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, 2021
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 **(State or other jurisdiction of incorporation or organization)**	**76-0274813** **(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 ☐

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, 2021, the aggregate market value of the voting and non-voting common equity of the registrant held by non-affiliates was approximately $175.0 million based on a closing price of $3.25 on June 30, 2021.

As of February 28, 2022, there were outstanding 58,669,028 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 Terms

Terms used to describe quantities of crude oil and natural gas

- *Bbl* — One stock tank barrel, or 42 United States ("U.S.") gallons liquid volume, of crude oil or other liquid hydrocarbons.
- *BOPD* — One barrel of crude oil per day.
- *MBbl* — One thousand Bbls.
- *MBOPD* — One thousand barrels of crude oil per day.
- *MMBbl* — One million Bbls.

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

- *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.
- *Carried interest* — Working interest (as described 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.
- *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.
- *PSC* — A production sharing contract; Etame PSC is the Etame Production Sharing Contract, as amended, and as it may be further amended, that we have entered into with Gabon, related to the Etame Marin block located offshore Gabon.
- *FPSO* — A floating, production, storage and offloading vessel.
- *FSO* – A floating storage and offloading vessel.
- *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.
- *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 production or, if the conveyance creating the interest provides, a specific portion of crude oil and natural gas produced, without any deduction for the costs to explore for, develop or produce the crude oil and natural gas.
- *Working interest* — A real property interest entitling the owner to receive a specified percentage of the proceeds of the sale of crude oil and natural gas 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 and natural gas. 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.

Terms used to describe interests in wells and acreage

- *Gross crude oil and natural gas 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 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 reserves* — Developed crude oil and natural 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.
- *Proved crude oil and natural gas reserves* — Proved crude oil and natural gas reserves are those quantities of crude oil and natural 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 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 and natural 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 crude oil and natural gas or related substances to market, and all permits and financing required to implement the project.
- *Proved undeveloped crude oil and natural gas reserve, PUDs* — Proved undeveloped crude oil and natural gas 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 and natural gas companies use seismic data as their principal source of information to locate crude oil and natural gas 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 and natural gas 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:

- the impact of the coronavirus (“COVID-19”) pandemic, including its impact on global demand for crude oil and crude oil prices, potential difficulties in obtaining additional liquidity when and if needed, disruptions in global supply chains, quarantines of our workforce or workforce reductions and other matters related to the pandemic;
- the impact of any future production quotas imposed by Gabon, as a member of the Organization of the Petroleum Exporting Countries (“OPEC”), as a result of agreements among OPEC, Russia and other allied producing countries (collectively, “OPEC+”) with respect to crude oil production levels;
- volatility of, and declines and weaknesses in crude oil and natural gas 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 and natural gas reserves;
- impairments in the value of our crude oil and natural gas 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 and natural gas;
- difficulties encountered during the exploration for and production of crude oil and natural gas;
- 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 and natural gas reserves;
- 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 availability and cost of seismic, drilling and other equipment;
- difficulties encountered in measuring, transporting and delivering crude oil to commercial markets;
- our ability to effectively replace the FPSO;
- timing and amount of future production of crude oil and natural gas;
- 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 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 21 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.

