which various countries and regions are parties.

The State of Gabon and the Republic of Equatorial Guinea did not sign the Global Renewables and Energy Efficiency Pledge at COP 28. However, a few oil companies operating in Gabon signed the Oil and Gas Decarbonization Charter at COP 28. One of them is ending its operations in Equatorial Guinea upon the expiration of its petroleum contracts.

On October 5, 2016, Canada ratified the Paris Agreement by a vote in Parliament. In August 2017, the U.S. Department of State officially informed the United Nations of the U.S.' intent to withdraw from the Paris Agreement, with such withdrawal becoming effective in November 2020. However, on January 20, 2021, President Biden issued written notification to the United Nations of the U.S.' intention to rejoin the Paris Agreement, which took effect on February 19, 2021, and on April 22, 2021, President Biden announced a target for the US to achieve a 50-52% reduction from 2005 levels in economy-wide GHG emissions by 2030. Following the Paris Agreement and its ratification in Canada, the Government of Canada also pledged to cut its emissions by 40-45% from 2005 levels by 2030. In June 2021, the Canadian federal government passed the Canadian Net-Zero Emissions Accountability Act (Canada), which provides a legal foundation and framework for Canada to achieve net-zero GHG emissions by 2050.

Given the political significance and uncertainty around the impact of climate change and how it should be dealt with, we cannot predict how legislation and regulation, including the Paris Agreement and any related GHG emissions targets, potential prices on carbon emissions, incentives to use renewable forms of energy or other requirements, will affect our financial condition and operating performance. Apart from any new legal developments, increased awareness and any adverse publicity in the global marketplace about potential impacts on climate change by us or other companies in our industry could harm our reputation, restrict our access to capital or impact the marketability of crude oil, natural gas and NGLs. In addition, the potential physical impacts of climate change on our operations are highly uncertain and would be particular to the geographic circumstances in areas in which we operate. These may include changes in rainfall amounts, storm patterns and storm intensities, water shortages, changing sea levels, and changing temperatures. These impacts may adversely impact the cost, production, and financial performance of our operations.

In part because they are economically developing countries, it is unclear how quickly and to what extent Gabon, Equatorial Guinea or Egypt will increase their regulation of climate change issues in the future. As of the date of this Annual Report, Equatorial Guinea has not adopted any new environmental legislation. Gabon has adopted Ordinance No. 019/2021 of September 13, 2021 on Climate Change, which ratification law has been published in the Official Gazette, with the objective of complying with the Paris Agreement (the "Ordinance on Climate Change"). The Ordinance on Climate Change particularly aims to: (a) provide a framework for targets to be set for controlling and reducing emissions and for increasing GHG absorption in the national climate change strategy and the national plans for climate change adaptation and mitigation; (b) define and develop tools and mechanisms for climate change adaptation and mitigation; (c) provide a framework for, and implement, strategies for adaptation, monitoring mitigation and assessment, action plans, policies, programs and adaptation and mitigation measures; (d) provide a framework and take effective response for adaptation and mitigation measures to facilitate the setting of specific sustainable development, security and energy efficiency goals; (e) promote and manage sustainable development through climate change mitigation and adaptation activities; (f) establish climate change financing mechanisms; and (g) complement international instruments addressing climate change. It also sets forth climate adaptation and mitigation measures for carbon intensive operators (which include petroleum companies) such as (a) the establishment of a National Plan on the Reduction of Gas Flaring with a zero flaring objective; (b) the establishment of a GHG emissions database and quota system, (c) a carbon offset register, and (d) penalties and sanctions for not complying with such measures. Egypt ratified the United Nations Framework Convention on Climate Change (UNFCCC) in 1994, signed the Paris Agreement in 2016 and ratified it in 2017. Egypt is among the top affected countries by climate change. Egypt is already implementing plans pertaining to energy resources diversification and acceleration of decreased carbon emissions, in line with its "Sustainable Development Strategy: Egypt Vision 2030", the "Integrated Sustainable Energy Strategy 2035" and its "National Climate Change Strategy 2050". Egypt was also host to the United Nations Climate Change Conference-COP27, during which the role of the oil and gas sector was the highlight of the "Decarbonization Day" thereof. Egypt submitted in June 2023 a revised Nationally Determined Contribution (NDC) to the United Nations Development Programme ("UNDP"), focusing on Egypt's commitment to reduce emissions by 65% in the oil and gas sector (1.7 Mt CO_2e) by 2030, increasing renewable energy capacities and alternative energy (including natural gas) sources to generate 42% of electricity by 2035, and increased policy actions and measures across key sectors including the oil and gas sector. Through 2022 to 2023, Egypt announced and signed further partnerships in the energy sector, particularly for green hydrogen and ammonia production. In December 2023, during COP28, Egypt formally launched the first African voluntary carbon marketplace.

Moreover, Gabon has recently adopted Law no. 007/2023 of November 2, 2023 on the prevention and management of disasters, which requires companies conducting activities defined as dangerous or operating at facilities that are deemed to have an impact on the environment, to obtain, as relevant, authorizations, or establish operational plans. There are no further guidelines on whether and how it will apply to the petroleum industry.

In addition, following the coup d'état on August 30, 2023 in Gabon, the establishment of a Transition Committee for the Restoration of Institutions, the swearing in of General Brice Oligui Nguema as President and the appointment of a Transition Government, with in view of holding elections in 2025 (tentative date), it is still unclear whether and how any environmental regulation having a material impact on petroleum operations will be adopted during the Transition Period, and how the current regulations will be implemented.

Any significant increase in the regulation or enforcement of environmental issues by Gabon, Equatorial Guinea or Egypt could have a material effect on us. Economically developing countries, in certain instances, have patterned environmental laws after those in the U.S. However, the extent that any environmental laws are enforced in economically developing countries varies significantly.

With regards to our development operations offshore West Africa, we are a member of Oil Spill Response Limited ("OSRL"), a global emergency and crude oil spill-response organization headquartered in London. OSRL has aircraft and equipment available for dispersant application or equipment transport, including various boom systems that can be used for offshore and shoreline recovery operations. In addition, VAALCO has a Tier 1 spill kit in-country for immediate deployment if required. See "*Item 1A. Risk Factors*" for further discussion on the impact of these and other regulations relating to environmental protection.

Item 1A. Risk Factors

Our business faces many risks. You should carefully consider the following risk factors in addition to the other information included in this Annual Report. If any of these risks or uncertainties actually occurs, our business, financial condition and results of operations could be materially adversely affected. Any risks discussed elsewhere in this Annual Report and in our other SEC filings could also have a material impact on our business, financial position or results of operations. Additional risks not presently known to us or that we consider immaterial based on information currently available to us may also materially adversely affect us.

Risks Relating to Our Business, Operations and Strategy

Our business requires significant capital expenditures and we may not be able to obtain needed capital or financing to fund our exploration and development activities or potential acquisitions on satisfactory terms or at all.

Our exploration and development activities, as well as our active pursuit of complementary opportunistic acquisitions, are capital intensive. To replace and grow our reserves, we must make substantial capital expenditures for the acquisition, exploitation, development, exploration and production of crude oil, natural gas and NGLs reserves. Historically, we have financed these expenditures primarily with cash from operations, debt, asset sales and private sales of equity. We are the operator of the Etame Marin block offshore Gabon, and are responsible for contracting on behalf of all the remaining parties participating in the project and rely on our joint venture owners to pay for 36.4% of the offshore Gabon budget. With respect to Block P, the EG MMH approved our appointment as technical operator in August 2020 and, since we were appointed, we will rely on the timely payment of cash calls by our joint venture owners to pay for 46.3% of the Equatorial Guinea budget, except during any development phases where we have agreed or will agree to carry their interests. The continued economic health of our joint venture owners could be adversely affected by low crude oil prices, thereby adversely affecting their ability to make timely payment of cash calls.

If low crude oil, natural gas and NGLs prices, operating difficulties or declines in reserves result in our revenues being less than expected or limit our ability to enter into debt financing arrangements, or our joint venture owners fail to pay their share of project costs, we may be unable to obtain or expend the capital necessary to undertake or complete future drilling programs or to acquire additional reserves.

We do not currently have any commitments for future external funding for capital expenditures or acquisitions beyond cash generated from operating activities and our $50 million Facility Agreement (the commitments under which decreased to $43.8 million beginning October 1, 2023). Our ability to secure additional or replacement financing to finance expenditure beyond our current committed capital expenditure for the next 12 months may be limited. We cannot provide any assurances that such additional debt or equity financing or cash generated by operations will be available to meet our capital requirements and fund acquisitions. We may not be able to obtain debt or equity financing on terms favorable to us, or at all. Even if we succeed in selling additional equity securities to raise funds, at such time the ownership percentage of our existing stockholders would be diluted, and new investors may demand rights, preferences or privileges senior to those of existing stockholders. If we raise additional capital through debt financing, the financing may involve covenants that restrict our business activities or our ability to make future acquisitions. If cash generated by operations or cash available under any financing sources is not sufficient to meet our capital requirements beyond our current committed expenditure for the next 12 months, the failure to obtain additional financing could result in a curtailment of our operations relating to the development of our properties or prevent us from consummating acquisitions of additional reserves. Such a curtailment in operations or activities could lead to a decline in our estimated net proved reserves and would likely materially adversely affect our business, financial condition and results of operations.

Unless we are able to replace the proved reserve quantities that we have produced through acquiring or developing additional reserves, our cash flows and production will decrease over time.

Our future success depends upon our ability to find, develop or acquire additional crude oil, natural gas and NGLs reserves that are economically recoverable. In general, production from crude oil, natural gas and NGLs properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our ability to make the necessary capital investment to maintain or expand our asset base of crude oil, natural gas and NGLs reserves would be limited to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves. Except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, our estimated net proved reserves will generally decline as reserves are produced.

There can be no assurance that our development and exploration projects and acquisition activities will result in significant additional reserves or that we will have continuing success drilling productive wells at economic finding costs. The drilling of crude oil, natural gas and NGLs wells involves a high degree of risk, especially the risk of dry holes or of wells that are not sufficiently productive to provide an economic return on the capital expended to drill the wells. Additionally, seismic and other technology does not allow us to know conclusively prior to drilling a well that crude oil natural gas or NGLs is present or economically producible. Our drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, including declines in crude oil, natural gas or NGLs prices and/or prolonged periods of historically low crude oil, natural gas and NGLs prices, weather conditions, political instability, availability of capital, economic/currency imbalances, compliance with governmental requirements, receipt of additional seismic data or the reprocessing of existing data, failure of wells drilled in similar formations, equipment failures (such as ESPs), delays in the delivery of equipment, and the availability of drilling rigs. If we are unable to increase our proved quantities, there will likely be a material impact on our cash flows, business and operations.

We may not enter into definitive agreements with the BWE Consortium to explore and exploit new properties, and we may not be in a position to control the timing of development efforts, the associated costs or the rate of production of the reserves operated by the BWE Consortium or from any non-operated properties in which we have an interest.

On October 11, 2021, we announced our entry into a consortium with the “BWE Consortium” and that the BWE Consortium had been provisionally awarded two blocks, G12-13 and H12-13, in the 12th Offshore Licensing Round in Gabon. Negotiations to finalize the commercial terms were held in 2023, however they were halted late in the year due to the presidential elections. The negotiations were kick started again at the request of the Gabonese Government in early February 2024, where the consortium and the government came to an agreement on the fiscal terms on February 9, 2024. The next step is concluding the terms of the production sharing contracts with the Gabonese government. BW Energy will be the operator with a 37.5% working interest and we and Panoro Energy will have a 37.5% working interest and 25% working interest, respectively, as non-operating joint owners. The joint owners in the BWE Consortium intend to reprocess existing seismic and carry out a 3-D seismic campaign on these two blocks and have also committed to drilling exploration wells on both blocks. Our obligations within the BWE Consortium are subject to a number of conditions, including the negotiation and execution of production sharing contracts with the Gabonese government, as well the entry into joint operating agreements with our joint interest owners. There is no assurance that we will be able to agree to terms on definitive production sharing contracts with the Gabonese government nor joint operating agreements with the joint owners in the BWE Consortium. If we are unable to negotiate and enter into definitive agreements with each party, we may not be able to explore, develop and exploit new properties, and our results of operations could be materially adversely affected.

We may have limited control over matters relating to development and exploitation activities, including the timing of and capital expenditures for such activities, in projects where we are not the operator, including properties operated by the BWE Consortium. The success and timing of development and exploitation activities on such properties, depends upon a number of factors, including:

- the timing and amount of capital expenditures;
- the availability of suitable offshore drilling rigs, drilling equipment, support vessels, production and transportation infrastructure and qualified operating personnel;
- the operator’s expertise, financial resources and willingness to initiate exploration or development projects;
- approval of other participants in drilling wells;
- risk of other a non-operator’s failure to pay its share of costs, which may require us to pay our proportionate share of the defaulting party’s share of costs;
- selection of technology;
- delays in the pace of exploratory drilling or development;
- the rate of production of the reserves; and/or
- the operator’s desire to drill more wells or build more facilities on a project inconsistent with our capital budget, whether on a cash basis or through financing, which may limit our participation in those projects or limit the percentage of our revenues from those projects.

The occurrence of any of the foregoing events could have a material adverse effect on our anticipated exploration and development activities.

Our offshore operations involve special risks that could adversely affect our results of operations.

Offshore operations are subject to a variety of operating risks specific to the marine environment. Our offshore production facilities are subject to hazards such as capsizing, sinking, grounding, collision and damage from severe weather conditions. The relatively deep offshore drilling that we conduct involves increased drilling risks of high pressures and mechanical difficulties, including stuck pipe, collapsed casing and separated cable. We have experienced pipeline blockages in the past and may experience additional pipeline blockages in the future. The impact that any of these risks may have upon us is increased due to the low number of producing properties we own. We could incur substantial expenses that could reduce or eliminate the funds available for exploration, development or license acquisitions, or result in loss of equipment and license interests.

Exploration and development operations offshore Africa often lack the physical and oilfield service infrastructure present in other regions. As a result, a significant amount of time may elapse between an offshore discovery and the marketing of the associated crude oil, natural gas and NGLs, increasing both the financial and operational risks involved with these operations. Offshore drilling operations generally require more time and more advanced drilling technologies, involving a higher risk of equipment failure and usually higher drilling costs. In addition, there may be production risks for which we are currently unaware. The development of new subsea infrastructure and use of floating production systems to transport crude oil from producing wells may require substantial time for installation or encounter mechanical difficulties and equipment failures that could result in loss of production, significant liabilities, cost overruns or delays.

In addition, in the event of a well control incident, containment and, potentially, clean-up activities for offshore drilling are costly. The resulting regulatory costs or penalties, and the results of third-party lawsuits, as well as associated legal and support expenses, including costs to address negative publicity, could well exceed the actual costs of containment and clean-up. As a result, a well control incident could result in substantial liabilities for us and have a significant negative impact on our earnings, cash flows, liquidity, financial position and stock price.

Acquisitions and divestitures of properties and businesses may subject us to additional risks and uncertainties, including that acquired assets may not produce as projected, may subject us to additional liabilities and may not be successfully integrated with our business. In addition, any sales or divestments of properties we make may result in certain liabilities that we are required to retain under the terms of such sales or divestments.

One of our growth strategies is to capitalize on opportunistic acquisitions of crude oil, natural gas and NGLs reserves and/or the companies that own them and other strategic transactions that fit within our overall business strategy. Any future acquisition will require an assessment of recoverable reserves, title, future crude oil, natural gas and NGLs prices, operating costs, potential environmental hazards, potential tax and employer liabilities, regulatory requirements and other liabilities and similar factors. Ordinarily, our review efforts are focused on the higher valued properties and are inherently incomplete because it generally is not feasible to review in depth every potential liability on each individual property involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and potential problems, such as ground water contamination and other environmental conditions and deficiencies in the mechanical integrity of equipment are not necessarily observable even when an inspection is undertaken. Any unidentified problems could result in material liabilities and costs that negatively impact our financial condition.

Additional potential risks related to acquisitions include, among other things:

- incorrect assumptions regarding the reserves, future production and revenues, or future operating or development costs with respect to the acquired properties, as well as future prices of crude oil, natural gas and NGLs;
- decreased liquidity as a result of using a significant portion of our cash from operations or borrowing capacity to finance acquisitions;
- significant increases in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs (including potential regulatory actions) that we are not indemnified for or that our indemnity, insurance or other protection is inadequate to protect against;
- an increase in our costs or a decrease in our revenues associated with any claims or disputes with governments or other interest owners;
- an incurrence of non-cash charges in connection with an acquisition and the potential future impairment of goodwill or intangible assets acquired in an acquisition;
- the risk that crude oil, natural gas and NGLs reserves acquired may not be of the anticipated magnitude or may not be developed as anticipated;
- difficulties in the assimilation of the assets and operations of the acquired business, especially if the assets acquired are in a new business segment or geographic area;
- the diversion of management’s attention from other business concerns during the acquisition and throughout the integration process;
- losses of key employees at the acquired businesses;
- difficulties in operating a significantly larger combined organization and adding operations;
- delays in achieving the expected synergies from acquisitions;
- the failure to realize expected profitability or growth;
- the failure to realize expected synergies and cost savings; and
- challenges in coordinating or consolidating corporate and administrative functions.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and you may not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in evaluating future acquisitions. In addition, acquisitions of businesses often require the approval of certain government or regulatory agencies and such approval could contain terms, conditions, or restrictions that would be detrimental to our business after a merger.

In the case of sales or divestitures of our properties and businesses, we may become exposed to future liabilities that arise under the terms of those sales or divestitures. Under such terms, sellers typically are required to retain certain liabilities for matters with respect to their sold properties or businesses. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a sale, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations. In addition, we may be required to recognize losses in accordance with exit or disposal activities.

The proposed acquisition of Svenska may not be consummated and if consummated, we may not realize the anticipated benefits expected from the acquisition.

On February 29, 2024, Buyer and Seller, entered into the Share Purchase Agreement pursuant to which the Buyer will purchase all of the issued shares in the capital of Svenska for $66.5 million in cash, subject to adjustment as described in the Share Purchase Agreement. Pursuant to the terms and subject to the conditions of the Share Purchase Agreement, upon Closing, Buyer will acquire Svenska and, as a result, Svenska’s primary asset: a 27.39% non-operated working interest in the deepwater producing Baobab field in Block CI-40, offshore Cote d’Ivoire in West Africa. Buyer will also acquire a 21.05% non-operated working interest in OML 145, a non-producing discovery located offshore of Nigeria that is not expected to be developed at this time. The Purchase Price will be funded by a combination of a dividend of cash on Svenska’s balance sheet to the Seller immediately prior to the consummation of the Acquisition and a portion of VAALCO’s cash-on-hand. VAALCO estimates that cash due from VAALCO at Closing will be in the range of approximately $30 to $40 million.

Closing is subject to obtaining necessarily regulatory approvals in Cote d'Ivoire and Sweden and the satisfaction of other customary closing conditions. If the closing conditions are not satisfied or waived within nine months of date of the Share Purchase Agreement, then either the Buyer or the Seller may, at its discretion, terminate the Share Purchase Agreement. No assurance can be given that the required approvals will be obtained or that the required conditions to closing will be satisfied or waived in a timely manner or at all, and accordingly consummation of the Acquisition may be delayed or not occur at all.

If consummated, the success of the Acquisition will depend, in part, on our ability to realize the anticipated benefits from combining our business with Svenska's business. The anticipated benefits and efficiencies of the Acquisition may not be realized fully or at all, may take longer to realize than expected, may not be realized or could have other adverse effects that we do not currently foresee. The failure to realize the anticipated benefits and synergies expected from the Acquisition could adversely affect our business, financial condition and operating results.

Our reserve information represents estimates that may turn out to be incorrect if the assumptions on which these estimates are based are inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present values of our reserves.

There are numerous uncertainties inherent in estimating quantities of proved crude oil, natural gas and NGLs reserves, including many factors beyond our control. Reserve engineering is a subjective process of estimating the underground accumulations of crude oil, natural gas and NGLs that cannot be measured in an exact manner. The estimates included in this document are based on various assumptions required by the SEC, including non-escalated prices and costs and capital expenditures subsequent to December 31, 2023, and, therefore, are inherently imprecise indications of future net revenues.

Estimates of economically recoverable crude oil, natural gas and NGLs reserves and the future net cash flows from them are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserves recovery, timing and amount of capital expenditures, marketability of crude oil, natural gas and NGLs, royalty rates, the assumed effects of regulation by governmental agencies, and future operating costs, all of which may vary materially from actual results. For those reasons, among others, estimates of the economically recoverable crude oil, natural gas and NGLs reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery, and estimates of future net revenues associated with reserves may vary and such variations may be material.

Actual future production, revenues, taxes, operating expenses, development expenditures and quantities of recoverable crude oil, natural gas and NGLs reserves may vary substantially from those assumed in the estimates. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves.

In addition, our reserves may be subject to downward or upward revision based upon production history, results of future development, availability of funds to acquire additional reserves, prevailing crude oil, natural gas and NGLs prices and other factors. Moreover, the calculation of the estimated present value of the future net revenue using a 10% discount rate as required by the SEC is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our reserves or the crude oil, natural gas and NGLs industry in general. It is also possible that reserve engineers may make different estimates of reserves and future net revenues based on the same available data.

Our reserve estimates are prepared using an average of the first day of the month prices received for crude oil, natural gas and NGLs for the preceding twelve months. Future reductions in prices, below the average calculated for 2023, would result in the estimated quantities and present values of our reserves being reduced. The forecast prices and costs assumptions assume changes in wellhead selling prices and take into account inflation with respect to future operating and capital costs.

Our proved reserves are in foreign countries and are or will be subject to service contracts, production sharing contracts and other arrangements. The quantity of crude oil, and natural gas and NGLs that we will ultimately receive under these arrangements will differ based on numerous factors, including the price of crude oil, and natural gas and NGLs, production rates, production costs, cost recovery provisions and local tax and royalty regimes. Changes in many of these factors could affect the estimates of proved reserves in foreign jurisdictions.

If our assumptions underlying accruals for abandonment/ decommissioning costs are too low, we could be required to expend greater amounts than expected.

All of our existing properties in Gabon which have future abandonment obligations are located offshore. Our existing properties in Egypt and Canada are onshore. The costs to abandon offshore on onshore wells and the related infrastructure may be substantial. For financial accounting purposes, we record the fair value of a liability for an asset retirement obligation in the period that it is incurred and capitalize the related costs as part of the carrying amount of the long-lived assets. The estimated liability is reflected in the "Asset retirement obligations" and the "Accrued liabilities and other" line items of our consolidated balance sheet.

As part of the Etame Marin block production license, we are subject to an agreed-upon cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin block. Based upon the most recent abandonment study completed in November 2021, the abandonment cost estimate used for this purpose is approximately \$81.3 million (\$47.8 million net to our 58.8% working interest) on an undiscounted basis. On an annual basis over the remaining life of the production license, we must fund a portion of these estimated abandonment costs. Future changes to the anticipated abandonment cost estimates could change our asset retirement obligations and increase the amount of future abandonment funding payments we are obligated to make.

In Egypt, under model concession agreements and the Egyptian Fuel Materials Law No. 66/1953 as amended and its Executive Regulations issued by Minister of Industry Decree No. 758/1972 as amended (the "Fuel Materials Law"), liabilities in respect of decommissioning movable and immovable assets (other than wells) passes to the Egyptian Government through the transfer of ownership from the contractor to the government under the cost recovery process. The model concession agreements do not deal with area handover and abandonment upon termination, expiration or withdrawal from a concession agreement and certain articles in the Fuel Materials Law may apply, albeit the matter in practice is within the discretion of the EGPC. While the current risk that we may become liable for decommissioning liabilities in Egypt is low, future changes to legislation or practice of the EGPC could result in decommissioning, abandonment and/or handover liabilities in Egypt. Any increase in Egyptian decommissioning liabilities could adversely affect our financial condition.

In relation to petroleum wells, the contractor is responsible for decommissioning non-producing wells under a decommissioning plan approved by EGPC. If EGPC agrees that a producing well is not economic, then the contractor will be responsible for decommissioning the well under an EGPC-approved decommissioning plan. EGPC, at its own discretion, may not require a well to be decommissioned if it wants to preserve the ability to use the well for other purposes. As EGPC has discretion on decommissioning wells, there is a risk that we could incur well decommissioning costs. In accordance with the respective concession agreements, expenses approved by EGPC are recoverable through the cost recovery mechanism.

In Canada, liabilities in respect of the decommissioning of our wells, fields and related infrastructure are derived from legislative and regulatory requirements concerning the decommissioning of wells and production facilities and require us to make provisions for and/or underwrite the liabilities relating to such decommissioning. It is difficult to accurately forecast the costs that we would incur in satisfying any decommissioning obligations. When such decommissioning liabilities crystallize, we will be liable either on our own or jointly and severally liable with any other former or current partners in the field. In the event that we are jointly and severally liable with other partners and such partners default on their obligations, we would remain liable, and our decommissioning liabilities could be magnified significantly through such default. Any significant increase in the actual or estimated decommissioning costs that we incur may adversely affect our financial condition. Under the Alberta LMF, the AER began to set annual mandatory closure spend targets for all licensees with inactive inventory in 2022. Under the AER's Closure Nomination Program, introduced in February 2023 through an update to AER Directive 088: Licensee Life-Cycle Management, eligible landowners or land rights holders can nominate oil and gas wells and facilities that have been inactive or abandoned for longer than five years, for closure, at the expense of the licensee. Liability management in the Alberta oil and gas sector will continue to evolve as the AER continues its phased implementation of the new LMF.

If we are required to expend greater amounts than expected on abandoning or decommissioning costs, this could materially affect our revenues and financial performance.

We may not generate sufficient cash to satisfy our payment obligations under the Merged Concession Agreement or be able to collect some or all of our receivables from the EGPC, which could negatively affect our operating results and financial condition.

On January 19, 2022, subsidiaries of TransGlobe executed the Merged Concession Agreement with the EGPC, which is effective upon the Merged Concession Effective Date. Under the Merged Concession Agreement, VAALCO is obligated to make modernization payments that total $65 million and are payable over six years from the Merged Concession Effective Date of which $45.0 million have been paid. Under the Merged Concession Agreement, TransGlobe will be required to pay an additional $10 million on February 1st for each of the next two years. In accordance with the Merged Concession Agreement, we agreed to substitute the 2023 and 2024 payments and issue two $10.0 million credits against receivables owed from EGPC. In addition, VAALCO has also committed to spending a minimum of $50 million over each five-year period for the 15 years of the primary term (total $150 million). Our ability to make scheduled payments arising from the Merged Concession Agreement will depend on our financial condition and operating performance, which would be subject to then prevailing economic, industry and competitive conditions and to certain financial, business, legislative, regulatory and other factors beyond our control. We may be unable to maintain a level of cash flow sufficient to permit us to satisfy the payment obligations under the Merged Concession Agreement. If we are unable to satisfy our obligations, it is possible that the EGPC could seek to terminate the Merged Concession Agreement, which would negatively affect our operating results and financial condition.

In addition, as of the Merged Concession Effective Date, there was an adjustment of funds owed to us for the difference between historic and Merged Concession Agreement commercial terms applied against Eastern Desert production from the Merged Concession Effective Date. The cumulative amount of the effective date adjustment was estimated at $67.5 million. However, the cumulative amount of the effective date adjustment is currently being finalized with EGPC and could result in a range of outcomes based on the final price per barrel negotiated. At December 31, 2023, the remaining $50.3 million is recorded on our consolidated balance sheet in Receivables-Other, net. If the EGPC's financial position becomes impaired or it disputes or if the EGPC refuses to pay some or all of the said amount, our ability to fully collect such receivable from the EGPC could be impaired, which could negatively affect our operating results and financial condition.

The Egyptian PSCs contain assignment provisions which, if triggered, could adversely affect our business.

On October 13, 2022, VAALCO completed its business combination transaction with TransGlobe whereby TransGlobe became an indirect wholly-owned subsidiary of VAALCO. Legacy subsidiaries of TransGlobe are party to the Egyptian PSCs, which contain restrictive wording relating to assignments of rights under such agreements which, if triggered, require consent of the Egyptian Government in connection with any such assignment (the "Assignment Provisions"). If triggered, the Assignment Provisions also provide that (i) in certain circumstances, the EGPC has the right to acquire the interest intended to be assigned; and (ii) an assignment fee is payable to the EGPC in an amount equal to 10% of the value of each assignment.

We do not believe the Arrangement triggered the Assignment Provisions. EGPC has not concurred that no assignment fee is payable. We are continuing to engage in discussions with the office of the Minister of Petroleum and Mineral Resources and the EGPC for the purpose of resolving the matter. Resolution of this matter could result in a range of outcomes and no assurance can be given that such outcomes will not involve an offset of amounts owed by EGPC to VAALCO. If the Arrangement is deemed to have triggered the Assignment Provisions or VAALCO agrees to make payment to EGPC as part of a resolution, such payment could have an adverse effect on the value of our assets and could adversely affect our results of operations or financial condition.

We could lose our interest in Block P in Equatorial Guinea if we do not meet our commitments under the production sharing contract.

Our Block P production sharing contract provides for a development and production period of 25 years from the date of approval of a development and production plan. We and our Block P joint venture owners are evaluating the timing and budgeting for development and exploration activities in the block. We have completed a feasibility study of a standalone production development opportunity of the Venus discovery on Block P and on July 15, 2022 submitted to the EG MMH a plan of development for Block P which on September 16, 2022 was approved by the government of Equatorial Guinea. Due to delays by the partners in agreeing on certain terms relating to joint operations, the EG MMH delayed commencement of the Plan of Development, but on August 24, 2023, the EG MMH directed that activities relating to the Plan of Development resume. There can be no certainty any such transaction will be completed or that we will be able to commence drilling operations in Block P. If the joint venture owners of Block P fail to meet the commitments under the production sharing contract amendment, our capitalized costs of $10 million associated with Block P interest would be impaired.

Commodity derivative transactions that we enter into may fail to protect us from declines in commodity prices and could result in financial losses or reduce our income.

In order to reduce the impact of commodity price uncertainty and increase cash flow predictability relating to the marketing of our crude oil, natural gas and NGLs we have entered into and may continue to enter into derivative arrangements with respect to a portion of our expected production.

Our derivative contracts typically consist of a series of commodity swap contracts, such as puts, collars and fixed price swaps, and are limited in duration.

The following table shows the hedges outstanding at December 31, 2023:

Settlement Period	Type of Contract	Index	Average Monthly Volumes (Bbls)	Weighted Average Put Price (per Bbl)	Weighted Average Call Price (per Bbl)
January 2024 - March 2024	Collars	Dated Brent	85,000	$ 65.00	$ 97.00
April 2024 - June 2024	Collars	Dated Brent	65,000	$ 65.00	$ 100.00

The following table shows the additional hedges entered into in 2024:

Settlement Period	Type of Contract	Index	Average Monthly Volumes (Bbls)	Weighted Average Put Price (per Bbl)	Weighted Average Call Price (per Bbl)
July 2024 - September 2024	Collars	Dated Brent	80,000	$ 65.00	$ 92.00

The hedge counterparty will be obligated to make payments to us to the extent that the floating (market) price is below an agreed fixed (strike) price. However, hedging agreements expose us to risk of financial loss if the counterparty to a hedging contract defaults on our contract obligations. Disruptions in the market could also lead to sudden changes in the liquidity of the counterparties to our hedge transactions which in turn limit our ability to perform under their hedging contracts with us. Even if we accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions. If the creditworthiness of our counterparties deteriorates and results in their non-performance, we could incur a significant loss.

Derivative arrangements also expose us to the risk of financial loss in some circumstances, including when production is less than the volume covered by the derivative instruments or when there is an increase in the differential between the underlying price and actual prices received in the derivative instrument. In addition, certain types of derivative arrangements may limit the benefit that we could receive from increases in the prices for crude oil. natural gas and NGLs, and may expose us to cash margin requirements.

We are exposed to the credit risks of the third parties with whom we contract.

We may be exposed to third-party credit risk through our contractual arrangements with government entities party to our PSCs, our current or future joint venture owners, marketers of our petroleum and natural gas production, purchasers of our oil, natural gas and NGLs products and other parties. In addition, we may be exposed to third-party credit risk from operators of properties in which we have a Working Interest or Royalty Interest. In the event such entities fail to meet their contractual obligations to us, such failures may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry generally and among our joint venture owners may affect a joint venture owner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until it finds a suitable alternative partner. To the extent that any of such third parties go bankrupt, become insolvent, or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in our inability to collect all or a portion of any money owing from such parties. Any of these factors could materially adversely affect our financial and operational results.

Our ability to collect payments from the sale of crude oil, natural gas and NGLs from our customers depends on the payment ability of our customer base, which may include a small number of significant customers. If our significant customers fail to pay for any reason, we could experience a material loss. In addition, if our significant customers cease to purchase or reduce the volume they purchase of our crude oil, natural gas or NGLs, the loss or reduction could have a detrimental effect on our production volumes and may cause a temporary interruption in sales of, or a lower price for, our crude oil, natural gas and NGLs.

In addition, we are and may in the future be exposed to third-party credit risk through our contractual arrangements with governmental entities in Gabon or the EGPC. Significant changes in the crude oil industry, including fluctuations in commodity prices and economic conditions, environmental regulations, government policy, royalty rates and other geopolitical factors, could adversely affect our ability to realize the full value of our accounts receivable from government entities in Gabon or the EGPC. Historically, we have had significant account receivables outstanding from governmental entities in Gabon and the EGPC. While the EGPC has made regular payments of these amounts owing, the timing of these payments has historically been longer than the normal industry standard. In addition, EGPC has at times faced difficulties in accessing foreign exchange markets for the purpose of obtaining U.S. dollars in exchange for Egyptian Pounds. In the event the Governments of Gabon or Egypt fails to meet their respective obligations or we are forced to accept payment in foreign currencies, such failures could materially adversely affect our financial and operational results.

We are also exposed to third-party credit risk through our banking relationships in the jurisdictions in which we operate. Recent macroeconomic conditions have caused turmoil in the banking sector in the United States and elsewhere. If any of the banks in which we keep our deposits is affected by such turmoil, we could be materially and adversely affected.

Our business could be materially and adversely affected by security threats, including cybersecurity threats, and other disruptions.

As a crude oil, natural gas and NGLs producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. The potential for such security threats has subjected our operations to increased risks that could have a material adverse effect on our business. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs. Costs for insurance may also increase as a result of security threats, and some insurance coverage may become more difficult to obtain, if available at all. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of sensitive information, critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations and cash flows.

Cybersecurity attacks in particular are becoming more sophisticated, and geopolitical tensions or conflicts, such as Russia’s invasion of Ukraine, may further heighten the risk of such attacks. We rely extensively on information technology systems, including internet sites, computer software, data hosting facilities and other hardware and platforms, some of which are hosted by third parties, to assist in conducting our business. Our technologies systems and networks, and those of our business associates may become the target of cybersecurity attacks, including without limitation malicious software, attempts to gain unauthorized access to data and systems, and other electronic security breaches that could lead to disruptions in critical systems and materially and adversely affect us in a variety of ways, including the following:

- unauthorized access to and release of seismic data, reserves information, strategic information or other sensitive or proprietary information, which could have a material adverse effect on our ability to compete for crude oil, natural gas and NGLs resources;
- data corruption, communication interruption, or other operational disruption during drilling activities could result in failure to reach the intended target or a drilling incident;
- unauthorized access to and release of personal identifying information of employees and vendors, which could expose us to allegations that we did not sufficiently protect that information;
- a cybersecurity attack on a vendor or service provider, which could result in supply chain disruptions and could delay or halt operations;
- a cybersecurity attack on third-party gathering, transportation, processing, fractionation, refining or export facilities, which could delay or prevent us from transporting and marketing our production, resulting in a loss of revenues;
- a cybersecurity attack involving commodities exchanges or financial institutions could slow or halt commodities trading, thus preventing us from engaging in hedging activities, resulting in a loss of revenues; and
- business interruptions, including use of social engineering schemes and/or ransomware, could result in expensive remediation efforts, distraction of management, damage to our reputation, or a negative impact on the price of our common stock.

To protect against such attempts of unauthorized access or attack, we have implemented multiple layers of cybersecurity protection, infrastructure protection technologies, disaster recovery plans and employee training. While we have invested significant amounts in the protection of our technology systems and maintain what we believe are adequate security controls over sensitive data, there can be no guarantee such plans will be effective.

Any cyber incident could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability. Additionally, certain cyber incidents, such as surveillance, may remain undetected for an extended period.

Current and future geopolitical events outside of our control could adversely impact our business, results of operations, cash flows, financial condition and liquidity.

We face risks related to geopolitical events, international hostility, epidemics, outbreaks and other macroeconomic events that are outside of our control. The occurrence of certain geopolitical events, including those arising from terrorist activity, international hostility, public health crisis, and the economic impact of global trade tension and the imposition of tariffs, could significantly disrupt our business and operational plans and adversely affect our results of operations, cash flows, financial condition and liquidity. For instance, the ongoing conflicts in the Middle East and between Russia and Ukraine have and may continue to cause geopolitical instability, and adversely impact the global economy, supply chains and specific markets and industries. Although we are not able to enumerate all potential risks to our business resulting from these and other similar events, we believe that such risks include, but are not limited to, the following:

- disruption to our supply chain for materials essential to our business, including restrictions on importing and exporting products;
- customers, suppliers and other third parties arguing that their non-performance under our contracts with them is permitted as a result of force majeure or other reasons;
- cybersecurity attacks, particularly as digital technologies may become more vulnerable and experience a higher rate of cyberattacks in the current environment of remote connectivity;
- any reductions of our workforce to adjust to market conditions, including severance payments, retention issues, and possible inability to hire employees when market conditions improve;
- logistical challenges, including those resulting from border closures and travel restrictions, as well as the possibility that our ability to continue production may be interrupted, limited or curtailed if workers and/or materials are unable to reach our offshore platforms and FSO charter vessel or our counterparties are unable to lift crude oil from our FSO charter vessel;
- we may be materially adversely affected by the effects of sanctions and other penalties imposed on Russia by the U.S., the European Union and other countries; and
- we may experience a structural shift in the global economy and our demand for crude oil, natural gas and NGLs as a result of changes in the way people work, travel and interact, or in connection with a global recession or depression.

We cannot reasonably estimate the period of time that these conditions will persist; the full extent of the impact they will have on our business, results of operations, cash flows, financial condition and liquidity; or the pace or extent of any subsequent recovery.

Production cuts mandated by the government of Gabon, a member of OPEC, could adversely affect our revenues, cash flow and results of operations.

After terminating its membership with OPEC in 1995, Gabon re-joined OPEC as a full member in July 2016. Historically and from time to time, members of OPEC have entered into agreements to reduce worldwide production of crude oil, including the agreement reached in April 2020 among OPEC member countries and other leading allied producing countries (collectively, “OPEC+”) to reduce the gap between excess supply and demand in an effort to stabilize the international oil market. Gabon undertook measures to comply with such OPEC+ production quota agreement. As a result, the Minister of Hydrocarbons in Gabon requested that we reduce our production beginning July 2020 and continuing through April 20, 2021 in compliance with the OPEC+ mandate, and we took measures to temporarily reduce our production. In July 2021, OPEC+ agreed to increase production beginning in August 2021 and to gradually phase out prior production cuts by September 2022. The decision to increase production was reaffirmed by an OPEC+ meeting held on February 2, 2022. However, as a result of the recent decline in oil prices, on October 5, 2022, OPEC+ announced plans to reduce overall oil production by 2 MMBbls per day starting November 2022. We have not received any mandate to reduce current oil production from the Etame Marin block as a result of the OPEC+ initiative and currently, our production is not impacted by OPEC+ curtailments. However, any future reduction in our crude oil production or export activities for a substantial period could materially and adversely affect our revenues, cash flows and results of operations. Gabon remains a member of OPEC+. There were no required curtailments in 2023.

We have less control over our investments in foreign properties than we would have over our domestic investments.

Our exploration, development and production activities are subject to various political, economic and other uncertainties, including but not limited to changes, sometimes frequent or marked, in energy policies or the personnel administering them, expropriation of property, cancellation or modification of contract rights, changes in laws and policies governing operations of foreign-based companies, unilateral renegotiation of contracts by governmental entities, uncertainties as to whether the laws and regulations will be applicable in any particular circumstance, uncertainty as to whether we will be able to demonstrate to the satisfaction of the applicable governing authorities compliance with governmental or contractual requirements, redefinition of international boundaries or boundary disputes, foreign exchange restrictions, currency fluctuations, foreign currency availability, royalty and tax increases, changes to tax legislation or the imposition of new taxes, the imposition of production bonuses or other charges and other risks arising out of governmental sovereignty over the areas in which our operations are conducted.

Our operations require, and any future opportunistic acquisitions may require, protracted negotiations with host governments, local governments and communities, local competent authorities, national oil companies, and third parties. Host governments may also conduct audits of our operations, the results of which may have a significant negative impact on our reported earnings or cash flows. Host governments may seek to participate in oil, natural gas or NGLs projects in a manner that could be diluted to our interests. Host governments may also require us to hire a specified percentage of local citizens in our operations. In addition, if a dispute arises with respect to our foreign operations, we may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons, especially foreign crude oil ministries and national oil companies, to the jurisdiction of the U.S.

In December 2021 and during 2022, the Bank of Central African States (“BEAC”), which is the central bank for the Central African Economic and Monetary Community (CEMAC), passed new regulations and instructions for the CEMAC FX regulations, which were introduced in 2018, that only apply to the extractive industry. The intent of the new regulations is to ensure the application of the FX regulations as of January 1, 2022, without impeding the operations of the extractive industry. Due to the lack of necessary banking infrastructure and preparedness by the banking sector and the various government agencies to apply the new regulations, it is foreseeable that we will run the risk of seeing delays in paying our vendors and domiciliation of goods and services into the CEMAC region throughout 2024 and beyond.

As part of securing the first of two five-year extensions to the Etame PSC in 2016, we agreed to a cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin block. On February 28, 2019, in accordance with certain foreign currency regulatory requirements, the Gabonese branch of the international commercial bank holding the abandonment funds in a U.S. dollar-denominated account transferred the funds to the Central Bank for CEMAC and later converted, at the request of BEAC, the funds in U.S. dollars to franc CFA, the currency of the CEMAC, of which Gabon is one of the six member states. The Etame PSC provides that these payments must be denominated in U.S. dollars. After continued discussions with CEMAC, they agreed to the return of the USD funds and on January 12, 2023, the abandonment funds were returned to the USD account of the Gabonese branch of the international commercial bank. We were allowed to re-establish a USD denominated account and made whole for the original USD amount. Pursuant to Amendment No. 5 of the Etame PSC, we are working with Directorate of Hydrocarbons in Gabon on establishing a payment schedule to resume funding of the abandonment fund in compliance with the Etame PSC.

Private ownership of crude oil reserves under crude oil leases in the U.S. differs distinctly from our rights in foreign reserves where the state generally retains ownership of the minerals, and in many cases participates in, the exploration and production of hydrocarbon reserves. Accordingly, operations outside the U.S. may be materially affected by host governments. While the laws of each of Gabon and Equatorial Guinea recognize private and public property and the right to own property is protected by law, the laws of each country reserve, at the respective government’s discretion, the right to expropriate property and terminate contracts (including the Etame PSC and the Block P PSC) for reasons of public interest, subject to reasonable compensation, determinable by the respective government in our discretion. The terms of the Etame PSC include provisions for, among other things, payments to the government of Gabon for a 13% Royalty Interest based on crude oil production at published prices and payments for a shared portion of “profit oil,” based on daily production rates, which such “profit oil” has been and can continue to be taken in-kind through taking crude oil barrels rather than making cash payments.

We have operated in Gabon since 1995 and believe we have good relations with the current Gabonese government. However, there can be no assurance that present or future administrations or governmental regulations in Gabon will not materially adversely affect our operations or cash flows.

The respective applicable laws governing the exploration and production of hydrocarbons in Gabon and Equatorial Guinea (Law No. 002/2019 in Gabon and Law No. 8/2006 in Equatorial Guinea) each provide their respective government officials with significantly broad regulatory, inspective and auditing powers with respect to the performance of petroleum operations, which include the powers to negotiate, sign, amend and perform all contracts entered into between the respective governments and independent contractors. The executive branches of each respective government also retain significant discretionary powers, giving considerable control over the executive, judiciary and legislative branches of each government, and the ability to adopt measures with a direct impact on private investments and projects, including the right to appoint ministers responsible for petroleum operations. Further, in Equatorial Guinea, any new PSC or equivalent agreement for the exploration and exploitation of hydrocarbons is subject to presidential ratification before it can become effective.

We are also now subject to political, economic and other uncertainties in Egypt.

Any of the factors detailed above or similar factors could have a material adverse effect on our business, results of operations or financial condition. If our operations are disrupted and/or the economic integrity of our projects are threatened for unexpected reasons, our business may be harmed. Prolonged problems may threaten the commercial viability of our operations.

Our operations may be adversely affected by political and economic circumstances in the countries in which we operate .

Our operations are subject to risks of loss due to civil strife, acts of war, acts of terrorism, piracy, disease, guerrilla activities, insurrection, military activities and other political risks, including tension and confrontations among political parties, that may result in:

- volatility in global crude oil prices, which could negatively impact the global economy, resulting in slower economic growth rates, which could reduce demand for our products;
- negative impact on the world crude oil supply if infrastructure or transportation are disrupted, leading to further commodity price volatility;
- difficulty in attracting and retaining qualified personnel to work in areas with potential for conflict;
- the inability of our personnel or supplies to enter or exit the countries where we are conducting operations;
- disruption of our operations due to evacuation of personnel;
- the inability to deliver our production due to disruption or closing of transportation routes;
- a reduced ability to export our production due to efforts of countries to conserve domestic resources;
- damage to or destruction of our wells, production facilities, receiving terminals or other operating assets;
- the incurrence of significant costs for security personnel and systems;
- damage to or destruction of property belonging to our commodity purchasers leading to interruption of deliveries, claims of force majeure, and/or termination of commodity sales contracts, resulting in a reduction in our revenues;
- the inability of our service and equipment providers to deliver items necessary for us to conduct our operations resulting in a halt or delay in our planned exploration activities, delayed development of major projects, or shut-in of producing fields;
- a lack of availability of drilling rig, oilfield equipment or services if third party providers decide to exit the region;
- the imposition of U.S. government or international sanctions that limit our ability to conduct our business;
- a shutdown of a financial system, communications network, or power grid causing a disruption to our business activities; and
- a capital market reassessment of risk and reduction of available capital making it more difficult for us and our joint owners to obtain financing for potential development projects.

Some of these risks may be higher in the developing countries in which we conduct our activities, namely, Gabon, Equatorial Guinea and Egypt.

For example, in September 2023, Gabon experienced a largely non-violent, military coup d’état and the country’s leadership changed hands. The group leading the coup created a Committee for the Transition and Restauration of Institutions and a new president was sworn in on the basis of a transition charter adopted by the group leading the coup. The new president has indicated that a new constitution for Gabon will be adopted and that elections will be held after a transition period. No assurance can be given that any such new constitution will be adopted or if adopted, that the content thereof will be in line with Gabon’s existing laws. Any of these developments may have an adverse effect on our operations and financial results.

While we monitor the economic and political environments of the countries in which we operate, loss of property and/or interruption of our business plans resulting from civil or political unrest could have a significant negative impact on our earnings and cash flow. In addition, losses caused by these disruptions may not be covered by insurance, or even if they are covered by insurance, we may not have enough insurance to cover all of these losses. If any violent action causes us to become involved in a dispute, we may be subject to the exclusive jurisdiction of courts outside the U.S. or may not be successful in subjecting non-U.S. persons to the jurisdiction of courts in the U.S. or international arbitration, which could adversely affect the outcome of such dispute.

Inflation could adversely impact our ability to control costs, including operating expenses and capital costs.

Inflation rose significantly in the second half of 2021 and through 2023. In addition, global and industry-wide supply chain disruptions have resulted in shortages in labor, materials and services. Such shortages have resulted in inflationary cost increases for labor, materials and services and could continue to cause costs to increase, as well as a scarcity of certain products and raw materials. To the extent inflation remains elevated, we may experience further cost increases for our operations, including oilfield services and equipment as increasing prices of oil, natural gas and NGLs, increased drilling activity in our areas of operations, as well as increased labor costs. An increase in the prices of oil, natural gas and NGLs may cause the costs of materials and services we use to rise. We cannot predict any future trends in the rate of inflation, and a significant increase in inflation, to the extent we are unable to recover higher costs through higher commodity prices and revenues, could negatively impact our business, financial condition and results of operation.

Our results of operations, financial condition and cash flows could be adversely affected by changes in currency exchange rates.

We are exposed to foreign currency risk from our foreign operations. While crude oil sales are denominated in U.S. dollars, portions of our costs in Gabon are denominated in the local currency. A weakening U.S. dollar will have the effect of increasing costs, while a strengthening U.S. dollar will have the effect of reducing operating costs. The Gabon local currency is tied to the Euro. The exchange rate between the Euro and the U.S. dollar has fluctuated widely in recent years in response to international political conditions, general economic conditions, the European sovereign debt crisis and other factors beyond our control. Our financial statements, presented in U.S. dollars, may be affected by foreign currency fluctuations through both translation risk and transaction risk. In addition, currency devaluation can result in a loss to us for any deposits of that currency, such as our deposits in the Etame PSC abandonment account, which have been converted from U.S. dollars to the Gabonese local currency.

We are also exposed to foreign currency exchange risk related to certain cash, accounts receivable, long-term debt, lease obligations and accounts payable and accrued liabilities denominated in Canadian dollars, and on cash balances denominated in Egyptian pounds. Some collections of our accounts receivable from the Egyptian Government are received in Egyptian pounds, and while we are generally able to spend the Egyptian pounds received on accounts payable denominated in Egyptian pounds, there remains foreign currency exchange risk exposure on Egyptian pound cash balances.

In addition, from time to time, emerging market countries such as those in which we operate adopt measures to restrict the availability of the local currency or the repatriation of capital across borders. These measures are imposed by governments or central banks, in some cases during times of economic instability, to prevent the removal of capital or the sudden devaluation of local currencies or to maintain in-country foreign currency reserves. In addition, many emerging markets countries require consents or reporting processes before local currency earnings can be converted into U.S. dollars or other currencies and/or such earnings can be repatriated or otherwise transferred outside of the operating jurisdiction. These measures may have a number of negative effects on us, including the reduction of the immediately available capital that we could otherwise deploy for investment opportunities or the payment of expenses. In addition, measures that restrict the availability of the local currency or impose a requirement to operate in the local currency may create other practical difficulties for us.

We do not utilize derivative instruments to manage these foreign currency risks. As a result, our consolidated earnings and cash flows may be impacted by movements in the exchange rates.

We operate in international jurisdictions, and we could be adversely affected by violations of the U.S. Foreign Corrupt Practices Act and similar worldwide anti-corruption laws.

We are subject to the provisions of the U.S. Foreign Corrupt Practices Act, the UK Bribery Act, the Corruption of Foreign Public Officials Act (Canada) and other similar laws. The foregoing laws prohibit companies and their intermediaries from making improper payments to officials for the purpose of obtaining or retaining business. In addition, such laws require the maintenance of records relating to transactions and an adequate system of internal controls over accounting. There can be no assurance that our internal control policies and procedures, compliance mechanisms or monitoring programs will protect us from recklessness, fraudulent behavior, dishonesty or other inappropriate acts or adequately prevent or detect possible violations under applicable anti-bribery and anti-corruption legislation.

Our failure to comply with anti-bribery and anti-corruption legislation could result in severe criminal or civil sanctions and may subject us to other liabilities, including fines, prosecution, potential debarment from public procurement and reputational damage, all of which could have a material adverse effect on our business, results of operations and financial condition. Investigations by governmental authorities could have a material adverse effect on our business, results of operations and financial condition.

There are inherent limitations in all control systems, and misstatements due to error or fraud that could seriously harm our business may occur and not be detected.

While our management has concluded that our internal control over financial reporting is effective, we do not expect that the relevant internal controls and disclosure controls will prevent or detect all possible errors or all instances of fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the fact that there are resource constraints, and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, an evaluation of controls can only provide reasonable assurance that all material control issues and instances of fraud, if any, have been or will be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistakes. Further, controls can be circumvented by the individual acts of some persons or by two or more persons acting in collusion. The design of any system of controls is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of inherent limitations in any control system designed under a cost-effective approach, misstatements due to error or fraud may occur and not be detected. A failure of the controls and procedures to detect error or fraud could seriously harm our business and results of operations.

We may not have enough insurance to cover all of the risks we face.

Our business is subject to all of the operating risks normally associated with the exploration for and production, gathering, processing, and transportation of crude oil, natural gas and NGLs, including blowouts, cratering and fire, any of which could result in damage to, or destruction of, crude oil, natural gas and NGLs wells or formations, production facilities, and other property, as well as injury to persons. For protection against financial loss resulting from these operating hazards, we maintain insurance coverage, including insurance coverage for certain physical damage, blowout/control of a well, comprehensive general liability, worker's compensation and employer's liability. However, our insurance coverage may not be sufficient to cover us against 100% of potential losses arising as a result of the foregoing, and for certain risks, such as political risk, nationalization, business interruption, war, terrorism, and piracy, for which we have limited or no coverage. In addition, we are not insured against all risks in all aspects of our business, such as hurricanes. The occurrence of a significant event that we are not fully insured against could have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

Our business could suffer if we lose the services of, or fail to attract, key personnel.

We are highly dependent upon the efforts of our senior management and other key employees. The loss of the services of our Chief Executive Officer or Chief Financial Officer, as well as any loss of the services of one or more other members of our senior management, could delay or prevent the achievement of our objectives. We do not maintain any “key-man” insurance policies on any of our senior management, and do not intend to obtain such insurance. In addition, due to the specialized nature of our business, we are highly dependent upon our ability to attract and retain qualified personnel with extensive experience and expertise in evaluating and analyzing drilling prospects and producing crude oil, natural gas and NGLs from proved properties and maximizing production from crude oil, natural gas and NGLs properties. There is competition for qualified personnel in the areas of our activities, and we may be unsuccessful in attracting and retaining these personnel.

We are subject to relinquishment obligations under certain of our title documents.

We are subject to relinquishment obligations under our title documents which oblige us to relinquish certain proportions of our concession lease and license areas and thereby reduce our acreage. Additionally, we may be unable to drill all of our prospects or satisfy our minimum work commitments prior to relinquishment and may be unable to meet our obligations under the title documents. Failure to meet such obligations could result in concessions, leases and licenses being suspended, revoked or terminated which could have a material adverse effect on our business.

We may be exposed to the risk of earthquakes in Alberta.

The AER monitors seismic activity across the province of Alberta in Canada to assess the risks associated with, and instances of, earthquakes induced by hydraulic fracturing. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, prompting regulatory authorities to investigate the practice further. The AER has developed monitoring and reporting requirements that apply to all oil and natural gas producers working in certain areas where the likelihood of an earthquake is higher, and implemented the requirements in Subsurface Order Nos. 2, 6, and 7 (the “Seismic Protocol Regions”). While we do not have operations in the Seismic Protocol Regions, we own production and working interest facilities and assets in the Harmattan area of west central Alberta and are exposed to the risks of earthquakes in that region. We routinely conduct hydraulic fracturing in our drilling and completion programs.

There may be valid challenges to title or legislative changes which affect our title to the oil, natural gas and NGLs properties we control in Canada.

Although title reviews may be conducted in Canada prior to the purchase of oil, natural gas and NGLs producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise. Due in part to the nature of property rights development historically in Canada as well as the common practice of splitting legal and beneficial title, public registries are not determinative of actual rights held by parties. Further, the fragmented nature of oil and gas rights, which may be held by the government or private individuals and companies, and may be split among a great number of different granting documents, means that despite best efforts of parties, latent defects may not be immediately discoverable. As such, our actual interest in properties may accordingly vary from our records. If a title defect does exist, it is possible that we may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on our business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect our title to the oil and natural gas properties that we control in Canada that could impair our activities and result in a reduction of the revenue we receive. Additionally, title claims by Indigenous groups could, among other things, delay or prevent the exploration or development of our properties, which in turn could have a material adverse effect on our business, financial condition, results of operations and prospects.

Our results of operations, financial condition and cash flows could be adversely affected by changes in currency regulations.

From time to time, emerging market countries such as those in which we operate adopt measures to restrict the availability of the local currency or the repatriation of capital across borders. These measures are imposed by governments or central banks, in some cases during times of economic instability, to prevent the removal of capital or the sudden devaluation of local currencies or to maintain in-country foreign currency reserves. In addition, many emerging markets countries require consents or reporting processes before local currency earnings can be converted into U.S. dollars or other currencies and/or such earnings can be repatriated or otherwise transferred outside of the operating jurisdiction. These measures may have a number of negative effects on us, including the reduction of the immediately available capital that we could otherwise deploy for investment opportunities or the payment of expenses. In addition, measures that restrict the availability of the local currency or impose a requirement to operate in the local currency may create other practical difficulties for us.

Our results of operations, financial condition and cash flows could be adversely affected by changes to interest rates.

Our Facility Agreement is for $43.8 million, none of which had been drawn as of December 31, 2023. An increase in interest rates could result in a significant increase in the amount we pay to service any subsequently drawn, and any future other debt taken out by us, resulting in a reduced amount available to fund our exploration and development activities and, if applicable, the cash available for dividends. Such an increase could also negatively impact the market price of the shares of common stock.

The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced.

At December 31, 2023, approximately 22% of our total estimated proved reserves were undeveloped reserves. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling. Our reserves data assumes that we can and will make these expenditures and conduct these operations successfully. These assumptions, however, may not prove correct. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices will reduce the value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. If we choose not to spend the capital to develop these reserves, or if we are not otherwise able to successfully develop these reserves, we will be required to write-off these reserves. In addition, under the SEC’s reserve rules, because proved undeveloped reserves may be recognized only if they relate to wells planned to be drilled within five years of the date of their initial recognition, we may be required to write-off any proved undeveloped reserves that are not developed within this five-year time frame.

Risks Relating to Our Industry

Crude oil, natural gas and NGLs prices are highly volatile and a depressed price regime, if prolonged, may negatively affect our financial results.

Our revenues, cash flow, profitability, crude oil, natural gas and NGLs reserves value and future rate of growth are substantially dependent upon prevailing prices for crude oil, natural gas and NGLs. Our ability to enter into debt financing arrangements and to obtain additional capital on reasonable terms, or at all, is substantially dependent on crude oil, natural gas and NGLs prices.

World-wide crude oil, natural gas and NGLs prices and markets have been volatile and may continue to be volatile in the future. Prices for crude oil, natural gas and NGLs are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for crude oil, natural gas and NGLs, market uncertainty and a variety of additional factors that are beyond our control. These factors include, but are not limited to, increases in supplies from U.S. shale production, international political conditions, including war, uprisings, terrorism and political unrest in the Middle East and Africa, slowdowns to the global supply chain, the domestic and foreign supply of crude oil, natural gas and NGLs, actions by OPEC+ member countries and other state-controlled oil companies to agree upon and maintain crude oil price and production controls, the level of consumer demand that is impacted by economic growth rates; weather conditions; domestic and foreign governmental regulations and taxes; the price and availability of alternative fuels; technological advances affecting energy consumption; the health of international economic and credit markets; and changes in the level of demand resulting from global or national health epidemics and concerns. In addition, various factors including the effect of federal, state and foreign regulation of production and transportation, general economic conditions, changes in supply due to drilling by other producers and changes in demand may adversely affect our ability to market our crude oil, natural gas and NGLs production.

In a period of depressed or declining crude oil, natural gas and NGLs prices, we are subject to numerous risks, including but not limited to the following:

- our revenues, cash flows and profitability may decline substantially, which could also indirectly impact expected production by reducing the amount of funds available to engage in exploration, drilling and production;
- third party confidence in our commercial or financial ability to explore and produce crude oil, natural gas and NGLs could erode, which could impact our ability to execute on our business strategy;
- our suppliers, hedge counterparties (if any), vendors and service providers could renegotiate the terms of our arrangements, terminate their relationship with us or require financial assurances from us;
- we may take measures to preserve liquidity, such us our decision to cease or defer discretionary capital expenditures during such periods of depressed or declining oil prices; and
- it may become more difficult to retain, attract or replace key employees.

The occurrence of certain of these events may have a material adverse effect on our business, results of operations and financial condition.

If crude oil, natural gas or NGLs prices decline, we expect that the estimated quantities and present values of our reserves will be reduced, which may necessitate further write-downs. Any future write-downs or impairments could have a material adverse impact on our results of operations. A material decline in prices could also result in a reduction of our net production revenue. Any substantial and extended decline in the price of oil, natural gas and NGLs would have an adverse effect on the carrying value of our reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on our business, financial condition, results of operations and prospects. Volatile oil, natural gas and NGLs prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil, natural gas and NGLs producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for, and project the return on, acquisitions and development and exploitation projects.

Exploring for, developing, or acquiring reserves is capital intensive and uncertain.

We may not be able to economically find, develop, or acquire additional reserves, or may not be able to make the necessary capital investments to develop our reserves, if our cash flows from operations decline or external sources of capital become limited or unavailable. Drilling activities are subject to many risks, including the risk that no commercially productive reservoirs will be encountered. There can be no assurance that new wells that we drill will be productive or that we will recover all or any portion of our investment. Drilling for crude oil, natural gas and NGLs may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. The cost of drilling, completing and operating wells is often uncertain and cost overruns are common. In particular, offshore drilling and development operations require highly capital-intensive techniques.

Our drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, many of which are beyond our control, including weather conditions, equipment failures or accidents, elevated pressure or irregularities in geologic formations, compliance with governmental requirements and shortages or delays in the delivery of or increased costs for equipment and services. If we are unable to continue drilling operations and we do not replace the reserves we produce or acquire additional reserves, our reserves, revenues and cash flow will decrease over time, which could have a material effect on our ability to continue as a going concern.

Our costs could escalate and become uncompetitive due to supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, and additional government intervention through stimulus spending or additional regulations. Our inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on our financial performance and cash flows.

Competitive industry conditions may negatively affect our ability to conduct operations.

The crude oil, natural gas, and NGLs industry is intensely competitive. Our competitors include major integrated oil companies and substantial independent energy companies, many of which possess greater financial, technological, personnel and other resources than we do.

We may be outbid by our competitors in our attempts to acquire exploration and production rights in crude oil, natural gas and NGLs properties. These properties include exploration prospects as well as properties with proved reserves. Our competitors may also use superior technology that we may be unable to afford or that would require costly investment in order to compete. There is also competition for contracting for drilling equipment and the hiring of experienced personnel. Factors that affect our ability to compete in the marketplace include, among other things:

- our access to the capital necessary to drill wells and acquire properties;
- our ability to acquire and analyze seismic, geological and other information relating to a property;
- our ability to retain and hire experienced personnel, especially for our engineering, geoscience and accounting departments; and
- the location of, and our ability to access, platforms, pipelines and other facilities used to produce and transport crude oil, natural gas and NGLs production.

In addition, competition due to advances in renewable fuels may also lessen the demand for our products and negatively impact our profitability.

Alternatives to petroleum-based products and production methods are continually under development. For example, a number of automotive, industrial and power generation manufacturers are developing alternative clean power systems using fuel cells or clean-burning gaseous fuels that may address increasing worldwide energy costs, the long-term availability of petroleum reserves and environmental concerns, which if successful could lower the demand for crude oil, natural gas and NGLs. If these non-petroleum based products and crude oil alternatives continue to expand and gain broad acceptance such that the overall demand for crude oil, natural gas and NGLs is decreased, it could have an adverse effect on our operations and the value of our assets.

Weather, unexpected subsurface conditions and other unforeseen operating hazards may adversely impact our crude oil, natural gas and NGLs activities.

The crude oil, natural gas and NGLs business involves a variety of operating risks, including fire; explosions; blow-outs; pipe failure, casing collapse; abnormally pressured formations; and environmental hazards such as crude oil spills, natural gas leaks, ruptures and discharges of toxic gases, underground migration, and surface spills or mishandling of well fluids, including chemical additives, the occurrence of any of which could result in substantial losses due to injury and loss of life, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations.

Climate change could have an effect on the severity of weather (including hurricanes, floods and wildfires), sea levels, the arability of farmland, and water availability and quality. If such effects were to occur, our exploration and production operations may be adversely affected. Potential adverse effects could include damages to our facilities, disruption of our production activities, less efficient or non-routine operating practices necessitated by climate effects or increased costs for insurance coverages in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship.

We maintain insurance against some, but not all, potential risks; however, there can be no assurance that such insurance will be adequate to cover any losses or exposure for liability. The occurrence of a significant unfavorable event not fully covered by insurance could have a material adverse effect on our financial condition, results of operations and cash flows. Furthermore, we cannot predict whether insurance will continue to be available to us at a reasonable cost or at all.

An increased societal and governmental focus on ESG and climate change issues may adversely impact our business, impact our access to investors and financing, and decrease demand for our product.

An increased expectation that companies address environmental (including climate change), social and governance (“ESG”) matters may have a myriad of impacts on our business. Some investors and lenders are factoring these issues into investment and financing decisions. They may rely upon companies that assign ratings to a company’s ESG performance. Unfavorable ESG ratings, as well as recent activism around fossil fuels, may dissuade investors or lenders from engaging with us in favor of companies in other industries, which could negatively impact our share price or our access to capital.

Moreover, while we have and may continue to create and publish voluntary disclosures regarding ESG matters from time to time, many of the statements in those voluntary disclosures are based on hypothetical expectations and assumptions that may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. Such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring and reporting on many ESG matters.

Approaches to climate change and transition to a lower-carbon economy, including government regulation, company policies, and consumer behavior, are continuously evolving. At this time, we cannot predict how such approaches may develop or otherwise reasonably or reliably estimate their impact on our financial condition, results of operations and ability to compete. However, any long-term material adverse effect on the oil and gas industry may adversely affect our financial condition, results of operations and cash flows.

In Canada, opposition by Indigenous groups to our operations, development or exploration activities may negatively impact us. Opposition by Indigenous groups to the conduct of our operations, development or exploratory activities in any of the jurisdictions in which we conduct business may negatively impact us in terms of public perception, diversion of management’s time and resources, legal and other advisory expenses, and could adversely impact our progress and ability to explore and develop properties.

Some Indigenous groups have established or asserted Indigenous treaty and title rights to portions of Canada. Although there are no Indigenous treaty or title rights claims on lands where we operate, no certainty exists that any lands currently unaffected by claims brought by Indigenous groups will remain unaffected by future claims. Such claims, if successful, could have a material adverse impact on our operations and pace of growth.

Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect asserted or proven Indigenous treaty or title rights and, in certain circumstances, accommodate their concerns. The scope of the duty to consult by federal and provincial governments varies with the circumstances and is often the subject of litigation. The fulfilment of the duty to consult Indigenous people and any associated duties of accommodation may adversely affect our ability, or increase the time required to obtain or renew, permits, leases, licenses and other approvals, or to meet the terms and conditions of those approvals.

Continued development of common law precedent regarding existing laws relating to Indigenous consultation and accommodation as well as the adoption of new laws are expected to continue to add uncertainty to the ability of entities operating in the Canadian oil and gas industry to execute on major resource development and infrastructure projects, including, among other projects, pipelines that could adversely impact our progress and ability to explore and develop properties in Canada. For example, Canada is a signatory to the United Nations Declaration of the Rights of Indigenous Peoples ("UNDRIP") and the principles set forth therein may continue to influence the role of Indigenous engagement in the development of the oil and gas industry in Western Canada. In June 2021, the United Nations Declaration on the Rights of Indigenous Peoples Act (Canada) ("UNDRIP Act") came into force in Canada. The UNDRIP Act requires the Government of Canada to take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives. Adding further uncertainty, on June 29, 2021, the British Columbia Supreme Court issued a judgement in Yahey v British Columbia (the "Blueberry Decision"), in which it determined that the cumulative impacts of industrial development on the traditional territory of the Blueberry River First Nation ("BRFN") in northeast British Columbia had breached BRFN's treaty rights. The Blueberry Decision may lead to similar claims of cumulative effects across Canada in other areas covered by treaties.

We face various risks associated with increased opposition to and activism against crude oil, natural gas and NGLs exploration and development activities.

The oil and natural gas exploration, development and operating activities that we conduct may, at times, be subject to public opposition. Opposition against crude oil, natural gas and NGLs drilling and development activity has been growing globally. Companies in the crude oil, natural gas and NGLs industry are often the target of activist efforts from both individuals and non-governmental organizations regarding safety, human rights, climate change, environmental matters, sustainability and business practices. Anti-development activists are working to, among other things, delay or cancel certain operations such as offshore drilling and development.

Such public opposition could expose us to higher costs, delays or even project cancellations, due to increased pressure on governments and regulators by special interest groups, including Indigenous groups, landowners, environmental interest groups (including those opposed to oil and natural gas production operations) and other non-governmental organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support from the federal, provincial or municipal governments, reputational damage, delays in, challenges to or the revocation of regulatory approvals, permits and/or licenses, and direct legal challenges, including the possibility of climate-related litigation. There is no guarantee that we will be able to satisfy the concerns of the special interest groups and non-governmental organizations, and attempting to address such concerns may require us to incur significant and unanticipated capital and operating expenditures.

Further, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector. Moreover, activist shareholders in our industry have introduced shareholder proposals that may seek to force companies to adopt aggressive emission reduction targets or to shift away from more carbon-intensive activities. While we cannot predict the outcomes of such proposals, they could ultimately make it more difficult for us to engage in exploration and production activities.

Risks Relating to Legal and Regulatory Matters

Our operations are subject to risks associated with climate change and potential regulatory programs meant to address climate change; these programs may impact or limit our business plans, result in significant expenditures or reduce demand for our product.

Climate change continues to be the focus of political and societal attention. Numerous proposals have been made and are likely to be forthcoming on the international, national, regional, state and local levels to reduce the emissions of GHG emissions. These efforts have included or may include cap-and-trade programs, carbon taxes, GHG emissions reporting obligations and other regulatory programs that limit or require control of GHG emissions from certain sources. These programs may limit our ability to produce crude oil, natural gas and NGLs, limit our ability to explore in new areas, or may make it more expensive to produce. In addition, these programs may reduce demand for our product either by incentivizing or mandating the use of other alternative energy sources, by prohibiting the use of our product, by requiring equipment using our product to shift to alternative energy sources, or by directly increasing the cost of fossil fuels to consumers.

Compliance with environmental and other government regulations could be costly and could negatively impact production.

The laws and regulations of the U.S., Canada, Egypt, Equatorial Guinea and Gabon control our current business. These laws and regulations may require that we obtain permits for our development activities, limit or prohibit drilling activities in certain protected or sensitive areas or restrict the substances that can be released in connection with our operations.

Our operations could result in liability for personal injuries, property damage, natural resource damages, crude oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. Failure to comply with environmental laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties and the issuance of orders enjoining operations. In addition, we could be liable for environmental damages caused by, among others, previous property owners or operators of properties that we purchase or lease. Some environmental laws provide for joint and several strict liability for remediation of releases of hazardous substances, rendering a person liable for environmental damage without regard to negligence or fault on the part of such person. As a result, we may incur substantial liabilities to third parties or governmental entities and may be required to incur substantial remediation costs. We could also be affected by more stringent laws and regulations adopted in the future, including any related to climate change and GHG and the use of hydraulic fracturing fluids, resulting in increased operating costs.

These laws and governmental regulations, which cover matters including drilling operations, taxation and environmental protection, may be changed from time to time in response to economic or political conditions and could have a significant impact on our operating costs, as well as the crude oil, natural gas and NGLs industry in general. While we believe that we are currently in compliance with environmental laws and regulations applicable to our operations, no assurances can be given that we will be able to continue to comply with such environmental laws and regulations without incurring substantial costs.

We have been, and in the future may become, involved in legal proceedings with governmental bodies and private litigants, and, as a result, may incur substantial costs in connection with those proceedings.

Our business subjects us to liability risks from litigation or government actions. We have been involved in legal proceedings from time to time and may in the future be party to various lawsuits or governmental actions. There is risk that any matter in litigation could be decided unfavorably against us, which could have a material adverse effect on our financial condition, results of operations and cash flows. Litigation can be very costly, and the costs associated with defending litigation could also have a material adverse effect on our results of operation, net cash flows and financial condition. Adverse litigation decisions or rulings may also damage our business reputation.

Often, our operations are conducted through joint ventures over which it may have limited influence and control. Private litigation or government proceedings brought against us could also result in significant delays in our operations.

Our failure to comply with applicable laws could subject us to penalties and other adverse consequences.

We are subject to a wide variety of laws relating to the environment, health and safety, taxes, employment, labor standards, money laundering, terrorist financing, and other matters in the jurisdictions in which they operate. Our failure to comply with any such legislation could result in severe criminal or civil sanctions and may subject us to other liabilities, including fines, prosecution and reputational damage, all of which could have a material adverse effect on our business, consolidated results of operations and consolidated financial condition. The compliance mechanisms and monitoring programs that we have adopted and implemented may not adequately prevent or detect possible violations of such applicable laws. Investigations by governmental authorities could also have a material adverse effect on our business, results of operations and financial condition.

Risks Relating to the Facility Agreement

A significant level of indebtedness incurred under the Facility may limit our ability to borrow additional funds or capitalize on acquisition or other business opportunities in the future. In addition, the covenants in the Facility impose restrictions that may limit our ability and the ability of our subsidiaries to take certain actions. Our failure to comply with these covenants could result in the acceleration of any future outstanding indebtedness under the Facility.

The Facility Agreement governing our Facility with Glencore contains certain affirmative and negative covenants, including, among other things, as to compliance with laws (including environmental laws and anti-corruption laws), delivery of quarterly and annual financial statements and borrowing base certificates, conduct of business, maintenance of property, maintenance of insurance, entry into certain derivatives contracts, restrictions on the incurrence of liens, indebtedness, asset dispositions, restricted payments. In addition, the Facility Agreement (i) requires us to maintain a ratio of Consolidated Total Net Debt to EBITDAX (as each term is defined in the Facility Agreement) for the trailing 12 months not exceeding 3.0x; (ii) requires us to maintain consolidated cash and cash equivalents shall not lower than $10.0 million; and (iii) restricts our ability to: dispose of assets, enter into guarantees or indemnities, enter into certain material contracts, merger or consolidate, or transfer all or substantially all of our assets and the assets of our subsidiaries, or pursue other corporate activities. We were in compliance with covenants under the Facility Agreement as of December 31, 2023.

Restrictions contained in the Facility governing any future indebtedness may reduce our ability to incur additional indebtedness, engage in certain transactions or capitalize on acquisition or other business opportunities. Any future indebtedness under the Facility and other financial obligations and restrictions could have financial consequences. For example, they could:

- impair our ability to obtain additional financing in the future for capital expenditures, potential acquisitions, general business activities or other purposes;
- increase our vulnerability to general adverse economic and industry conditions;
- require us to dedicate a substantial portion of future cash flow to payments of our indebtedness and other financial obligations, thereby reducing the availability of our cash flow to fund working capital, capital expenditures and other general corporate requirements;
- limit our flexibility in planning for, or reacting to, changes in our business and industry; and
- place us at a competitive disadvantage to those who have proportionately less debt.

In addition, our ability to comply with the Facility Agreement's covenants could be affected by events beyond our control and we cannot assure you that we will satisfy those requirements. A prolonged period of oil and gas prices at declined levels could further increase the risk of our inability to comply with covenants to maintain specified financial ratios. A breach of any of these provisions could result in a default under the Facility, which could allow all amounts outstanding thereunder to be declared immediately due and payable. In the event of such acceleration, we cannot assure that we would be able to repay our debt or obtain new financing to refinance our debt. Even if new financing was made available to us, it may not be on terms acceptable to us. We may also be prevented from taking advantage of business opportunities that arise if we fail to meet certain ratios or because of the limitations imposed on us by the restrictive covenants under the Facility.

The borrowing base under the Facility may be reduced pursuant to the terms of the Facility Agreement, which may limit our available funding for exploration and development. We may have difficulty obtaining additional credit, which could adversely affect our operations and financial position.

In the future we may depend on the Facility for a portion of our capital needs. The initial maximum borrowing base under the Facility is $50.0 million (which maximum was reduced to $43.8 million beginning on October 1, 2023) and is re-determined on March 31 and September 30 of each year. Borrowings under the Facility are limited to a borrowing base amount calculated pursuant to the Facility Agreement based on our proved producing reserves and a portion of our proved undeveloped reserves. The lenders will re-determine the borrowing base based on forecasts of cash flow and debt service projections with respect to the borrowing base assets, which may result in a reduction of the borrowing base.

In the future, we may not be able to access adequate funding under the Facility as a result of (i) a decrease in our borrowing base due to the outcome of a subsequent borrowing base redetermination, or (ii) an unwillingness or inability on the part of the Lenders to meet their funding obligations. As a result, we may be unable to obtain adequate funding under the Facility. If funding is not available when needed, or is available only on unfavorable terms, it could adversely affect our development plans as currently anticipated, which could have a material adverse effect on our production, revenues and results of operations.

Risks Relating to Ownership of Our Common Stock

The price of our Common Stock may fluctuate significantly.

Our common stock currently trades on the NYSE and the LSE, but an active trading market for our common stock may not be sustained. The market price of our common stock could fluctuate significantly as a result of:

- dilutive issuances of our common stock;
- announcements relating to our business or the business of our competitors;
- changes in expectations as to our future financial performance or changes in financial estimates of public market analysis;
- actual or anticipated quarterly variations in our operating results;
- conditions generally affecting the crude oil, natural gas and NGLs industry;
- the success of our operating strategy; and
- the operating and stock price performance of other comparable companies.

Many of these factors are beyond our control, and we cannot predict their potential effects on the price of our common stock. In addition, the stock markets can experience considerable price and volume fluctuations. Recent volatility in the financial markets has resulted in significant price and volume fluctuations that have affected the market prices of equity securities without regard to a company’s operating performance, underlying asset values or prospects. Accordingly, the market price of our common stock may decline even if our operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause decreases in asset values, which may result in impairment losses. There is no assurance that fluctuations in the price and volume of publicly traded equity securities will not occur. If such increased levels of volatility and market turmoil continue, our operations could be adversely impacted, and the trading price of our common stock may be adversely affected.

We currently intend to pay dividends on, and effect share buybacks, with respect to our common stock; however, our ability to take these actions in the future may be limited and no assurance can be given that we will be able to pay dividends to our stockholders or effect share buybacks in the future at indicated levels or at all.

On February 14, 2023, we announced that our board of directors adopted a quarterly cash dividend policy of an expected $0.0625 per share of common stock commencing in the first quarter of 2023. On November 1, 2022, the Company announced that the Company’s board of directors formally ratified and approved a share buyback program. The board of directors also directed management to implement a Rule 10b5-1 trading plan (the “10b5-1 Plan”) to facilitate share purchases through open market purchases, privately negotiated transactions, or otherwise in compliance with Rule 10b-18 under the Securities Exchange Act of 1934. The 10b5-1 Plan provides for an aggregate purchase of currently outstanding common stock up to $30 million over a maximum period of 20 months. Payment for shares repurchased under the share buyback program will be funded using the Company's cash on hand and cash flow from operations. To the extent we have adequate cash on hand and cash flows from operations, we will consider continuing to take these actions in the future. Payment of future dividends and effectuation of share buybacks, if any, and the establishment of future record and payment dates will be at the discretion of our board of directors after taking into account various factors, including current financial condition, the tax impact of repatriating cash, operating results and current and anticipated cash needs. As a result, no assurance can be given that we will be able to continue to pay dividends to our stockholders or the terms on which we will effectuate share buybacks in the future or that the level of any future dividends will achieve a market yield or increase or even be maintained over time, any of which could materially and adversely affect the market price of our common stock.

Dual-listing on the NYSE and the LSE may lead to an inefficient market in our common stock.

Our common stock is quoted on the NYSE and the LSE. Consequently, the trading in and liquidity of our common stock are split between these two exchanges. The price of our common stock may fluctuate and may at any time be different on the NYSE and the LSE. Dual-listing of our common stock will result in differences in liquidity, settlement and clearing systems, trading currencies, and prices and transaction costs between the exchanges where our common stock will be quoted. These and other factors may hinder the transferability of our common stock between the two exchanges.

Investors could seek to sell or buy our common stock to take advantage of any price differences between the two markets through a practice referred to as arbitrage. Any arbitrage activity could create unexpected volatility in both common stock prices on either exchange and in the volumes of our common stock available for trading on either market. This could adversely affect the trading of our common stock on these exchanges and increase their price volatility and/or adversely affect the price and liquidity of the shares of common stock on these exchanges. In addition, holders of our common stock in either jurisdiction will not be immediately able to transfer such shares for trading on the other market without effecting necessary procedures with our transfer agents/registrars. This could result in time delays and additional cost for stockholders.

Our common stock is quoted and traded in USD on the NYSE and traded in GBX on the LSE. The market price of our common stock on those exchanges may also differ due to exchange rate fluctuations.

Substantial future sales of our common stock, or the perception that such sales might occur, or additional offerings of our common stock could depress the market price of our common stock.

We cannot predict what effect, if any, future sales of our common stock, or the availability of our common stock for future sale, or the offer of additional our common stock in the future, will have on the market price of our common stock. Sales or an additional offering of substantial numbers of our common stock in the public market, or the perception or any announcement that such sales or an additional offering could occur, could adversely affect the market price of our common stock and may make it more difficult for stockholders to sell their common stock at a time and price that they deem appropriate and could also impede our ability to raise capital through the issuance of equity securities.

Any issuance of preferred shares will rank in priority to our shares of common stock.

While we do not currently have any preferred shares outstanding, under our certificate of incorporation, we are authorized to issue up to 500,000 preferred shares. Any issuance of preferred shares would rank in priority to our shares of common stock with respect to the payment of dividends, liquidation, and other matters.

Our certificate of incorporation and bylaws do not contain any rights of pre-emption in favor of existing stockholders, which means that stockholders may be diluted if additional shares of common stock are issued.

Our stockholders do not have pre-emptive rights and we, without stockholder consent, may issue additional shares of common stock, preferred shares, warrants, rights, units and debt securities for general corporate purposes, including, but not limited to, working capital, capital expenditures, investments, acquisitions and repayment or refinancing of borrowings. We actively seek to expand our business through complementary or strategic acquisitions and may issue additional shares of common stock in connection with those acquisitions. We also issue shares of our common stock to our executive officers, employees and independent directors as part of their compensation. This may have the effect of diluting the interests of existing stockholders. Additionally, to the extent that pre-emptive rights are granted, stockholders in certain jurisdictions may experience difficulties or may be unable to exercise their pre-emptive rights.

The choice of forum provisions in our Third Amended and Restated Bylaws (the "Bylaws") could limit our stockholders' ability to obtain a favorable judicial forum for disputes.

Our Bylaws provide that the Court of Chancery of the State of Delaware (or, if the Court of Chancery does not have jurisdiction, the federal district court for the District of Delaware) shall be the sole and exclusive forum for (i) any derivative action or proceeding brought in the name or right of the Company or on its behalf, (ii) any action asserting a claim for breach of a fiduciary duty owed by any director, officer, employee, stockholder or other agent of the Company to the Company or the stockholders, (iii) any action arising or asserting a claim arising pursuant to any provision of the General Corporation Law of Delaware (the "DGCL") or any provision of our Restated Certificate of Incorporation, as amended (the "Charter"), or the Bylaws or as to which the DGCL confers jurisdiction on the Court of Chancery of the State of Delaware or (iv) any action asserting a claim governed by the internal affairs doctrine, including, without limitation, any action to interpret, apply, enforce or determine the validity of the Charter or the Bylaws. Nonetheless, pursuant to our Bylaws, the foregoing provisions will not apply to suits brought to enforce a duty or liability created by the Exchange Act or any other claim for which the federal courts have exclusive jurisdiction. Our Bylaws further provide that unless we consent in writing to the selection of an alternative forum, the federal district courts of the U.S. shall be the exclusive forum for the resolution of any complaint asserting a cause of action arising under the Securities Act. Under the Securities Act, federal and state courts have concurrent jurisdiction over all suits brought to enforce any duty or liability created by the Securities Act, and stockholders cannot waive compliance with the federal securities laws and the rules and regulations thereunder. Accordingly, there is uncertainty as to whether a court would enforce such a forum selection provision as written in connection with claims arising under the Securities Act. Any person or entity purchasing or otherwise acquiring any interest in shares of our capital stock will be deemed to have notice of and have consented to the provisions in the Bylaws related to choice of forum. The choice of forum provisions in our Bylaws may limit our stockholders' ability to obtain a favorable judicial forum for disputes with us. Additionally, the enforceability of choice of forum provisions in other companies' governing documents has been challenged in legal proceedings, and it is possible that, in connection with any applicable action brought against us, a court could find the choice of forum provisions contained in our Bylaws to be inapplicable or unenforceable in such action. If so, we may incur additional costs associated with resolving such action in other jurisdictions, which could harm our business, results of operations, and financial condition.

Item 1B. Unresolved Staff Comments

None.

Item 1C. Cybersecurity

Risk management and strategy

Our corporate information technology, communication networks, enterprise applications, accounting and financial reporting platforms, and related systems are necessary for the operation of our business. We use these systems, among others, to manage our exploration, development and production processes, for internal communications, for accounting to operate record-keeping function, and for many other key aspects of our business. Our business operations rely on the secure collection, storage, transmission, and other processing of proprietary, confidential, and sensitive data.