- Events outside of our control, such as the ongoing COVID-19 pandemic, could adversely impact our business, results of operations, cash flows, financial condition and liquidity.
- 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.
- 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.
- All of the value of our current production and reserves is concentrated in a single block offshore Gabon, and any production problems or reductions in reserve estimates related to this property would adversely impact our business.
- 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 we have an interest in.
- Our offshore operations involve special risks that could adversely affect our results of operations.
- If we are not able to timely implement the transition to the FSO unit before the expiration of the FPSO contract in September 2022, our results of operations could be materially adversely affected.
- 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.
- We may experience a financial loss if our significant customer fails to pay us for our crude oil or natural gas or reduce the volume of crude oil and natural gas that they purchase from us.
- 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 costs are too low, we could be required to expend greater amounts than expected.
- We could lose our interest in Block P if we do not meet our commitments under the production sharing contract.
- Commodity derivative transactions we enter into may fail to protect us from declines in commodity prices and could result in financial losses or reduce our income.
- Our business could be materially and adversely affected by security threats, including cybersecurity threats, and other disruptions.
- 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, and added risk in foreign countries may affect our foreign investments.
- Our operations may be adversely affected by political and economic circumstances in the countries in which we operate.
- Our results of operations, financial condition and cash flows could be adversely affected by changes in currency exchange rates and by currency regulations.
- We operate in international jurisdictions, and we could be adversely affected by violations of the United States 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.
- Crude oil and natural gas 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.
- Material declines in crude oil and natural gas prices have required us, and may require us in the future, to take write-downs in the value of our crude oil and natural gas properties.
- Competitive industry conditions may negatively affect our ability to conduct operations.
- Competition due to advances in renewable fuels may lessen the demand for our products and negatively impact our profitability.
- Weather, unexpected subsurface conditions and other unforeseen operating hazards may adversely impact our crude oil and natural gas activities.
- 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 activism against crude oil and natural gas exploration and development activities.
- Compliance with environmental and other government regulations could be costly and could negatively impact production.
- The physical and regulatory impact of climate change could disrupt our business and cause us to incur significant costs in preparing for or responding to their effects.

PART I

Item 1. Business

BACKGROUND

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. Information contained on our website is not incorporated by reference into this Annual Report. 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 independent energy company engaged in the acquisition, exploration, development and production of crude oil. Our primary source of revenue has been from the Etame PSC related to the Etame Marin block located offshore Gabon in West Africa. We also currently own an interest in an undeveloped block offshore Equatorial Guinea, West Africa.

STRATEGY

We own crude oil producing properties and conduct operating activities offshore West Africa with a focus on maximizing the value of our Gabon resources and expanding into new development opportunities across Africa. Our financial results are heavily dependent upon the margins between prices received for our offshore Gabon crude oil production and the costs to find and produce such crude oil. On September 25, 2018, the term of the Etame PSC with Gabon related to the Etame Marin block located offshore Gabon was extended 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. We also completed a dual listing of our common stock on the London Stock Exchange on September 26, 2019, which we believe will provide us access to additional sources of capital to help fund our growth objectives.

In September 2019, we commenced our 2019/2020 drilling campaign. We drilled one development well and one appraisal wellbore in 2019, and during the first quarter of 2020, we drilled one development well and one appraisal wellbore. In addition, we successfully completed drilling the South East Etame 4H development well and brought the well onto production on March 21, 2020.

In December 2020, we completed the acquisition of approximately 1,000 square kilometers of new dual-azimuth proprietary 3-D seismic data over the entire Etame Marin block, which will be used to optimize and de-risk future drilling locations and potentially identify new drilling locations. We expect the seismic data to enhance sub-surface imaging by merging legacy data with newly acquired seismic data, allowing for the first continuous 3-D seismic survey over the entire block.

On February 25, 2021, we completed the acquisition of Sasol Gabon S.A.’s (“Sasol’s”) 27.8% working interest in the Etame Marin block offshore Gabon pursuant to the sale and purchase agreement dated November 17, 2020 (the “SPA”).

On October 11, 2021 we announced our entry into a consortium with BW Energy and Panoro Energy (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.

The award is subject to 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.

In December 2021, we commenced our 2021/2022 drilling campaign offshore Gabon with the Etame 8-H well. We expect to drill a minimum of four wells with options to drill additional wells. In February 2022 we completed the drilling of the Etame 8-H well and moved the drilling rig to the Avouma platform to drill the Avouma 3H-ST1 development well, which is targeting the Gamba reservoir. The initial flow rate of the ETAME 8-H well was 5,000 BOPD, 2,560 BOPD net to VAALCO's 58.8% working interest in 2022.

We are now focused on maximizing value, growing reserves and increasing production and will continue our efforts to repeat similar drilling campaigns in the future.

Our strategy is to create long-term value for all stakeholders by focusing on profitable growth from low-risk reserve development while maintaining financial discipline. 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 prices;
- Manage capital expenditures related to the Etame drilling program 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 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 prices; and
- Actively pursue strategic, value-accretive mergers and acquisitions of similar properties to diversify our portfolio of producing assets.
- Strategy related to BWE Consortium

We believe that we have strong management and technical expertise specific to West Africa, and that our strengths include:

- Our reputation as a safe and efficient operator in Africa;
- 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.