We have implemented and maintain various information security processes designed to identify, assess and manage material risks from cybersecurity threats to our critical computer networks, third-party hosted services, communications systems, hardware and software, and our critical data, including confidential information that is proprietary, strategic or competitive in nature ("Information Systems and Data").

We rely on a multidisciplinary team, including our information security function, legal department, management, and third-party service providers, as described further below, to identify, assess, and manage cybersecurity threats and risks. We identify and assess risks from cybersecurity threats by monitoring and evaluating our threat environment and our risk profile using various methods including, for example, using manual and automated tools, subscribing to reports and services that identify cybersecurity threats, analyzing reports of threats and threat actors, conducting scans of the threat environment, evaluating our industry's risk profile, utilizing internal and external audits, and conducting threat and vulnerability assessments.

Depending on the environment, we implement and maintain various technical, physical, and organizational measures, processes, standards, and/or policies designed to manage and mitigate material risks from cybersecurity threats to our Information Systems and Data, including risk assessments, incident detection and response, vulnerability management, disaster recovery and business continuity plans, internal controls within our accounting and financial reporting functions, encryption of data, network security controls, access controls, physical security, asset management, systems monitoring, vendor risk management program, infrastructure protection technologies, disaster recovery plans, employee training, and penetration testing.

We work with third parties from time to time that assist us to identify, assess, and manage cybersecurity risks, including professional services firms, consulting firms, threat intelligence service providers and penetration testing firms.

To operate our business, we utilize certain third-party service providers to perform a variety of functions. We seek to engage reliable, reputable service providers that maintain cybersecurity programs. Depending on the nature of the services provided, the sensitivity and quantity of information processed, and the identity of the service provider, our vendor management process may include reviewing the cybersecurity practices of such provider, contractually imposing obligations on the provider, conducting security assessments, and conducting periodic reassessments during their engagement.

We are not aware of any risks from cybersecurity threats, including as a result of any cybersecurity incidents, which have materially affected or are reasonably likely to materially affect our Company, including our business strategy, results of operations, or financial condition. Refer to "Item 1A. Risk factors" in this annual report on Form 10-K, including "Our business could be materially and adversely affected by security threats, including cybersecurity threats, and other disruptions", for additional discussion about cybersecurity-related risks.

Governance

Our Board of Directors holds oversight responsibility over the Company's strategy and risk management, including material risks related to cybersecurity threats. This oversight is performed by the Board of Directors and its committees. The Board of Directors oversees the management of systemic risks, including cybersecurity. The Board of Directors engages in discussions with management when management identifies any significant financial risk exposures that may result from material cybersecurity threats and the measures implemented to monitor and control these risks.

Our management, represented by our Chief Financial Officer, Ron Bain, and our [Information Technology Manager], leads our cybersecurity risk assessment and management processes and oversees their implementation and maintenance.

Our IT Manager is an experienced information technology professional in our information technology department and has served as Information Technology Manager since 2014. He works with the Company's internal information technology department and external partners to monitor and improve our cybersecurity capabilities. Our IT Manager possesses extensive experience in technology and cybersecurity, gained over his career spanning more than 10 years. Our IT Manager earned a Bachelor of Science and Bachelor of Applied Science degrees in Information Technology Specializing in Security from Colorado Technical University.

Management, in coordination with our information technology department, is responsible for hiring appropriate personnel, helping to integrate cybersecurity risk considerations into the Company's overall risk management strategy, and communicating key priorities to relevant personnel. Management is responsible for approving budgets, approving cybersecurity processes, and reviewing cybersecurity assessments and other cybersecurity-related matters.

Our cybersecurity incident response and vulnerability management processes are designed to escalate certain cybersecurity incidents to members of management depending on the circumstances. Management, including the Information Technology Manager and the Chief Financial Officer, serves on the Company's incident response team to help the Company mitigate and remediate cybersecurity incidents of which they are notified. In addition, the Company's incident response processes include reporting to the Board of Directors for certain cybersecurity incidents. The Board of Directors holds regular meetings throughout the year and receives periodic reports from management, including our Chief Financial Officer, concerning the Company's significant cybersecurity threats and risk and the processes the Company has implemented to address them.

Item 2. Properties

The location and general character of our principal crude oil, natural gas and NGLs assets, production facilities, and other important physical properties have been described by segment under Item 1. "*Business*." Information about crude oil, natural gas and NGLs reserves, including the basis for their estimation, is discussed in Item 1. "*Business*."

Item 3. Legal Proceedings

We are subject to litigation claims and governmental and regulatory proceedings arising in the ordinary course of business. It is management's opinion that all claims and litigation we are currently involved in are not likely to have a material adverse effect on our consolidated financial position, cash flows or results of operations.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is traded on the New York Stock Exchange and London Stock Exchange under the symbol "EGY".

As of February 29, 2024, based upon information received from our transfer agent and brokers and nominees, there were approximately 78 holders of record of VAALCO common stock. This number does not include beneficial or other owners for whom common stock may be held in "street" names.

Dividends

On February 14, 2023, we announced that our board of directors adopted a quarterly cash dividend policy of an expected $0.0625 per common share per quarter commencing in the first quarter of 2023 and continued throughout the year. The following table is a schedule of our dividends paid during 2023:

Dividend Payment Date		Amount per common share	Record Date
March 31, 2023	$	0.0625	March 24, 2023
June 23, 2023	$	0.0625	May 24, 2023
September 22, 2023	$	0.0625	August 25, 2023
December 21, 2023	$	0.0625	November 24, 2023
Aggregate per share amount paid in 2023	$	0.2500	

In connection with the RBL facility, we are required to provide a cash flow projection prior to any distribution, share buyback, or stock repurchase. As long as a group liquidity test is above the required ratio outlined in the RBL facility agreement, and no event of default exists, we may make distributions, buyback shares, or repurchase stock without further approval. In the event the liquidity test is not met, an approval or waiver would need to be obtained from Glencore in order to make distributions, buyback shares, or repurchase stock. For the year ended December 31, 2023, no specific approval or waivers were required to make distributions or repurchase stock.

To the extent we have adequate cash on hand and cash flows from operations, we will consider paying additional cash dividends on a quarterly basis; however, any future dividend payments, if any, will be at the discretion of the Board of Directors after taking into account various factors, including current financial condition, the tax impact of repatriating cash, operating results and current and anticipated cash needs.

Securities Authorized for Issuance Under Equity Compensation Plans

See "*Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*" for discussion of shares of common stock that may be issued under our compensation plans.

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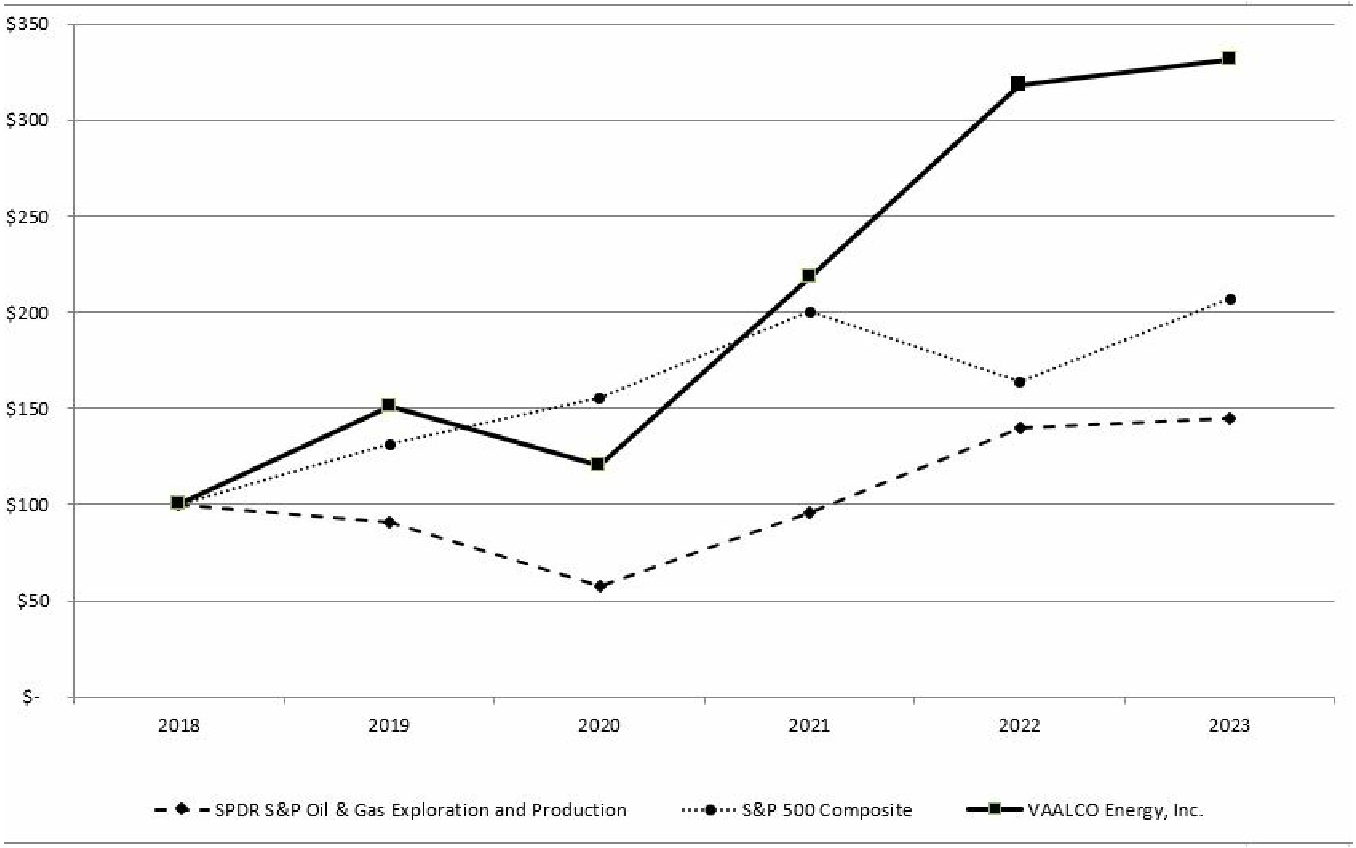
Performance Graph

The following graph compares the annual percentage change in our cumulative total stockholder return on common shares with the cumulative total return of the S&P 500 Index and the SPDR S&P Oil & Gas Exploration and Production Index. The graph assumes $100 was invested on December 29, 2018 in our common stock and in each index, and that all dividends, if any, are reinvested. Stockholder returns over the indicated period may not be indicative of future stockholder returns.



	2018	2019	2020	2021	2022	2023
SPDR S&P Oil & Gas Exploration and Production	$ 100	$ 91	$ 58	$ 96	$ 140	$ 145
S&P 500 Composite	$ 100	$ 131	$ 155	$ 200	$ 164	$ 207
VAALCO Energy, Inc.	$ 100	$ 151	$ 120	$ 218	$ 318	$ 332

Unregistered Sales of Equity Securities and Use of Proceeds

There were no sales of unregistered securities during the quarter ended December 31, 2023 that were not previously reported on a Current Report on Form 8-K.

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Issuer Repurchases of Common Stock

The Company has implemented a Rule 10b5-1 trading plan (the "10b5-1 Plan") to facilitate share purchases through open market purchases, privately negotiated transactions, or otherwise under the Securities Exchange Act of 1934. The 10b5-1 Plan provides for an aggregate purchase of currently outstanding common stock up to $30 million over a maximum period of up to 20 months. Payment for shares repurchased under the share buyback program will be funded using the Company's cash on hand and cash flow from operations.

The below table shows the repurchases of equity securities related to the share repurchase program during the quarter ended December 31, 2023:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Programs	Maximum Amount that May Yet Be Used to Purchase Shares Under the Program
October 1, 2023 - October 31, 2023	491,869	$ 4.07	491,869	$ 9,515,101
November 1, 2023 - November 30, 2023	472,141	$ 4.24	472,141	$ 7,515,171
December 1, 2023 - December 31, 2023	449,839	$ 4.45	449,839	$ 5,515,237
Total	1,413,849		1,413,849	

The below table shows the repurchases of equity securities related to the share repurchase program during the fiscal year ended December 31, 2023:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Programs	Maximum Amount that May Yet Be Used to Purchase Shares Under the Program
January 1, 2023 - January 31, 2023	350,832	$ 4.29	350,832	$ 25,502,669
February 1, 2023 - February 28, 2023	326,992	$ 4.61	326,992	$ 24,003,172
March 1, 2023 - March 31, 2023	303,176	$ 4.97	303,176	$ 22,503,206
April 1, 2023 - April 30, 2023	303,969	$ 4.94	303,969	$ 21,003,245
May 1, 2023 - May 31, 2023	362,843	$ 4.14	362,843	$ 19,502,740
June 1, 2023 - June 30, 2023	494,164	$ 4.05	494,164	$ 17,504,007
July 1, 2023 - July 31, 2023	505,720	$ 3.96	505,720	$ 15,504,180
August 1, 2023 - August 31, 2023	435,342	$ 4.61	435,342	$ 13,505,242
September 1, 2023 - September 30, 2023	462,300	$ 4.31	462,300	$ 11,514,870
October 1, 2023 - October 31, 2023	491,869	$ 4.07	491,869	$ 9,515,101
November 1, 2023 - November 30, 2023	472,141	$ 4.24	472,141	$ 7,515,171
December 1, 2023 - December 31, 2023	449,839	$ 4.45	449,839	$ 5,515,237
Total	4,959,187		4,959,187	

The following table shows the repurchases of our equity securities related to our share repurchase program after December 31, 2023 through March 8, 2024:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Programs	Maximum Amount that May Yet Be Used to Purchase Shares Under the Program
January 1, 2024 - January 31, 2024	446,366	$ 4.48	446,366	$ 3,516,205
February 1, 2024 - February 29, 2024	474,100	$ 4.22	474,100	$ 1,516,630
March 1, 2024 - March 08, 2024	272,248	$ 4.32	272,248	$ 339,362
Total	1,192,714		1,192,714	

Item 6. [Reserved].

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following management's discussion and analysis describes the principal factors affecting our capital resources, liquidity, and results operations. This management's discussion and analysis should be read in conjunction with the accompanying Financial Statements and related notes, information about our business practices, significant accounting policies, risk factors, and the transactions that underlie our financial results, which are included in various parts of this Annual Report. For discussion related to changes in financial condition and results of operations for 2022 as compared with 2021, refer to Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2022 Form 10-K, which was filed with the SEC on April 6, 2023. Certain statements in our discussion below are forward-looking statements. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause actual results to differ materially from those implied or expressed by the forward-looking statements. Please see "Cautionary Statement Regarding Forward-Looking Statements" and "Item 1A. Risk Factors" for further details about these statements.

INTRODUCTION

We are a Houston, Texas-based, African-focused independent energy company with strong production and reserve portfolio of assets in Gabon, Egypt, Equatorial Guinea and Canada, currently engaged in the acquisition, exploration, development and production of crude oil, natural gas and NGLs. For further discussion of our four operating segments see "*Item 1. Business – Segment and Geographical Information* – "*Gabon Segment*", "*Egypt Segment", "Canada Segment",* and "*Equatorial Guinea Segment*"".

We own a working interest in, and are the operator of, the Etame PSC related to the Etame Marin block located offshore Gabon in West Africa. The Etame Marin block covers an area of approximately 46,200 gross acres located 20 miles offshore in water depths of approximately 250 feet. Currently, our working interest in the Etame Marin block is 58.8%, and we are designated as the operator on behalf of the Etame Consortium. The block is subject to a 7.5% back-in carried interest by the government of Gabon, which they have assigned to a third party. Our working interest will decrease to 57.2% in June 2026 when the back-in carried interest increases to 10%.

We are also a member of a consortium with BW Energy and Panoro Energy (the "BWE Consortium"). The BWE Consortium has been provisionally awarded two blocks in the 12th Offshore Licensing Round in Gabon. Negotiations to finalize the commercial terms were held in 2023, however, they were halted late in the year due to the presidential elections. The next step is concluding the terms of PSCs with the Gabonese government. The negotiations were kick started again at the request of the Gabonese Government in early February 2024, where the consortium and the government came to an agreement on the fiscal terms on February 9, 2024. The next step is concluding the terms of the PSC with the Gabonese government. BW Energy will be the operator with a 37.5% working interest, with VAALCO (37.5% working interest) and Panoro Energy (25% working interest) as non-operating joint owners. The two blocks, G12-13 and H12-13 are adjacent to our Etame PSC as well as BW Energy and Panoro's Dussafu PSC offshore Southern Gabon and cover an area of 2,989 square kilometers and 1,929 square kilometers, respectively.

As a result of the Arrangement with TransGlobe in 2022, we own a 100% working interest in PSCs covering two regions: the Eastern Desert, which contains the West Gharib, West Bakr and North West Gharib merged concessions (45,067 acres) and the Western Desert which contains the South Ghazalat concession (7,340 acres). We also acquired TransGlobe's production and working interests in Cardium light oil and Mannville liquids-rich gas assets located in Harmattan, Canada (47,400 gross acers developed). See Note 4 to the consolidated financial statements for further discussion regarding the Arrangement.

Recent Operational Updates

Gabon

VAALCO completed its 2021/2022 drilling campaign in the fourth quarter of 2022. We are currently evaluating locations and planning for the next drilling campaign at Etame that is expected to occur late in 2024. In October 2022, VAALCO successfully completed its transition to a Floating Storage and Offloading vessel ("FSO") and related field reconfiguration processes. This project provides a low cost FSO solution that increases the storage capacity for the Etame block and improved operational performance. The Company will continue to focus on operational excellence, including production uptime and enhancement in 2024 to minimize decline until the next drilling campaign.

At the end of December 2023, all wells were online from the end of 2022 as the gas lift compression system was successfully commissioned. This gas lift compression system increased the production and the reliability of two subsea wells, positively impacting our volumes for the year ended December 31, 2023. Gas lift compression and subsea wells remained online with a high level of reliability through the year ended December 31, 2023.

The focus during the beginning of 2023 was continued production optimization of the new flow line configurations at the Etame Facility, as all production transits through the Etame platform for final processing before being pumped to the FSO. Since the field reconfiguration in 2022, a better understanding of the field's operating parameters, through the new central processing facility (CPF) on Etame, has resulted in a more efficient and cost effective flow assurance program. Continued optimization and understanding of the post reconfiguration process dynamics of the Etame platform, have maintained a very high uptime availability of Etame Facility and in turn the complete Etame field during the second quarter. Combining this with individual well and facility chemical injection optimization and facility pipeline pigging adjustments both on frequency of pigging and flow path targeting, has increased production through decrease in pipeline internal buildup and resulting drop in pipeline back pressure, this in turn has provided more stable operations resulting in lower downtime. Through the fourth quarter of 2023, this continues to be a focus with positive results in production rates and uptime.

Preventative maintenance activities remained at levels prior to the field reconfiguration, as the focus was on steady state operation following project completion. Equipment reliability and availability remain at high levels. The actual percentages of Corrective Maintenance performed versus Preventative Maintenance performed remain well within VAALCO and Industry Best Practice standards. Major planned maintenance was carried out on Etame Power generation turbines.

Charter Agreement for the Floating Storage and Offloading Unit in Gabon

In August of 2021, we and our co-venturers at Etame approved the FSO Agreements with World Carrier to replace the existing FPSO with an FSO. The FSO Agreements required a prepayment of $2 million gross ($1.2 million net to VAALCO) in 2021 and $5 million gross ($3.2 million net to VAALCO) in 2022 of which $6 million will be recovered against future rentals.

On October 19, 2022, the replacement of the existing FPSO was completed and we signed the final acceptance certificate, at which time control of the FSO vessel transferred to us. The new FSO has been named “Teli” (renamed from “Cap Diamant”) and is on site and accepting oil at the Etame Marin block.

Total field conversion expenses were $122 million gross ($77 million net to VAALCO).

The FPSO charter we were party to prior to the FSO installation was set to expire in September 2022, but on September 9, 2022 we signed an addendum to the FPSO contract which extended the use of the FPSO through October 4, 2022, and ratified certain decommissioning and demobilization items associated with exiting the contract. Pursuant to the addendum, VAALCO Gabon agreed to pay the charterer day rate of $150,000 from August 20, 2022 through October 4, 2022 and other demobilization fees totaling $15.3 million on a gross basis ($8.9 million net to VAALCO).

The demobilization of the FPSO was carried out from October 5, 2022 through to November 19, 2023. This included the cleaning and removal of waste from the Cargo and Slop Tanks.

In the fourth quarter of 2023, the joint operating group in Gabon reached a settlement agreement with Tinworth to release the joint operating group from any further obligation pertaining to the former FPSO. The signed agreement, dated December 12, 2023, called for the group to pay an additional $8 million gross ($4.7 million net to VAALCO) to Tinworth in exchange for the release. The payment was made on December 22, 2023. Based on this and the prior expense incurred earlier in the year, VAALCO reported $7.5 million in FPSO Demobilization costs on the income statement for the year ended December 31, 2023. The sail date on the FPSO was November 19, 2023.

Egypt

VAALCO continued to use the EDC-64 rig in the Eastern Desert drilling campaign. We continue to drill an average of two wells per month with the EDC-64 rig and we drilled 18 wells in year 2023.

The SGZ-6X well remains shut-in. We continue to evaluate our strategic options. There was no production from South Ghazalat due to the SGZ-6X remaining shut-in. There is a planned workover for this well in 2024 to resume production.

A summary of the Egyptian drilling campaign's impact during 2023 is presented below:

VAALCO Egypt 2023 Wells

Well	Spud date	Net Pay (ft)	Penetrated Pay Zones	Completion Zone	Perforation Interval (ft)	IP-30 Rate (BOPD)
EastArta-53	1/15/2023	14.8	Redbed	Redbed	Hydraulic Frac	35
K-81	2/2/2023	68.9	Asl-D and E	Asl-E	13.1	255
K-79	2/21/2023	190	Asl-A, B, D, E and F	Asl-B1 and B2	59	150
Arta-80	3/10/2023	33	Redbed	Redbed	32	440
Arta-81	3/21/2023	28.5	Redbed	Redbed	26	340
HE-4	4/2/2023	27.9	Asl-B1 and B2	Asl-B2	13.1	440
HE-5 Injector	4/16/2023	4.9	Asl-B2	Asl-B2	9.8	NA
HE-3	5/10/2023	9.2	Asl-B1 and B2	Asl-B2	16.4	235
Arta-82	5/25/2023	42	Redbed	Redbed	28	150
Arta-84	6/6/2023	34	Nukhul	Nukhul	Hydraulic Frac	68
NWG-5C1	6/16/2023	none	Nukhul	Temporarily Abandoned	none	none
K-80	6/30/2023	141.4	Asl-A, B, D and E	Asl-E	16.4	144
K-84	7/16/2023	98.8	Asl-D, E, F and G	Asl-G2	19.7	125
K-85	7/31/2023	63.3	Asl-D, E, F and G	Asl-E	9.8	82
M-24	8/14/2023	70.2	Asl-A, B and D	Asl-D	9.8	134
Arta-91	9/1/2023	40	Nukhul and Redbed	Redbed	20	150
EA-54	9/12/2023	none	Nukhul, Thebes and Redbed	Plugged & Abandoned	none	none
EA-55	10/4/2023	42	Redbed	Redbed	Hydraulic Frac	Pending Frac

Canada

Early in 2023, two wells, the 04-10-29-03W5 and the 04-19-29-3W5, were tied in. Both wells are now online and producing.

The 2023 drilling campaign commenced in January 2023 with the drilling of 12-12-30-4W5, spudded on January 28, 2023. The well was drilled to a total depth of 22,024 feet. The second well of the program, 16-30-29-3W5, was spudded on February 22, 2023, and drilled to a total depth of 14,446 feet. The two wells were completed between late March and early April and tied in and equipped in April and early May. 12-12-30-4W5 was put online in late April, and 16-30-29-3W5 was put online in early May with cycle times that were significantly less than historical cycle times. The wells free flowed in the months of May and June. In early July, the pump and rods were run on both wells. Both wells continue to produce and both wells continued to exceed expectations during the fourth quarter of 2023.

A summary of the Canada drilling campaign's impact during 2023 is presented below:

VAALCO Canada 2023 Wells

Well	Spud date	Net Pay (ft)	Penetrated Pay Zones	Completion Zone	Perforation Interval (ft)	IP-30 Rate (BOPD)
100/12-12	1/28/2023	14,430	Upper Bioturbated Cardium	118 Stg x 15T Hydraulic Fracture Treatment	n/a	444 BOPD ; 500 BOEPD
102/16-30	2/22/2023	7,870	Upper Bioturbated Cardium	55 Stg x 15T Hydraulic Fracture Treatment	n/a	374 BOPD ; 426 BOEPD

CAPITAL RESOURCES AND LIQUIDITY

Cash Flows

Our cash flows for the years ended December 31, 2023 and 2022 are as follows:

	Twelve Months Ended December 31,		
	2023	2022	**Increase (Decrease) in 2023 over 2022**
		(in thousands)	
Net cash provided by operating activities before changes in operating assets and liabilities	**$ 182,745**	$ 127,817	$ 54,928
Net change in operating assets and liabilities	**40,867**	1,101	39,766
Net cash provided by (used in) continuing operating activities	**223,612**	128,918	94,694
Net cash used in discontinued operating activities	**(15)**	(72)	57
Net cash provided by (used in) operating activities	**223,597**	128,846	94,751
Net cash provided by (used in) investing activities	**(97,223)**	(123,211)	25,988
Net cash provided by (used in) in financing activities	**(56,819)**	(17,955)	(38,864)
Effects of exchange rate changes on cash	**(153)**	(218)	(371)
Net change in cash, cash equivalents and restricted cash	**$ 69,402**	$ (12,538)	$ 81,504

The $54.9 million increase in net cash provided by our operating activities before changes in operating assets and liabilities for the year ended December 31, 2023 compared to the same period of 2022 was due to higher pricing, more production and the increased number of producing wells. The net increase in changes provided by operating assets and liabilities of $39.8 million for the year ended December 31, 2023 compared to the same period of 2022 was primarily related to decreases in accounts with joint venture owners, other receivables and foreign income taxes receivable partially offset by changes in accounts payable and accrued liabilities.

The $26.0 million increase in net cash used in investing activities during the year ended December 31, 2023 was due to decreases in cash capital spending in 2023. In 2022 we incurred significant capital for the 2021/2022 Etame drilling campaign and the Etame field reconfiguration. In 2023 capital spending for the drilling program in Egypt and Canada was less due to the lower per well costs for onshore wells is than Etame's offshore wells and there were no costs associated with field reconfiguration in 2023.

Net cash used in financing activities during the year ended December 31, 2023 included $26.8 million dividends paid to common shareholders, $23.6 million for treasury stock purchases made under our stock repurchase plan, or as a result of tax withholding on options exercised and vested restricted stock as discussed in Note 17 to our consolidated financial statements, and $7.2 million related to principal finance lease payments partially offset by $0.7 million in proceeds from options exercised.

Capital Expenditures

During 2023, we had accrual basis expenditures attributable to continuing operations of $72.6 million, that includes $17.0 million for Gabon, $37.9 million for Egypt, $16.8 million for Canada and $1.0 million for the corporate offices, compared to $434.4 million for 2022. Capital expenditures in 2023 were attributable to expenditures primarily related to the payments for the 2023 drilling campaigns in Egypt and Canada. The 2022 capital expenditures include TransGlobe assets acquired for stock. The difference between capital expenditures and the property and equipment expenditures reported in the consolidated statements of cash flows is attributable to changes in accruals for costs incurred but not yet invoiced or paid on the report dates. Capital expenditures in 2022 were attributable to expenditures related to the 2021/2022 drilling program, the Etame field reconfiguration and drilling activity in Egypt and Canada.

Regulatory and Joint Interest Audits

We are subject to periodic routine audits by various government agencies, including audits of our petroleum Cost Account, customs, taxes and other operational matters, as well as audits by other members of the contractor group under our joint operating agreements. See Note 12 to the Consolidated Financial Statements for further discussion.

Commodity Price Hedging

The price we receive for our crude oil significantly influences our revenue, profitability, liquidity, access to capital and prospects for future growth. Crude oil commodities and, therefore their prices can be subject to wide fluctuations in response to relatively minor changes in supply and demand. We believe these prices will likely continue to be volatile in the future.

Due to the inherent volatility in crude oil prices, we use commodity derivative instruments such as swaps to hedge price risk associated with a portion of our anticipated crude oil production. These instruments allow us to reduce, but not eliminate, the potential effects of variability in cash flow from operations due to fluctuations in commodity prices. The instruments provide only partial protection against declines in crude oil prices and may limit our potential gains from future increases in prices. None of these instruments are used for trading purposes. We do not speculate on commodity prices but rather attempt to hedge physical production by individual hydrocarbon product in order to protect returns. The counterparty to our derivative swap transactions was a major oil company’s trading subsidiary, and our costless collars are with Glencore. We have not designated any of our derivative contracts as fair value or cash flow hedges. The changes in fair value of the contracts are included in the consolidated statements of operations and other comprehensive income (loss). We record such derivative instruments as assets or liabilities in the consolidated balance sheet. We do not anticipate any substantial changes in our hedging policy.

Please see Item 15, Note 10 Derivatives and Fair Value in our Consolidated Finance Statements for more information on the related hedges.

Cash on Hand

At December 31, 2023 and 2022, we had unrestricted cash of $121.0 mill ion and $37.2 million, respectively. We invest cash not required for immediate operational and capital expenditure needs in short-term money market instruments primarily with financial institutions where we determine our credit exposure is negligible. As operator of the Etame Marin block in Gabon, we enter into project-related activities on behalf of our working interest joint venture owners. We generally obtain advances from joint venture owners prior to significant funding commitments. Our cash on hand will be utilized, along with cash generated from operations, to fund our operations.

We currently sell our crude oil production from Gabon under a crude oil sales and marketing agreement ("COSMA") with Glencore. Under the COSMA all oil produced from the Etame G4-160 Block offshore Gabon from August 2022 through the final maturity date of the Facility, expected to be May 15, 2027, will be bought and marketed by Glencore, with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors. Sales with Glencore are normally settled 30 days from the delivery date.

Revenues associated with the sales of our crude oil in Egypt are recognized by reference to actual volumes sold and quoted market prices in active markets for Dated Brent, adjusted according to specific terms and conditions as applicable per the sales contracts. Revenue is measured at the fair value of the consideration received or receivable. For reporting purposes, we record the EGPC’s share of production as royalties which are netted against revenue. With respect to taxes in Egypt, our income taxes under the terms of the Merged Concession Agreement are the liability of TransGlobe Petroleum International ("TGPI"), a wholly-owned indirect subsidiary of VAALCO. TGPI's income taxes are paid by EGPC on behalf of TGPI out of EGPC’s production entitlement. The income taxes paid to the Arab Republic of Egypt on behalf of TGPI are recognized as oil and gas sales revenue and income tax expense for reporting purposes. Terms of settlement for sales to EGPC are within 30 days from the delivery date.

Revenues from the sale of crude oil, natural gas, condensate and NGLs in Canada are recognized by reference to actual volumes delivered at contracted delivery points and prices. Prices are determined by reference to quoted market prices in active markets for crude oil, natural gas, condensate, and NGLs based on product, each adjusted according to specific terms and conditions applicable per the sales contracts. Revenues are recognized net of royalties and transportation costs. Revenues are measured at the fair value of the consideration received or receivable. Settlement of accounts receivable in Canada occur on the 25th of the following month after production.

Capital Resources, Liquidity and Cash Requirements

Our primary source of liquidity has been cash flows from operations and our primary use of cash has been to fund capital expenditures for development activities in the Etame Marin block. We continually monitor the availability of capital resources, including equity and debt financings that could be utilized to meet our future financial obligations, planned capital expenditure activities and liquidity requirements including those to fund opportunistic acquisitions. Our future success in growing proved reserves, production and balancing the long-term development of our assets with a focus on generating attractive corporate-level returns will be highly dependent on the capital resources available to us.

Based on current expectations, we believe we have sufficient liquidity through our existing cash balances and cash flow from operations, including the addition of our Egypt and Canada segments, to support our current cash requirements, including the FSO charter, drilling programs, as well as transaction expenses and capital and operational costs associated with our business segments' operations. However, our ability to generate sufficient cash flow from operations or fund any potential future acquisitions, consortiums, joint ventures or pay dividends for other similar transactions depends on operating and economic conditions, some of which are beyond our control. If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. We are continuing to evaluate all uses of cash, including opportunistic acquisitions, and whether to pursue growth opportunities and whether such growth opportunities, additional sources of liquidity, including equity and/or debt financings, are appropriate to fund any such growth opportunities.

Merged Concession Agreement

For information on the Merged Concession Agreement, see Note 12 to the Consolidated Financial Statements.

RBL Facility Agreement and Available Credit

For information on our RBL Facility Agreement and Available Credit, see Note 13 to the Consolidated Financial Statements.

Cash Requirements

Our material cash requirements generally consist of finance leases, operating leases, purchase obligations, capital projects and 3D seismic processing, the TransGlobe acquisition transaction costs, dividend payments, funding of our share buyback program, merged concession agreement, future lease payments and abandonment funding, each of which is discussed in further detail below.

Potential Acquisition - On February 29, 2024, we entered into a Share Purchase Agreement to purchase all of the issued shares in the capital of Svenska for $66.5 million in cash, subject to adjustment as described in the Share Purchase Agreement. Pursuant to the terms and subject to the conditions of the Share Purchase Agreement, we will acquire Svenska's primary asset: a 27.39% non-operated working interest in the deepwater producing Baobab field in Block CI-40, offshore Cote d'Ivoire in West Africa. We will also acquire a 21.05% non-operated working interest in OML 145, a non-producing discovery located offshore of Nigeria that is not expected to be developed at this time. The purchase price will be funded by a combination of a dividend of cash on Svenska's balance sheet to the seller immediately prior to the consummation of the acquisition and a portion of VAALCO's cash-on-hand. We estimate that cash due from VAALCO at closing will be in the range of approximately $30 to $40 million. The acquisition is expected to close in the second quarter of 2024, with timing dependent upon receipt of all necessary regulatory approvals.

Abandonment Funding - Under the terms of the Etame PSC, we have a cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin block. As a result of the PSC Extension, annual funding payments are spread over the periods from 2018 through 2028, under the applicable abandonment study. The amounts paid will be reimbursed through the Cost Account and are non-refundable. In November 2021, a new abandonment study was done and the estimate used for this purpose is approximately $81.3 million ($47.8 million, net to VAALCO) on an undiscounted basis. The new abandonment estimate has been presented to the Gabonese Directorate of Hydrocarbons as required by the PSC. In the first quarter of 2023, the Directorate of Hydrocarbons in Gabon approved a $26.6 million ($15.6 million, net to VAALCO) abandonment funding payment associated with the FPSO retirement. The Company received payment of $15.6 million in March 2023. No activity was noted in the abandonment funding account during the remaining three quarters of the year. At December 31, 2023, the balance of the abandonment fund was $10.7 million ($6.3 million, net to VAALCO) on an undiscounted basis. The annual payments will be adjusted based on revisions in the abandonment estimate. This cash funding is reflected under "Other noncurrent assets" in the "Abandonment funding" line item of the consolidated balance sheets. Future changes to the anticipated abandonment cost estimate could change the asset retirement obligation and the amount of future abandonment funding payments.

Leases - We are a party to several operating and financing lease arrangements, including operating leases for the corporate office, a drilling rig, rental of marine vessels and helicopter, warehouse and storage facilities, equipment and financing lease agreements for the FSO, a marine vessel, generators and turbines used in the operations of the Etame Marin block and for equipment, offices and vehicles used in the operations of Canada and Egypt. The annual costs of these leases are significant to us. For further information see Note 14 to our consolidated financial statements.

Merged Concession Agreement - On January 20, 2022, prior to the consummation of the Arrangement, TransGlobe announced a fully executed Merged Concession Agreement with EGPC that merged the three existing Eastern Desert concessions with a 15-year primary term and improved economics. In advance of the Minister of Petroleum and Mineral Resources of the Arab Republic of Egypt (the "Minister") executing the Merged Concession Agreement, TransGlobe paid the first modernization payment of $15.0 million and signature bonus of $1.0 million as part of the conditions precedent to the official signing ceremony on January 19, 2022. On February 1, 2022, TransGlobe paid the second modernization payment of $10.0 million. In accordance with the Merged Concession Agreement, we agreed to substitute the 2023 and 2024 payments and issue two $10.0 million credits against receivables owed from EGPC. We will make two further annual equalization payments of $10.0 million each beginning February 1, 2025 until February 1, 2026. We also have minimum financial work commitments of $50.0 million per each five-year period of the primary development term, commencing on February 1, 2020 (the "Merged Concession Effective Date"). As of December 31, 2023, the $50 million of financial work commitments had been delivered to EGPC.

FSO Agreements – On August 31, 2021, we and our Etame co-venturers approved the Bareboat Contract and Operating Agreement with World Carrier to replace the existing FPSO with an FSO unit at the Etame Marin block offshore Gabon. Pursuant to the Bareboat Charter, World Carrier will provide use of the *Teli* vessel to VAALCO Gabon for an initial eight-year term, subject to optional two successive one-year extensions. Pursuant to the Operating Agreement, VAALCO Gabon agreed to engage World Carrier for the purposes of maintaining and operating the FSO on its behalf in accordance with the specifications therein and to provide other services to VAALCO Gabon in connection with the operation and maintenance of the FSO. As consideration for the performance by World Carrier of the Operator Services, VAALCO Gabon agreed to pay a daily operating fee (to be paid monthly) beginning on the date of issuance of the Fit to Receive Certificate (as defined in the Operating Agreement) until the end of the term, with such term being the same as the term in the Bareboat Charter. On October 19, 2022, we issued final acceptance certificate of the FSO. On December 4, 2022, the first lifting from the FSO was successfully completed at the same time the final remaining volumes from the FPSO were removed.

BWE Consortium – On October 11, 2021, we announced our entry into a consortium with BW Energy and Panoro Energy and that the BWE Consortium has been provisionally awarded two blocks in the 12th Offshore Licensing Round in Gabon. Negotiations to finalize the commercial terms were held in 2023, however they were halted late in the year due to the presidential elections. The negotiations were kick started again at the request of the Gabonese Government in early February 2024, where the consortium and the government came to an agreement on the fiscal terms on February 9, 2024. The next step is concluding the terms of the PSC with the Gabonese government. BW Energy will be the operator with a 37.5% working interest. We will have a 37.5% working interest and Panoro Energy will have a 25% working interest as non-operating joint owners. The two blocks, G12-13 and H12-13, are adjacent to our Etame PSC, as well as BW Energy and Panoro's Dussafu PSC offshore Southern Gabon, and cover an area of 2,989 square kilometers and 1,929 square kilometers, respectively. The two blocks, held by the BWE Consortium and the PSCs over the blocks, are currently under negotiation with the Gabonese government.

Dividend Policy – On February 14, 2023, we announced that our board of directors adopted of a quarterly cash dividend policy of an expected $0.0625 per common share per quarter, which commenced in the first quarter of 2023 and continued throughout the year. Payment of future dividends, if any, will be at the discretion of the board of directors after taking into account various factors, including current financial condition, the tax impact of repatriating cash, operating results and current and anticipated cash needs.

Share Buyback Program – On November 1, 2022, the Company announced that the Company's board of directors formally ratified and approved a share buyback program. The board of directors also directed management to implement a Rule 10b5-1 trading plan (the "10b5-1 Plan") to facilitate share purchases through open market purchases, privately negotiated transactions, or otherwise in compliance with Rule 10b-18 under the Securities Exchange Act of 1934. The 10b5-1 Plan provides for an aggregate purchase of currently outstanding common stock up to $30 million over a maximum period of up to 20 months. Payment for shares repurchased under the share buyback program will be funded using the Company's cash on hand and cash flow from operations. As of December 31, 2023, approximately $5.5 million remained available for repurchase under current authorizations.

Trends and Uncertainties

Geopolitical Conflict and Other Market Forces – The outbreak of armed conflict between Russia and Ukraine in February 2022 and the subsequent sanctions imposed on the Russian Federation has, and may continue to have, a destabilizing effect on the European continent and the global oil and natural gas markets. The ongoing conflict has caused, and could continue to intensify, volatility in oil and natural gas prices, and the extent and duration of the military action, sanctions and resulting market disruptions could be significant and could potentially have a substantial negative impact on the global economy and/or our business for an unknown period of time.

For example, shortly after the outbreak of the conflict through the year ended December 31, 2023 and on-going into 2024, we noticed that the lead times associated with obtaining materials to support our operations and drilling activities has lengthened, leading to delays and, in most cases, prices for materials have increased. Management believes the ongoing war between Russia and Ukraine, the Houthis attacks on maritime vessels in the Red Sea region, conflicts in the Middle East and the related impact on the global economy are causing supply chain issues and energy concerns in parts of the global economy. In addition, increased inflation, higher interest rates and current turmoil in certain governments are impacting the global supply chain market.

Commodity Prices – Historically, the markets for oil, natural gas and NGLs have been volatile. Oil, natural gas and NGLs prices are subject to wide fluctuations in supply and demand. Our cash flows from operations may be adversely impacted by volatility in crude oil and natural gas prices, a decrease in demand for crude oil, natural gas or NGLs and future production cuts by OPEC+. However, the Company has not received any mandate to reduce its current oil production from the Etame Marin block as a result of the OPEC+ initiatives.

ESG and Climate Change Effects – Sustainability matters continue to attract considerable public, regulatory and scientific attention. In particular, we expect continued required reporting attention on climate change issues and emissions of greenhouse gases (“GHG”), including methane (a primary component of natural gas) and carbon dioxide (a byproduct of crude oil and natural gas combustion) and freshwater use. This increased attention to climate change and environmental conservation coupled with stepped up government incentives around renewable energy sources may result in demand shifts away from crude oil and natural gas products, higher regulatory and compliance costs, additional governmental investigations and private litigation against us. For example, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. In addition, institutional investors, proxy advisory firms and other industry participants continue to focus on ESG matters, including climate change. We expect that this heightened focus will continue to drive ESG efforts across our industry and influence investment and voting decisions, which for some investors may lead to less favorable sentiment towards carbon assets and diversion of investment to other industries. Consistent with the increased attention on ESG matters and climate change, we have prioritized and are committed to responsible environmental practices by monitoring our adherence to ESG reporting requirements, including establishing and communicating short and long-term goals and targets, furthering the reduction of our carbon footprint and measurement of GHG emissions. Sustainability remains an important topic to us, and we are in the process of developing a multi-year plan to establish and document our progress in achieving goals we set for ourselves across all areas of sustainability. Our plans will enable us to monitor and improve matters related to ESG and climate change going forward.