RECENT DEVELOPMENTS

On February 25, 2021, we completed the acquisition of Sasol's 27.8% working interest in the Etame Marin block offshore Gabon pursuant to the SPA (the "Sasol Acquisition"). Prior to the Sasol Acquisition, we owned and operated a 31.1% working interest in Etame. The Sasol Acquisition increased our working interest to 58.8%, almost doubling our total production and reserves. The effective date of the transaction was July 1, 2020. We completed the Sasol Acquisition for a final cash settlement payment of $29.6 million, which was paid from cash on hand and reflected the $44.0 million purchase price less (i) a cash deposit of approximately $4.3 million paid on the SPA execution date, (ii) net cash flows generated from the Sasol interest from July 1, 2020 through the closing date and (iii) other purchase price adjustments pursuant to the SPA. In addition, under the terms of the SPA, a contingent payment of $5.0 million was payable to Sasol should the average Dated Brent price over a consecutive 90-day period from July 1, 2020 to June 30, 2022 exceed $60.00 per barrel. The conditions related to the contingent payment were met and on April 29, 2021, the Company paid the $5.0 million contingent amount to Sasol in accordance with the terms of the SPA. As a result of the acquisition, our net portion of production and costs relating to our Etame operations has increased from 31.1% to 58.8%. For further discussion on the Sasol Acquisition, see "*Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Recent Developments*."

The World Health Organization declared a global pandemic on March 11, 2020. The adverse economic effects of the COVID-19 outbreak materially decreased demand for crude oil based on the restrictions in place by governments trying to curb the outbreak and changes in consumer behavior. This led to a significant global oversupply of crude oil and consequently a substantial decrease in crude oil prices in 2020.

In response to the oversupply of crude oil, global crude oil producers, including the Organization of Petroleum Exporting Countries and other oil producing nations ("OPEC+"), reached agreement in April 2020 to cut crude oil production. Further, in connection with the

OPEC+ agreement, the Minister of Hydrocarbons in Gabon requested that the Company reduce its production. In response to such request from the Minister of Hydrocarbons, between July 2020 and April 2021, the Company temporarily reduced production from the Etame Marin block. Currently, the Company's production is not impacted by OPEC+ curtailments. 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 in production was reaffirmed by an OPEC+ meeting held on February 2, 2022.

We considered the impact of the COVID-19 pandemic and the substantial decline in crude oil prices on the assumptions and estimates used for preparation of the financial statements. As a result, we recognized a number of material charges during the three months ended March 31, 2020, including impairments to our capitalized costs for proved crude oil and natural gas properties and valuation allowances on its deferred tax assets. These are discussed further in the notes to our consolidated financial statements included in this report.

For the year ended December 31, 2021, crude oil prices have improved, there were no disruptions to operations as a result of COVID-19 or any strain thereof, global economic activity has steadily increased, and oil demand has stabilized over multiple quarters removing much of the uncertainty and instability in the industry. Therefore, no additional charges or impairments were required for the twelve months ended December 31, 2021. Crude oil prices have continually increased and are currently at the highest levels seen in recent years. The average annual Brent price per barrel for the year ended December 31, 2020 was $41.96 and increased 69% to $70.86 for the year ended December 31, 2021. At the end of 2021 and continuing into 2022, travel-related restrictions have lessened, access to vaccines that reduce the spread and impact of COVID-19 and its variants have become more accessible and the global economy appears more flexible to continuing to effectively operate in a COVID-19 environment. However, while the business environment in 2021 improved, the COVID-19 situation and effects thereof remain fluid. A prolonged outbreak may have a material adverse impact on our financial results and business operations, including the timing and ability of us to complete future drilling campaigns and other efforts required to advance the development of our crude oil and natural gas properties. For further discussion on the impact on operations of the COVID-19 pandemic and the current crude oil pricing environment see "*Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Recent Developments*."