For the past three years the Company has matured its reporting in line with the recommendations of the Task force on Climate-related Financial Disclosures (“TCFD”), which is recognized as the global standard in climate-related reporting. The full TCFD report was included within the 2023 ESG Report (rather than in this Annual Report on Form 10-K or in the annual report which was published in connection with the annual meeting), as the ESG Report details with environmental, social and governance matters which the TCFD report forms an important part of the 2023 Sustainability Report is available on the Company's website.

In summary the Company considers itself aligned with both the Governance and Strategy pillars and the recommendations therein. It does not consider itself aligned with Risk Management nor Metrics and Targets, but has made meaningful progress against certain of the underlying recommendations and provides statements of intent to address these recommendations during 2024. For further detail see the table below.

Governance	Describe the Board's oversight of climate-related risks and opportunities	The Board is actively engaged in understanding the climate-related risks relevant to the business. Board supported establishment of decarbonization program and receives regular updates on progress. At each board meeting, the Director of Global Sustainability & Regulatory Reporting reports emissions performance and progress within decarbonization program. Management receives periodic updates from the ESG Engineer and outside consultants relating to climate-related matters. The formalized management of climate-related matters, and specifically the Company's efforts to management its emissions profile, is delivered through its decarbonization working group and steering group, for identification of emissions reduction projects and subsequent approval respectively.
	Describe management's role in assessing and managing climate-related risks and opportunities.	The Company considers its approach to governance consistent with the recommendations.
Strategy	Describe the climate-related risks and opportunities the organization has identified over the short, medium and long term.	The Company has identified transitional and physical risks and opportunities identified over the short (<2 years), medium (2 to 10 years) and long term (>10 years) within its Sustainability Report.
	Describe the impact of climate-related risks and opportunities on the organization's businesses, strategy, and financial planning.	The Company has indicated the potential impact of these risks and associated mitigations. The Company continues to mature its approach to factoring in climate-related risks and opportunities into its strategy and financial planning. This also includes its diligence through M&A activity.
	Describe the resilience of the organization's strategy, taking into consideration different climate-related scenarios, including a 2°C or lower scenario	This year, the business conducted scenario analysis using the IEA's Net Zero Emissions (NZE), Announced Pledges Scenario (APS) and Stated Policies Scenario (STEPS), the details and findings for which are enclosed in the Sustainability Report. The Company considers its approach to Strategy consistent with the recommendations.
Risk Management	Describe the organization's processes for identifying and assessing climate-related risks.	The Company has a defined risk management process for identifying and assessing risk, which incorporates climate-related risks. Detail to this process can be found within the Sustainability Report and this Annual Report on Form 10-K.
	Describe the organization's processes for managing climate-related risks.	Whilst in development through the Decarbonization Program, the company considers its processes for managing climate-related risk to be inconsistent with the recommendations.
	Describe how processes for identifying, assessing, and managing climate-related risks are integrated into the organization's overall risk management.	During 2024, the Company will continue to conduct a review of its risk management processes, particularly in view of its enlarged portfolio.
Metrics and Targets	Disclose the metrics used by the organization to assess climate-related risks and opportunities in line with its strategy and risk management process.	The Company reports its scope 1 and 2 emissions but has not yet set any targets. In 2024, the Company expects to set and communicate its short-, mid-, and long-range emission targets.
	Disclose Scope 1, Scope 2 and, if appropriate Scope 3 greenhouse gas (GHG) emissions and the related risks.	The Company considers its approach to metrics and targets for all aspects of its sustainability effort inconsistent with the recommendations and, through its decarbonization program, is seeking to set targets for its GHG emissions and other material topics in its sustainability efforts going forward.
	Describe the targets used by the organization to manage climate-related risks and opportunities and performance against targets	

RESULTS OF OPERATIONS

Year Ended December 31, 2023 Compared to Year Ended December 31, 2022

We reported net income for the year ended December 31, 2023 of $60.4 million, compared to a net income of $51.9 million for the year ended December 31, 2022. The year-over-year increase in earnings was mainly due to increases in sales volume partially offset by increased depreciation, depletion and amortization expense, production expenses and income taxes. Further discussion of results by significant line item follows.

	Twelve Months Ended December 31,		
	2023	2022	**Increase/(Decrease)**
	(in thousands except per Boe information)		
Net crude oil, natural gas, and NGLs sales volume (MBoe)	**6,832**	3,677	3,155
Average crude oil, natural gas and NGLs sales price (per Boe)	**$ 65.83**	$ 94.77	$ (28.94)
Net crude oil, natural gas, and NGLs revenue	**$ 455,066**	$ 354,326	$ 100,740
Operating costs and expenses:			
Production expense	**153,157**	112,661	40,496
FPSO demobilization and other costs	**7,484**	8,867	(1,383)
Exploration expense	**1,965**	258	1,707
Depreciation, depletion and amortization	**115,302**	48,143	67,159
General and administrative expense	**23,840**	10,077	13,763
Credit (recovery) losses and other	**(4,906)**	3,082	(7,988)
Total operating costs and expenses	**296,842**	183,088	113,754
Other operating income (expense), net	**433**	38	395
Operating income	**$ 158,657**	$ 171,276	$ (12,619)

The revenue changes between the years ended December 31, 2023 and 2022 identified as related to changes in price or volume are shown in the table below:

(in thousands)	
Price (1)	$ (197,741)
Volume	299,042
Other	(561)
Total net revenue	$ 100,740

(1) The price in the table above excludes revenues attributed to carried interests.

The table below shows net production, sales volumes and realized prices for both years.

	Twelve Months Ended December 31,	
	2023	2022
Net crude oil, natural gas and NGLs production (MBoe)	**6,833**	3,729
Net crude oil, natural gas and NGLs sales (MBoe)	**6,832**	3,677
Average realized crude oil, natural gas and NGLs price ($/Boe)	**$ 65.83**	$ 94.77
Average Dated Brent spot price* ($/Bbl)	**$ 82.49**	$ 100.93

*Average of daily Dated Brent spot prices posted on the U.S. Energy Information Administration website.

Crude oil, natural gas and NGLs net revenues increased $100.7 million, or approximately 28%, during the year ended December 31, 2023 compared to the same period of 2022. This is due primarily to TransGlobe being included in revenues for only part of the fourth quarter of 2022.

Gabon

Crude oil sales in Gabon are a function of the number and size of crude oil liftings in each year and thus crude oil sales do not always coincide with volumes produced in any given year. The Company’s Gabon segment contributed $260.3 million of revenue to the Company’s total revenue during the year ended December 31, 2023. This compares to the $306.8 million of revenue contributed by the Segment during the year ended December 31, 2022. The total barrels lifted in Gabon for the year ended December 31, 2023 was less than the barrels lifted during the same period in 2022, mainly due to the timing of liftings. In addition, the Gabon per barrel price received during the year ended December 31, 2023 was $22.90 less than the price received in 2022. Our share of crude oil inventory, excluding royalty barrels, was approximately 68,766 and 76,274 barrels at December 31, 2023 and 2022, respectively.

Egypt

Crude oil sales in Egypt are either sold to a third party via a cargo lifting or sold directly to the government, EGPC. During the year ended December 31, 2023, the oil sold in Egypt was to a combination of Mercuria Energy and EGPC. The Company's Egypt segment contributed $161.0 million of revenue to the Company's total revenue for the year ended December 31, 2023. This compares to the $37.8 million of revenue contributed by the Segment during the year ended December 31, 2022. The increase in revenues is due to the Company acquiring its Egypt segment in the fourth quarter of 2022. At December 31, 2023, the Company's Egypt segment had zero barrels in oil inventory.

Canada

Crude oil sales in Canada are normally sold through pipelines to a third party. The Company's Canadian segment contributed $34.4 million of revenue to the Company's total revenue for the year ended December 31, 2023. This compares to the $9.8 million of revenue contributed by the Segment during the year ended December 31, 2022. The increase is due to the Company acquiring its Canadian segment in the fourth quarter of 2022.

Production expenses increased $40.5 million, or approximately 36%, in the year ended December 31, 2023 compared to the same period of 2022. The increase in production expense was primarily driven by increased production and costs associated with the TransGlobe combination as well as higher Gabon costs due to the completed 2021/2022 drilling campaign. During 2023, an unplanned maintenance issue resulted in our Gabon SENT gas line being down for a period of the year which resulted in increased diesel costs as the FSO required to be fueled by diesel rather than feed gas resulting in higher fuel costs. VAALCO has also continued to see inflationary pressure on marine support vessels, our personnel and contractor costs. On a per barrel basis, production expense, excluding workover expense and stock compensation expense, for the year ended December 31, 2023 decreased to $17.66 per barrel from $29.33 per barrel for the year ended December 31, 2022, primarily as a result of higher sales volumes. For the twelve months ended December 31, 2023, we have not experienced any material operational disruptions associated with the COVID-19 pandemic. For same period in 2022, we incurred $1.8 million, net to VAALCO, higher costs related to the proactive measures taken in response to the pandemic.

FPSO demobilization costs decreased $1.4 million, or approximately 16%*,* to $7.5 million in the year ended December 31, 2023 compared to the same period of 2022. In 2023, it was determined that there was additional normally occurring radioactive material (NORMs) waste than anticipated connected to the FPSO from the Contractors' usage. As such, VAALCO and JOA partners incurred an additional $7.5 million (net to VAALCO) in decommissioning fees, which was reported as a separate line item on the income statement. These costs were incurred to retire the FPSO as we transitioned the Etame block to the FSO.

*Exploration expen*ses increased $1.7 million or approximately 662%, in the year ended December 31, 2023 compared to the same period of 2022 due primarily to the abandonment of the Egyptian East Arta - 54 appraisal well and the abandonment of the NWG-5C1 appraisal well. In 2022, exploration expense was not material to our results.

Depreciation, depletion and amortization increased $67.2 million, or approximately 139%, in the year ended December 31, 2023 compared to the same period of 2022. The increase in depreciation, depletion and amortization expense is due to higher depletable costs associated with the FSO, the field reconfiguration capital costs at Etame and fair value of the acquired TransGlobe assets. In addition, capital expenditures on new wells were brought online in 2023 for both Egypt and Canada, which also increased depreciation, depletion and amortization expense.

General and administrative expenses increased $13.8 million, or approximately 137% in the year ended December 31, 2023 compared to $10.1 million in the same period of 2022. The increase in general and administrative expenses is primarily due to professional fees, accounting and legal services, and salaries and wages.

Credit loss and other allowances - Credit loss and other expense decreased $8.0 million, or approximately 259% in the year ended December 31, 2023 compared to the same period of 2022 We adopted Accounting Standards Update 2016-13, Financial Instruments—Credit Losses ("ASU 2016-13") on January 1, 2023. In connection with the adoption of ASU 2016-13, we established an opening balance sheet adjustment related to a receivable from a state sponsored oil refinery where we delivered oil pursuant to the domestic market needs obligation under the Etame PSC. During the year ended December 31, 2023, the decrease in credit loss and other allowances was primarily due to two credit loss and other allowance reversals in 2023. First, the Sogara receivable credit loss and other allowance was reversed for $3.1 million and second, the TVA receivable credit loss and other allowance was reversed for $7.6 million. These reversals were offset by a credit loss and other allowance adjustment in Egypt of $5.2 million.

Other operating income (expense), net had no significant change from the prior year.

Derivative instruments gain (loss), net is attributable to our commodity instruments as discussed in Note 10 to the consolidated financial statements. Derivative losses decreased $38.0 million to a gain of $0.2 million for the year ended December 31, 2023 from a loss of $37.8 million for the year ended December 31, 2022. Derivative gains (losses) for the year ended December 31, 2023, are a result of the increase in the price of Dated Brent crude oil over the initial strike price per barrel of the option over the year ended December 31, 2022. The same increase in price occurred, but to a lesser extent, in 2023. During 2022, we changed our approach and the type of derivative instruments from swaps to costless collars. Our derivative instruments currently cover a portion of our production through June 2024.

Interest (expense) income, net increased $4.4 million to an expense of $6.5 million for the year ended December 31, 2023 from expense of $2.0 million during the same period in 2022. The increase of net interest expense for the year ended December 31, 2023, primarily results from our finance lease relating to the FSO but also includes commitments fees incurred on the Facility, amortization of debt issue costs related to the Facility and interest associated with our other finance leases partially offset by interest income.

Other (expense) income, net decreased $5.8 million to an expense of $2.3 million for the year ended December 31, 2023 from an expense of $8.0 million for the year ended December 31, 2022. Other (expense) income, net normally consists of foreign currency losses as discussed in Note 2 to the consolidated financial statements. However, for the year ended December 31, 2022, other (expense) income, net, also included $14.6 million of transaction costs associated with the Arrangement with TransGlobe, $2.7 million of foreign exchange losses associated with the TransGlobe activity from October 13, through December 31, 2022 partially offset by a bargain purchase gain of $9.7 million associated with the acquisition of TransGlobe.

Income tax expense (benefit) for the year ended December 31, 2023 was an expense of $89.7 million. This is comprised of $92.6 million of current tax provision and a deferred tax benefit of $2.9 million. Income tax expense for the year ended December 31, 2022 was an expense of $71.4 million. This is comprised of $26.6 million of current tax provision and a deferred tax provision of $44.8 million. The current tax provision in both periods is primarily attributable to our operations in Gabon, Egypt and Canada. The income tax expense is higher in 2023 than income tax for the comparable 2022 period as a result of higher revenues. See Note 8 to the Consolidated Financial Statements for further discussion.

CRITICAL ACCOUNTING ESTIMATES

The preparation of Financial Statements in accordance with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the Financial Statements and the reported amounts of revenues and expenses during the respective reporting periods. Accounting estimates are considered to be critical if (1) the nature of the estimates and assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change, and (2) the impact of the estimates and assumptions on financial condition or operating performance is material. Actual results could differ from the estimates and assumptions used. Further, in some cases, GAAP allows more than one alternative accounting method for reporting. In those cases, our reported results of operations would be different should we employ an alternative accounting method. See Note 2 to the Consolidated Financial Statements for our accounting policy elections.

Income Taxes

Our annual tax provision is based on expected taxable income, statutory rates and tax planning opportunities available to us in the various jurisdictions in which we operate. The determination and evaluation of our annual tax provision and tax positions involves the interpretation of the tax laws in the various jurisdictions in which we operate and requires significant judgment and the use of estimates and assumptions regarding significant future events such as the amount, timing and character of income, deductions and tax credits. Changes in tax laws, regulations, agreements and tax treaties or our level of operations or profitability in each jurisdiction would impact our tax liability in any given year. We also operate in foreign jurisdictions where the tax laws relating to the crude oil, natural gas and NGLs industry are open to interpretation, which could potentially result in tax authorities asserting additional tax liabilities. While our income tax provision (benefit) is based on the best information available at the time, a number of years may elapse before the ultimate tax liabilities in the various jurisdictions are determined.

Judgment is required in determining whether deferred tax assets will be realized in full or in part. Management assesses the available positive and negative evidence to estimate if existing deferred tax assets will be utilized. When it is estimated to be more-likely-than-not that all or some portion of the deferred tax assets will not be realized, a valuation allowance must be established for the amount of the deferred tax assets that are estimated to not be realizable. Factors considered include earnings generated in previous periods, forecasted earnings, the expiration period of carryovers, and overall economic conditions of the industry. As of December 31, 2023, we had deferred tax assets of $120.9 million primarily attributable to Canada, Gabon and U.S. basis differences in fixed assets, foreign tax credit carryforwards, and foreign net operating loss carryforwards. A valuation allowance of $83.9 million has been established against the deferred tax assets as of December 31, 2023, as management has concluded that it was more-likely-than-not that only some portion of the deferred tax assets would be realized. In future periods, we may determine that it is more-likely-than-not that all or some portion of the deferred tax assets will be realized, and in such period all or a portion of this valuation allowance may be reversed as the evidence warrants.

In certain jurisdictions, we may deem the likelihood of realizing deferred tax assets as remote where we expect that, due to the structure of operations and applicable law, the operations in such jurisdictions will not give rise to future tax consequences. Should our expectations change regarding the expected future tax consequences, we may be required to record additional deferred taxes that could have a material effect on our consolidated financial position and results of operations. For further discussion, see Note 8 to the Consolidated Financial Statements.

Oil and Gas Accounting Reserves Determination

The successful efforts method of accounting depends on the estimated reserves we believe are recoverable from our crude oil, natural gas and NGLs reserves. The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data.

To estimate the economically recoverable crude oil, natural gas and NGLs reserves and related future net cash flows, we incorporate many factors and assumptions including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future crude oil, natural gas and NGLs quality differentials;
- assumed effects of regulation by governmental agencies; and
- future development and operating costs.

We believe our assumptions are reasonable based on the information available to us at the time we prepare our estimates. However, these estimates may change substantially going forward as additional data from development activities and production performance becomes available and as economic conditions impacting crude oil, natural gas and NGLs prices and costs change.

Management is responsible for estimating the quantities of proved crude oil, natural gas and NGLs reserves and for preparing related disclosures. Estimates and related disclosures are prepared in accordance with SEC requirements and generally accepted industry practices in the U.S. as prescribed by the Society of Petroleum Engineers. Reserve estimates are independently evaluated at least annually by our independent qualified reserves engineers, NSAI for Gabon and Egypt, while GLJ evaluates our Canadian reserves. Equatorial Guinea will receive a Management Case Report.

Our Board of Directors has established the Technical and Reserves ("T&R") Committee with the authority, responsibility and primary purpose of assisting the board of directors in its oversight responsibilities relating to evaluating and reporting on oil and gas reserves. The T&R Committee, to the extent it deems necessary or appropriate, will oversee (i) annual review of oil and gas reserves, (ii) procedures for evaluating and reporting oil and gas producing activities, and (iii) compliance with applicable regulatory and securities laws relating to the preparation and disclosure of information with respect to oil and gas reserves and shall consult with the Audit Committee on such matters relating to oil and gas reserves which impact our financial statements.

Our senior executives and reserve engineers oversee the preparation of our crude oil, natural gas and NGLs reserves and related disclosures by our appointed independent reserve engineers. The T&R Committee and senior executives meet with the reserve engineers periodically to review the reserves process and results, and to confirm that the independent reserve engineers have had access to sufficient information, including the nature and satisfactory resolution of any material differences of opinion between us and the independent reserve engineers.

Reserves estimates are critical to many of our accounting estimates, including:

- determining whether or not an exploratory well has found economically producible reserves;
- calculating our unit-of-production depletion rates. Proved developed reserves estimates are used to determine rates that are applied to each unit-of-production in calculating our depletion expense; and
- assessing, when necessary, our crude oil, natural gas and NGLs assets for impairment using undiscounted future cash flows based on management's estimates. If impairment is indicated, discounted values will be used to determine the fair value of the assets. The critical estimates used to assess impairment, including the impact of changes in reserves estimates, are discussed below.

See "*Item 15. Exhibits and Financial Statement Schedules – Supplemental Information on crude oil, natural gas and NGLs Producing Activities (unaudited).*"

Impairment of crude oil, natural gas and NGLs producing properties

We review the crude oil, natural gas and NGLs producing properties for impairment quarterly or whenever events or changes in circumstances indicate that the carrying amount of such properties may not be recoverable. When a crude oil, natural gas and NGLs property's undiscounted estimated future net cash flows are not sufficient to recover its carrying amount, an impairment charge is recorded to reduce the carrying amount of the asset to its fair value. Our assessment involves a high degree of estimation uncertainty as it requires us to make assumptions and apply judgment to estimate undiscounted future net cash flows related to proved reserves. Such assumptions include commodity prices, capital spending, production and abandonment costs and reservoir data. The fair value of the asset is measured using a discounted cash flow model relying primarily on Level 3 inputs to estimate the undiscounted future net cash flows. The undiscounted estimated future net cash flows used in the impairment evaluations at each quarter end are based upon the most recently prepared independent reserve engineers' report adjusted to use forecasted prices from the forward strip price curves near each quarter end and adjusted as necessary for drilling and production results. For further discussion, see Note 9 to the Consolidated Financial Statements.

Impairment of Unproved Property

We evaluate our undeveloped crude oil, natural gas and NGLs leases for impairment on at least a quarterly basis by considering numerous factors that could include nearby drilling results, seismic interpretations, market values of similar assets, existing contracts and future plans for exploration or development. When undeveloped crude oil, natural gas and NGLs leases are deemed to be impaired, exploration expense is charged. Unproved property costs consist mainly of acquisition costs related to undeveloped acreage in the Etame Marin block in Gabon and to Block P in Equatorial Guinea. In connection with the TransGlobe acquisition as discussed under Note 4 to the Consolidated Financial Statements, reserves in Egypt and Canada were also attributed to undeveloped properties and leasehold costs.

Business Combinations

We apply the acquisition method of accounting for business combinations, under which we record the acquired assets and assumed liabilities at fair value and recognize goodwill to the extent the consideration transferred exceeds the fair value of the net assets acquired. To the extent the fair value of the net assets acquired exceeds the consideration transferred, we recognize a bargain purchase gain.

In estimating the fair values of assets acquired and liabilities assumed in a business combination, various assumptions are made. The most significant assumptions relate to the estimated fair values assigned to proved and unproved crude oil, natural gas and NGLs properties. If sufficient market data is not available regarding the fair values of proved and unproved properties, estimates of the fair value of crude oil and gas reserves are prepared. Estimates of future prices to apply to the estimated reserves quantities acquired and estimates of future operating and development costs are used to estimate future net cash flows. For estimated proved reserves, the future net cash flows are discounted using a market-based discount rate determined appropriate at the time of the acquisition. Estimated deferred taxes are based on available information concerning the tax basis of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

We estimate the fair values of the acquired assets and assumed liabilities as of the date of the acquisition, and our estimates are subject to adjustment through completion, which is in each case within one year of the acquisition date, based on our ongoing assessments of the fair values of property and equipment, intangible assets, other assets and liabilities and our evaluation of tax positions and contingencies.

ACCOUNTING STANDARDS

See Note 3 to the Consolidated Financial Statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risk, including the effects of adverse changes in foreign exchange rates and commodity prices as described below.

Foreign Exchange Rate Risk

Our results of operations and financial condition are affected by currency exchange rates. While crude oil sales are denominated in U.S. dollars, portions of our costs in Gabon are denominated in the local currency (the Central African CFA Franc, or XAF), and our VAT receivable as well as certain liabilities in Gabon are also denominated in XAF. A weakening U.S. dollar will have the effect of increasing costs while a strengthening U.S. dollar will have the effect of reducing costs. For our VAT receivable in Gabon, a strengthening U.S. dollar will have the effect of decreasing the value of this receivable resulting in foreign exchange losses, and vice versa. The Gabon local currency is tied to the Euro. The exchange rate between the Euro and the U.S. dollar has historically fluctuated in response to international political conditions, general economic conditions and other factors beyond our control. As of December 31, 2023, we had net monetary assets of $5.8 million (XAF 3,463.4 million) denominated in XAF. A 10% weakening of the CFA relative to the U.S. dollar would have a $0.5 million reduction in the value of these net assets. For the year ended December 31, 2023, we had expenditures of approximately $48.8 million denominated in XAF.

Related to our Canadian operations, our currency exchange risk relates primarily to certain cash and cash equivalents, accounts receivable, lease obligations and accounts payable and accrued liabilities denominated in Canadian dollars. We estimate that a 10% increase in the value of the Canadian dollar against the US dollar would decrease net earnings for the year ended December 31, 2023 by approximately $0.2 million. Conversely, a 10% decrease in the value of the Canadian dollar against the US dollar would increase net earnings for the year ended December 31, 2023 by approximately $0.1 million.

We are also exposed to foreign currency exchange risk on cash balances denominated in Egyptian pounds. Some collections of accounts receivable from the Egyptian Government are received in Egyptian pounds, and while we are generally able to use the Egyptian pounds received on accounts payable denominated in Egyptian pounds, there remains foreign currency exchange risk exposure on Egyptian pound cash balances. Using month-end cash balances converted at month-end foreign exchange rates at December 31, 2022, we estimate that a 10% increase in the value of the Egyptian pound against the US dollar would increase net earnings for the year ended December 31, 2022 by approximately $0.3 million. Conversely, a 10% decrease in the value of the Egyptian pound against the US dollar would decrease net earnings for the year ended December 31, 2022 by approximately $0.2 million.

We do not utilize derivative instruments to manage foreign exchange risk.

We maintain nominal balances of British Pounds Sterling to pay in-country costs incurred in operating our London office. Foreign exchange risk on these funds is not considered material.

Commodity Price Risk

Our major market risk exposure continues to be the prices received for our crude oil, natural gas and NGLs production. Sales prices are primarily driven by the prevailing market prices applicable to our production. Market prices for crude oil, natural gas and NGLs have been volatile and unpredictable in recent years, and this volatility may continue. Sustained low crude oil, natural gas and NGLs prices or a resumption of the decreases in crude oil, natural gas and NGLs prices could have a material adverse effect on our financial condition, the carrying value of our proved reserves, our undeveloped leasehold interests and our ability to borrow funds and to obtain additional capital on attractive terms. If crude oil sales were to remain constant at the most recent annual sales volumes of 6,832 MBoe, a $5 per Bbl decrease in crude oil price would be expected to cause a $34.2 million decrease per year in revenues and operating income (loss) and a $25.4 million decrease per year in net income (loss).

With respect to our crude oil sales in Gabon, the price received is based on Dated Brent prices plus or minus a differential. If crude oil sales were to remain constant at the most recent annual sales volumes of 3,196 MBbls, a $5 per Bbl decrease in crude oil price would be expected to cause a $16.0 million decrease per year in revenues and operating income (loss) and a $14.3 million decrease per year in net income (loss).

Egypt production is based on Dated Brent prices, less a quality differential and is shared with the Egyptian government through PSCs. When the price of oil increases, it takes fewer barrels to recover costs (cost oil or cost recovery barrels) which are assigned 100% to the Company. The PSCs provide for cost recovery per quarter up to a maximum percentage of total production. Timing differences often exist between VAALCO's recognition of costs and their recovery as VAALCO accounts for costs on an accrual basis, whereas cost recovery is determined on a cash basis. If the eligible cost recovery is less than the maximum defined cost recovery, the difference is defined as "excess". In Egypt, depending on the PSCs, our share of excess ranges between 5% and 15%. If the eligible cost recovery exceeds the maximum allowed percentage, the unclaimed cost recovery is carried forward to the next quarter. Typically, maximum cost oil ranges from 25% to 40% in Egypt. The balance of the production after maximum cost recovery is shared with the government (profit oil). Depending on the contract, the Egyptian government receives 67% to 84% of the profit oil. Production sharing splits are set in each contract for the life of the contract. Typically, the government's share of profit oil increases when production exceeds pre-set production levels in the respective contracts. During times of high oil prices, the Company may receive less cost oil and may receive more profit-sharing oil. During times of lower oil prices, the Company receives more cost oil and may receive less profit oil.

With respect to our crude oil and NGLs sales in Canada, the prices received is based on NYMEX WTI (west Texas Intermediate) prices plus or minus a differential. Natural gas sales are based on Canadian index price that whose price is based, in part, on the NYMEX Henry Hub Natural Gas futures contracts. If Canadian BOE sales were to remain constant at the most recent yearly sales volumes of 865 MBbls, a $5 per Bbl decrease in crude oil price would be expected to cause a $4.3 million decrease per year in revenues and operating income (loss) and a $3.3 million decrease per year in net income (loss).

As of December 31, 2023, we had unexpired derivative instruments outstanding covering approximately 450 MBbls of production through June of 2024. To date in 2024, we added costless collars covering 240 MBbls covering a portion of our production from July 2024 - September 2024. During the year ended December 31, 2022, we had derivative instruments outstanding. These instruments were intended to be an economic hedge against declines in crude oil prices; however, they were not designated as hedges for accounting purposes. See "*Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation*s – *Derivative instruments and hedging activities*" above.

Interest Rate Risk

At both December 31, 2023 and on the filing date of this Annual Report, we had a zero balance on our Facility. Loans under the Facility will bear interest at a rate equal to SOFR plus the Applicable Margin of (i) 6.00% until the third anniversary of the Facility Agreement or (ii) 6.25% from the third anniversary of the Facility Agreement until the Final Maturity Date. On October 3, 2023, the Company signed an Amended and Restated Facility Agreement to replace the LIBOR component in the original Facility Agreement, with a SOFR plus credit adjustment spread rate. The SOFR plus credit adjustment spread rate is intended to approximate the LIBOR component in the original Facility Agreement. The LIBOR component was replaced due to the phase out of LIBOR as a global reference rate. Any increases in these interest rates can have an adverse impact on our results of operations and cash flows. For additional information on the Facility Agreements terms and conditions, see "*Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity—RBL Facility Agreement and Available Credit*" above.

Item 8. Consolidated Financial Statements and Supplementary Data

The information required here begins on page F-1 as described in "*Item 15. Exhibits and Financial Statement Schedules—Index to Consolidated Financial Information*".

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

DISCLOSURE CONTROLS AND PROCEDURES

We maintain disclosure controls and procedures that are designed to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Exchange Act, is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including the Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure. In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management was required to apply its judgment in evaluating and implementing possible controls and procedures. Management, including our principal executive officer and principal financial officer, has evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report on Form 10-K. Based on this evaluation, our principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of December 31, 2023.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management, including our Chief Executive Officer and our Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Under the supervision and with the participation of management, including our principal executive and principal financial officers, we conducted an evaluation of the effectiveness of our internal control over financial reporting using the criteria set forth in the Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Based on the evaluation, our management concluded that, the Company's internal control over financial reporting was effective as of December 31, 2023.

REMEDIATION OF MATERIAL WEAKNESSES

As discussed in our Annual Report on Form 10-K for the year ended December 31, 2022, our management concluded that there were material weaknesses in our internal control over financial reporting related to (i) accounting for leases, (ii) complex accounting for business combinations, (iii) financial reporting and consolidation, and (iv) accounting for income taxes.

In response to the identified material weakness at December 31, 2022, our management, with oversight from our Audit Committee, made the following changes in its financial reporting processes in 2023:

- We added additional resources to the accounting and finance function who had relevant public company financial reporting, accounting and internal controls skillsets.
- We redesigned our control framework related to accounting for leases, complex accounting for business combinations, financial reporting and consolidation, and the accounting for income taxes. Through this, the company redesigned the controls over the application of the proper accounting treatment for these business processes and defined the precision and the performance of our controls.
- We enhanced documentary evidence for relevant management review controls over certain business processes including precision of review and evidence of review procedures performed to demonstrate effective operation of such controls.

After completing our testing of the design and operational effectiveness of these controls, our management concluded that we remediated the previously identified material weaknesses as of December 31, 2023.

Our internal controls over financial reporting as of December 31, 2023 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report which is included in Item 8 of this Annual Report. KPMG LLP has provided an attestation report on the Company's internal control over financial reporting which is included in Item 8 of this Annual Report.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

Other than as stated above, there have been no changes in our internal control over financial reporting during the three months ended December 31, 2023 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

During the three months ended December 31, 2023, none of the Company's directors or officers (as defined in Rule 16a-1(f) of the Exchange Act) adopted, terminated or modified a Rule 10b5-1 trading arrangement or non-Rule 10b5-1 trading arrangement (as such terms are defined in Item 408 of Regulation S-K of the Securities Act).

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information required by this item will be included in the proxy statement for our 2024 annual meeting, which will be filed with the SEC within 120 days of December 31, 2023, and that is incorporated herein by reference.

Item 11. Executive Compensation

Information required by this item will be included in the proxy statement for our 2024 annual meeting, which will be filed with the SEC within 120 days of December 31, 2023, and that is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by this item under Item 403 of Regulation S-K concerning the security ownership of certain beneficial owners and management will be included in the proxy statement for our 2024 annual meeting, which will be filed with the SEC within 120 days of December 31, 2023, and which is incorporated herein by reference.

The following table provides information as of December 31, 2023 regarding the number of shares of common stock that may be issued under our compensation plans. Please refer to Note 17 to the Financial Statements for additional information on stock-based compensation.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants, and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issues under equity compensation plans (excluding securities reflected in the first column)
Equity compensation plans approved by security holders	780,997	$ 4.10	1,808,989
Total	780,997	$ 4.10	1,808,989

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by this item will be included in the proxy statement for our 2024 annual meeting, which will be filed with the SEC within 120 days of December 31, 2023, and that is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

Information required by this item will be included in the proxy statement for our 2024 annual meeting, which will be filed with the SEC within 120 days of December 31, 2023, and that is incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) 1. The following is an index to the Financial Statements that are filed as part of this Form 10-K.

VAALCO ENERGY, INC. AND SUBSIDIARIES

(a) 2. Other schedules are omitted because they are not required, not applicable or the required information is included in the Financial Statements or notes thereto.

(a) 3. Exhibits:

2.1	Sale and Purchase Agreement, dated as of November 17, 2020, by and between Sasol Gabon S.A. and VAALCO Gabon S.A. (filed as Exhibit 2.1 to the Company's Annual Report on Form 10-K filed on March 9, 2021, and incorporated herein by reference).
2.2	Arrangement Agreement, dated as of July 13, 2022, by and among VAALCO Energy, Inc., VAALCO Energy Canada ULC and TransGlobe Energy Corporation (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K filed on July 14, 2022 and incorporated herein by reference).
2.3	Share Purchase Agreement, dated February 29, 2024, by and between VAALCO Energy (Holdings), Inc., Petroswede AB (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K filed on February 29, 2024 and incorporated herein by reference).
3.1	Restated Certificate of Incorporation as amended through May 7, 2014 (filed as Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q filed on November 10, 2014, and incorporated herein by reference).
3.1.1	Certificate of Amendment to Restated Certificate of Incorporation of VAALCO, dated October 13, 2022 (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K filed on October 13, 2022 and incorporated herein by reference).
3.2	Third Amended and Restated Bylaws, dated July 30, 2020 (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K filed on August 4, 2020, and incorporated herein by reference).
3.3	Certificate of Elimination of Series A Junior Participating Preferred Stock of VAALCO Energy, Inc., dated as of December 22, 2015 (filed as Exhibit 3.2 to the Company's Current Report on Form 8-K filed on December 23, 2015, and incorporated herein by reference).
4.1	Description of securities (filed as Exhibit 4.1 to the Company's Current Report on Form 10-K filed on March 9, 2020, and incorporated herein by reference).
10.1	Exploration and Production Sharing Contract, dated July 7, 1995, between the Republic of Gabon and VAALCO Gabon (Etame), Inc. (filed as Exhibit 10.1 to the Company's Annual Report on Form 10-K filed on March 7, 2018, and incorporated herein by reference).
10.2	Addendum No. 1 to Exploration and Production Sharing Contract, dated July 7, 2001, between the Republic of Gabon and VAALCO Gabon (Etame), Inc. (filed as Exhibit 10.2 to the Company's Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.3	Addendum No. 2 to Exploration and Production Sharing Contract, dated July 7, 2006, between the Republic of Gabon and VAALCO Gabon (Etame), Inc. (filed as Exhibit 10.3 to the Company's Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.4	Addendum No. 3 to Exploration and Production Sharing Contract, dated November 26, 2009, between the Republic of Gabon and VAALCO Gabon (Etame), Inc. (filed as Exhibit 10.4 to the Company's Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.5	Addendum No. 4 to Exploration and Production Sharing Contract, dated January 5, 2012, between the Republic of Gabon and VAALCO Gabon (Etame), Inc. (filed as Exhibit 10.5 to the Company's Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).

10.6	Addendum No. 5 to Exploration and Production Sharing Contract, dated April 25, 2016, between the Republic of Gabon and VAALCO Gabon (Etame), Inc. (filed as Exhibit 10.6 to the Company's Annual Report on Form 10-K filed on March 7, 2018, and incorporated herein by reference).
10.7	Addendum No. 6 to Exploration and Production Sharing Contract, dated September 17, 2018, between the Republic of Gabon, VAALCO Gabon S.A., Addax Petroleum Oil & Gas Gabon, Sasol Gabon S.A. and Petroenergy Resources Corporation (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed on November 7, 2018, and incorporated herein by reference).
10.8	Deed of Novation of Trustee and Paying Agent Agreement, dated June 22, 2017, between VAALCO Gabon (Etame), Inc., VAALCO Gabon S.A. and The Bank of New York Mellon, London Branch as the Trustee and Paying Agent and the Account Bank (filed as Exhibit 10.7 to the Company's Annual Report on Form 10-K filed on March 7, 2018, and incorporated herein by reference).
10.9*	VAALCO Energy, Inc. 2014 Long Term Incentive Plan (filed as Appendix A to the Company's Definitive Proxy Statement on Schedule 14A filed on April 17, 2014, and incorporated herein by reference).
10.10*	Form of Restricted Stock Award Agreement under the VAALCO Energy, Inc. 2014 Long Term Incentive Plan (filed as Exhibit 10.20 to the Company's Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.11*	Form of Non statutory Stock Option Agreement under the VAALCO Energy, Inc. 2014 Long Term Incentive Plan (filed as Exhibit 10.21 to the Company's Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.12*	Form of Stock Award Agreement (for Directors) under the VAALCO Energy, Inc. 2014 Long Term Incentive Plan (filed as Exhibit 10.22 to the Company's Annual Report on Form 10-K filed on March 16, 2015, and incorporated herein by reference).
10.13*	VAALCO Energy, Inc. 2016 Stock Appreciation Rights Plan (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on March 15, 2016, and incorporated herein by reference).
10.14*	Form of Stock Appreciation Rights Agreement under the VAALCO Energy, Inc. 2016 Stock Appreciate Rights Plan (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed on March 15, 2016, and incorporated herein by reference).
10.15*	Form of Change in Control Agreement (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 8, 2019, and incorporated herein by reference).
10.16*	VAALCO Energy, Inc. 2020 Long Term Incentive Plan (filed as Appendix B to the Company's Definitive Proxy Statement on Schedule 14A filed on April 29, 2020, and incorporated herein by reference).
10.17*	First Amendment to VAALCO Energy, Inc. 2020 Long Term Incentive Plan (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on June 8, 2021, and incorporated herein by reference).
10.18*	Form of Restricted Stock Award Agreement (Director) under the VAALCO Energy, Inc. 2020 Long Term Incentive Plan (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed on June 30, 2020, and incorporated herein by reference).
10.19*	Form of Restricted Stock Award Agreement (Employee) under the VAALCO Energy, Inc. 2020 Long Term Incentive Plan (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K filed on June 30, 2020, and incorporated herein by reference).
10.20*	Form of Nonqualified Stock Option Agreement under the VAALCO Energy, Inc. 2020 Long Term Incentive Plan (filed as Exhibit 10.4 to the Company's Current Report on Form 8-K filed on June 30, 2020, and incorporated herein by reference).
10.21*	Employment Agreement, by and between VAALCO Energy, Inc. and George Maxwell, effective as of April 19, 2021 (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed on April 12, 2021, and incorporated herein by reference).
10.21.1*	Amendment No. 1 to Employment Agreement, by and between VAALCO Energy, Inc. and George Maxwell, effective as of January 27, 2022 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on January 28, 2022, and incorporated herein by reference).
10.21.2*	Amendment No. 2 to Employment Agreement, by and between VAALCO Energy, Inc. and George Maxwell, effective as of November 23, 2022 (filed as Exhibit 10.21.2 to the Company's Annual Report on Form 10-K filed on April 6, 2023, and incorporated herein by reference).
10.22*	Employment Agreement, dated as of May 25, 2021, by and between VAALCO Energy, Inc. and Michael Silver (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 28, 2021, and incorporated herein by reference).
10.22.1*	First Amendment to Employment Agreement, dated as of August 30, 2022, by and between VAALCO Energy, Inc. and Michael Silver (filed as Exhibit 10.1 to the Company's Current Report on form 10-Q filed on November 8th, 2022, and incorporated herein by reference).
10.23*	Employment Agreement, by and between VAALCO Energy, Inc. and Ronald Bain, effective as of June 21, 2021 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on June 22, 2021, and incorporated herein by reference).
10.23.1*	Amendment No. 1 to Employment Agreement, effective as of January 27, 2022, by and between VAALCO Energy, Inc. and Ronald Bain (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed on January 28, 2022, and incorporated herein by reference).
10.23.2*	Amendment No. 2 to Employment Agreement, effective as of November 23, 2022, by and between VAALCO Energy, Inc. and Ronald Bain (filed as Exhibit 10.23.2 to the Company's Annual Report on Form 10-K filed on April 6, 2023, and incorporated herein by reference).
10.24*	TransGlobe Energy Corporation Amended and Restated Deferred Share Unit Plan (filed as Exhibit 10.24 to the Company's Annual Report on Form 10-K filed on April 6, 2023, and incorporated herein by reference).

10.25**	Bareboat Charter, by and between VAALCO Energy, Inc. and World Carrier Offshore Services Corp, dated August 31, 2021 (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed on November 3, 2021, and incorporated by reference herein).
10.25.1**	Deed of Novation and Amendment to Bareboat Charter, by and between VAALCO Gabon SA, World Carrier Offshore Services Corp. and Ocean Cloud Navigation Inc., dated as of November 15, 2022 (filed as Exhibit 10.25.1 to the Company's Annual Report on Form 10-K filed on April 6, 2023, and incorporated herein by reference).
10.25.2**	Second Amendment to Bareboat Charter, by and between VAALCO Gabon SA and Ocean Cloud Navigation Inc., dated as of March 22, 2023 (filed as Exhibit 10.25.2 to the Company's Annual Report on Form 10-K filed on April 6, 2023, and incorporated herein by reference).
10.26**	Operating Agreement, by and between VAALCO Energy, Inc. and World Carrier Offshore Services Corp, dated August 31, 2021 (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed on November 3, 2021, and incorporated herein by reference).
10.26.1**	Deed of Novation and Amendment to Operating Agreement, by and between VAALCO Gabon SA, World Carrier Offshore Services Corp. and Atlantic Energy Logistics SASU, dated as of November 15, 2022 (filed as Exhibit 10.26.1 to the Company's Annual Report on Form 10-K filed on April 6, 2023, and incorporated herein by reference).
10.27	Deed of Guarantee and Indemnity, by and between VAALCO Energy, Inc. and World Carrier Offshore Services Corp., dated August 31, 2021 (filed as Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q filed on November 3, 2021, and incorporated herein by reference).
10.27.1	Deed of Novation and Amendment to Deed of Guarantee and Indemnity, by and between VAALCO Energy, Inc., World Carrier Offshore Services Corp. and Ocean Cloud Navigation Inc., dated as of November 15, 2022.(filed as Exhibit 10.27.1 to the Company's Annual Report on Form 10-K filed on April 6, 2023, and incorporated herein by reference).
10.28	Deed of Guarantee and Indemnity, by and between VAALCO Energy, Inc. and World Carrier Offshore Services Corp., dated August 31, 2021 (filed as Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q filed on November 3, 2021, and incorporated herein by reference)
10.28.1**	Deed of Novation and Amendment to Deed of Guarantee and Indemnity, by and between VAALCO Energy, Inc., World Carrier Offshore Services Corp. and Atlantic Energy Logistics SASU, dated as of November 15, 2022 (filed as Exhibit 10.28.1 to the Company's Annual Report on Form 10-K filed on April 6, 2023, and incorporated herein by reference).
10.29	Concession Agreement for Petroleum Exploration, Development and Exploitation between The Arab Republic of Egypt and the Egyptian General Petroleum Corporation and TransGlobe West Bakr Inc. and TransGlobe West Gharib Inc. and TG NW Gharib Inc. in Merged Development Areas of West Bakr Area, West Gharib Area, Northwest Gharib Onshore Area, Eastern Desert, A.R.E. (furnished as Exhibit 1 to TransGlobe Energy Corporation's Report of Foreign Private Issuer on Form 6-k furnished on March 24, 2022, and incorporated herein by reference)
10.30**	Facility Agreement, by and among VAALCO Energy, Inc., VAALCO Gabon (Etame), Inc., VAALCO Gabon, SA, Glencore Energy UK Ltd., the Law Debenture Trust Corporation P.L.C., and the other financial institutions named therein, dated May 16, 2022 (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed on August 10, 2022, and incorporated herein by reference).
10.30.1**	Amended and Restated Facility Agreement, by and among VAALCO Energy, Inc., VAALCO Gabon (Etame), Inc., VAALCO Gabon, SA, Glencore Energy UK Ltd., the Law Debenture Trust Corporation P.L.C., and the other financial institutions named therein, dated October 3, 2023 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on October 5, 2023, and incorporated herein by reference).
10.31**	Crude Oil Sale and Marketing Agreement, by and between VAAALCO Gabon S.A. and Glencore Energy UK Ltd., dated May 20, 2022 (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed on August 10, 2022, and incorporated herein by reference).
21.1(a)	List of subsidiaries of the Company.
23.1(a)	Consent of BDO USA, P.C.
23.2(a)	Consent of KPMG LLP
23.3(a)	Consent of Netherland, Sewell & Associates, Inc. — Independent Petroleum Engineers.
23.4(a)	Consent of GLJ Ltd. — Independent Petroleum Engineers.
31.1(a)	Sarbanes-Oxley Section 302 certification of Principal Executive Officer.
31.2(a)	Sarbanes-Oxley Section 302 certification of Principal Financial Officer.
32.1(b)	Sarbanes-Oxley Section 906 certification of Principal Executive Officer.
32.2(b)	Sarbanes-Oxley Section 906 certification of Principal Financial Officer.
97.1(a)	Clawback Policy.
99.1(a)	Report of Netherland, Sewell & Associates, Inc. (International Properties)- Egypt
99.2(a)	Report of Netherland, Sewell & Associates, Inc. (International Properties) - Gabon
99.3(a)	Report of GLJ Ltd.
101.INS(a)	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH(a)	Inline XBRL Taxonomy Schema Document.
101.CAL(a)	Inline XBRL Calculation Linkbase Document.
101.DEF(a)	Inline XBRL Definition Linkbase Document.
101.LAB(a)	Inline XBRL Label Linkbase Document.
101.PRE(a)	Inline XBRL Presentation Linkbase Document.
104(a)	Cover Page Interactive Data File (formatted as Inline XBRL and Contained in Exhibit 101).

(a) Filed herewith
(b) Furnished herewith
* Management contract or compensatory plan or arrangement
**Information in this exhibit has been omitted pursuant to Item 601(b)(10)(iv) of Regulation S-K.

Item 16. Form 10-K Summary

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

VAALCO ENERGY, INC.
(Registrant)

By	/s/ George W.M. Maxwell George W.M. Maxwell Chief Executive Officer

Dated March 15, 2024

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on the 14th day of March 2024, by the following persons on behalf of the registrant and in the capacities indicated.

Signature		Title
By:	/s/ George Maxwell George Maxwell	Chief Executive Officer (Principal Executive Officer) and Director
By:	/s/ Ron Bain Ron Bain	Chief Financial Officer (Principal Financial Officer)
By:	/s/ Jason Doornik Jason Doornik	Chief Accounting Officer (Principal Accounting Officer)
By:	/s/ Andrew L. Fawthrop Andrew L. Fawthrop	Chairman of the Board and Director
By:	/s/ Catherine L. Stubbs Catherine L. Stubbs	Director
By:	/s/ Fabrice Nze-Bekale Fabrice Nze-Bekale	Director
By:	/s/ Edward LaFehr Edward LaFehr	Director

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors
VAALCO Energy, Inc.:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheet of VAALCO Energy, Inc. and subsidiaries (the Company) as of December 31, 2023, the related consolidated statements of operations and comprehensive income (loss), shareholders' equity, and cash flows for the year ended December 31, 2023, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2023, and the results of its operations and its cash flows for the year ended December 31, 2023, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 15, 2024 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audit included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audit provides a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of a critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Assessment of the impact of estimated crude oil, natural gas and natural gas liquids (NGLs) proved reserves on depletion expense related to crude oil and natural gas properties

As discussed in Note 2 to the consolidated financial statements, the Company determines depletion of crude oil and natural gas properties on a block basis under the unit-of-production method based upon estimates of proved reserves. For the year ended December 31, 2023, the Company recorded depreciation, depletion and amortization expense of $115 million. The estimation of proved reserves requires the expertise of reserve engineer specialists, who take into consideration future production, future operating and capital costs, and historical crude oil, natural gas and NGLs prices inclusive of price differentials. The Company engages independent reserve engineer specialists to estimate proved reserves, which are an input to the calculation of depletion.

We identified the assessment of the impact of estimated crude oil, natural gas and NGLs proved reserves on depletion expense related to crude oil and natural gas properties as a critical audit matter. Changes in assumptions used to estimate the proved reserves could have had a significant impact on depletion expense. Complex auditor judgment was required in evaluating the Company's estimate of proved reserves. Specifically, auditor judgment was required to evaluate the assumptions used by the Company related to future production and future operating and capital costs.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls over the Company's depletion process, including controls over the estimation of proved reserves. We evaluated the professional qualifications and knowledge, skills, and ability of the Company's internal reserve engineers and the independent reserve engineer specialists and the independent reserve engineering firms engaged by the Company. We evaluated the relationship of the independent reserve engineer specialists and independent reserve engineering firms to the Company. We analyzed and assessed the determination of depletion expense for compliance with industry and regulatory standards. We assessed compliance of the methodology used by the Company's independent reserve engineer specialists to estimate proved reserves with industry and regulatory standards. We read and considered the report of the Company's independent reserve engineering firms in connection with our evaluation of the Company's proved reserve estimates. We compared future production to historical production rates. We evaluated the future operating and capital costs by comparing them to historical costs.

/s/ KPMG LLP

We have served as the Company's auditor since 2023.

Houston, Texas
March 15, 2024

Report of Independent Registered Public Accounting Firm

Shareholders and Board of Directors
VAALCO Energy, Inc.
Houston, Texas

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheet of VAALCO Energy, Inc. (the "Company") as of December 31, 2022, the related consolidated statements of operations and comprehensive income (loss), shareholders' equity, and cash flows for the years ended December 31, 2022 and 2021, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2022, and the results of its operations and its cash flows for the years ended December 31, 2022 and 2021, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ BDO USA, LLP

We served as the Company's auditor from 2016 to 2023.

Houston, Texas

April 6, 2023

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors
VAALCO Energy, Inc.:

Opinion on Internal Control Over Financial Reporting

We have audited VAALCO Energy, Inc. and subsidiaries' (the Company) internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheet of the Company as of December 31, 2023, the related consolidated statements of operations and comprehensive income (loss), shareholders' equity, and cash flows for the year ended December 31, 2023, and the related notes (collectively, the consolidated financial statements), and our report dated March 14, 2024 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ KPMG LLP

Houston, Texas
March 15, 2024

VAALCO ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31, 2023	As of December 31, 2022
	(in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 121,001**	$ 37,205
Restricted cash	**114**	222
Receivables:		
Trade, net of allowances for credit loss and other of $0.5 and $0.0 million, respectively	**44,888**	52,147
Accounts with joint venture owners, net of allowance for credit losses of $0.8 and $0.3 million, respectively	**1,814**	15,830
Foreign income taxes receivable	**—**	2,769
Egypt receivables and other, net of allowances for credit loss and other of $4.6 and $0.0 million, respectively	**45,942**	68,519
Crude oil inventory	**1,948**	3,335
Prepayments and other	**12,434**	20,070
Total current assets	**228,141**	200,097
Crude oil, natural gas and NGLs properties and equipment, net	**459,786**	495,272
Other noncurrent assets:		
Restricted cash	**1,795**	1,763
Value added tax and other receivables, net of allowances for credit loss and other of $0.0 million and $8.4 million, respectively	**4,214**	7,150
Right of use operating lease assets	**2,378**	2,777
Right of use finance lease assets	**89,962**	90,698
Deferred tax assets	**29,242**	35,432
Abandonment funding	**6,268**	20,586
Other long-term assets	**1,430**	1,866
Total assets	**$ 823,216**	$ 855,641
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	**$ 22,152**	$ 59,886
Accounts with joint venture owners	**5,990**	—
Accrued liabilities and other	**66,924**	91,392
Operating lease liabilities - current portion	**2,396**	2,314
Finance lease liabilities - current portion	**10,079**	7,811
Foreign income taxes payable	**19,261**	—
Current liabilities - discontinued operations	**673**	687
Total current liabilities	**127,475**	162,090
Asset retirement obligations	**47,343**	41,695
Operating lease liabilities - net of current portion	**33**	686
Finance lease liabilities - net of current portion	**78,293**	78,248
Deferred tax liabilities	**73,581**	81,223
Other long-term liabilities	**17,709**	25,594
Total liabilities	**344,434**	389,536
Commitments and contingencies (Note 12)		
Shareholders' equity:		
Preferred stock, $25 par value; 500,000 shares authorized, none issued	**—**	—
Common stock, $0.10 par value; 160,000,000 shares authorized, 121,397,553 and 119,482,680 shares issued, 104,346,233 and 107,852,857 shares outstanding, respectively	**12,140**	11,948
Additional paid-in capital	**357,498**	353,606
Accumulated other comprehensive income	**2,880**	1,179
Less treasury stock, 17,051,320 and 11,629,823 shares, respectively, at cost	**(71,222)**	(47,652)
Retained earnings	**177,486**	147,024
Total shareholders' equity	**478,782**	466,105
Total liabilities and shareholders' equity	**$ 823,216**	$ 855,641

See notes to consolidated financial statements.

VAALCO ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)

	Twelve Months Ended December 31,		
	2023	2022	2021
	(in thousands, except per share amounts)		
Revenues:			
Crude oil, natural gas and natural gas liquids sales	**$ 455,066**	$ 354,326	$ 199,075
Operating costs and expenses:			
Production expense	**153,157**	112,661	81,255
FPSO demobilization and other costs	**7,484**	8,867	—
Exploration expense	**1,965**	258	1,579
Depreciation, depletion and amortization	**115,302**	48,143	21,060
General and administrative expense	**23,840**	10,077	14,766
Credit (recovery) losses and other	**(4,906)**	3,082	875
Total operating costs and expenses	**296,842**	183,088	119,535
Other operating income (expense), net	**433**	38	(440)
Operating income	**158,657**	171,276	79,100
Other income (expense):			
Derivative instruments gain (loss), net	**232**	(37,812)	(22,826)
Interest income (expense), net	**(6,452)**	(2,034)	10
Other income (expense), net	**(2,291)**	(8,048)	3,494
Total other expense, net	**(8,511)**	(47,894)	(19,322)
Income from continuing operations before income taxes	**150,146**	123,382	59,778
Income tax expense (benefit)	**89,777**	71,420	(22,156)
Income from continuing operations	**60,369**	51,962	81,934
Loss from discontinued operations, net of tax	**(15)**	(72)	(98)
Net income	**$ 60,354**	$ 51,890	$ 81,836
Other comprehensive income (loss)			
Currency translation adjustments	**1,701**	1,179	—
Comprehensive income	**$ 62,055**	$ 53,069	$ 81,836
Basic net income per share:			
Income from continuing operations	**$ 0.56**	$ 0.74	$ 1.38
Loss from discontinued operations, net of tax	**—**	—	—
Net income per share	**$ 0.56**	$ 0.74	$ 1.38
Basic weighted average shares outstanding	**106,376**	69,568	58,230
Diluted net income per share:			
Income from continuing operations	**$ 0.56**	$ 0.73	$ 1.37
Loss from discontinued operations, net of tax	**—**	—	—
Net income per share	**$ 0.56**	$ 0.73	$ 1.37
Diluted weighted average shares outstanding	**106,555**	69,982	58,755

See notes to consolidated financial statements

VAALCO ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common Shares Issued	Treasury Shares	Common Stock	Additional Paid-In Capital	Accumulated Other Comprehensive Loss	Treasury Stock	Retained Earnings	Total
				(in thousands)				
Balance at January 1, 2021	67,897	(10,366)	6,790	74,437	—	(42,421)	22,652	$ 61,458
Shares issued - stock-based compensation	1,665	(573)	166	1,203	—	—	—	1,369
Stock-based compensation expense	—	—	—	1,060	—	—	—	1,060
Treasury stock	—	—	—	—	—	(1,426)	—	(1,426)
Net income	—	—	—	—	—	—	81,836	81,836
Balance at December 31, 2021	69,562	(10,939)	$ 6,956	$ 76,700	$ —	$ (43,847)	$ 104,488	$ 144,297
Shares issued - stock-based compensation	614	—	61	251	—	—	—	312
Stock-based compensation expense	—	—	—	2,105	—	—	—	2,105
Conversion of Liability Awards to Equity	—	—	—	5,336	—	—	—	5,336
Acquisition of TransGlobe	49,307	—	4,931	269,214	—	—	—	274,145
Treasury stock	—	(691)	—	—	—	(3,805)	—	(3,805)
Dividend distributions	—	—	—	—	—	—	(9,354)	(9,354)
Other comprehensive income	—	—	—	—	1,179	—	—	1,179
Net income	—	—	—	—	—	—	51,890	51,890
Balance at December 31, 2022	119,483	(11,630)	$ 11,948	$ 353,606	$ 1,179	$ (47,652)	$ 147,024	$ 466,105
Shares issued - stock-based compensation	1,915	—	192	482	—	—	—	674
Stock-based compensation expense	—	—	—	3,410	—	—	—	3,410
Treasury stock	—	(5,421)	—	—	—	(23,570)	—	(23,570)
Dividend distributions	—	—	—	—	—	—	(26,772)	(26,772)
Cumulative effect of adjustment upon adoption of ASU 2016-13 on January 1, 2023	—	—	—	—	—	—	(3,120)	(3,120)
Other comprehensive income	—	—	—	—	1,701	—	—	1,701
Net income	—	—	—	—	—	—	60,354	60,354
Balance at December 31, 2023	**121,398**	**(17,051)**	**$ 12,140**	**$ 357,498**	**$ 2,880**	**$ (71,222)**	**$ 177,486**	**$ 478,782**

See notes to consolidated financial statements.

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VAALCO ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Twelve Months Ended December 31,		
	2023	**2022**	**2021**
		(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	**$ 60,354**	$ 51,890	$ 81,836
Adjustments to reconcile net income to net cash provided by operating activities:			
Loss from discontinued operations, net of tax	**15**	72	98
Depreciation, depletion and amortization	**115,302**	48,143	21,060
Bargain purchase gain	**1,412**	(10,819)	(7,651)
Exploration expense	1,841	—	—
Deferred taxes	**(2,864)**	44,805	(39,978)
Unrealized foreign exchange loss	**52**	(1,043)	(291)
Stock-based compensation	**3,323**	2,200	2,459
Cash settlements paid on exercised stock appreciation rights	**(378)**	(827)	(3,271)
Derivative instruments (gain) loss, net	**(232)**	37,812	22,826
Cash settlements paid on matured derivative contracts, net	**(127)**	(42,935)	(18,020)
Cash settlements paid on asset retirement obligations	**(6,747)**	(6,577)	—
Credit (recovery) losses and other	**7,543**	3,082	875
Other operating loss, net	**55**	(38)	440
Operational expenses associated with equipment and other	**3,196**	2,052	2,415
Change in operating assets and liabilities:			
Trade, net	**6,723**	18,385	(11,308)
Accounts with joint venture owners, net	**19,571**	(18,929)	1,594
Egypt receivables and other, net	**14,802**	(9,290)	(9,736)
Crude oil inventory	**1,387**	(1,742)	5,022
Prepayments and other	**4,743**	(4,387)	1,617
Value added tax and other receivables	**2,427**	(5,193)	(1,593)
Other long-term assets	**3,830**	(2,730)	(1,176)
Accounts payable	**(28,102)**	23,920	(922)
Foreign income taxes receivable/(payable)	**22,030**	(5,897)	2,268
Accrued liabilities and other	**(6,544)**	6,964	1,645
Net cash provided by (used in) continuing operating activities	**223,612**	128,918	50,209
Net cash used in discontinued operating activities	**(15)**	(72)	(92)
Net cash provided by (used in) operating activities	**223,597**	128,846	50,117
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property and equipment expenditures	**(97,223)**	(159,897)	(16,558)
Cash acquired from TransGlobe acquisition	—	36,686	—
Acquisition of crude oil and natural gas properties	—	—	(22,505)
Net cash provided by (used in) continuing investing activities	**(97,223)**	(123,211)	(39,063)
Net cash used in discontinued investing activities	—	—	—
Net cash provided by (used in) investing activities	**(97,223)**	(123,211)	(39,063)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from the issuances of common stock	**673**	312	1,369
Dividend distribution	**(26,772)**	(9,354)	—
Treasury shares	**(23,570)**	(3,805)	(1,426)
Deferred financing costs	—	(2,069)	—
Payments of finance lease	**(7,150)**	(3,039)	—
Net cash provided by (used in) in continuing financing activities	**(56,819)**	(17,955)	(57)
Net cash used in discontinued financing activities	—	—	—
Net cash provided by (used in) in financing activities	**(56,819)**	(17,955)	(57)
Effects of exchange rate changes on cash	**(153)**	(218)	—
NET CHANGE IN CASH, CASH EQUIVALENTS AND RESTRICTED CASH	**69,402**	(12,538)	10,997
CASH, CASH EQUIVALENTS AND RESTRICTED CASH AT BEGINNING OF PERIOD	**59,776**	72,314	61,317
CASH, CASH EQUIVALENTS AND RESTRICTED CASH AT END OF PERIOD	**$ 129,178**	$ 59,776	$ 72,314

See notes to consolidated financial statements.

VAALCO ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS SUPPLEMENTAL DISCLOSURES

To Be Updated	Twelve Months Ended December 31,		
	2023	**2022**	**2021**
		(in thousands)	
Supplemental disclosure of cash flow information:			
Income taxes paid in-kind with crude oil	**$ 32,776**	$ **26,257**	$ **20,103**
Interest paid, net of amounts capitalized	**$ 9,122**	$ 1,656	$ —
Supplemental disclosure of non-cash investing and financing activities:			
Property and equipment additions incurred but not paid at end of period	**$ 14,137**	$ 41,060	$ 15,021
Non-cash consideration exchanged in the acquisition of TransGlobe	$ —	$ 274,145	$ —
Recognition of right-of-use operating lease assets and liabilities	**$ 2,582**	$ —	$ 581
Recognition of right-of-use finance lease assets and liabilities	**$ 7,875**	$ 87,166	$ —
Reclassification of other long-term assets to right-of-use finance lease assets	$ —	$ 4,116	$ —
Liability awards converted to equity	$ —	$ 5,336	$ —
Asset retirement obligations adjustments	**$ 2,487**	$ —	$ 21,733

See notes to consolidated financial statements.

VAALCO ENERGY, INC. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION

VAALCO Energy, Inc. (together with its consolidated subsidiaries “we”, “us”, “our”, “VAALCO” or the “Company”) is a Houston, Texas-based independent energy company engaged in the acquisition, exploration, development and production of crude oil, natural gas and NGLs properties. As operator, the Company has production operations and conducts exploration activities in Gabon and Canada and hold interests in two production sharing contracts ("PSCs") in Egypt. The Company has opportunities to participate in development and exploration activities in Equatorial Guinea, West Africa.

On October 13, 2022, the Company completed the business combination involving TransGlobe Energy Corporation (“TransGlobe”),

As of December 31, 2023, the Company’s consolidated subsidiaries were VAALCO Gabon (Etame), Inc., VAALCO Production (Gabon), Inc., VAALCO Gabon S.A., VAALCO Angola (Kwanza), Inc., VAALCO Energy (EG), Inc., VAALCO Energy Mauritius (EG) Limited, VAALCO Energy, Inc. (UK Branch), VAALCO Energy (USA), Inc, VAALCO Energy (International), LLC, VAALCO Energy (Holdings), LLC, VAALCO International Management, LLC, TransGlobe Energy Corporation, TransGlobe Energy UK Ltd, TransGlobe Petroleum International Inc., TransGlobe Holdings Yemen Inc., TransGlobe West Bakr Inc., TransGlobe West Gharib Inc., TransGlobe Energy Marketing Inc., TransGlobe NW Gharib Inc. and TransGlobe S Ghazalat Inc.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of consolidation – The accompanying consolidated financial statements (“Financial Statements”) include the accounts of VAALCO and its wholly owned subsidiaries. Investments in unincorporated joint ventures and undivided interests in certain operating and non-operating assets are consolidated on a pro rata basis. All intercompany transactions within the consolidated group have been eliminated in consolidation.

Use of estimates – The preparation of the Financial Statements in conformity with generally accepted accounting principles in the U.S. (“GAAP”) requires estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the Financial Statements and the reported amounts of revenues and expenses during the respective reporting periods. The Financial Statements include amounts that are based on management’s best estimates and judgments. Actual results could differ from those estimates.

Estimates of crude oil, natural gas and NGLs reserves used to estimate depletion expense and impairment charges require significant judgments and are generally less precise than other estimates made in connection with financial disclosures. Due to inherent uncertainties and the limited nature of data, estimates are imprecise and subject to change over time as additional information becomes available.

Cash and cash equivalents – Cash and cash equivalents includes deposits and funds invested in highly liquid instruments with original maturities of three months or less at the date of purchase. The Company maintains its cash accounts in financial institutions that are insured by the Federal Deposit Insurance Corporation. From time to time, cash balances may exceed the insured amounts, however, the Company has not experienced any losses in such accounts and does not believe it is exposed to any significant credit risks associated with cash and cash equivalents.

Restricted cash and abandonment funding – Restricted cash includes cash that is contractually restricted. Restricted cash is classified as a current or non-current asset based on its designated purpose and estimated timing of usage. Current amounts in restricted cash at December 31, 2023 and 2022 each include an escrow amount representing bank guarantees for customs clearance in Gabon. For Canada, approximately $ 0.1 million has been set aside as of December 31, 2023 related to property taxes. Long-term amounts at December 31, 2023 and 2022 include a charter payment escrow for the FPSO offshore Gabon as discussed in Note 12.

On January 22, 2024 VAALCO received notice that the final compensation payment was made for the charter payment escrow for the FPSO, which released VAALCO and its partners of any further obligation to restrict this cash amount. The remaining cash in the account is to be distributed to VAALCO and the joint operating partners. As of December 31, 2023, VAALCO's share of this restricted cash amount was $ 1.8 million.

In the first quarter of 2023, the Directorate of Hydrocarbons in Gabon approved a $ 26.6 million ($ 15.6 million, net to VAALCO) abandonment funding payment associated with the FPSO retirement. The Company received payment of $ 15.6 million in March 2023. The remaining balance of the abandonment fund was unchanged during the remainder of 2023.

The Company invests restricted and excess cash in readily redeemable money market funds. The following table provides a reconciliation of cash, cash equivalents, and restricted cash reported within the consolidated balance sheets to the amounts shown in the consolidated statements of cash flows.

	As of December 31,	
	2023	**2022**
	(in thousands)	
Cash and cash equivalents	**$ 121,001**	$ 37,205
Restricted cash - current	**114**	222
Restricted cash - non-current	**1,795**	1,763
Abandonment funding	**6,268**	20,586
Total cash, cash equivalents and restricted cash	**$ 129,178**	$ 59,776

Accounts with joint venture owners, net – Accounts with joint venture owners represent the excess of charges billed over cash calls paid by the joint venture owners for exploration, development and production expenditures made by the Company as an operator. Joint owner receivables are secured through cash calls and other mechanisms for collection under the terms of the joint operating agreements. For credit loss and other allowances associated with accounts with joint venture owners, see allowance for credit loss and other below.

Trade, net – The Company's trade accounts receivable results from sales of crude oil, natural gas and NGLs. For credit losses associated with accounts with trade receivables, see allowance for credit losses and other below.

Egypt receivables and other, net – On January 19, 2022, TransGlobe's West Gharib, West Bakr and North West Gharib (collectively the "Eastern Desert") concessions were merged into the Merged Concession Agreement with the Egyptian General Petroleum Corporation ("EGPC"). The Merged Concession includes improved cost recovery and production sharing terms scaled to oil prices with a new 15-year development term and a 5-year extension option. Upon execution of the Merged Concession, there was an effective date adjustment owed to the Company for the difference between historic and Merged Concession Agreement commercial terms applied against Eastern Desert production from the Merged Concession Effective Date, February 1, 2020. The cumulative amount of the effective date adjustment was estimated at $ 67.5 million and was recorded as part of the TransGlobe arrangement. During the fourth quarter of 2022, the Company received $ 17.2 million. At December 31, 2023, the remaining $ 45.6 , net of credit loss ($ 4.6 million) million was recorded on the consolidated balance sheet in current receivables in the "Egypt receivables and other, net" line item.

For credit losses associated with Egypt receivables and other, net, see allowance for credit losses and other below.

Value added tax and other receivables, net – The Company incurs receivables from the government of Gabon for reimbursable Value-Added Tax ("VAT").

As of December 31, 2023, the outstanding VAT receivable balance was approximately $ 1.6 million, net to VAALCO. As of December 31, 2022, the outstanding VAT receivable balance, excluding the allowance, was approximately $ 21.8 million ($ 13.9 million, net to VAALCO). The receivable amount, net of allowances, is reported as a non-current asset in the "Value added tax and other receivables" line item in the condensed consolidated balance sheets. Because both the VAT receivable and the related allowances are denominated in XAF, the exchange rate revaluation of these balances into U.S. dollars at the end of each reporting period also has an impact on the Company's results of operations. Such foreign currency gains (losses) are reported separately in the "Other expense, net" line item of the consolidated statements of operations and comprehensive income. For the allowance associated with VAT, see allowance for credit losses and other below.

Allowance for credit losses and other – On *January 1, 2023,* the Company adopted Accounting Standards Update *2016-13,* Financial Instruments—Credit Losses ("*ASU 2016-13*"). ASU *2016-13* requires an entity to measure credit losses of certain financial assets, including trade receivables, utilizing a methodology that reflects expected credit losses and requires consideration of a broader range of reasonable and supportable information to form credit loss estimates. All other amounts previously disclosed as allowances for bad debt were transferred to allowances for credit loss and other.

The Company estimates the current expected credit loss and other allowances based primarily using either an aging analysis or discounted cash flow methodology that incorporates consideration of current and future conditions that could impact its counterparties' credit quality and liquidity. Uncollectible receivables are written off when a settlement is reached for an amount that is less than the outstanding historical balance or when the Company has determined that the balance will *not* be collected.

The Company has identified the following types of financial assets that are within the scope of ASU *2016-13:*

- Trade, net;
- Accounts with joint venture owners, net; and
- Egypt receivables and other, net

As a result of adopting ASU 2016-13 on January 1, 2023, the Company recognized a $ 3.1 million cumulative effect adjustment within retained earnings. During the year ended December 31, 2023, the Company reversed $ 12.4 million of credit loss and other allowances due to recoveries from VAT and the Sogara refinery. The Company recognized $ 7.5 million in credit loss and other allowances mainly due to amounts owed from EGPC. As of December 31, 2023, the Company has established a credit loss and other allowance for the full $ 0.8 million receivable from one of the non-operating partners in Block P offshore Equatorial Guinea.

The following table provides an analysis of the change in the aggregate credit loss and other allowances:

	Twelve Months Ended December 31, 2023	2022
	(in thousands)	
Allowance for credit losses and other		
Balance at beginning of period	**$ (8,704)**	$ (5,741)
Credit losses and other	**(7,543)**	(3,380)
Credit recoveries and other	**12,449**	298
Adjustment associated with Sasol Acquisition	**—**	—
Cumulative effect of adjustment upon adoption of ASU 2016-13 on January 1, 2023	**(3,120)**	—
Foreign currency gain	**889**	119
Balance at end of period	**$ (6,029)**	$ (8,704)

Crude oil inventory – Crude oil inventories are carried at the lower of cost or net realizable value. In Gabon, inventories represent the Company's share of crude oil produced and stored on the FSO at December 31, 2023 and the FPSO at December 31, 2022, but unsold at the end of each period. In Egypt, inventory consists of the Company's entitlement crude oil barrels not yet sold.

Prepayments and other – Included in "Prepayments and other" line item of the Company's December 31, 2023 and 2022 consolidated balance sheet are the following assets:

	As of December 31, 2023	As of December 31, 2022
	(in thousands)	
Prepaid fixed asset progress payments	**$ 2,314**	$ 3,991
Gabon prepaid royalties	**1,246**	4,800
Prepaid insurance	**474**	117
Egypt advances to contractors	**2,656**	4,914
Gabon employee loans and advances	**1,299**	1,146
Refundable deposits	**345**	623
Derivative receivables	**403**	102
Other prepayments	**3,697**	4,377
Total prepayments and other	**$ 12,434**	$ 20,070

Crude oil, natural gas and NGLs properties, equipment and other – The Company uses the successful efforts method of accounting for crude oil, natural gas and NGLs producing activities.

- ***Capitalization*** – Costs of successful wells, development dry holes and leases containing productive reserves are capitalized and amortized on a unit-of-production basis over the life of the related reserves. Other exploration costs, including dry exploration well costs, geological and geophysical expenses applicable to undeveloped leaseholds, leasehold expiration costs and delay rentals, are expensed as incurred. The costs of exploratory wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. Cost incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (b) sufficient progress in assessing the reserves and the economic and operating viability of the project has been made. The status of suspended well costs is monitored continuously and reviewed quarterly. Due to the capital-intensive nature and the geographical characteristics of certain projects, it may take an extended period of time to evaluate the future potential of an exploration project and the economics associated with making a determination of its commercial viability. Costs of seismic studies that are utilized in development drilling within an area of proved reserves are capitalized as development costs.

- ***Capitalized equipment spare parts*** – Capitalized equipment inventory represents the costs incurred in purchasing and bringing the inventory to its present location and condition and is based on purchase costs calculated on weighted average cost basis, including transportation costs. Capitalized equipment inventory is classified as long term when the Company expects to utilize the inventory beyond the normal operating cycle.

- ***Depreciation, depletion and amortization*** – Depletion of wells, platforms, and other production facilities are calculated on a block basis under the unit-of-production method based upon estimates of total proved developed reserves. Depletion of leasehold acquisition costs are provided on a block basis under the unit-of-production method based upon estimates of total proved reserves. Support equipment (other than equipment inventory) and leasehold improvements related to crude oil, natural gas and NGLs producing activities, as well as property, plant and equipment unrelated to crude oil, natural gas and NGLs producing activities, are recorded at cost and depreciated on a straight-line basis over the estimated useful lives of the assets, which are typically five years for office and miscellaneous equipment and five to seven years for leasehold improvements.

- ***Unproved Property Cost*** – Significant unproved properties are assessed individually for impairment and when events or circumstances indicate that the carrying value of property may not be recovered a valuation allowance is provided if an impairment is indicated. The unproved property costs are not subject to depreciation, depletion and amortization, until they are classified as proved properties.

- ***Impairment*** – The Company reviews the crude oil, natural gas and NGLs properties and equipment, net for impairment on a block basis whenever events or changes in circumstances indicate that the carrying amount of such properties may not be recoverable. If the sum of the expected undiscounted future cash flows from the use of the asset and its eventual disposition is less than the carrying amount of the asset, an impairment charge is recorded based on the fair value of the asset. This may occur if the block contains lower than anticipated reserves or periods of sustained declines in commodity prices. The fair value measurement used in the impairment test is generally calculated with a discounted cash flow model using several Level 3 inputs that are based upon estimates, the most significant of which is the estimate of net proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond the Company's control. Reserve engineering is a subjective process of estimating underground accumulations of crude oil, natural gas and NGLs that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of crude oil, natural gas and NGLs that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future crude oil, natural gas and NGLs sales prices may all differ from those assumed in these estimates.

  Capitalized equipment inventory is reviewed regularly for obsolescence.

  When undeveloped crude oil, natural gas and NGLs leases are deemed to be impaired, exploration expense is charged. Unproved property costs consist of acquisition costs related to unproved property costs in the Etame Marin block in Gabon, Canada, Egypt and in Block P in Equatorial Guinea.

Lease commitments – At inception, contracts are reviewed to determine whether an agreement contains a lease as defined under Accounting Standards Codification ("ASC") 842, *Leases.* If a lease is identified within the contract, a determination is made whether the lease qualifies as an operating or financing lease. Regardless of the type of lease, the initial measurement of the lease results in recording a right of use ("ROU") asset and a lease liability at the present value of the future lease payments.

Asset retirement obligations ("ARO") – The Company has legal obligations to remove tangible equipment and restore land or seabed at the end of crude oil, natural gas and NGLs production operations. The removal and restoration obligations are primarily associated with plugging and abandoning wells, removing and disposing of all or a portion of onshore or offshore crude oil, natural gas and NGLs platforms, and capping pipelines. Estimating the future restoration and removal costs requires management to make estimates and judgments. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety, and public relations considerations.

A liability for ARO is recognized in the period in which the legal obligations are incurred if a reasonable estimate of fair value can be made. The ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with crude oil, natural gas and NGLs properties and equipment, net. The Company uses current retirement costs to estimate the expected cash outflows for retirement obligations. Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental, and political environments. Initial recording of the ARO liability is offset by the corresponding capitalization of asset retirement cost recorded to crude oil, natural gas and NGLs properties and equipment, net. To the extent these or other assumptions change after initial recognition of the liability, the fair value estimate is revised and the recognized liability adjusted, with a corresponding adjustment made to the related capitalized asset retirement cost or through a charged to earnings, as appropriate. Depreciation of capitalized asset retirement costs and accretion of asset retirement obligations are recorded over time. Depreciation is generally determined on a units-of-production basis for crude oil, natural gas and NGLs properties and equipment, net production facilities, while accretion escalates over the lives of the assets to reach the expected settlement value. Where there is a downward revision to the ARO that exceeds the net book value of the related asset, the corresponding adjustment is limited to the amount of the net book value of the asset and the remaining amount is recognized as a gain.

Revenue recognition – The Company's revenues are derived from contracts with customers. Royalties are considered to be part of the price of the sale transaction and are therefore presented as a reduction to revenues. Revenues associated with the sale of crude oil, natural gas and NGLs are measured based on the consideration specified in contracts with customers.

Revenues from contracts with customers are recognized when the Company satisfies a performance obligation by transferring a good or service to a customer. A good or service is transferred when the customer obtains control of the good or service. The transfer of control of oil, natural gas and NGLs usually coincides with title passing to the customer and the customer taking physical possession. VAALCO mainly satisfies its performance obligations at a point in time and the amounts of revenues recognized relating to performance obligations satisfied over time are not significant. Sales and delivery costs associated with certain sales are netted against revenue in accordance with the Company's policy regarding classification of these type of expenses. The Company has utilized the practical expedient in ASC Topic 606-10-50-14(a), which states that the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation.

Revenues associated with the sales of the Company's crude oil, natural gas, condensates and natural gas liquids ("NGLs") are recognized by reference to actual volumes sold and quoted market prices in active markets for crude oil, natural gas, condensates and NGLs, adjusted according to specific terms and conditions as applicable per the sales contracts. Revenue is measured at the fair value of the consideration received or receivable.

Major maintenance activities – Costs for major maintenance are expensed in the period incurred and can include the costs of workovers of existing wells, contractor repair services, materials and supplies, equipment rentals and labor costs.

Stock-based compensation – The Company measures the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award on the date of the grant. The grant date fair value for options or stock appreciation rights ("SARs") is estimated using either the Black-Scholes or Monte Carlo method depending on the complexity of the terms of the awards granted. The SARs fair value is estimated at the grant date and remeasured at each subsequent reporting date until exercised, forfeited or cancelled.

Black-Scholes and Monte Carlo models employ assumptions, based on management's best estimates at the time of grant, which impact the calculation of fair value and ultimately, the amount of expense that is recognized over the life of the stock options or SAR award. These models use the following inputs: (i) the quoted market price of the Company's common stock on the valuation date, (ii) the maximum stock price appreciation that an employee may receive, (iii) the expected term that is based on the contractual term, (iv) the expected volatility that is based on the historical volatility of the Company's stock for the length of time corresponding to the expected term of the option or SAR award, (v) the expected dividend yield that is based on the anticipated dividend payments and (vi) the risk-free interest rate that is based on the U.S. treasury yield curve in effect as of the reporting date for the length of time corresponding to the expected term of the option or SAR award.

For restricted stock awards, the grant date fair value is determined using the market value of the common stock on the date of grant.

The stock-based compensation expense for equity awards is recognized over the period that services are provided. For awards considered liabilities under US GAAP, awards are measured at fair value on the grant date and remeasured at fair value until the award is settled.

Foreign currency transactions – The U.S. dollar is the functional currency of the Company’s foreign operating subsidiaries except for Canada. When the Company’s subsidiaries' functional currency is the US dollar, gains and losses on foreign currency transactions are included in income. When the Company’s subsidiaries functional currency is the local currency, not the US dollar, the cumulative effects of translating the balance sheet accounts from the functional currency into the U.S. dollar at current exchange rates are included in accumulated other comprehensive income (loss). The Company recognized losses on foreign currency transactions of $ 0.9 million in 2023, $ 4.2 million in 2022 and $ 0.7 million in 2021.

Income taxes – The tax provision is based on expected taxable income, statutory rates and tax planning opportunities available to the Company in the various jurisdictions in which the Company operates. The determination and evaluation of the annual tax provision and tax positions involves the interpretation of the tax laws in the various jurisdictions in which the Company operates and requires significant judgment and the use of estimates and assumptions regarding significant future events such as the amount, timing and character of income, deductions and tax credits. Changes in tax laws, regulations, agreements and tax treaties or the level of operations or profitability in each jurisdiction would impact the tax liability in any given year. The Company also operates in foreign jurisdictions where the tax laws relating to the crude oil, natural gas and NGLs industry are open to interpretation, which could potentially result in tax authorities asserting additional tax liabilities. While the income tax provision (benefit) is based on the best information available at the time, a number of years may elapse before the ultimate tax liabilities in the various jurisdictions are determined. The Company also records as income tax expense the increase or decrease in the value of the government’s allocation of profit oil, which is due to changes in value from the time the allocation is originally produced to the time the allocation is actually lifted.

Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax basis. Deferred tax assets are recognized when it is more likely than not that they will be realized. We periodically assess our deferred tax assets and reduce such assets by a valuation allowance if we deem it is more likely than not that some portion or all of the deferred tax assets will not be realized. Judgment is required in determining whether deferred tax assets will be realized in full or in part. Management assesses the available positive and negative evidence to estimate if existing deferred tax assets will be utilized, and when it is estimated to be more-likely-than-not that all or some portion of specific deferred tax assets, such as net operating loss carry forwards or foreign tax credit carryovers, will not be realized. A valuation allowance must be established for the amount of the deferred tax assets that are estimated to not be realizable. Factors considered are earnings generated in previous periods, forecasted earnings and the expiration period of carryovers.

Derivative instruments and hedging activities – The Company enters into crude oil hedging arrangements from time to time in an effort to mitigate the effects of commodity price volatility and enhance the predictability of cash flows relating to the marketing of a portion of our crude oil production. While these instruments mitigate the cash flow risk of future decreases in commodity prices, they may also curtail benefits from future increases in commodity prices.

The Company records balances resulting from commodity risk management activities in the consolidated balance sheets as either assets or liabilities measured at fair value. The Company has elected not to offset fair value amounts of qualifying derivatives under a master netting arrangement and associated fair value amounts for cash collateral receivables and payables. Gains and losses from the change in fair value of derivative instruments and cash settlements on commodity derivatives are presented in the “Derivative instruments gain (loss), net” line item located within the “Other income (expense)” section of the consolidated statements of operations and comprehensive income (loss).

Fair value – Fair value is defined as the price that would be received to sell an asset or the price paid to transfer a liability in an orderly transaction between market participants at the measurement date. Inputs used in determining fair value are characterized according to a hierarchy that prioritizes those inputs based on the degree to which they are observable. The three input levels of the fair-value hierarchy are as follows:

Level 1 – Inputs are observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the measurement date.

Level 2 – Inputs are observable market-based inputs or unobservable inputs that are corroborated by market data.

Level 3 – Inputs are unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

Nonrecurring Fair Value Measurements – The Company applies fair value measurements to its nonfinancial assets and liabilities measured on a nonrecurring basis, which consist of measurements or remeasurements of impairment of crude oil, natural gas and NGLs properties and equipment, net, asset retirement assets and liabilities and assets acquired and liabilities assumed in a business combination. VAALCO uses market-observable prices for assets when comparable transactions can be identified that are similar to the asset being valued. When VAALCO is required to measure fair value and there is not a market-observable price for the asset or for a similar asset then the cost or income approach is used depending on the quality of information available to support management's assumptions. The cost approach is based on management's best estimate of the current asset replacement cost. The income approach is based on management's best assumptions regarding expectations of future net cash flows. The expected cash flows are discounted using a commensurate risk-adjusted discount rate. Such evaluations involve significant judgment, and the results are based on expected future events or conditions such as sales prices, estimates of future oil and gas production or throughput, development and operating costs and the timing thereof, economic and regulatory climates and other factors, most of which are often are often outside of management's control. However, assumptions used to reflect a market participant's view of long term prices, costs and other factors and are consistent with assumptions used in VAALCO's business plans and investment decisions.

Fair value of financial instruments – The Company determines the fair value of our assets and liabilities subject to fair value measurement by using the highest possible "level" of inputs.

		As of December 31, 2023			
	Balance Sheet Line	**Level 1**	**Level 2**	**Level 3**	**Total**
		(in thousands)			
Assets					
Derivative asset	Prepayments and other	$ —	$ **403**	$ —	$ **403**
		$ —	$ **403**	$ —	$ **403**
Liabilities					
SARs liability	Accrued liabilities and other	$ —	**$ 163**	$ —	**$ 163**
Derivative liability	Accrued liabilities and other	—	**—**	—	**—**
		$ —	**$ 163**	$ —	**$ 163**

		As of December 31, 2022			
	Balance Sheet Line	**Level 1**	**Level 2**	**Level 3**	**Total**
		(in thousands)			
Assets					
Derivative asset	Prepayments and other	$ —	$ 102	$ —	$ 102
		$ —	$ 102	$ —	$ 102
Liabilities					
SARs liability	Accrued liabilities and other	$ —	$ 556	$ —	$ 556
		$ —	$ 556	$ —	$ 556

Earnings per Share – Basic earnings per common share is calculated by dividing earnings available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings per common share is calculated by dividing earnings available to common stockholders by the weighted average number of diluted common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities consist of unvested restricted stock awards and stock options using the treasury method. Under the treasury method, the amount of unrecognized compensation expense related to unvested stock-based compensation grants or the proceeds that would be received if the stock options were exercised are assumed to be used to repurchase shares at the average market price. When a loss exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share.

3. NEW ACCOUNTING STANDARDS

Adopted

In June 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Codification ("ASU") No. 2016-13, *Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments* ("ASU 2016-13") related to the calculation of credit losses on financial instruments. All financial instruments not accounted for at fair value are impacted, including the Company's trade and joint venture owners' receivables. Allowances are to be measured using a current expected credit loss ("CECL") model as of the reporting date that is based on historical experience, current conditions and reasonable and supportable forecasts. This is significantly different from the current model that increases the allowance when losses are probable. ASU 2016-13 is effective for Securities and Exchange Commission filers, excluding smaller reporting companies, for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. The Company was required to adopt the new standard for the fiscal years beginning after December 15, 2022, including interim periods within those fiscal years. The Company adopted ASU 2016-13 ("ASC 326") on January 1, 2023 using the modified-retrospective approach. The modified-retrospective approach consists of applying the amendments in ASU 2016-13 through a cumulative-effect adjustment, if required, to retained earnings as of the beginning of the first reporting period in which the guidance is effective. The Company's current method and timing of recognizing credit loss and other allowances are in accordance with ASC 326 and is consistent with the previous method of recognizing credit loss and other allowances, except for one receivable, which now utilizes the Discounted Cash Flow method for computing its Expected Credit Loss ("ECL"). The Company recorded an ECL allowance of $ 3.1 million as an opening balance adjustment to retained earnings at January 1, 2023.

In March 2020, the FASB issued ASU 2020-04, "Reference Rate Reform (Topic 848)," which provides for applying U.S. GAAP to debt contracts, receivables, leases, derivatives, and other contracts impacted by reference rate reform and other transactions affected by the cessation of the LIBOR. The expiration date of ASU 2020-04 was December 31, 2022. In December 2022, the FASB issued ASU 2022-06, "Reference Rate Reform (Topic 848): Deferral of the Sunset Date of Topic 848, to extend the expiration date of Topic 848 through December 31, 2024. On October 3, 2023, the Company adopted the provisions of ASU 2022-06, "Reference Rate Reform Topic 848. The adoption of the standard did not have a material impact to the company.

Not Yet Adopted

In December 2023, FASB issued new guidance to improve Income Tax disclosures to provide information to assess how an entity's operations and related tax risks and tax planning and operational opportunities affect its tax rate and prospects for future cash flows. The rules become effective for annual periods beginning after December 15, 2024. The standard modifies required income tax disclosures. VAALCO is currently evaluating the impact of adopting this guidance on the consolidated financial statements.

In November 2023, FASB issued new guidance to improve reportable segment disclosure requirements, primarily through enhanced disclosures about significant segment expenses. The rules become effective for the fiscal years beginning after December 15, 2023. The standard requires additional disclosures about operating segments. VAALCO is currently evaluating the impact of adopting this guidance on the consolidated financial statements.

In August 2023, FASB issued new guidance to provide specific guidance on how a joint venture, upon formation, should recognize and initially measure assets contributed and liabilities assumed. The rules become effective prospectively for all joint venture formations occurring on or after January 1, 2025. VAALCO is currently assessing the impact of this guidance.

4. ACQUISITIONS AND DISPOSITIONS

Acquisition of TransGlobe Energy Corporation

On October 13, 2022, the Company and AcquireCo completed the previously announced business combination with TransGlobe whereby AcquireCo acquired all of the issued and outstanding common shares of TransGlobe and TransGlobe became a direct wholly owned subsidiary of AcquireCo and an indirect wholly owned subsidiary of the Company pursuant to an Arrangement agreement entered into by the Company, AcquireCo and TransGlobe on July 13, 2022.

At the effective time of the Arrangement and pursuant to the Arrangement Agreement, each common share of TransGlobe issued and outstanding immediately prior to the effective time of the Arrangement (the "TransGlobe common shares") was converted into the right to receive 0.6727 (the "exchange ratio") of a share of VAALCO common stock, par value $ 0.10 per share. The total number of VAALCO shares issued to TransGlobe's shareholders was approximately 49.3 million. The Arrangement resulted in VAALCO stockholders owning approximately 54.5 %, and TransGlobe shareholders owning approximately 45.5 % of the Combined Company, calculated based on vested outstanding shares of each company as of the date of the Arrangement Agreement. The Combined Company results of operations of VAALCO and TransGlobe for the period of October 14, 2022 to December 31, 2022 are included in the Company's consolidated results for the period ending December 31, 2022.

Prior to the Arrangement, TransGlobe was an oil and gas exploration and development company whose activities were concentrated in Egypt and Canada. The Combined Company is an African-focused operator with a portfolio of assets in Gabon, Egypt, Equatorial Guinea and Canada. The transaction qualified as a business combination under ASC 805, *Business Combinations* and the Company is the accounting acquiror.

During the first quarter of 2023, a measurement period adjustment was recorded impacting the deferred tax liability and bargain purchase gain. The purchase accounting for the business combination was completed by September 30, 2023. During the year ended December 31, 2023, the deferred tax liability in Egypt was increased by $ 1.4 million, respectively, as of the date of the acquisition. This resulted in a decrease to the bargain purchase gain of a corresponding $ 1.4 million for the year ended December 31, 2023, and is reflected in VAALCO's consolidated statements of operations in the line, “Other expense, net.”

The following table shows the 2023 adjustment as if the adjustment was made on the date of acquisition:.

	October 13, 2022	Measurement Period Adjustment *(in thousands)*	October 13, 2022 (As Adjusted)
Purchase Consideration			
Common stock issued to TransGlobe shareholders	$ 274,145	$ —	$ 274,145

	October 13, 2022	Measurement Period Adjustment *(in thousands)*	October 13, 2022
Assets acquired:			
Cash	$ 36,686	$ —	$ 36,686
Wells, platforms and other production facilities	243,669	—	243,669
Equipment and other	2,099	—	2,099
Undeveloped acreage	30,216	—	30,216
Accounts receivable - trade	48,068	—	48,068
Accounts receivable - other	50,275	—	50,275
Accounts with joint venture owners	68	—	68
Right of use operating leases	1,609	—	1,609
Right of use financing leases	204	—	204
Prepayment and other	7,627	—	7,627
Liabilities assumed:			-
Asset retirement obligations	(6,134)	—	(6,134)
Accounts payable	(10,223)	—	(10,223)
Accrued liabilities and other	(50,128)	—	(50,128)
Operating lease liabilities - current portion	(961)	—	(961)
Financing lease liabilities - current portion	(125)	—	(125)
Operating lease liabilities - net of current portion	(688)	—	(688)
Financing lease liabilities - net of current portion	(21)	—	(21)
Deferred tax liabilities	(40,964)	(1,412)	(42,376)
Other long-term liabilities	(26,313)	—	(26,313)
Bargain purchase gain	(10,819)	1,412	(9,407)
Total purchase price	$ 274,145	$ —	$ 274,145

All assets and liabilities associated with TransGlobe, including crude oil, natural gas and NGLs properties, asset retirement obligations and working capital items, were recorded at their fair value. The Company used estimated future crude oil prices as of the closing date, October 13, 2022, to apply to the estimated reserve quantities acquired and market participant assumptions to the estimated future operating and development costs to arrive at the estimates of future net revenues. The future net revenues were discounted using a weighted average cost of capital to determine the fair value at closing. The valuations to derive the purchase price included the use of both proved and unproved categories of reserves, expectation for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates, and specific risk adjustment factors based on reserve category discount rates. The purchase price allocation was finalized in the third quarter of 2023. A bargain purchase gain of $ 10.8 million was recognized based on the difference in the fair value of assets and liabilities assumed and the purchase price and is included in the “Other income (expense), net” in the consolidated statements of operations and comprehensive income.

For the twelve months ended December 31, 2022, included in the line item "Other income (expense), net" is $ 14.6 million of transactions costs associated with the Arrangement with TransGlobe.

The unaudited pro forma results presented below have been prepared to give the effect to the TransGlobe Acquisition discussed above on the Company's results of operations for the years ended December 31, 2022 and 2021, as if the Arrangement had been consummated on January 1, 2021. The unaudited pro forma results do not purport to represent what the Company's actual results of operations would have been if the TransGlobe arrangement had been completed on such date or to project the Company's results of operations for any future date or period.

	Year Ended December 31, 2022	Measurement Period Adjustment	Year Ended December 31, 2022 (As Adjusted)	Year Ended December 31, 2021	Measurement Period Adjustment	Year Ended December 31, 2021 (As Adjusted)
		(in thousands)			*(in thousands)*	
Pro forma (unaudited):						
Crude oil, natural gas and natural gas liquids sales	$ 547,670**(a)**	$ —	$ 547,670**(a)**	$ 367,210 **(a)**	$ —	$ 367,210 **(a)**
Operating income	$ 267,582**(b)**	$ —	$ 267,582**(c)**	$ 104,924 **(c)**	$ —	$ 104,924 **(c)**
Net income	$ 130,425**(d)**	$ 1,412**(g)**	$ 131,837**(d)**	$ 54,534**(e,f)**	$ (1,412) **(g)**	$ 53,122**(e,f)**
Basic net income per share:	$ 1.21	$ 0.01**(g)**	$ 1.22	$ 0.51	$ (0.02) **(g)**	$ 0.49
Basic weighted average shares outstanding	108,206	108,206	108,206	107,537	107,537	107,537
Diluted net income per share:	$ 1.20	$ 0.01**(g)**	$ 1.21	$ 0.50	$ (0.01) **(g)**	$ 0.49
Diluted weighted average shares outstanding	108,642	108,642	108,642	108,062	108,062	108,062

(a) The unaudited pro forma net revenues associated with Crude oil, natural gas and natural gas liquids sales have been adjusted for shipping and handling costs based on the Company's historical policy and revenue recognition is based on the Company's working interest, less royalties, the entitlement method.

(b) The unaudited pro forma operating income for the year ended December 31, 2022 removes the $ 23.7 million impairment reversal recorded by TransGlobe in 2022, excludes $ 10.2 million of severance costs associated with the Arrangement, excludes $ 6.5 million of TransGlobe transaction costs associated with the Arrangement, reclassifies depreciation expense, for certain leases identified as operating leases, to production expense and adjusts depreciation, depletion and amortization expense related to the depletable assets and asset retirement obligations acquired in the Arrangement based on the purchase price allocation.

(c) The unaudited pro forma operating income for the year ended December 31, 2021 removes the $ 31.5 million impairment reversal recorded by TransGlobe in 2021, adjusts costs associated with overlifts to reduce revenue, includes $ 10.2 million of severance costs associated with the Arrangement, reclassifies depreciation expense, for certain leases identified as operating leases, to production expense and adjusts depreciation, depletion and amortization expense related to the depletable assets and asset retirement obligations acquired in the Arrangement based on the purchase price allocation (the impairment reversal was allowable under IFRS by TransGlobe in 2021).

(d) The unaudited pro forma net income for the year ended December 31, 2022 excludes $ 14.6 million of transaction costs incurred by VAALCO associated with the Arrangement, excludes the bargain purchase gain of $ 10.8 million and reclassifies interest expense, for certain leases identified as operating leases, as production expense.

(e) The unaudited pro forma net income for the year ended December 31, 2021 includes $ 21.1 million of transaction costs incurred by VAALCO and TransGlobe associated with the Arrangement, includes the bargain purchase gain of $ 10.8 million and reclassifies interest expense, for certain leases identified as operating leases, as production expense.

(f) The unaudited pro forma net income for the year ended December 31, 2021 excludes nonrecurring pro forma adjustments directly attributable to the Sasol Acquisition, consisting of a bargain purchase gain of $ 7.7 million and transaction costs of $ 1.0 million.

(g) The Measurement Period Adjustment is due to an original deferred tax liability being estimated at closing. Additional information about the deferred tax liability was identified in the first part of 2023 creating the need for the $ 1.4 million adjustment.

5. SEGMENT INFORMATION

The Company's operations are based in Gabon, Egypt, Canada and Equatorial Guinea. Each of the reportable operating segments are organized and managed based upon geographic location. The Company's Chief Executive Officer, who is the chief operating decision maker evaluates the operation of each geographic segment separately primarily based on Operating income (loss). The operations of all segments include exploration for and production of hydrocarbons where commercial reserves have been found and developed. Revenues are based on the location of hydrocarbon production. Corporate and other is primarily corporate and operations support costs that are not allocated to the reportable operating segments. No transactions occurred between segments.

Segment activity of continuing operations for the years ended December 31, 2023, 2022 and 2021 and long-lived assets and segment assets at December 31, 2023 and 2022 are as follows:

	Year ended December 31, 2023					
(in thousands)	Gabon	Egypt	Canada	Equatorial Guinea	Corporate and Other	Total
Revenues:						
Crude oil, natural gas and natural gas liquids sales	$ 260,346	$ 161,049	$ 33,671	$ —	$ —	$ 455,066
Operating costs and expenses:						
Production expense	87,131	54,779	9,463	1,481	303	153,157
FPSO demobilization and other costs	7,484	—	—	—	—	7,484
Exploration expense	51	1,914	—	—	—	1,965
Depreciation, depletion and amortization	62,622	35,095	17,398	—	187	115,302
General and administrative expense	1,769	974	—	416	20,681	23,840
Credit (recovery) losses and other	(10,596)	5,182	—	508	—	(4,906)
Total operating costs and expenses	148,461	97,944	26,861	2,405	21,171	296,842
Other operating income (expense), net	(55)	(241)	729	—	—	433
Operating income (loss)	111,830	62,864	7,539	(2,405)	(21,171)	158,657
Other income (expense):						
Derivative instruments gain (loss), net	—	—	—	—	232	232
Interest (expense) income, net	(5,563)	(2,110)	(4)	—	1,225	(6,452)
Other income (expense), net	(820)	—	2	(6)	(1,467)	(2,291)
Total other income (expense), net	(6,383)	(2,110)	(2)	(6)	(10)	(8,511)
Income (loss) from continuing operations before income taxes	105,447	60,754	7,537	(2,411)	(21,181)	150,146
Income tax expense	50,692	32,859	—	—	6,226	89,777
Income (loss) from continuing operations	54,755	27,895	7,537	(2,411)	(27,407)	60,369
Loss from discontinued operations, net of tax	—	—	—	—	(15)	(15)
Net income (loss)	$ 54,755	$ 27,895	$ 7,537	$ (2,411)	$ (27,422)	$ 60,354
Consolidated capital expenditures	$ 17,011	$ 37,866	$ 16,809	$ —	$ 950	$ 72,636

(in thousands)	Gabon	Egypt	Canada	Equatorial Guinea	Corporate and Other	Total
	Year Ended December 31, 2022					
Revenues:						
Crude oil, natural gas and natural gas liquids sales	$ 306,775	$ 37,710	$ 9,841	$ —	$ —	$ 354,326
Operating costs and expenses:						
Production expense	96,854	11,936	1,972	1,899	—	112,661
FPSO demobilization and other costs	8,867	—	—	—	—	8,867
Exploration expense	258	—	—	—	—	258
Depreciation, depletion and amortization	34,651	10,444	2,921	—	127	48,143
General and administrative expense	3,101	—	—	538	6,438	10,077
Credit (recovery) losses and other	2,743	—	—	339	—	3,082
Total operating costs and expenses	146,474	22,380	4,893	2,776	6,565	183,088
Other operating income (expense), net	38	—	—	—	—	38
Operating income (loss)	160,339	15,330	4,948	(2,776)	(6,565)	171,276
Other income (expense):						
Derivative instruments gain (loss), net	—	—	13	—	(37,825)	(37,812)
Interest (expense) income, net	(1,446)	(596)	—	—	8	(2,034)
Other expense, net	(1,484)	—	—	—	(6,564)	(8,048)
Total other income (expense), net	(2,930)	(596)	13	—	(44,381)	(47,894)
Income (loss) from continuing operations before income taxes	157,409	14,734	4,961	(2,776)	(50,946)	123,382
Income tax (benefit) expense	68,509	6,254	-	1	(3,344)	71,420
Income (loss) from continuing operations	88,900	8,480	4,961	(2,777)	(47,602)	51,962
Loss from discontinued operations, net of tax	—	—	—	—	(72)	(72)
Net income (loss)	$ 88,900	$ 8,480	4,961	(2,777)	$ (47,674)	$ 51,890
Consolidated capital expenditures (1)	$ 162,375	$ 168,012	103,263	—	$ 710	$ 434,360

(1) Includes assets acquired in the TransGlobe acquisition.

(in thousands)	Gabon	Equatorial Guinea	Corporate and Other	Total
	Year Ended December 31, 2021			
Revenues:				
Crude oil and natural gas sales	$ 199,075	$ —	$ —	$ 199,075
Operating costs and expenses:				
Production expense	80,717	532	6	81,255
Exploration expense	1,579	—	—	1,579
Depreciation, depletion and amortization	20,972	—	88	21,060
General and administrative expense	1,301	321	13,144	14,766
Credit (recovery) losses and other	875	—	—	875
Total operating costs and expenses	105,444	853	13,238	119,535
Other operating income (expense), net	(440)	—	—	(440)
Operating income (loss)	93,191	(853)	(13,238)	79,100
Other income (expense):				
Derivative instruments loss, net	—	—	(22,826)	(22,826)
Interest income, net	—	—	10	10
Other income (expense), net	6,925	(3)	(3,428)	3,494
Total other income (expense), net	6,925	(3)	(26,244)	(19,322)
Income (loss) from continuing operations before income taxes	100,116	(856)	(39,482)	59,778
Income tax (benefit) expense	12,392	1	(34,549)	(22,156)
Income (loss) from continuing operations	87,724	(857)	(4,933)	81,934
Loss from discontinued operations, net of tax	—	—	(98)	(98)
Net income (loss)	$ 87,724	$ (857)	$ (5,031)	$ 81,836
Consolidated capital expenditures	$ 79,169	$ —	$ 52	$ 79,221

(in thousands)	Gabon	Egypt	Canada	Equatorial Guinea	Corporate and Other	Total
Long-lived assets from continuing operations:						
As of December 31, 2023	**$ 171,787**	**$ 171,224**	**$ 105,189**	**$ 10,000**	**$ 1,586**	**$ 459,786**
As of December 31, 2022	$ 213,204	$ 168,012	$ 103,263	$ 10,000	$ 793	$ 495,272

(in thousands)	Gabon	Egypt	Canada	Equatorial Guinea	Corporate and Other	Total
Total assets from continuing operations:						
As of December 31, 2023	**$ 309,394**	**$ 263,015**	**$ 114,215**	**$ 11,327**	**$ 125,265**	**$ 823,216**
As of December 31, 2022	$ 395,393	$ 293,640	$ 110,071	$ 10,861	$ 45,676	$ 855,641

6. EARNINGS PER SHARE

Basic earnings per share (“EPS”) is calculated using the average number of shares of common stock outstanding during each period. For the calculation of diluted shares, the Company assumes that restricted stock is outstanding on the date of vesting, and the Company assumes the issuance of shares from the exercise of stock options using the treasury stock method.

A reconciliation of reported net income (loss) to net income (loss) used in calculating EPS as well as a reconciliation from basic to diluted shares follows:

	Twelve Months Ended December 31, 2023	2022	2021
		(in thousands)	
Net income (numerator):			
Income from continuing operations	**$ 60,369**	$ 51,962	$ 81,934
Income from continuing operations attributable to unvested shares	**(632)**	(594)	(1,336)
Numerator for basic	**59,737**	51,368	80,598
Loss from continuing operations attributable to unvested shares	**1**	3	—
Numerator for dilutive	**$ 59,737**	$ 51,371	$ 80,598
Loss from discontinued operations, net of tax	**$ (15)**	$ (72)	$ (98)
Loss from discontinued operations attributable to unvested shares	**0**	1	2
Numerator for basic	**(15)**	(71)	(96)
(Income) loss from discontinued operations attributable to unvested shares	**(0)**	—	—
Numerator for dilutive	**$ (15)**	$ (71)	$ (96)
Net income	**$ 60,354**	$ 51,890	$ 81,836
Net income attributable to unvested shares	**(632)**	(593)	(1,334)
Numerator for basic	**59,722**	51,297	80,502
Net (income) loss attributable to unvested shares	**1**	3	—
Numerator for dilutive	**$ 59,723**	$ 51,300	$ 80,502
Weighted average shares (denominator):			
Basic weighted average shares outstanding	**106,376**	69,568	58,230
Effect of dilutive securities	**178**	414	525
Diluted weighted average shares outstanding	**106,555**	69,982	58,755
Stock options and unvested restricted stock grants excluded from dilutive calculation because they would be anti-dilutive	**385**	189	169

7. REVENUE

Gabon

Revenues from contracts with customers are generated from sales in Gabon pursuant to crude oil sales and purchase agreements (“COSPAs”) or crude oil sales and marketing agreements ("COSMA or COSMAs"). Except for internal costs, which are expensed as incurred, there are no upfront costs associated with obtaining a new COSPA or COSMA.

Customer sales generally occur on a monthly basis when the customer’s tanker arrives at the FPSO or FSO and the crude oil is delivered to the tanker through a connection. There is a single performance obligation (delivering crude oil to the delivery point, i.e. the connection to the customer’s crude oil tanker) that gives rise to revenue recognition at the point in time when the performance obligation event takes place. This is referred to as a “lifting”. Liftings can take one to two days to complete.

The Company accounts for sales based on the Company’s working interest, less royalties. Imbalances are valued based on the actual sales proceeds. Historically as operator, the volumes sold may be more or less than the volumes that the Company is entitled based on the ownership interest in the property, and the Company would recognize a liability if the volumes sold exceeded the Company’s ownership interest.

For each lifting completed under a COSPA or COSMA, payment is made by the customer in U.S. dollars by electronic transfer 30 days after the date of the bill of lading. For each lifting of crude oil, pricing is based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors.

In addition to revenues from customer contracts, the Company has other revenues related to contractual provisions under the Etame Marin block PSC. The Etame PSC is not a customer contract, and therefore the associated revenues are not within the scope of ASC 606. The terms of the Etame PSC includes provisions for payments to the government of Gabon for: royalties based on 13 % of production at the published price and a shared portion of “Profit Oil” determined based on daily production rates, as well as a gross carried working interest of 7.5 % (increasing to 10 % beginning June 20, 2026) for all costs. For both royalties and Profit Oil, the Etame PSC provides that the government of Gabon may settle these obligations in-kind, i.e. taking crude oil barrels, rather than with cash payments.

To date, the government of Gabon has not elected to take its royalties in-kind, and this obligation is settled through a monthly cash payment. Payments for royalties are reflected as a reduction in revenues from customers.

With respect to the government's share of Profit Oil, the Etame PSC provides that corporate income tax is satisfied through the payment of Profit Oil. In the consolidated statements of operations and comprehensive income (loss), the government's share of revenues from Profit Oil is reported in revenues with a corresponding amount reflected in the current provision for income tax expense. The amount associated with the Profit Oil under the terms of the Etame PSC is reflected as revenue with an offsetting amount reported in current income tax expense. Payments of the income tax expense are reported in the period that the government takes its Profit Oil in-kind, *i.e.* the period in which it lifts the crude oil. In 2023, an in-kind payment of $ 32.8 million was made with the November 2023 lifting. The Company has a $ 18.9 million foreign income tax payable as of December 31, 2023. In the prior year, an in-kind payment of $ 26.3 million was made with the December 2022 lifting. With this lifting, the government lifted more oil in-kind than what was owed to it in foreign taxes. Therefore, as of December 31, 2022, the foreign income taxes receivable attributable to this obligation was $ 2.8 million.

Certain amounts associated with the carried interest in the Etame Marin block are reported as revenues. In this carried interest arrangement, the carrying parties, which include the Company and other working interest owners, are obligated to fund all of the working interest costs that would otherwise be the obligation of the carried party. The carrying parties recoup these funds from the carried interest party's revenues.

The following table presents revenues in Gabon from contracts with customers as well as revenues associated with the obligations under the Etame PSC:

	Twelve Months Ended December 31,		
	2023	**2022**	**2021**
Revenues from customer contracts:		***(in thousands)***	
Sales under the COSPA or COSMA	**$ 261,801**	$ 320,522	$ 200,321
Other items reported in revenue not associated with customer contracts:			
Gabonese government share of Profit Oil taken in-kind	**32,776**	26,257	20,103
Carried interest recoupment	**5,301**	5,843	7,517
Royalties	**(39,532)**	(45,847)	(28,866)
Net revenues	**$ 260,346**	$ 306,775	$ 199,075

Egypt

Revenues from sales in Egypt are generally made through direct sales to EGPC or through contracts with customers pursuant to crude oil sales and purchase agreements ("COSPAs") or crude oil sales and marketing agreements ("COSMA or COSMAs"). EGPC and the Company each own a 50 % interest, respectively, in the operating company which is a party to the Merged Concession Agreement. EGPC and the Company each also own a 50 % interest, respectively, in the operating company that is a party to the South Ghazalat concession agreement.

Customer sales generally occur on daily when sales are directly to EGPC or haphazardly production is sold through a cargo lifting. Regardless of the type of sales, there is a single performance obligation (delivering crude oil to the delivery point) that gives rise to revenue recognition at the point in time when the performance obligation event takes place.

For reporting purposes, the Company records EGPC's share of production as royalties which are netted against revenue, whether EGPC's share of production arises from EGPC's share of profit oil or excess cost oil which is discussed below.

With respect to Egyptian income taxes, which are the Company's liability under the terms of the Merged Concession Agreement, these taxes are paid by EGPC on behalf of the Company out of EGPC's share of production entitlement. The income taxes paid to the Arab Republic of Egypt on behalf of the Company are recognized as crude oil revenue and income tax expense for reporting purposes.

EGPC owns the storage and export facilities where the Company's production is delivered and the Company requires EGPC cooperation and approval to schedule liftings. Once liftings occur, the Company has a 30-day collection cycle on liftings as a result of direct marketing to international purchasers. Depending on the Company's assessment of the credit of crude oil cargo buyers, they may be required to post irrevocable letters of credit to support the sales prior to the cargo liftings. Direct sales to EGPC are normally settled two to four weeks from delivery.

In some instances, the Company will borrow or loan production volumes in order to achieve a required amount of crude oil for cargo sales. In these instances, the Company can be in an overlift or underlift position. Regardless of being in an over lift or underlift position, sales are based on the Company's working interest, less royalties. Imbalances are valued based on the actual sales proceeds and the Company will record a payable, if in an overlift position, or a receivable, if in an underlift position, based on the fair value of the consideration received or receivable.

The following table presents revenues in Egypt from contracts with customers:

	Period Ended December 31,	
	2023	**2022**
Revenues from customer contracts:	*(in thousands)*	
Gross sales	**$ 272,613**	$ 56,452
Royalties	**(110,569)**	(18,742)
Selling costs	**(995)**	—
Net revenues	**$ 161,049**	$ 37,710

Canada

Customer sales generally occur on a daily basis when crude oil, natural gas, condensate or NGL's are sold, normally via pipeline, to a delivery point. Regardless of the type of sales, there is a single performance obligation (delivering crude oil, natural gas, condensate or NGL's to the delivery point) that gives rise to revenue recognition at the point in time when the performance obligation event takes place. VAALCO pays royalties to the Alberta provincial government and other mineral rights owners in accordance with the established royalty regime. For reporting purposes, the Company records revenues net of royalties.

Settlement of accounts receivable in Canada occur on the 25th of the following month following production.

The following table presents revenues in Canada from contracts with customers:

	Period Ended December 31,	
	2023	**2022**
Revenues from customer contracts:	*(in thousands)*	
Oil revenue	**$ 28,287**	$ 7,362
Gas revenue	**3,467**	1,340
NGL revenue	**8,440**	2,235
Other revenue	—	41
Royalties	**(5,821)**	(1,137)
Selling costs	**(702)**	—
Net revenues	**$ 33,671**	$ 9,841

Information about the Company' s most significant customers -

The Company currently sells crude oil production from Gabon under a COSPA or COSMA with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors.

On May 16, 2022, the Company entered into a COSMA with Glencore pursuant to which the Company agreed to make Glencore the exclusive offtaker and marketer of all of the crude oil produced from the Etame G4- 160 Block, offshore Gabon during the period from August 1, 2022 until the final maturity date of the Facility (as defined in the Facility Agreement) which is May 15, 2027 unless early terminated. Pursuant to the COSMA, Glencore agreed to buy and market the Company's crude oil with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors.

The Company entered an COSPA and amendments with ExxonMobil that covered sales from February 2020 through July 2022 with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors.

For the year ended December 31, 2023, the Company had one customer that comprised 100 % of its sales for Gabon. In Egypt, two customers made up 62 % and 38 %, respectively. In Canada, three customers made up approximately 52 %, 37 % and 7 % of revenue.

8. INCOME TAXES

VAALCO and its domestic subsidiaries file a consolidated U.S. income tax return. Certain foreign subsidiaries also file tax returns in their respective local jurisdictions that include Canada, Egypt, Equatorial Guinea and Gabon.

Income taxes attributable to continuing operations for the years ended December 31, 2023 and December 31, 2022 are attributable to foreign taxes payable in Gabon and Egypt, whereas for the year ended December 31, 2021 the income taxes are attributable to foreign taxes payable in Gabon as well as income taxes in the U.S.

Provision for income taxes related to income (loss) from continuing operations consists of the following:

	Twelve Months Ended December 31,		
	2023	2022	2021
U.S. Federal:		*(in thousands)*	
Current	$ —	$ —	$ —
Deferred	**6,214**	(3,344)	(34,548)
Foreign:			
Current	**92,642**	26,615	20,282
Deferred	**(9,079)**	48,149	(7,890)
Total	**$ 89,777**	$ 71,420	$ (22,156)

As of December 31, 2023, the Company had total deferred tax assets of $ 120.9 million primarily attributable to Canada, Gabon and the U.S. whereas for December 31, 2022 deferred tax assets were $ 99.6 million primarily attributable to Canada, Gabon and the U.S. In both years, the income taxes related to basis differences in fixed assets, foreign tax credit carryforwards, as well as foreign net operating loss carryforwards and in the December 31,2022, period U.S. net operating loss carryforward as well. In assessing the realizability of the deferred tax assets, the Company considers all available positive and negative evidence by jurisdiction and makes a determination whether it is more likely than not that some or all of the deferred tax assets will be realized. The ultimate realization of the deferred tax assets is dependent upon the generation of future income in periods in which the deferred tax assets can be utilized. Numerous judgments and assumptions are inherent in this assessment, including the determination of future taxable income, future operating conditions, particularly as related to prevailing crude oil prices.

As of December 31, 2023, the Company determined that it is more likely than not that it would not be able to utilize its deferred tax assets in Canada and in Egypt for its South Ghazalat concession, nor its Foreign Tax Credit carryforwards in the U.S. As of December 31, 2022, the Company determined that it is more likely than not that it would not be able to utilize its deferred tax assets in Canada and in Egypt for its South Ghazalat concession, and that it is more likely than not that it would not be able to utilize a portion of its deferred tax assets in the U.S. On the basis of these evaluations, a valuation allowance of $ 83.9 million and $ 47.6 million were recorded as of December 31, 2023 and 2022, respectively. Valuation allowances reduce the deferred tax assets to the amount that is more likely than not to be realized.

The primary differences between the financial statement and tax bases of assets and liabilities resulted in deferred tax assets associated with continuing operations at December 31, 2023 and 2022 are as follows:

	As of December 31,	
(in thousands)	**2023**	2022
Deferred tax assets:		
Basis difference in fixed assets (1)	$ **9,132**	$ 9,299
Foreign tax credit carryforward	**55,069**	14,848
Net operating losses	**32,306**	48,981
Asset retirement obligations	**9,631**	8,531
ROU lease liabilities	**10,345**	10,753
Basis difference in accrued liabilities	**3,808**	3,800
Basis difference in receivables	**(146)**	2,783
Other	**719**	622
Total deferred tax assets	**120,864**	99,617
Valuation allowance	**(83,893)**	(47,583)
Net deferred tax assets	**$ 36,971**	$ 52,034
Deferred tax liabilities:		
Basis difference in fixed assets	**(81,310)**	(97,825)
Net deferred tax liabilities	**$ (81,310)**	$ (97,825)

(1) This line includes ROU lease asset.

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Foreign net operating losses ("NOLs") are subject to varying expiration periods depending on the jurisdiction. The NOLs for the Gabon subsidiaries are included in the respective subsidiaries' cost oil accounts, which will be offset against future taxable revenues and do not expire. U.S. federal NOLs incurred after 2017 do not expire. The ability to utilize NOLs and other tax attributes could be subject to a limitation if the Company were to undergo an ownership change as defined in Section 382 of the Tax Code. Foreign tax credits will expire between the years 2024 and 2032. The Company does not anticipate utilization of the foreign tax credits prior to expiration and has recorded a full valuation allowance on these deferred tax assets.

The Company has NOL's, *(in '000s)* in the following jurisdictions as of December 31, 2023:

Jurisdiction		**Amount**	**Expiration Period**
U.S.	$	-	No expiration
Gabon	$	-	No expiration
Egypt	$	16,000	2024-2028
Canada	$	85,407	2031-2040
Equatorial Guinea	$	12,313	No expiration
UK	$	7,222	No expiration

The Company recognizes the financial statement benefit of a tax position only after determining that they are more likely than not to sustain the position following an audit. The Company believes that its income tax positions and deductions will be sustained on audit, and therefore no reserves for uncertain tax positions have been established. Accordingly, no interest or penalties have been accrued as of December 31, 2023 and 2022. The Company's policy is to include interest and penalties related to unrecognized tax benefits as a component of income tax expense.

Income (loss) from continuing operations before income taxes is attributable as follows:

	Year Ended December 31,					
(in thousands)		**2023**		**2022**		**2021**
U.S.	**$**	**(15,781)**	$	(56,750)	$	(38,867)
Foreign		**165,927**		180,132		98,645
	$	**150,146**	$	123,382	$	59,778

The reconciliation of income tax expense (benefit) attributable to income (loss) from continuing operations to income tax on income (loss) from continuing operations at the U.S. statutory rate is as follows:

	Year Ended December 31,					
(in thousands)		**2023**		**2022**		**2021**
Tax provision computed at U.S. statutory rate	**$**	**31,530**	$	25,910	$	12,553
Foreign taxes not offset in U.S. by foreign tax credits		**25,719**		53,851		35,306
Permanent differences		**3,455**		778		(703)
Foreign tax credit expirations		—		17,247		14,060
Increase/(decrease) in valuation allowance		**27,656**		(25,623)		(83,372)
Other		**1,417**		(743)		—
Total income tax expense (benefit)	**$**	**89,777**	$	71,420	$	(22,156)

For the years ended December 31, 2023, 2022 and 2021, the Company is subject to foreign and U.S. federal taxes only, with no allocations made to state and local taxes. The following table summarizes the tax years that remain subject to examination by major tax jurisdictions.

Jurisdiction	**Years**
U.S.	2014 - 2023
Gabon	2019 - 2023
Egypt	2017 - 2023
Canada	2018 - 2023

With respect to the earnings of VAALCO's Canadian foreign subsidiary, the Company does not intend to repatriate funds and will indefinitely reinvest these foreign earnings. Determining the amount of the unrecorded deferred tax liability related to temporary differences at this time is not practicable. If circumstances change and it becomes apparent that some or all the undistributed earnings of our Canadian subsidiary will be remitted in the foreseeable future, the Company shall accrue as an expense of the current period income taxes attributable to that remittance.

With respect to the earnings of VAALCO's Egyptian foreign subsidiaries, the earnings are available for repatriation, but the corresponding incremental tax expense on any remittances is not expected to be material.

On August 16, 2022, legislation commonly known as the Inflation Reduction Act was signed into law. Among other things, the Inflation Reduction Act includes a 1% excise tax on corporate stock repurchases (applicable to repurchases after December 31, 2022) as well as a new minimum tax based on book income. The Company has determined that the Inflation Reduction Act did not have a material impact on its effective tax rate in December 31, 2023 and 2022.

9. CRUDE OIL, NATURAL GAS AND NGLs PROBERTIES AND EQUIPMENT, NET

The Company's crude oil, natural gas and NGLs properties and equipment, net is comprised of the following:

Crude oil, natural gas and NGLs properties and equipment, net	As of December 31, 2023	As of December 31, 2022
	(in thousands)	
Wells, platforms and other production facilities	**$ 1,468,542**	$ 1,406,888
Work-in-progress	**4,183**	—
Undeveloped acreage	**52,109**	56,251
Capitalized equipment spare parts and other	**47,794**	38,796
	1,572,628	1,501,935
Accumulated depreciation, depletion, amortization and impairment	**(1,112,842)**	(1,006,663)
Crude oil, natural gas and NGLs properties and equipment, net	**$ 459,786**	$ 495,272

There were no triggering events in the years ended December 31, 2023 and 2022 that would cause the Company to believe the value of crude oil, natural gas and NGLs properties and equipment, net should be impaired. Factors considered included higher forward price curves for the fourth quarter of 2023 and capital expenditures in the period related to its future reserves in Gabon, Egypt and Canada.

Unproved property costs

See the table below for the list of unproved property costs at December 31, 2023 and December 31, 2022, respectively:

	As of December 31, 2023	As of December 31, 2022
Unproved Property Costs	(in thousands)	
Etame Marin Block	**$ 13,735**	$ 13,735
Equatorial Guinea	**10,000**	10,000
Egypt	**11,444**	15,850
Canada	**16,930**	16,666
Unproved Property Costs	**$ 52,109**	$ 56,251

Capitalized equipment spare parts

Capitalized equipment is reviewed regularly for obsolescence. During the years ended December 31, 2023, 2022 and 2021, adjustments for inventory obsolescence were not material.

Exploration expense

During 2023, two appraisal wells, both in Egypt, were abandoned and also expensed to Exploration Expense. The impact resulted in $ 2.0 million of expense during the year ended December 31, 2023.

10. DERIVATIVES AND FAIR VALUE

Commodity swaps

Outstanding derivative contracts at December 31, 2023 are as follows:

Settlement Period	Type of Contract	Index	Average Monthly Volumes	Weighted Average Put Price	Weighted Average Call Price
			(Bbls)	(per Bbl)	(per Bbl)
January 2024 - March 2024	Collars	Dated Brent	85,000	$ 65.00	$ 97.00
April 2024 - June 2024	Collars	Dated Brent	65,000	$ 65.00	$ 100.00

The following table sets forth the gain (loss) on derivative instruments on the Company's consolidated statements of operations and comprehensive income (loss):

Derivative Item	Statements of Operations Line	Twelve Months Ended December 31, 2023	2022	2021
			(in thousands)	
Commodity derivatives	Cash settlements paid on matured derivative contracts, net	$ **(127)**	$ (42,935)	$ (18,020)
	Unrealized gain (loss)	**359**	5,123	(4,806)
	Derivative instruments gain (loss), net	$ **232**	$ (37,812)	$ (22,826)

11. ASSET RETIREMENT OBLIGATIONS

The following table summarizes the changes in the Company's asset retirement obligations ("ARO's"):

(in thousands)	As of December 31, 2023	As of December 31, 2022
Beginning balance	**$ 42,001**	$ 40,694
Accretion	**2,352**	1,958
Additions	**2,487**	6,134
Revisions	**6,889**	(43)
Settlements	**(6,747)**	(6,577)
Foreign currency gain (loss)	**361**	(165)
Ending balance	**$ 47,343**	$ 42,001

Accretion is recorded in the line item "Depreciation, depletion and amortization" on the consolidated statements of operations and comprehensive income (loss).

In connection with the TransGlobe Arrangement in October 2022, the Company added $6.1 million of ARO for the future abandonment and reclamation costs of the Canadian assets. The Egypt concessions have no ARO.

12. COMMITMENTS AND CONTINGENCIES

Abandonment funding

Gabon

Under the terms of the Etame PSC, the Company has a cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin block. As a result of the PSC Extension, annual funding payments are spread over the life of the Etame Marin Block, under the applicable abandonment study. The amounts paid will be reimbursed through the Cost Account and are non-refundable. In August 2023, a new abandonment study was completed and which estimated abandonment costs of approximately $ 77.9 million ($ 45.9 million, net to VAALCO) on an undiscounted basis. The new abandonment estimate has been presented to the Gabonese Directorate of Hydrocarbons as required by the PSC. At December 31, 2023, $ 10.7 million ($ 6.3 million, net to VAALCO) on an undiscounted basis has been funded. The annual payments will be adjusted based on revisions in the abandonment estimate. This cash funding is reflected under "Other noncurrent assets" in the "Abandonment funding" line item of the consolidated balance sheets. Future changes to the anticipated abandonment cost estimate could change the asset retirement obligation and the amount of future abandonment funding payments.

In the first quarter of 2023, the Directorate of Hydrocarbons in Gabon approved a $ 26.6 million ($ 15.6 million, net to VAALCO) abandonment funding payment associated with the FPSO retirement. The Company received payment of $ 15.6 million in March 2023. No activity occurred in the abandonment funding account during the remainder of 2023. The Company is working with the Directorate of Hydrocarbons in Gabon to establish a payment schedule to resume funding of the abandonment fund in compliance with the Etame PSC.

FPSO charter

As operator of the Etame Marin block, the Company chartered a floating production storage and offtake vessel ("FPSO"), from Tinworth for use in its operations. In the fourth quarter of 2023, the Company reached a settlement agreement with Tinworth to release the Company from any further obligation relating to the FPSO. The signed settlement agreement required the Company and other non-operators to pay an additional $ 8.0 million gross ($ 4.7 million net to VAALCO) to Tinworth in exchange for the release. The Company had previously accrued $ 4.9 million of the $ 8.0 million in 2022. The Company recorded an additional $ 3.2 million ($ 1.8 million net to VAALCO) in the income statement under the line item FPSO demobilization and other costs. The $ 8.0 million payment was made on December 22, 2023.

In connection with the above settlement, on January 22, 2024, certain funds held in escrow as part of the FPSO agreements were released to the Company and its non-operating partners. As of December 31, 2023, VAALCO's share of this restricted cash amount was $ 1.8 million.

Regulatory and Joint Interest Audits and Related Matters

The Company is subject to periodic audits by various government agencies in Gabon, including audits by the government of Gabon and other members of the Company's joint operating agreements.

Merged Concession Agreement

The Company is a party to the Merged Concession Agreement with the Egyptian General Petroleum Corporation (“EGPC”). In accordance with the Merged Concession Agreement, we are required to make $ 10.0 million annual modernization payments through February 1, 2026. The $10.0 million modernization payment due February 1, 2024, was offset against receivables owed to the Company from EGPC. On the consolidated balance sheet, $ 9.9 million of the modernization payment liability was recorded in the line item "Accrued liabilities and other" and $ 17.7 million was recorded in "Other long-term liabilities".

The Company also has minimum financial work commitments of $ 50.0 million per each five-year period of the primary development term, commencing on February 1, 2020 for a total of $ 150 million over the 15 year license contract term. Through December 31, 2023, the Company's financial work commitments have exceeded the five-year minimum $50 million threshold and any excess carries forward to offset against subsequent five-year commitments.

The amounts that will be paid for such outstanding off-balance sheet financial work commitments as of December 31, 2023 are $ 10.0 million in 2024, $ 10.0 million in 2025, $ 10.0 million 2026, $ 10.0 million in 2027, $ 10.0 million in 2028 and $ 70.0 million in 2029 and thereafter.

Domestic Market Needs Obligation

Under Article *35* of the Etame PSC, the Company can be required to contribute to meeting the domestic market needs of Gabon by delivering to the Government, or another entity designated by the Government, an amount of its crude oil proportional to the Company's share of production to the total production in Gabon over the year.

Potential Business Combination

On February 29, 2024, the Company entered into a Share Purchase Agreement (the "Share Purchase Agreement") to purchase all of the issued shares in the capital of Svenska Petroleum Exploration Aktiebolag, a company incorporated in Sweden ("Svenska") for $ 66.5 million in cash (the "Purchase Price"), subject to adjustment as described in the Share Purchase Agreement. There can be no assurance that the proposed arrangement will be completed.

13. DEBT

As of December 31, 2023 and 2022, the Company had no outstanding debt.

RBL Facility

On May 16, 2022, the Company entered into an agreement with Glencore, and other lenders, to provide a senior secured reserve-based revolving credit facility for a maximum principal amount of up to $ 50.0 million. Beginning October 1, 2023 and thereafter on April 1 and October 1 of each year during the term of the RBL Facility, the $ 50 million initial commitment, will be reduced by $ 6.3 million. At December 31, 2023, the amount available to be drawn under the facility was $ 43.8 million.

The Facility provides for determination of the borrowing base asset based on the Company's proved producing reserves in Gabon and a portion of the Company's proved undeveloped reserves in Gabon. The borrowing base is re-determined by the Glencore and other lenders on March 31 and September 30 of each year.

The RBL Facility originally bore an interest at a rate equal to LIBOR plus a margin (the "Applicable Margin") of (i) 6.00 % until the third anniversary of the Facility Agreement or (ii) 6.25 % from the third anniversary of the Facility Agreement until the Final Maturity Date (defined below). On October 3, 2023 the Company signed an Amended and Restated Facility Agreement to replace the LIBOR component, in the original Facility Agreement, with a SOFR plus credit adjustment spread rate. The SOFR plus credit adjustment spread rate is intended to approximate the LIBOR component in the original Facility Agreement and the LIBOR component was replaced due to LIBOR being discontinued as a global reference rate.

Pursuant to the RBL Facility agreement, the Company shall pay to Glencore for the account of each Lender a quarterly commitment fee equal to (i) 35 % per annum of the Applicable Margin on the daily amount by which the lower of the total commitments and the borrowing base amount exceeds the amount of all outstanding utilizations under the Facility, plus (ii) 20 % per annum of the Applicable Margin on the daily amount by which the total commitments exceed the borrowing base amount. The Company is also required to pay customary arrangement and security agent fees.

The RBL Facility agreement contains certain debt covenants, including that, as of the last day of each calendar quarter, (i) the ratio of Consolidated Total Net Debt to EBITDAX (as each term is defined in the RBL Facility agreement) for the trailing 12 months shall not exceed 3.0x and (ii) consolidated cash and cash equivalents shall not be lower than $ 10.0 million at any time. The amount the Company can borrow with respect to the borrowing base is subject to compliance with the financial covenants and other provisions of the RBL Facility agreement. Regarding the requirement, the Company must deliver its annual financial statements to Glencore within 90 days of the end of each fiscal year. At December 31, 2023, the Company was in compliance with all other debt covenants and had no outstanding borrowings under the facility.

The RBL Facility will mature on the earlier of (i) the fifth anniversary of the date on which all conditions precedent to the first utilization of the RBL Facility have been satisfied and (ii) the Reserve Tail Date (as defined in the RBL Facility agreement).

14. LEASES

Under the leasing standard that became effective January 1, 2019, there are two types of leases: finance and operating. Regardless of the type of lease, the initial measurement of the lease results in recording a ROU asset and a lease liability at the present value of the future lease payments.

Practical Expedients

The Company elected to use all the practical expedients, effectively carrying over its previous identification and classification of leases that existed as of January 1, 2019. Additionally, a lessee may elect not to recognize ROU assets and liabilities arising from short-term leases provided there is no purchase option the entity is likely to exercise. The Company has elected this short-term lease exemption.

Operating leases

The Company is currently a party to several operating lease agreements for the corporate office, rental of marine vessels and transportation equipment and a drilling rig used in the Company's Egyptian operations. The duration for these agreements ranges from 5 to 15 months. In some cases, the lease contracts require the Company to make payments both for the use of the asset itself and for operations and maintenance services. Only the payments for the use of the asset related to the lease component are included in the calculation of ROU assets and lease liabilities. Payments for the operations and maintenance services are considered non-lease components and are not included in calculating the ROU assets and lease liabilities. For leases on ROU assets used in joint operations, generally the operator reflects the full amount of the lease component, including the amount that will be funded by the non-operators. As operator for the Etame Marin block, the ROU asset recorded for marine vessels, and certain equipment used in the joint operations includes the gross amount of the lease components.

The marine vessels and certain equipment leases include provisions for variable lease payments, under which the Company is required to make additional payments based on the level of production or the number of days or hours the asset is deployed, or the number of persons onboard the vessel. Because the Company does *not* know the extent that the Company will be required to make such payments, they are excluded from the calculation of ROU assets and lease liabilities.

Financing leases

The Company is currently a party to several financing lease agreements for the FSO and generators and marine vessels used in the operations of the Etame Marin block. The duration for these agreements ranges from 25 to 105 months. In some cases, the lease contracts require the Company to make payments both for the use of the asset itself and for operations and maintenance services. Only the payments for the use of the asset related to the lease component are included in the calculation of ROU assets and lease liabilities. Payments for the operations and maintenance services are considered non-lease components and are not included in calculating the ROU assets and lease liabilities.

All leases

For all leases that contain an option to extend the initial lease term, the Company has evaluated whether it is reasonably certain that the Company will extend the lease beyond the initial lease term. When the Company believes it is reasonably certain it will utilize these leased assets beyond the initial lease term, those payments have been included in the calculation of the ROU assets and liabilities. The discount rate used to calculate ROU assets and lease liabilities represents the Company's incremental borrowing rate. The Company determined this by considering the term and economic environment of each lease, and estimating the resulting interest rate the Company would incur to borrow the lease payments.

For the years ended December 31, 2023 and 2022, the components of the lease costs and supplemental information was as follows:

	Twelve Months Ended December 31,		
	2023	**2022**	**2021**
Lease cost:		*(in thousands)*	
Finance lease cost (1)	**$ 17,297**	$ 3,682	$ —
Operating lease cost	**1,403**	11,040	17,692
Short-term lease cost (2)	**6,574**	5,213	2,258
Variable lease cost (3)	653	4,513	6,188
Total lease expense	**25,927**	24,448	26,138
Lease costs capitalized	**55**	4,127	232
Total lease costs	**$ 25,982**	$ 28,575	$ 26,370

(1)Represents depreciation and interest associated with financing leases.
(2)Represents short term leases under contracts that are 1 year or less where a ROU asset and lease liability are not required to be recorded.
(3)Variable costs represent differences between minimum lease costs and actual lease costs incurred under lease contracts.

Other information:

	Twelve Months Ended December 31,		
	2023	2022	2021
Other information:		(in thousands)	
Cash paid for amounts included in the measurement of lease liabilities:			
Financing cash flows attributable to finance leases (in thousands)	**$ 7,161**	$ 3,039	$ —
Weighted-average remaining lease term (in years)	**8.16**	9.65	—
Weighted-average discount rate	**7.99%**	4.59%	—
Operating cash flows attributable to operating leases (in thousands)	**$ 505**	$ 19,300	$ 23,925
Weighted-average remaining lease term (in years)	**0.67**	1.35	0.91
Weighted-average discount rate	**8.45%**	9.91%	5.91%

The table below describes the presentation of the total lease cost on the Company's consolidated statements of operations and other comprehensive income (loss). As discussed above, the Company's joint venture owners are required to reimburse the Company for their share of certain expenses, including certain lease costs.

	Twelve Months Ended December 31,		
	2023	2022	2021
		(in thousands)	
Finance lease cost	**$ 10,231**	$ 2,188	$ —
Production expense	**3,556**	12,222	13,457
General and administrative expense	**196**	160	193
Lease costs billed to the joint venture owners	**11,964**	11,390	12,573
Total lease expense	**25,947**	25,960	26,223
Lease costs capitalized	**35**	2,615	147
Total lease costs	**$ 25,982**	$ 28,575	$ 26,370

The following table describes the future maturities of the Company's operating and financing lease liabilities at December 31, 2023:

	Operating Leases	Finance Leases
Year	(in thousands)	
2024	$ 2,414	$ 16,801
2025	33	18,555
2026	—	16,674
2027	—	15,023
2028	—	11,321
Thereafter	—	40,241
	2,447	118,615
Less: imputed interest	18	30,243
Total lease liabilities	$ 2,429	$ 88,372

Under the joint operating agreements, other joint venture owners are obligated to fund $ 49.7 million of the $ 121.1 million in future lease liabilities as of December 31, 2023.

15. ACCRUED LIABILITIES AND OTHER

Accrued liabilities and other balances were comprised of the following:

	As of December 31, 2023	As of December 31, 2022
	(in thousands)	
Accrued accounts payable invoices	**$ 21,225**	$ 28,360
Gabon contractual obligations	**15,794**	10,509
Capital expenditures	**10,136**	26,618
Accrued wages and other compensation	**3,746**	8,161
ARO obligation	**—**	306
Egypt modernization payments	**9,933**	9,933
Other	**6,090**	7,505
Total accrued liabilities and other	**$ 66,924**	$ 91,392

16. SHAREHOLDERS' EQUITY

Dividend Policy

In the first quarter of 2023, the Company announced that the Company's board of directors increased the cash dividend to $ 0.0625 per common share. The following table is a schedule of dividends paid during 2023:

Dividend Payment Date	Amount per common share		Record Date
March 31, 2023	$	0.0625	March 24, 2023
June 23, 2023	$	0.0625	May 24, 2023
September 22, 2023	$	0.0625	August 25, 2023
December 21, 2023	$	0.0625	November 24, 2023
Aggregate per share amount paid in 2023	$	0.2500	

Preferred stock – Authorized preferred stock consists of 500,000 shares with a par value of $ 25 per share. No shares of preferred stock were issued and outstanding as of December 31, 2023 or 2022.

Treasury stock

On November 1, 2022, the Company announced that the Company's board of directors formally ratified and approved a share buyback program. The board of directors also directed management to implement a Rule 10b5-1 trading plan (the "10b5-1 Plan") to facilitate share purchases through open market purchases, privately negotiated transactions, or otherwise in compliance with Rule 10b-18 under the Securities Exchange Act of 1934. The 10b5-1 Plan provides for an aggregate purchase of currently outstanding common stock up to $ 30 million over a maximum period of 20 months. Payment for shares repurchased under the share buyback program will be funded using the Company's cash on hand and cash flow from operations.

The below table shows the repurchases of equity securities related to the share repurchase program during the fiscal year ended December 31, 2023:

Period	Total Number of Shares Purchased	Average Price Paid per Share		Total Number of Shares Purchased as Part of Publicly Announced Programs	Maximum Amount that May Yet Be Used to Purchase Shares Under the Program	
January 1, 2023 - January 31, 2023	350,832	$	4.29	350,832	$	25,502,669
February 1, 2023 - February 28, 2023	326,992	$	4.61	326,992	$	24,003,172
March 1, 2023 - March 31, 2023	303,176	$	4.97	303,176	$	22,503,206
April 1, 2023 - April 30, 2023	303,969	$	4.94	303,969	$	21,003,245
May 1, 2023 - May 31, 2023	362,843	$	4.14	362,843	$	19,502,740
June 1, 2023 - June 30, 2023	494,164	$	4.05	494,164	$	17,504,007
July 1, 2023 - July 31, 2023	505,720	$	3.96	505,720	$	15,504,180
August 1, 2023 - August 31, 2023	435,342	$	4.61	435,342	$	13,505,242
September 1, 2023 - September 30, 2023	462,300	$	4.31	462,300	$	11,514,870
October 1, 2023 - October 31, 2023	491,869	$	4.07	491,869	$	9,515,101
November 1, 2023 - November 30, 2023	472,141	$	4.24	472,141	$	7,515,171
December 1, 2023 - December 31, 2023	449,839	$	4.45	449,839	$	5,515,237
Total	4,959,187			4,959,187		

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17. STOCK-BASED COMPENSATION AND OTHER BENEFIT PLANS

The Company's stock-based compensation has been granted under several stock incentive and long-term incentive plans. The plans authorize the Compensation Committee of the Company's Board of Directors to issue various types of incentive compensation. The Company had previously issued stock options and restricted shares under the 2014 Long-Term Incentive Plan ("2014 Plan") and stock appreciation rights under the 2016 Stock Appreciation Rights Plan. On June 25, 2020, the Company's stockholders approved the 2020 Long-Term Incentive Plan (as amended, the "2020 Plan") under which 5,500,000 shares are authorized for grants. In June 2021, the Company's stockholders approved an amendment to the 2020 Plan pursuant to which an additional 3,750,000 shares were authorized for issuance pursuant to awards under the 2020 Plan. At December 31, 2023, 1,808,989 shares were available for future grants.

For each stock option granted, the number of authorized shares under the 2020 Plan will be reduced on a one-for-one basis. For each restricted share granted, the number of shares authorized under the 2020 Plan will be reduced by twice the number of restricted shares. The Company has no set policy for sourcing shares for option grants. Historically the shares issued under option grants have been new shares.

As referenced in the table below, the Company records compensation expense related to stock-based compensation as general and administrative expense associated with the issuance of stock options, restricted stock and stock appreciation rights. During the years ended December 31, 2023, 2022 and 2021, the Company settled in cash $ 0.4 million, $ 0.8 million and $ 3.3 million, respectively, for SARs. During the years ended December 31, 2023, 2022 and 2021, the Company received in cash $ 0.7 million, $ 0.3 million and $ 1.4 million, respectively from stock option exercises.

	Twelve Months Ended December 31,		
	2023	**2022**	**2021**
		(in thousands)	
Stock-based compensation - equity awards	**$ 3,338**	$ 2,045	$ 1,060
Stock-based compensation - liability awards	**(15)**	155	1,399
Total stock-based compensation	**$ 3,323**	$ 2,200	$ 2,459

Stock options and performance shares

Stock options have an exercise price that may not be less than the fair market value of the underlying shares on the date of grant. In general, stock options granted to participants will become exercisable over a period determined by the Compensation Committee of the Company's Board of Directors that is generally a three-year period, vesting in three equal parts on the anniversaries from the date of grant, and may contain performance hurdles.

In June 2023, the Company granted options to certain employees of the Company that are considered performance stock options to purchase an aggregate of 334,753 shares at an exercise price of $ 4.19 per share and a life of ten years. For each performance stock option award, one-third of the underlying shares vest on the later of the first anniversary of the grant date and the date on which the Company's stock price, determined using a 30-day average, exceeds $ 4.82 per share; performance stock options with respect to one-third of the underlying shares vest on the later of the second anniversary of the grant date and the date on which the Company's stock price, determined using a 30-day average, exceeds $ 5.54 per share; and performance stock options with respect to the remaining one-third of the underlying shares vest on the later of the third anniversary of the grant date and the date on which the Company's stock price, determined using a 30-day average, exceeds $ 6.37 per share. These awards are option awards that contain a market condition. Compensation cost for such awards is recognized ratably over the derived service period and compensation cost related to awards with a market condition will not be reversed if the Company does not believe it is probable that such performance criteria will be met or if the service provider (employee or otherwise) fails to meet such performance criteria.

During the year ended December 31, 2023, 2022 and 2021 the weighted average assumptions shown below were used to calculate the weighted average grant date fair value of performance stock options grants under the Monte Carlo model.

	Twelve Months Ended December 31,		
	2023	**2022**	**2021**
Weighted average exercise price - ($/share)	**$ 4.19**	$ 6.41	$ 3.14
Expected life in years	**6.4**	6.0	6.0
Average expected volatility	**68%**	72%	75
Risk-free interest rate	**3.73%**	1.98%	0.95
Expected dividend yield	5.97%	2.30%	—
Weighted average grant date fair value - ($/share)	**$ 2.29**	$ 2.84	$ 2.07

Performance stock options activity associated with the Monte Carlo model for the year ended December 31, 2023 is provided below:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
	(in thousands)		*(in years)*	*(in thousands)*
Outstanding at January 1, 2023	444	$ 3.95		
Granted	335	4.19		
Exercised	(168)	(1.74)		
Unvested shares forfeited	—	—		
Vested shares expired	—	—		
Outstanding at December 31, 2023	611	$ 4.69	8.72	$ 255
Exercisable at December 31, 2023	118	$ 4.56	7.60	$ 116

The intrinsic value of a performance stock option awards is the amount that the current market value of the underlying stock exceeds the exercise price of the award. The intrinsic performance stock option awards exercised in 2023 was $ 0.5 million.

As of December 31, 2023, unrecognized compensation cost related to outstanding performance stock option awards was $ 0.8 million, which is expected to be recognized over a weighted average period of 2.0 years.

During the year ended December 31, 2023, 5,959 shares were added to treasury as a result of tax withholding on performance stock option awards exercised.

Regular stock options (stock options without a performance condition) activity associated with the Black-Scholes model for the year ended December 31, 2023 is provided below:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
	(in thousands)		*(in years)*	*(in thousands)*
Outstanding at January 1, 2023	387	$ 1.86		
Granted	—	—		
Exercised	(217)	(1.75)		
Unvested shares forfeited	—	—		
Vested shares expired	—	—		
Outstanding at December 31, 2023	170	$ 1.99	0.27	$ 425
Exercisable at December 31, 2023	170	$ 1.99	0.27	$ 425

The intrinsic value of a stock option is the amount that the current market value of the underlying stock exceeds the exercise price of the option. The intrinsic value of stock options exercised in 2023, 2022 and 2021 was $ 0.6 million, $ 1.2 million, and $ 1.6 million, respectively.

There was no unrecognized stock compensation cost as of December 31, 2023 and December 31, 2022, respectively.

Restricted shares

Restricted stock granted to employees will vest over a period determined by the Compensation Committee that is generally a three-year period, vesting in three equal parts on the anniversaries following the date of the grant. Restricted stock granted to directors will vest on the earlier of (i) the first anniversary of the date of grant and (ii) the first annual meeting of stockholders following the date of grant (but not less than fifty (50) weeks following the date of grant).

The following is the activity for the Company's restricted stock for the year ended December 31, 2023:

	Restricted Stock	Weighted Average Grant Date Fair Value
	(in thousands)	
Non-vested shares outstanding at January 1, 2023	665	$ 4.59
Awards granted	796	4.19
Awards vested	(354)	3.92
Awards forfeited	(22)	5.35
Non-vested shares outstanding at December 31, 2023	1,085	$ 4.50

The total fair value of vested restricted stock awards during 2023, 2022 and 2021 was $ 1.5 million, $ 2.4 million, and $ 1.8 million, respectively. The weighted average grant date fair value per share of restricted stock awards, which vested during 2023, 2022 and 2021, was $ 3.92 , $ 2.25 and $ 1.28 , respectively.

As of December 31, 2023, unrecognized compensation cost related to restricted stock totaled $ 2.4 million and is expected to be recognized over a weighted average period of 1.5 year.

In connection with the Arrangement with TransGlobe and pursuant to the Arrangement Agreement, at the effective time of the Arrangement, certain awards previously issued to TransGlobe's key employees and board members who continued their relationship as employees or board members of VAALCO following the Arrangement, will continue to be governed by the applicable TransGlobe plan, provided that each such applicable plan has been amended to provide that VAALCO common stock shall be issuable in lieu of cash or TransGlobe common stock with respect to TransGlobe's deferred share units ("DSU"s), performance share units ("PSU"s) and restricted stock units ("RSU"s), in each case, based on the exchange ratio in the Arrangement. For the PSUs that will remain outstanding following the effective time of the Arrangement as described in the immediately preceding sentence, the applicable vesting percentage was determined by the TransGlobe board of directors to be 200 % for PSUs granted in 2020 and 2021; and 64.4 % for PSUs granted in 2022.

On the effective date of the Arrangement, October 13, 2022, the combined fair value of the DSUs, PSU's and RSU's liability from TransGlobe was $ 6.0 million. On December 16, 2022, the Compensation Committee determined that the awards would be settled in shares from the 2020 Plan, thereby converting all the awards from cash-settled liability awards to equity awards. On the date of this conversion, the awards were revalued based on VAALCO's share price, and the Company recognized a gain of $ 0.6 million in its consolidated statements of operations and comprehensive income (loss).

RSUs were issued to directors, officers and employees of TransGlobe in the ordinary course of business prior to the Arrangement. Each RSU vests annually over a three-year period. On December 16, 2022, Compensation Committee determined that the awards would be settled in shares from the 2020 Plan, thereby converting all the awards to equity awards instead of cash-settled liability awards.

RSU activity for the twelve months ended December 31, 2023 is presented in the table below:

	Restricted Stock	Weighted Average Conversion Date Fair Value
	(in thousands)	
Non-vested shares outstanding at January 1, 2023	383	$ 4.27
Awards granted	183	4.19
Awards vested	(285)	4.27
Awards forfeited	(58)	4.23
Non-vested shares outstanding at December 31, 2023	223	$ 4.22

The total fair value of vested RSU awards during 2023 was $ 1.2 million. The weighted average grant date fair value per share of RSU, which vested during 2023, was $ 4.27 .

As of December 31, 2023, unrecognized compensation cost related to RSU's totaled $ 0.7 million and is expected to be recognized over a weighted average period of 1.1 years.

During the year ended December 31, 2023, 173,738 shares were added to treasury as a result of tax withholding on the vesting of RSU's.

PSUs are similar to RSUs except that they originally contained a performance factor affecting the vesting percentage. For the PSUs that remained outstanding following the effective time of the Arrangement, the applicable vesting percentage was determined by the TransGlobe board of directors to be 200% for PSUs granted in 2020 and 2021; and 64.4% for PSUs granted in 2022. All PSUs granted vest on the third anniversary of their grant date. On December 16, 2022, the Compensation Committee determined that the awards would be settled in shares from the 2020 Plan, thereby converting all the awards to equity awards instead of cash-settled liability awards.

PSU activity for the twelve months ended December 31, 2023 is presented in the table below:

	Restricted Stock	Weighted Average Conversion Date Fair Value
	(in thousands)	
Non-vested shares outstanding at January 1, 2023	690	$ 4.27
Awards granted	—	—
Awards vested	(533)	4.27
Awards forfeited	(36)	4.27
Non-vested shares outstanding at December 31, 2023	121	$ 4.27

As of December 31, 2023, unrecognized compensation cost related to PSU's totaled $ 0.1 million and is expected to be recognized over a weighted average period of 0.7 years.

During the twelve months ended December 31, 2023, 156,616 shares were added to treasury as a result of tax withholding on the vesting of PSU's.

DSUs are similar to RSUs, except that they become fully vested on the date of grant and are only issued to directors of the Company. Distributions under the DSU plan do not occur until the retirement of the DSU holder from the Company's Board of Directors. On December 16, 2022, the Compensation Committee determined that the awards would be settled in shares from the 2020 Plan, thereby converting all the awards to equity awards instead of cash-settled liability awards. At June 30, 2023, approximately 101,313 DSUs are vested but not converted. During the second quarter of 2023, 358,563 DSUs were converted to shares of common stock of the company following the departure of Mr. David Cook and Mr. Timothy Marchant from the board of directors, of which 65,582 shares were forfeited back to VAALCO to satisfy applicable tax withholding obligations.

Stock appreciation rights ("SARs")

SARs may be granted under the VAALCO Energy, Inc. 2016 Stock Appreciation Rights Plan and the 2020 Plan. A SAR is the right to receive a cash amount equal to the spread with respect to a share of common stock upon the exercise of the SAR. The spread is the difference between the SAR exercise price per share specified in the SAR award (that may not be less than the fair market value of the Company's common stock on the date of grant) and the fair market value per share of the Company's common stock on the date of exercise of the SAR. SARs granted to participants will become exercisable over a period determined by the Compensation Committee of the Company's Board of Directors. In addition, SARs will become exercisable upon a change in control, unless provided otherwise by the Compensation Committee of the Company's Board of Directors.

During the years ended December 31, 2023 and 2022, the Company did not grant SARs to employees or directors. SAR activity for the year ended December 31, 2023 is provided below:

	Number of Shares Underlying SARs	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
	(in thousands)		*(in years)*	*(in thousands)*
Outstanding at January 1, 2023	202	$ 1.87		
Granted	—	—		
Exercised	(126)	1.59		
Unvested SARs forfeited	—	—		
Vested SARs expired	—	—		
Outstanding at December 31, 2023	76	$ 2.33	0.16	$ 164
Exercisable at December 31, 2023	76	$ 2.33	0.16	$ 164

The intrinsic value of a SAR is the amount that the current market value of the underlying stock exceeds the exercise price of the award. The intrinsic value of SARs exercised in 2023, 2022 and 2021 was $ 0.4 million, $ 0.8 million, and 0.8 million respectively.

SARs considered liabilities under US GAAP and the awards are measured at fair value on the grant date and remeasured at fair value until the award is settled. On February 28, 2024, all remaining SAR awards were exercised.

Other Benefit Plans

The Company has adopted forms of change in control agreements for its named executive officers and certain other officers of the Company as well as a severance plan for its Houston-based non-executive employees in order to provide severance benefits in connection with a change in control. Upon a termination of a participant's employment by the Company without cause or a resignation by the participant for good reason three months prior to a change in control or six months following a change in control, executives and officers with change in control agreements and participants in the severance plan will be entitled to receive 100 % and 50 %, respectively, of the participant's base salary and continued participation in the Company's group health plans for the participant and his or her eligible spouse and other dependents for six months. In addition, certain named executive officers will receive 75 % of their target bonus. Some of the named executive officers are also entitled to severance payments under their employment agreements.

18. RELATED PARTY TRANSACTIONS

VAALCO has entered into various agreements with related parties. The Company paid approximately $ 0.2 million to these related parties for each of the years ended December 31, 2023 and 2022, respectively. The amounts in both 2023 and 2022 were primarily for contract engineering services paid to an entity owned and controlled by a related party of an officer of the Company.

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19. OTHER COMPREHENSIVE INCOME

At December 31, 2023, the Company's accumulated other comprehensive income was $ 2.9 million. All of the Company's other comprehensive income arises from the currency translation of TransGlobe Energy Corporation to USD.

The components of accumulated other comprehensive income are as follows:

	Currency Translation Adjustments
	(in thousands)
Balance at December 31, 2022	$ 1,179
Amounts reclassified from accumulated other comprehensive income (loss)	1,701
Balance at December 31, 2023	$ 2,880

SUPPLEMENTAL INFORMATION ON CRUDE OIL, NATURAL GAS AND NGLs PRODUCING ACTIVITIES (UNAUDITED)

This supplemental information is presented in accordance with certain provisions of ASC Topic 932 – *Extractive Activities- Oil and Natural Gas*. The geographic areas reported are the U.S. (North America), which includes the producing properties in offshore Gabon (Africa), and onshore in Egypt and Canada.

Costs Incurred for Acquisition, Exploration and Development Activities

Costs incurred during the year:	**Gabon**	**Egypt**	**Canada**	**Total**
Year Ended December 31, 2023		*(in thousands)*		
Exploration costs - expensed	**$ 51**	**$ 1,914**	$ —	**$ 1,965**
Acquisition of properties	—	—	—	—
Development costs	**17,011**	**37,866**	**16,809**	**71,686**
Total	**$ 17,062**	**$ 39,780**	**$ 16,809**	**$ 73,651**

	Gabon	**Egypt**	**Canada**	**Total**
Year Ended December 31, 2022		*(in thousands)*		
Exploration costs - capitalized	$ 47	$ —	$ —	$ 47
Exploration costs - expensed	258	—	—	258
Acquisition of properties	—	170,982	104,390	275,372
Development costs	162,328	7,515	2,187	172,030
Total	$ 162,633	$ 178,497	$ 106,577	$ 447,707

	Gabon	**Total**
Year Ended December 31, 2021	*(in thousands)*	
Exploration costs - capitalized	$ 254 (1)	$ 254
Exploration costs - expensed	1,579	1,579
Acquisition of properties	42,744	42,744
Development costs	36,223	36,223
Total	$ 80,800	$ 80,800

(1) - Primarily associated with the Southeast Etame 4P appraisal wellbore.

Capitalized Costs Relating to crude oil, natural gas and NGLs Producing Activities

Capitalized costs pertain to the producing activities in Gabon, Egypt and Canada and to undeveloped leasehold in Gabon, Egypt, Canada and Equatorial Guinea.

	As of December 31,	
	2023	**2022**
Capitalized costs:	*(in thousands)*	
Properties not being amortized	**$ 79,406**	$ 71,670
Properties being amortized	**1,467,039**	1,406,888
Total capitalized costs	**$ 1,546,445**	$ 1,478,558
Less accumulated depletion, amortization and impairment	**(1,091,910)**	(986,952)
Net capitalized costs	**$ 454,535**	$ 491,606

Results of Operations for crude oil, natural gas and NGLs Producing Activities

For Egypt and Canada, all activity pertains to the year ended December 31, 2023 and the period of October 14, 2022 - December 31, 2022, after the acquisition of TransGlobe.

	International				
	Gabon	**Egypt**	**Canada**	**U.S.**	**Total**
Year Ended December 31, 2023			***(In thousands)***		
Revenues	**$ 260,346**	**$ 161,049**	**$ 33,671**	$ —	**$ 455,066**
Production costs and other expense (1)	**(94,615)**	**(54,779)**	**(9,463)**	—	**(158,857)**
Depreciation, depletion, amortization	**(62,622)**	**(35,095)**	**(17,398)**	—	**(115,115)**
Exploration expenses	**(51)**	**(1,914)**	—	—	**(1,965)**
Other operating expense	**(55)**	**(241)**	**729**	—	**433**
Income tax benefit (expense)	**(67,982)**	**(37,271)**	—	—	**(105,253)**
Results from crude oil and natural gas producing activities	**$ 35,021**	**$ 31,749**	**$ 7,539**	$ —	**$ 74,309**

	International				
	Gabon	**Egypt**	**Canada**	**U.S.**	**Total**
Year Ended December 31, 2022			***(In thousands)***		
Crude oil and natural gas sales	$ 306,775	$ 37,710	$ 9,841	$ —	$ 354,326
Production costs and other expense (1)	(108,701)	(11,936)	(1,972)	—	(122,609)
Depreciation, depletion, amortization	(34,651)	(10,444)	(2,921)	—	(48,016)
Exploration expenses	(258)	—	—	—	(258)
Other operating expense	38	—	—	—	38
Credit (recovery) losses and other	(2,743)	—	—	—	(2,743)
Income tax benefit (expense)	(16,641)	(6,254)	—	—	(22,895)
Results from crude oil and natural gas producing activities	$ 143,819	$ 9,076	$ 4,948	—	$ 157,843

	Gabon	**U.S.**	**Total**
Year Ended December 31, 2021		***(In thousands)***	
Crude oil and natural gas sales	$ 199,075	$ —	$ 199,075
Production costs and other expense (1)	(81,984)	-	(81,984)
Depreciation, depletion, amortization	(20,972)	—	(20,972)
Exploration expenses	(1,579)	—	(1,579)
Impairment of proved properties	—	—	—
Other operating expense	(440)	—	(440)
Credit (recovery) losses and other	(875)	—	(875)
Income tax benefit (expense)	(9,626)	—	(9,626)
Results from crude oil and natural gas producing activities	$ 83,599	$ -	$ 83,599

(1) Includes local general and administrative expenses but excludes corporate general and administrative expenses and allocated corporate overhead.

Estimated Quantities of Proved Reserves

The estimation of net recoverable quantities of crude oil, natural gas and NGLs is a highly technical process that is based upon several underlying assumptions that are subject to change. See “*Item 1A. Risk Factors*” and “*Item 7. Management’s Discussion and Analysis of Financial Condition, Cash Flows and Liquidity – Critical Accounting Policies and Estimates – Successful Efforts Method of Accounting for crude oil, natural gas and NGLs Activities.* ” For a discussion of the reserve estimation process, including internal controls, see “*Item 1. Business – Reserve Information*.”

For Egypt and Canada, all activity pertains to the year ended December 31, 2023 and the period of October 14, 2022 - December 31, 2022, after the acquisition of TransGlobe.

	Oil			
Proved reserves:	Gabon (MBbls)	Egypt (MBbls)	Canada (MBbls)	Total (MBbls)
Balance at January 1, 2021	3,216	—	—	3,216
Production	(2,599)	—	—	(2,599)
Purchase of reserves	2,633	—	—	2,633
Extensions and discoveries	—	—	—	-
Revisions of previous estimates	7,968	—	—	7,968
Balance at December 31, 2021	11,218	—	—	11,218
Production	(2,971)	(547)	(72)	(3,718)
Purchase of reserves	—	9,124	3,679	12,931
Extensions and discoveries	—	—	—	—
Revisions of previous estimates	1,972	—	—	1,972
Balance at December 31, 2022	10,219	8,577	3,607	22,403
Production	**(3,197)**	**(2,771)**	**(334)**	**(6,302)**
Purchase of reserves	—	**—**	—	**-**
Extensions and discoveries	—	**93**	**810**	**903**
Revisions of previous estimates	**2,042**	**4,693**	**(652)**	**6,083**
Balance at December 31, 2023	**9,064**	**10,592**	**3,431**	**23,087**

	Oil			
	Gabon (MBbls)	Egypt (MBbls)	Canada (MBbls)	Total (MBbls)
Year-end proved developed reserves:				
2023	**8,053**	**10,141**	**1,309**	**19,503**
2022	10,219	8,001	1,722	19,942
2021	7,227	—	—	7,227
2020	3,216	—	—	3,216
Year-end proved undeveloped reserves:				
2023	**1,011**	**451**	**2,122**	**3,584**
2022	—	576	1,885	2,461
2021	3,991	—	—	3,991
2020	—	—	—	—

	Natural Gas			
Proved reserves:	Gabon (MMcf)	Egypt (MMcf)	Canada (MMcf)	Total (MMcf)
Balance at December 31, 2021	—	—	—	—
Production	—	—	(396)	(396)
Purchase of reserves	—	—	16,935	16,935
Extensions and discoveries	—	—	—	—
Revisions of previous estimates	—	—	—	—
Balance at December 31, 2022	—	—	16,539	16,539
Production	—	—	**(1,528)**	**(1,528)**
Purchase of reserves	—	—	—	—
Extensions and discoveries	—	—	**3,219**	**3,219**
Revisions of previous estimates	—	—	**(1,298)**	**(1,298)**
Balance at December 31, 2023	—	—	**16,932**	**16,932**

	Natural Gas			
	Gabon (MMcf)	Egypt (MMcf)	Canada (MMcf)	Total (MMcf)
Year-end proved developed reserves:				
2023	—	—	**9,011**	**9,011**
2022	—	—	11,023	11,023
Year-end proved undeveloped reserves:				
2023	—	—	**7,921**	**7,921**
2022	—	—	5,516	5,516

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Proved reserves:	NGLs Gabon (MBbls)	Egypt (MBbls)	Canada (MBbls)	Total (MBbls)
Balance at December 31, 2021	—	—	—	—
Production	—	—	(73)	(73)
Purchase of reserves	—	—	2,870	2,870
Extensions and discoveries	—	—	—	—
Revisions of previous estimates	—	—	—	—
Balance at December 31, 2022	—	—	2,797	2,797
Production	—	—	**(270)**	**(270)**
Purchase of reserves	—	—	—	—
Extensions and discoveries	—	—	**505**	**505**
Revisions of previous estimates	—	—	**(295)**	**(295)**
Balance at December 31, 2023	—	—	**2,737**	**2,737**

	NGLs Gabon (MBbls)	Egypt (MBbls)	Canada (MBbls)	Total (MBbls)
Year-end proved developed reserves:				
2023	—	—	**1,449**	**1,449**
2022	—	—	1,855	1,855
Year-end proved undeveloped reserves:				
2023	—	—	**1,289**	**1,289**
2022	—	—	942	942

Proved reserves:	Total Reserves (1) Gabon (MBoe)	Egypt (MBoe)	Canada (MBoe)	Total (MBoe)
Balance at January 1, 2021	3,216	—	—	3,216
Production	(2,599)	—	—	(2,599)
Extensions and discoveries	—	—	—	—
Purchase of reserves	2,633	—	—	2,633
Revisions of previous estimates	7,968	—	—	7,968
Balance at December 31, 2021	11,218	—	—	11,218
Production	(2,971)	(547)	(211)	(3,729)
Extensions and discoveries	—	—	—	—
Purchase of reserves	—	9,124	9,372	18,496
Revisions of previous estimates	1,972	—	—	1,972
Balance at December 31, 2022	10,219	8,577	9,161	27,957
Production	**(3,197)**	**(2,771)**	**(859)**	**(6,827)**
Purchase of reserves	—	**—**	**—**	**—**
Extensions and discoveries	—	**93**	**1,852**	**1,945**
Revisions of previous estimates	**2,042**	**4,693**	**(1,163)**	**5,572**
Balance at December 31, 2023	**9,064**	**10,592**	**8,991**	**28,647**

(1) - To convert Natural Gas to MBoe, MMcf is divided by 6.

	Total Reserves (1) Gabon (MBoe)	Egypt (MBoe)	Canada (MBoe)	Total (MBoe)
Year-end proved developed reserves:				
2023	**8,053**	**10,141**	**4,260**	**22,454**
2022	10,219	8,001	5,414	23,634
2021	7,227	—	—	7,227
2020	3,216	—	—	3,216
Year-end proved undeveloped reserves:				
2023	**1,011**	**451**	**4,731**	**6,193**
2022	—	576	3,746	4,322
2021	3,991	—	—	3,991
2020	—	—	—	—

(1) To convert Natural Gas to MBoe, MMcf is divided by 6.

In 2023, operations in Gabon had 2.0 MMBoes of reserves added through positive revisions of previous estimates. 2.8 MMBoes of the positive revisions were due to performance offset by 0.8 MMBoes of negative revisions through price. For Egypt at December , 31, 2023, 4.7 MMBoes of reserves were added through positive revisions of previous estimates. 5.3 MMBoes of the positive revisions were due to performance offset by 0.6 MMBoes of negative revisions through price. For Canada at December , 31, 2023, 1.2 MMBoes of reserves were removed through negative revisions of previous estimates. 0.9 MMBoes of the negative revisions were due to performance and 0.3 MMBoes of negative revisions were through price.

In 2022, operations in Gabon had 2.0 MMBoes of positive revision of reserves due to the 2021/2022 drilling campaign. 0.7 MMBoes of the positive revision was due to performance and the remaining 1.3 MMBoes of positive revisions was due to price.

In 2021, the Company added 2.6 MMBoes of reserves due the acquisition of Sasol's interest in the Etame Marin block. In addition, the Company added 8.0 MMBoes due to positive revisions. The positive revision of 8.0 MMBoes was due to positive revision of 3.0 MMBoes due to price and positive revisions of 5.0 MMBoes due to performance.

In accordance with the guidelines of the SEC, the Company does not book proved reserves on discoveries until such time as a development plan has been prepared for the discovery indicating that the development well will be drilled within five years from the date of its initial booking. Additionally, the development plan is required to have the approval of the joint venture owners in the discovery. Furthermore, if a government agreement that the reserves are commercial is required to develop the block, this approval must have been received prior to booking any reserves.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Crude Oil Reserves

The information that follows has been developed pursuant to procedures prescribed under GAAP and uses reserve and production data estimated by independent petroleum consultants. The information may be useful for certain comparison purposes, but should not be solely relied upon in evaluating its or the Company's performance.

In accordance with the guidelines of the SEC, the estimates of future net cash flow from the properties and the present value thereof are made using crude oil, natural gas and NGLs contract prices using a twelve month average of beginning of month prices and are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. The future cash flows are also based on costs in existence at the dates of the projections, excluding Gabon royalties, and the interests of other Consortium members. Future production costs do not include overhead charges allowed under joint operating agreements or headquarters general and administrative overhead expenses. However, all future costs related to future property abandonment when the wells become uneconomic to produce are included in future development costs for purposes of calculating the standardized measure of discounted net cash flows. There were no discounted future net cash flows attributable to U.S. properties as of December 31, 2023, 2022 and 2021.

	International			
(In thousands)	**Gabon**	**Egypt**	**Canada**	**Total**
Year Ended December 31, 2023				
Future cash inflows	**$ 761,919**	**$ 828,418**	**$ 352,666**	**$ 1,943,003**
Future production costs	**(410,425)**	**(383,957)**	**(129,317)**	**(923,699)**
Future development costs (1)	**(88,868)**	**(84,132)**	**(80,129)**	**(253,129)**
Future income tax expense	**(148,750)**	**(144,269)**	**—**	**(293,019)**
Future net cash flows	**113,876**	**216,060**	**143,220**	**473,156**
Discount to present value at 10% annual rate	**(6,052)**	**(54,313)**	**(70,857)**	**(131,222)**
Standardized measure of discounted future net cash flows	**$ 107,824**	**$ 161,747**	**$ 72,363**	**$ 341,934**
Year Ended December 31, 2022				
Future cash inflows	$ 1,035,667	$ 729,236	$ 506,247	$ 2,271,150
Future production costs	(450,639)	(273,260)	(135,082)	(858,981)
Future development costs (1)	(58,057)	(12,079)	(69,346)	(139,482)
Future income tax expense	(248,024)	(146,835)	—	(394,859)
Future net cash flows	278,947	297,062	301,819	877,828
Discount to present value at 10% annual rate	(34,520)	(70,174)	(148,669)	(253,363)
Standardized measure of discounted future net cash flows	$ 244,427	$ 226,888	$ 153,150	$ 624,465
Year Ended December 31, 2021				
Future cash inflows	$ 782,006	$ —	$ —	$ 782,006
Future production costs	(416,819)	—	—	(416,819)
Future development costs (1)	(128,984)	—	—	(128,984)
Future income tax expense	(116,637)	—	—	(116,637)
Future net cash flows	119,566	—	—	119,566
Discount to present value at 10% annual rate	(20,308)	—	—	(20,308)
Standardized measure of discounted future net cash flows	$ 99,258	$ —	$ —	$ 99,258

(1) Includes costs expected to be incurred to abandon the properties, where applicable.

International income taxes represent amounts payable to the Government of Gabon on Profit Oil as final payment of corporate income taxes, and domestic income taxes (including other expenses treated as taxes).

Changes in Standardized Measure of Discounted Future Net Cash Flows

The following table sets forth the changes in standardized measure of discounted future net cash flows as follows:

	Year Ended December 31,		
	2023	2022	2021
		(in thousands)	
Balance at beginning of period	**$ 624,465**	$ 99,258	$ 14,733
Sales of crude oil and natural gas, net of production costs	**(296,209)**	(233,421)	(118,358)
Net changes in prices and production costs	**(210,703)**	264,804	126,668
Extensions and discoveries	28,849	—	—
Revisions of previous quantity estimates	**139,856**	95,623	158,213
Purchases	—	415,385	9,285
Changes in estimated future development costs	**(92,641)**	(23,243)	(39,969)
Development costs incurred during the period	—	101,495	2,629
Accretion of discount	**62,447**	9,926	2,752
Net change of income taxes	**77,757**	(121,490)	(60,218)
Change in production rates (timing) and other	**8,113**	16,128	3,523
Balance at end of period	**$ 341,934**	$ 624,465	$ 99,258

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond the Company's control. Reserve engineering is a subjective process of estimating underground accumulations of crude oil, natural gas and NGLs that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of crude oil, natural gas and NGLs that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future crude oil, natural gas and NGLs sales prices may all differ from those assumed in these estimates. The standardized measure of discounted future net cash flow should not be construed as the current market value of the estimated crude oil, natural gas and NGLs reserves attributable to the properties. The information set forth in the foregoing tables includes revisions for certain reserve estimates attributable to proved properties included in the preceding year's estimates. Such revisions are the result of additional information from subsequent completions and production history from the properties involved or the result of a decrease (or increase) in the projected economic life of such properties resulting from changes in product prices. Moreover, crude oil amounts shown for Gabon are recoverable under a service contract and the reserves in place at the end of the contract period remain the property of the Gabon government.

In accordance with the current SEC guidelines, estimates of future net cash flow from our properties and the present value thereof are made using the average of the first-day-of-the-month price for each of the twelve months of the year adjusted for quality, transportation fees and market differentials. Such prices are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. For 2023, the average of such prices used for our reserve estimate was $83.22 per Bbl for crude oil for Gabon. Prices were between $64.59 per Bbl for crude oil from Egypt and $71.67 per Bbl for crude oil from Canada. For 2022, the average of such prices used for our reserve estimates was $100.35 per Bbl for crude oil from Gabon. Prices were between $84.76 and $85.65 per Bbl for crude oil from Egypt and $89.61 per Bbl for crude oil from Canada. For Gabon, this compares to the average of such price used for 2021 of $69.10 per Bbl.

For 2023, the adjusted average price for our reserves associated with natural gas was $1.91 per MCF, $5.20 per Bbl for Ethane, $20.18 per Bbl for propane, $36.69 per Bbl for butane and $74.76 per Bbl for condensates. For 2022, the adjusted average price for our reserves associated with natural gas was $4.13 per MCF, $12.77 per Bbl for Ethane, $40.27 per Bbl for propane, $43.85 per Bbl for butane and $91.57 per Bbl for condensates.

Under the Etame PSC in Gabon, the Gabonese government is the owner of all crude oil, natural gas and NGLs mineral rights. The right to produce the crude oil, natural gas and NGLs is stewarded by the Directorate Generale de Hydrocarbures and the Etame PSC was awarded by a decree. Pursuant to the contract, the Gabon government receives a fixed royalty rate of 13%. Originally, under the Etame PSC, Gabonese government was not anticipated to take physical delivery of its allocated production. Instead, the Company was authorized to sell the Gabonese government's share of production and remit the proceeds to the Gabonese government. Beginning in February 2018, the Gabonese government elected to take physical delivery of its allocated production volumes for Profit Oil (see discussion in Note 7 above).

The Etame Consortium maintains a Cost Account, which entitles it to receive a portion of the production remaining after deducting the 13% royalty so long as there are amounts remaining in the Cost Account ("Cost Recovery"). Prior to the PSC Extension, the Consortium was entitled to a 70% Cost Recovery Percentage. Under the PSC Extension, the Cost Recovery Percentage is increased to 80% for the ten-year period from September 17, 2018 through September 16, 2028. After September 16, 2028, the Cost Recovery Percentage returns to 70%. As payment of corporate income taxes, the Etame Consortium pays the government an allocation of the remaining Profit Oil production from the contract area ranging from 50% to 60% of the crude oil remaining after deducting the royalty and Cost Recovery. The percentage of Profit Oil paid to the government as tax is a function of production rates. However, when the Cost Account becomes substantially recovered, the Company only recovers ongoing operating expenses and new project capital expenditures, resulting in a higher tax rate. Also because of the nature of the Cost Account, decreases in crude oil prices result in a higher number of barrels required to recover costs.

The Etame PSC allows for exploitation period through the carve-out of development areas, which include all producing fields in the Etame Marin block as well as additional undeveloped areas where reserves may exist. The PSC Extension extends the term for each of the three exploitation areas in the Etame Marin block for a period of ten years with effect from September 17, 2018, the effective date of the PSC Extension. The PSC Extension also grants the Etame Consortium the right for two additional extension periods of five years each. This compares to the economic end date of reserves under the current reserve report prepared by the independent reserve engineering firm of Netherland, Sewell & Associates, Inc.

The PSC for Block P in Equatorial Guinea entitles the Company to receive up to 70% of any future production after royalty deduction so long as there are amounts remaining in the Cost Account. Royalty rates are 10-16% depending on production rates. The Etame Consortium pays the government an allocation of the remaining “profit oil” production from the contract area ranging from 10% to 60% of the crude oil remaining after deducting the royalty and Cost Recovery. The percentage of “profit oil” paid to the government as tax is a function of cumulative production. In addition, Equatorial Guinea imposes a 25% income tax on net profits. The Block P PSC provides for a discovery to be reclassified into a development area with a term of 25 years. At December 31, 2023, the Company has no proved reserves related to Block P in Equatorial Guinea.

Egypt production is based on Dated Brent prices, less a quality differential and is shared with the Egyptian government through PSCs. When the price of oil increases, it takes fewer barrels to recover costs (cost oil or cost recovery barrels) which are assigned 100% to the Company. The PSCs provide for cost recovery per quarter up to a maximum percentage of total production. Timing differences often exist between the Company's recognition of costs and their recovery as the Company accounts for costs on an accrual basis, whereas cost recovery is determined on a cash basis. If the eligible cost recovery is less than the maximum defined cost recovery, the difference is defined as "excess". In Egypt, depending on the PSCs, the Contractor's share of excess ranges between 5% and 15%. If the eligible cost recovery exceeds the maximum allowed percentage, the unclaimed cost recovery is carried forward to the next quarter. Typically maximum cost oil ranges from 25% to 40% in Egypt. The balance of the production after maximum cost recovery is shared with the government (profit oil). Depending on the contract, the Egyptian government receives 67% to 84% of the profit oil. Production sharing splits are set in each contract for the life of the contract.

Under the Modernized Royalty Framework (the “MRF”) in Alberta, producers initially pay a flat royalty of 5% on production revenue from each producing well until payout, which is the point at which cumulative gross revenues from the well equals the applicable drilling and completion cost allowance. After payout, producers pay an increased royalty of up to 40% that will vary depending on the nature of the resource and market prices. Once the rate of production from a well is too low to sustain the full royalty burden, its royalty rate is gradually adjusted downward as production declines, eventually reaching a floor of 5%. The MRF applies to the hydrocarbons produced by wells spud or re-entered on or after January 1, 2017. The Royalty Guarantee Act (Alberta) came into effect in July 2019, amending the Mines and Minerals Act (Alberta) and guaranteeing no major changes to the oil and gas royalty structure for a period of 10 years.

Royalty rates for the production of privately owned oil and natural gas are negotiated between the producer and the resource owner. The Government of Alberta levies annual freehold mineral taxes for production from freehold mineral lands. On average, the tax levied in Alberta is 4% of revenues reported from freehold mineral title properties and is payable by the registered owner of the mineral rights.

Exhibit 21.1

Subsidiary Name	**Place of Incorporation**
VAALCO Energy (USA), Inc.	Delaware
VAALCO Gabon (Etame), Inc.	Delaware
VAALCO Production (Gabon), Inc.	Delaware
VAALCO Angola (Kwanza), Inc.	Delaware
VAALCO Energy (EG), Inc.	Delaware
VAALCO Energy Mauritius (EG), Ltd	Mauritius
VAALCO Gabon S.A.	Gabon
VAALCO Energy (International) LLC	Delaware
VAALCO Energy (Holdings), LLC	Delaware
VAALCO International Management, LLC	Delaware
TransGlobe Energy Corporation	Province of Alberta
TG Energy UK Ltd	United Kingdom
TransGlobe Petroleum International Inc.	Turks & Caicos
TG Holdings Yemen Inc.	Turks & Caicos
TransGlobe West Bakr Inc.	Turks & Caicos
TransGlobe West Gharib Inc.	Turks & Caicos
TG Energy Marketing Inc.	Turks & Caicos
TG NW Gharib Inc.	Turks & Caicos
TransGlobe S Ghazalat Inc.	Turks & Caicos

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

VAALCO Energy, Inc.
Houston, Texas

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-261934) and Form S-8 (Nos. 333-257028, 333-239424, 333-218824 and 333-197180) of VAALCO Energy, Inc. of our report dated April 6, 2023, relating to the consolidated financial statements, which appears in this Annual Report on Form 10-K.

/s/ BDO USA, P.C.

Houston, Texas
March 15, 2024

Exhibit 23.2

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the registration statement (No. 333-261934) on Form S-3 and the registration statements (Nos. 333-257028, 333-239424, 333-218824 and 333-197180) on Form S-8 of our reports dated March 15, 2024, with respect to the consolidated financial statements of VAALCO Energy, Inc. and the effectiveness of internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
March 15, 2024

Exhibit 23.3

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

The undersigned hereby consents to the references to our firm in the form and context in which they appear in the Annual Report on Form 10-K of VAALCO Energy, Inc. for the year ended December 31, 2023. We hereby further consent to the use of information contained in our reports setting forth the estimates of revenues from VAALCO Energy, Inc.'s oil and gas reserves as of December 31, 2023, 2022, and 2021, and to the inclusion of our reports dated March 13, 2024, as exhibits to the Annual Report on Form 10-K of VAALCO Energy, Inc. for the year ended December 31, 2023. We further consent to the incorporation by reference thereof into VAALCO Energy, Inc.'s Registration Statements on Forms S-3 (Nos. 333-261934) and Forms S-8 (Nos. 333-257028, 333-239424, 333-218824, and 333-197180).

NETHERLAND, SEWELL & ASSOCIATES, INC.

/s/ Richard B. Talley, Jr.

By:
Richard B. Talley, Jr., P.E.
Chief Executive Officer

Houston, Texas
March 14, 2024

CONSENT OF GLJ LTD.

To:
U.S. Securities and Exchange Commission

Dear Sirs/Mesdames:

Re: Vaalco Energy Inc.

Annual Report on Form 10-K

We refer to our report dated effective December 31, 2023, with a preparation date of February 14, 2024, assessing and evaluating the proved, probable and possible reserves of Vaalco Energy Inc. located in the Harmattan property of Canada (the "Report"). We hereby consent to the references in this Annual Report on Form 10-K of Vaalco Energy Inc. (the “Company”), to our summary reports on audits of the estimated quantities of certain proved reserves of oil and gas, net to the Company’s interest, and to such report and this consent being filed as exhibits to this Form 10-K. We have read the Form 10-K and have no reason to believe that there is any misrepresentation in the information contained therein derived from the Report or that is within our knowledge as a result of the services we provided in preparing the Report. We further consent to the incorporation by reference thereof into Vaalco Energy Inc.’s Registration Statements on Form S-3 (No. 333-261934) and Form S-8 (Nos. 333-257028, 333-239424, 333-218824 and 333-197180).

Yours truly,

GLJ LTD.

Carolyn Baird

Carolyn L. Baird, P. Eng. Manager, Engineering

Calgary, Alberta March 12, 2024

Exhibit 31.1

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO
EXCHANGE ACT RULES 13a-14(a) AND 15d-14(a),
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, George W.M. Maxwell certify that:

(1) I have reviewed this annual report on Form 10-K of VAALCO Energy, Inc.;

(2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

(3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

(4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

(5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 15, 2024

/s/ George W.M. Maxwell
George W.M. Maxwell
Chief Executive Officer

Exhibit 31.2

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO
EXCHANGE ACT RULES 13a-14(a) AND 15d-14(a),
AS ADOPTED PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Ronald Bain, certify that:

(1) I have reviewed this Annual Report on Form 10-K of VAALCO Energy, Inc.;

(2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

(3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

(4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

(5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 15, 2024

/s/ Ronald Bain
Ronald Bain
Chief Financial Officer
(Principal Financial Officer)

EXHIBIT 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of VAALCO Energy, Inc. (the "Company") on Form 10-K for the year ended December 31, 2023, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, George W.M. Maxwell, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities and Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 15, 2024

/s/ George W.M. Maxwell
George W.M. Maxwell, Chief Executive Officer

EXHIBIT 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of VAALCO Energy, Inc. (the “Company”) on Form 10-K for the annual period ended December 31, 2023, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Ronald Bain, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities and Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 15, 2024

/s/ Ronald Bain
Ronald Bain, Chief Financial Officer

Exhibit 97.1

VAALCO ENERGY INC.
CLAWBACK POLICY

The following clawback policy (the "Policy") of VAALCO Energy Inc., a Delaware corporation (the " Company") requires the recovery of erroneously awarded compensation in order to satisfy the requirements of Section 303A.14 of the New York Stock Exchange Listed Company Manual (the "Listing Standards") and to satisfy the requirements of Rule 10D-1 (" Rule 10D-1"), as adopted by the Securities and Exchange Commission (the "SEC") pursuant to the Securities Exchange Act of 1934 (the " Exchange Act") to implement Section 954 of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010.

Section 1. **Definitions**. As used in this Policy, the following definitions shall apply:

(a)" Applicable Period" means the three completed fiscal years prior to the earlier of (i) the date the Company's Board, a Board committee, or officer(s) authorized to take such action if Board action is not required, concludes, or reasonably should have concluded, that the Company is required to prepare a Restatement or (ii) the date a court, regulator, or other legally authorized body directs the Company to prepare a Restatement. In addition to the last three completed fiscal years described in the preceding sentence, the Applicable Period includes any transition period (that results from a change in the Company's fiscal year) within or immediately following those three completed fiscal years; provided, however, a transition period between the last day of the Company's previous fiscal year end and the first day of its new fiscal year that comprises a period of nine to 12 months would be deemed a completed fiscal year for purposes of the Applicable Period.

(b) "Board" means the Board of Directors of the Company.

(c)" Committee" means the Compensation Committee of the Board of Directors of the Company.

(d)" Covered Executive" means all of the Company's current and former executive officers, as determined by the Committee, in accordance with the Listing Standards, Rule 10D-1 and the definition of executive officer as defined in Rule 10D-1(d).

(e)" Erroneously Awarded Compensation" means the amount of Incentive-Based Compensation received by a Covered Executive that exceeds the amount of Incentive-Based Compensation that otherwise would have been received had it been determined based on the restated financial statements.

(f)" Incentive-Based Compensation" means all compensation (including cash bonuses or other cash incentive awards (including any deferred element thereof), and vested and unvested equity awards, including options, restricted stock and restricted stock units, performance stock unit awards and performance stock awards) from the Company or a subsidiary of the Company that is granted, earned, or vested based wholly or in part upon the attainment of a Financial Reporting Measure. For the avoidance of doubt, Incentive-Based Compensation does not include annual salary, compensation awarded based on completion of a specified period of service, or compensation awarded based on subjective standards, strategic measures, or operational measures, unless also based on attainment of a Financial Reporting Measure.

(g)" Financial Reporting Measures" are measures that are determined and presented in accordance with the accounting principles used in preparing the Company's financial statements, and

any measures that are derived wholly or in part from such measures, including stock price and total shareholder return.

(h)" Restatement" means an accounting restatement of the Company's financial statements due to material noncompliance with any financial reporting requirement under the federal securities laws, including any required accounting restatement to correct an error in previously issued financial statements that is material to the previously issued financial statements, or that would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period.

Section 2. Recovery Event. If the Company is required to prepare a Restatement, then, as determined by the Committee, all or a portion of the Covered Executive's unsettled Incentive-Based Compensation will be subject to forfeiture, and all or a portion of the Covered Executive's settled Incentive-Based Compensation will be subject to recoupment, subject to the following:

(a) The forfeiture or recoupment of the Incentive-Based Compensation will apply to a recipient of Incentive-Based Compensation if the recipient of the Incentive-Based Compensation was a Covered Executive at any time during the performance period for such Incentive-Based Compensation. This Policy applies to Incentive-Based Compensation received by a Covered Executive after beginning services as a Covered Executive, and any subsequent changes in a Covered Executive's employment status, including retirement or termination of employment, do not affect the Company's rights to recover Erroneously Awarded Compensation pursuant to this Policy.

(b) The amount to be forfeited or recouped will equal the Erroneously Awarded Compensation. The Committee will take actions it deems reasonable in its discretion to recover the Erroneously Awarded Compensation reasonably promptly following a Restatement. Where the amount of Erroneously Awarded Compensation is not subject to mathematical recalculation directly from the information the Restatement, the amount must be based on a reasonable estimate of the effect of the Restatement on stock price or total shareholder return upon which the Incentive- Based Compensation was granted, vested, paid or settled. The Company will maintain documentation of the determination of that reasonable estimate and provide such documentation to the New York Stock Exchange as required. The amount of the Erroneously Awarded Compensation shall not be reduced based on, or otherwise calculated with regard to, any taxes paid by the Covered Executive with respect to such amounts.

(c) This Policy shall only apply to Incentive-Based Compensation that was received (or would have been settled in the absence of an elective deferral of payment by the individual) during, or in respect of, the Applicable Period and that was received (or would have been settled in the absence of an elective deferral of payment by the individual) during the period while the Company has a class of securities listed on a national securities exchange or a national securities association. For purposes of this Policy, Incentive-Based Compensation shall be deemed to have been received during the fiscal period in which the financial reporting measure specified in the applicable Incentive-Based Compensation is attained, even if such Incentive-Based Compensation is paid or granted after the end of such fiscal period. The Company's obligation to recover erroneously awarded compensation is not dependent on if or when the restated financial statements are filed.

Section 3. Impracticability. The Company shall recover any Erroneously Awarded Compensation unless the conditions set forth in clauses (a), (b) or (c) of the following sentence are met and such recovery would be impracticable, as determined by the Committee in accordance with Rule 10D-1 and the Listing Standards. No recovery shall be required if:

(a) the direct expense paid to a third party to assist in enforcing this Policy would exceed the amount to be recovered; *provided* that before concluding that it would be impractical to recover any amount of Erroneously Awarded Compensation based on this clause (a), the Company shall make a reasonable attempt to recover such Erroneously Awarded Compensation, document such reasonable attempt(s) and provide such documentation to the New York Stock Exchange as required;

(b) recovery would violate home country law where that law was adopted prior to November 28, 2022; *provided* that before concluding that it would be impractical to recover any amount of Erroneously Awarded Compensation based on this clause (b), the Company shall obtain an opinion of home country counsel, acceptable to the New York Stock Exchange, that recovery would result in such violation, and shall provide such opinion to the New York Stock Exchange; or

(c) recovery would likely cause an otherwise tax-qualified retirement plan, under which benefits are broadly available to employees of the Company or a subsidiary, to fail to meet the requirements of Section 401(a)(13) or Section 411(a) of the Code.

Section 4. Method of Clawback. The Committee shall determine, in its sole discretion, the method of recovering any Erroneously Awarded Compensation pursuant to this Policy, which may include, without limitation:

(a) requiring reimbursement of cash Erroneously Awarded Compensation previously paid;

(b) seeking recovery of any gain realized on the vesting, exercise, settlement, sale, transfer, or other disposition of any equity-based awards;

(c) offsetting the recouped amount from any compensation otherwise owed by the Company or any subsidiary to the Covered Executive;

(d) cancelling outstanding vested or unvested equity awards; and/or

(e) taking any other remedial and recovery action, as determined by the Committee; provided, however that any such action pursuant to subsections (a) through (c) shall be subject to applicable law and shall be subject to compliance with Section 409A of the Internal Revenue Code.

Section 5. Suspension of Outstanding Incentive-Based Compensation.

(a) After a determination by the Committee that a Restatement may be required, the Committee may suspend all Incentive-Based Compensation that the Committee determines may be forfeited under this Policy or otherwise subject to offset pursuant to Section 4, in which case and subject to the terms of this Section, Incentive-Based Compensation subject to the suspension: (i) if unvested, will not vest, and (ii) otherwise will not be distributed or permitted to be exercised or otherwise settled. In the event the term of an option award will expire during a period of suspension, the Covered Executive will be permitted to exercise the option before it expires; however settlement of the option award following such exercise will remain suspended and the securities otherwise deliverable upon settlement shall remain subject to forfeiture under the terms of this Policy.

(b) Following suspension of Incentive-Based Compensation under subsection (a) of this Section 5, the Committee will determine as promptly as practicable whether the suspended Incentive- Based Compensation is to be forfeited or whether the suspension of the Incentive-Based Compensation

is to be ended. For Incentive-Based Compensation that are ultimately not forfeited, the following provisions will apply upon the Committee's determination to lift the suspension:

(i) Unvested awards that would not otherwise have vested during the suspension by their original terms will be thereafter subject to vesting under their original terms;

(ii) Unvested awards that otherwise would have vested during the suspension will vest as soon as practicable and otherwise consistent with their original terms;

(iii) Cash awards such as annual bonus withheld during the suspension will be immediately payable;

(iv) In no event will distribution of cash or shares be made to a Covered Executive with respect to Incentive-Based Compensation if, by reason of termination of employment or otherwise, the Covered Executive would have forfeited the Incentive-Based Compensation if the Incentive-Based Compensation had not been suspended; and

(v) Distribution or settlement of Incentive-Based Compensation will be made no later than the latest date on which such distribution or settlement would be required to avoid additional tax by reason of Section 409A of the Internal Revenue Code; provided, however, that if such distribution or settlement occurs during a period when such Incentive-Based Compensation remains suspended pursuant to this Section 5, then the after-tax proceeds of such distribution or settlement shall be held in escrow until such time as such Incentive-Based Compensation is no longer subject to a suspension or such amounts are determined to have been forfeited by the Committee.

Section 6. Committee Administration and Discretion. The authority to manage the operation and administration of this Policy is vested in the Committee. This authority includes the obligation to determine (a) whether a Restatement has occurred for the purposes of this Policy, Rule 10D-1 and the Listing Standards and (b) the amount of Erroneously Awarded Compensation. The Committee may retain and rely upon the advice and determinations of legal counsel, accountants and other relevant experts to operate and administer this Policy. Any interpretation of this Policy by the Committee and any decision made by it with respect to this Policy will be final, binding and conclusive on all persons.

Section 7. No Indemnification. The Company shall not indemnify any current or former Covered Executive against the loss of Erroneously Awarded Compensation, and shall not pay, or reimburse any Covered Executives for premiums, for any insurance policy to fund such executive's potential repayment obligations.

Section 8. Notice. Before the Committee determines to seek recovery pursuant to this Policy, it shall provide the Covered Executive with written notice and the opportunity to be heard at a meeting of the Committee or the Board (either in person or via telephone).

Section 9. Effective Date. This Policy is effective as of as of December 1, 2023 (the "Effective Date"), and until it is cancelled or the Company no longer has a class of securities listed on a national securities exchange. The terms of this Policy shall apply to any Incentive-Based Compensation that is received by a Covered Executive on or after the Effective Date, even if such Incentive-Based Compensation was approved, awarded, granted or paid to the Covered Executive prior to the Effective Date. Subject to applicable law, the Committee may effect forfeiture or recoupment under this Policy

from any amount of compensation approved, awarded, granted, payable or paid to the Covered Executive prior to, on or after the Effective Date.

Section 10. Amendment and Interpretation. The Committee may amend this Policy from time to time in its discretion, and shall amend this Policy as it deems necessary, appropriate or advisable to reflect the regulations adopted by the SEC and to comply with any rules or standards adopted by a national securities exchange on which the Company's securities are then listed. The Committee is authorized to interpret and construe this Policy and to make all determinations necessary, appropriate, or advisable for the administration of this Policy. It is intended that this Policy be interpreted in a manner that is consistent with the requirements of Rule 10D-1 and any applicable rules or standards adopted by the SEC and any national securities exchange on which the Company's securities are then listed.

Section 11. Other Recoupment Rights. The Committee may require that any employment agreement, equity award agreement, or similar agreement entered into, amended or restated on or after the Effective Date shall, as a condition to the grant of any benefit thereunder, require a Covered Executive to agree to abide by the terms of this Policy and the application of this Policy to any award made prior to the Effective Date. Any right of recoupment under this Policy is in addition to, and not in lieu of, any other remedies or rights of recoupment that may be available to the Company pursuant to the terms of any other recoupment or recoupment policy, any similar policy in any employment agreement, equity award agreement, or similar agreement and any other legal remedies available to the Company.

Section 12. **Successors**. This Policy shall be binding and enforceable against all Covered Executives and their beneficiaries, heirs, executors, administrators or other legal representatives.

Section 13. **Disclosure Obligations**. The Company shall file all disclosures with respect to this Policy required by applicable SEC filings and rules.

Section 14. **Entire Agreement.** To the extent inconsistent with this Policy, this Policy supersedes all prior contracts, agreements and understandings, written or oral, with any Covered Executive. In the event any contract, agreement or understanding with any Covered Executive is inconsistent with the terms of this Policy, the terms of this Policy shall govern.

Exhibit 99.1

March 13, 2024

Mr. George Maxwell
VAALCO Energy Inc.
9800 Richmond Avenue, Suite 700
Houston, Texas 77042

Dear Mr. Maxwell:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2023, to the VAALCO Energy Inc. (VAALCO) interest in certain oil properties located in the Petrobakr Merged Concession, Egypt. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute approximately 38 percent of all proved reserves owned by VAALCO. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future United States income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for VAALCO's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the gross (100 percent) oil reserves and the net oil reserves and future net revenue to the VAALCO interest in these properties, as of December 31, 2023, to be:

	Oil Reserves (MBBL)		Future Net Revenue (M$)	
Category	Gross (100%)	Net	Total	Present Worth at 10%
Proved Developed Producing	16,668.4	9,628.8	189,188.4	148,121.7
Proved Developed Non-Producing	883.5	512.2	18,410.4	9,043.5
Proved Undeveloped	785.5	451.2	8,460.8	4,581.4
Total Proved (1P)	18,337.5	10,592.2	216,059.5	161,746.5

Totals may not add because of rounding.

The oil volumes shown include crude oil only. Oil volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Produced gas is flared or consumed in field operations. Monetary values shown in this report are expressed in United States dollars ($) or thousands of United States dollars (M$).

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

The contractors' share of production is calculated pursuant to the provisions of the production sharing contract for the Petrobakr Merged Concession. Included are determinations of cost oil incorporating the unrecovered cost pool and estimated cost-recoverable expenditures scheduled in the future; the portion of cost oil remaining after these expenditures have been recovered is referred to as excess cost oil. Also included are determinations of profit oil based on estimated future oil production rates.

Gross revenue is VAALCO's share of the gross (100 percent) revenue from the properties after deducting the Egyptian national government (the State) share of profit oil. Future net revenue is after deductions for these amounts and VAALCO's share of capital costs, abandonment costs, bonuses paid to the State, the State's share of excess cost oil, and operating expenses. The future net revenue is before consideration of any United States income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

The oil price used in this report is based on the 12-month unweighted arithmetic average of the first-day-of-the-month Platts Dated Brent spot price for each month in the period January through December 2023. The average price of $83.27 per barrel is adjusted for quality, transportation fees, and market differentials. The adjusted oil price of $64.59 per barrel is held constant throughout the lives of the properties.

Operating costs used in this report are based on operating expense records of VAALCO, the operator of the properties. As requested, operating costs are limited to direct concession- and field-level costs and VAALCO's estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Operating costs have been divided into concession-level costs, per-well costs, and per-unit-of-production costs and are not escalated for inflation.

Capital costs used in this report were provided by VAALCO and are based on authorizations for expenditure, internal planning budgets, and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, recurring maintenance projects, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Capital costs are not escalated for inflation. It is our understanding that VAALCO would not incur any costs due to abandonment, nor would it realize any salvage value for the lease and well equipment.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical concession-level accounting statements.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by VAALCO, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from VAALCO, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. John R. Cliver, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2009 and has over 5 years of prior industry experience. Zachary R. Long, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2007 and has over 2 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

/s/ Richard B. Talley, Jr.
By:
Richard B. Talley, Jr., P.E.
Chief Executive Officer

/s/ John R. Cliver	/s/ Zachary R. Long
By:	By:
John R. Cliver, P.E. 107216	Zachary R. Long, P.G. 11792
Senior Vice President	Vice President
Date Signed: March 13, 2024	Date Signed: March 13, 2024

JRC:WKE

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2018 Petroleum Resources Management System:

Developed Producing Reserves – 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 – 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.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities* .

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i) : The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs*.

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities —Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)
b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.
b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.
c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.
d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.
e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.
f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells

on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

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(32) *Unproved properties.* Properties with no proved reserves.

Exhibit 99.2

March 13, 2024

Mr. George Maxwell
VAALCO Energy Inc.
9800 Richmond Avenue, Suite 700
Houston, Texas 77042

Dear Mr. Maxwell:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2023, to the VAALCO Energy Inc. (VAALCO) interest in certain oil properties located in the Etame Marin Permit, offshore Gabon. We completed our evaluation on February 6, 2024. It is our understanding that the proved reserves estimated in this report constitute approximately 33 percent of all proved reserves owned by VAALCO. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future United States income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for VAALCO's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the gross (100 percent) oil reserves and the net oil reserves and future net revenue to the VAALCO interest in these properties, as of December 31, 2023, to be:

	Oil Reserves (MBBL)		Future Net Revenue (M$)	
Category	Gross (100%)	(1)Net(1)	Total	Present Worth at 10%
Proved Developed Producing	15,872.4	8,053.0	112,165.8	108,192.7
Proved Undeveloped(2)	2,030.4	1,010.8	1,710.1	-368.6
Total Proved	17,902.9	9,063.8	113,876.0	107,824.1

Totals may not add because of rounding.

(1) Net reserves are prior to deductions for "income tax barrels".
(2) These reserves have been included based on VAALCO's declared intent to drill this well.

The oil volumes shown include crude oil and condensate. Oil volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Produced gas is flared or consumed in field operations. Monetary values shown in this report are expressed in United States dollars ($) or thousands of United States dollars (M$).

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. Estimates of proved undeveloped reserves have been included for the ETBNM-3 well, which generates positive future net revenue but has negative present worth discounted at 10 percent based on the constant price and cost parameters discussed in subsequent paragraphs of this letter. This location has been included based on VAALCO's declared intent to drill this well, as evidenced by its internal budget, reserves estimates, and price forecast. As requested, probable and possible reserves that exist for these properties have not been included. Our study indicates that as of December 31, 2023, there are no proved developed non-producing reserves for these properties. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

The contractors' share of production is calculated pursuant to the provisions of the production sharing contract for the Etame Marin Permit. Included are determinations of cost oil incorporating the unrecovered cost pool and estimated cost-recoverable expenditures scheduled in the future. Also included are determinations of profit oil based on estimated future oil production rates.

As requested, our estimates of net reserves are prior to deductions for the portion of the Gabonese national government (the State) share of the profit oil required for payment of VAALCO's Gabonese income taxes, referred to herein as "income tax barrels". These income tax barrels have been calculated as the State's share of profit oil multiplied by VAALCO's working interest, net of the State participation.

Gross revenue is VAALCO's share of the gross (100 percent) revenue from the properties after deducting all production sharing revenue paid to the State. Future net revenue is after deductions for these amounts and VAALCO's share of capital costs, abandonment costs, operating expenses, and production taxes; the production taxes include bonuses and fees paid to the State for training funds, hydrocarbon support funds, corporate social responsibility, domestic market obligations, and Provision pour Investissements Diversifiées (PID)/Provision pour Investissements en Hydrocarbures (PIH). The future net revenue also includes credits for VAALCO's share of the State reimbursement and is before consideration of any United States income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

The oil price used in this report is based on the 12-month unweighted arithmetic average of the first-day-of-the-month Platts Dated Brent spot price for each month in the period January through December 2023. The average price of $83.27 per barrel is adjusted for quality, transportation fees, and market differentials. The adjusted oil price of $83.22 per barrel is held constant throughout the lives of the properties.

Operating costs used in this report are based on operating expense records of VAALCO, the operator of the properties. As requested, operating costs are limited to direct permit- and field-level costs and VAALCO's estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Operating costs have been divided into permit-level costs, per-well costs, and per-unit-of-production costs and include the costs associated with recurring electric submersible pump replacements, diesel purchases during periods where gas production is insufficient to fuel operations, and contractual changes to the floating storage and offloading vessel (FSO) charter fees. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by VAALCO and are based on authorizations for expenditure and internal planning budgets. Capital costs are included as required for new development wells, recurring maintenance projects, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are VAALCO's estimates of the costs to abandon the wells, platforms, and production facilities; these estimates do not include any salvage value for the platform and well equipment. It is our understanding that VAALCO has established escrow accounts for abandonment liability and expects these accounts to be fully funded by December 31, 2038. We further understand that if the economic limit for the permit area is reached before this date, then all abandonment costs not yet prefunded will be spent by December 31 of the year after the economic limit date. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical permit-level accounting statements.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by VAALCO, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from VAALCO, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. John R. Cliver, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2009 and has over 5 years of prior industry experience. Zachary R. Long, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2007 and has over 2 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

/s/ Richard B. Talley, Jr.
By:
Richard B. Talley, Jr., P.E.
Chief Executive Officer

/s/ John R. Cliver	/s/ Zachary R. Long
By:	By:
John R. Cliver, P.E. 107216	Zachary R. Long, P.G. 11792
Senior Vice President	Vice President
Date Signed: March 13, 2024	Date Signed: March 13, 2024

JRC:WKE

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2018 Petroleum Resources Management System:

Developed Producing Reserves – 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 – 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.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities*.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and
(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural

resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs*.

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data,

can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities —Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)
b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.
b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.
c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.
d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.
e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.
f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

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(32) *Unproved properties.* Properties with no proved reserves.

Exhibit 99.3

March 12, 2024

Project 1234021

The Board of Directors of Vaalco Energy Inc.
Vaalco Energy Inc.
900, 444 – 5th Avenue S.W.
Calgary, Alberta T2P 2T8

Dear Board Members:

Re: <u>Third Party Report on Reserves</u>

This report was prepared to satisfy requirements contained in Item 1202(a)(8) of U.S. Securities and Exchange Commission Regulation S-K and to provide the qualifications of the technical persons responsible for overseeing the reserve estimation process.

The numbering of items below corresponds to the requirements set out in Item 1202(a)(8) of Regulation S-K. Terms to which a meaning is ascribed in *Regulation S-K* and *Regulation S-X* have the same meaning in this report.

i. We have prepared an independent evaluation of the Canadian reserves of Vaalco Energy Inc. (the "Company") for the management and the board of directors of the Company. The primary purpose of our evaluation report was to provide estimates of reserves information in support of the Company's year-end reserves reporting requirements under US Securities Regulation S-K and for other internal business and financial needs of the Company.

ii. We have evaluated and reviewed certain reserves of the Company as at December 31, 2023. The completion (transmittal) date of our report is February 14, 2024.

iii. The following table sets forth the proved gross (100%) and net after royalty reserves under constant prices and costs covered by our report by geographic area, and the proportion of the Company covered.

Category	Oil (Mbbl)		Gas (Mmcf)		NGL (Mbbl)		BOE (Mbbl)[3]		Future Net Revenue Before Tax (M$)	
	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]	Total	Present Worth at 10%
<u>Canada</u>										
Proved Developed Producing	1,512	1,277	10,165	8,897	1,728	1,429	4,934	4,189	68,614	46,988
Proved Developed Non-Producing	34	32	120	114	20	19	75	70	2,273	1,691
Proved Undeveloped	2,478	2,122	8,661	7,921	1,472	1,289	5,394	4,731	72,334	23,685
Total Proved	**4,024**	**3,431**	**18,946**	**16,932**	**3,221**	**2,737**	**10,403**	**8,991**	**143,220**	**72,363**
<u>Total Evaluated</u>										
Proved Developed Producing	1,512	1,277	10,165	8,897	1,728	1,429	4,934	4,189	68,614	46,988
Proved Developed Non-Producing	34	32	120	114	20	19	75	70	2,273	1,691
Proved Undeveloped	2,478	2,122	8,661	7,921	1,472	1,289	5,394	4,731	72,334	23,685
Total Proved	**4,024**	**3,431**	**18,946**	**16,932**	**3,221**	**2,737**	**10,403**	**8,991**	**143,220**	**72,363**

(1) Gross reserves represents 100% ownership before royalties.
(2) Net reserves represents company interest reserves net of royalty deductions.
(3) Oil equivalence factors: Crude Oil and NGL 1 bbl/bbl, Natural Gas 6 Mcf/bbl interest reserves net of royalty deductions.

In aggregate, the Canadian assets which GLJ evaluates account for 31.4 percent of the Company's net proved reserves. The Company provided to us the total Company reported reserves to derive the portion evaluated by GLJ. We express no opinion on this portion of the Company's reserves that we did not evaluate.

iv. Our report covered 31.4 percent of the Company's total proved reserves; our evaluation coverage from the perspective of the Company's total reserves is provided above in item iii. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") with the necessary modifications to reflect definitions and standards under the U.S. Financial Accounting Standards Board policies (the "FASB Standards") and the legal requirements under the U.S. Securities and Exchange Commission ("SEC requirements").

The economic evaluation was prepared to reflect the net present value of the Company before any incremental US taxes. Canadian income taxes were included, as well as the Company supplied estimates of abandonment and reclamation obligations.

Data used in our evaluation was obtained from regulatory agencies, public sources and from Company personnel and Company files. In the preparation of our report we have accepted as presented, and have relied, without independent verification, upon a variety of information furnished by the Company such as interests and burdens, recent production, product transportation and marketing and sales agreements, historical revenue, capital costs, operating expense data, budget forecasts, capital cost estimates and well data for recently drilled wells. If in the course of our evaluation, the validity or sufficiency of any material information was brought into question, we did not rely on such information until such concerns were satisfactorily resolved.

The Company has warranted in a representation letter to us that, to the best of the Company's knowledge and belief, all data furnished to us was accurate in all material respects, and no material data relevant to our evaluation was omitted.

A field examination of the evaluated property was not performed nor was it considered necessary for the purposes of our report.

In our opinion, estimates provided in our report have, in all material respects, been determined in accordance with the applicable industry standards, and results provided in our report and summarized herein are appropriate for inclusion in filings under Regulation S-K.

v. As required under SEC Regulation S-X, reserves are those quantities of oil and gas that are estimated to be economically producible under existing economic conditions. As specified, in determining economic production, constant product reference prices have been based on a 12 month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12 month period prior to the effective date of our report. The following average prices have been adjusted for quality, transportation fees and market differentials.

Country	Oil ($/bbl)	Gas ($/mcf)	Ethane ($/bbl)	Propane ($/bbl)	Butane ($/bbl)	Condensate ($/bbl)
Canada	$74.70	$2.04	$6.31	$22.40	$33.73	$76.98

The adjusted prices presented below have been held constant throughout the lives of the properties.

Country	Country	Oil ($/bbl)	Gas ($/mcf)	Ethane ($/bbl)	Propane ($/bbl)	Butane ($/bbl)	Condensate ($/bbl)
Harmattan	Canada	$71.67	$1.91	$5.20	$20.18	$36.69	$74.76

In our economic analysis, operating and capital costs are those costs estimated as applicable at the effective date of our report, with no future escalation. Where deemed appropriate, the capital costs and revised operating costs associated with the implementation of committed projects designed to modify specific field operations in the future may be included in economic projections.

vi. Our report has been prepared assuming the continuation of existing regulatory and fiscal conditions subject to the guidance in the COGE Handbook and SEC regulations. Notwithstanding that the Company currently has regulatory approval to produce the reserves identified in our report, there is no assurance that changes in regulation will not occur; such changes, which cannot reliably be predicted, could impact the Company's ability to recover the estimated reserves.

vii. Oil and gas reserves estimates have an inherent degree of associated uncertainty, the degree of which is affected by many factors. Reserves estimates will vary due to the limited and imprecise nature of data upon which the estimates of reserves are predicated. Moreover, the methods and data used in estimating reserves are often necessarily indirect or analogical in character rather than direct or deductive. Furthermore, the persons involved in the preparation of reserves estimates and associated information are required, in applying geosciences, engineering and evaluation principles, to make numerous unbiased judgments based upon their educational background, professional training, and professional experience. The extent and significance of the judgments to be made are, in themselves, sufficient to render reserves estimates inherently imprecise. Reserves estimates may change substantially as additional data becomes available and as economic conditions impacting oil and gas prices and costs change. Reserves estimates will also change over time due to other factors such as knowledge and technology, fiscal and economic conditions, and contractual, statutory and regulatory provisions.

viii. In our opinion, the reserves information evaluated by us have, in all material respects, been determined in accordance with all appropriate industry standards, methods and procedures applicable for the filing of reserves information under U.S. SEC Regulation S-K.

ix. A summary of the Company reserves evaluated by us was provided for item iii. Of the 8,991 Mboe total proved net after royalty reserves evaluated by us, 4,259 Mboe are proved developed and 4,731 Mboe are proved undeveloped.

GLJ is a private firm established in 1972 whose business is the provision of independent geological and engineering services to the petroleum industry. GLJ is among the largest evaluation firms in North America with approximately 50 engineering and geoscience personnel. Ms. Baird conducted the evaluation and is a qualified, independent reserves evaluator as defined in COGEH, and is a registered Practicing Professional Engineer in the Province of Alberta. Ms. Baird has in excess of 22 years of practical experience in petroleum engineering, has been employed at GLJ as an evaluator/auditor since 2000.

We trust this meets your current requirements.

Yours truly,

GLJ LTD.

Carolyn L. Baird, P. Eng.
Manager, Engineering

CLB/vdp