We are currently a party to an FPSO charter for the storage of all of the crude oil that we produce. This contract will expire in September 2022. On August 31, 2021, we and our co-venturers at Etame approved the Bareboat Contract and Operating Agreement (collectively, the "FSO Agreements") with World Carrier Offshore Services Corp. to replace the existing FPSO with a Floating Storage and Offloading unit ("FSO"). The FSO Agreements require a prepayment of $2 million gross ($1.2 million, net to VAALCO) in 2021 and $5 million gross ($3.2 million net) in 2022 of which $6 million will be recovered against future rentals. No other prepayments are required under the FSO Agreements until the vessel is accepted by the Company at the Etame Marin Block location, which is expected during the third quarter of 2022. The Bareboat Contract contains purchase provisions and termination provisions. We currently do not expect to utilize the termination provisions under the FSO Agreements. In addition, total field level capital conversion estimates, to accept and implement the FSO, are $40 to $50 million gross ($26 to $32 million net to VAALCO).

The BWE Consortium of VAALCO, BW Energy and Panoro Energy was provisionally awarded two blocks in the 12th Offshore Licensing Round in Gabon. The award is subject to concluding the terms of production sharing contracts ("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.

On November 3, 2021, we announced that our board of directors adopted a quarterly cash dividend policy of an expected $0.0325 per common share commencing in the first quarter of 2022. On January 28, 2022, our board of directors declared a quarterly cash dividend of $0.0325 per share of common stock, which is payable on March 18, 2022 to stockholders of record at the close of business on February 18, 2022. Payment of future dividends, if any, and the establishment of future record and payment dates 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.

SEGMENT AND GEOGRAPHIC INFORMATION

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

Gabon Segment

Offshore – Etame Marin Block

Our most significant asset, which accounts for 100% of our current revenues, is the Etame PSC related to the Etame Marin block 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%.

Development

We commenced our 2019/2020 drilling campaign in September 2019 and completed the campaign in April 2020. In September 2019, we spud the Etame 9P appraisal wellbore at the Etame block offshore Gabon. In October 2019, the Etame 9P, targeting the subcropping Dentale reservoir, was successfully drilled to a total depth of 10,260 feet and encountered both Gamba and Dentale crude oil sands. In December 2019, VAALCO reached total depth of approximately 8,900 feet in drilling the Etame 9H development well and completed approximately 1,000 feet of the horizontal section within the Gamba reservoir as planned. The horizontal section of the Etame 9H development well is at the top of the Gamba structure where the high-quality reservoir is approximately 45 feet thick. After installing production equipment, the Etame 9H development well was brought online at an initial rate of 5,500 BOPD gross, (1,500 BOPD net to VAALCO's 31.1% working interest in 2019).

Shortly after completion of the Etame 9H development well, we began drilling the Etame 11H horizontal development well from the Etame platform, targeting the same Gamba reservoir at a different location in the Etame block. We reached a total measured depth of approximately 9,022 feet in the Etame 11H development well and completed approximately 860 feet of horizontal section within the Gamba reservoir. Similar to Etame 9H well, the horizontal section of the Etame 11H well is at the top of the Gamba structure but at a different location. After installing production equipment, the Etame 11H well was brought online at an initial flow rate of approximately 5,200 BOPD gross, (1,400 BOPD net to VAALCO's 31.1% working interest in 2020) , in early January 2020.

We drilled the SE Etame 4P appraisal wellbore to evaluate a Gamba step out area in the Etame block during the first quarter of 2020. With the drilling of the SE Etame 4P appraisal wellbore, we satisfied the drilling commitment as part of the PSC Extension that we signed in late 2018. The SE Etame 4P appraisal wellbore indicated the presence of approximately 1.0 to 2.0 MMBbls of hydrocarbons in the Gamba reservoir, and the Company began drilling a third development well, the SE Etame 4H as part of the 2019/2020 drilling campaign. This development well was brought online in late March of 2020. With respect to all of the wells drilled in the 2019/2020 drilling campaign, we did not encounter hydrogen sulfide ("H_2S") in either the Gamba or Dentale reservoirs, which could impact the safety and marketability of production from those wells.

As discussed above, in December 2020, we completed the acquisition of approximately 1,000 square kilometers of new dual-azimuth proprietary 3-D seismic data over the entire Etame Marin block. We expect the seismic data to enhance sub-surface imaging by merging legacy data with newly acquired seismic allowing for the first continuous 3-D seismic over the entire block. The processing of the seismic data began in January 2021, and was completed by the fourth quarter of 2021. The seismic data will be used to optimize and de-risk future drilling locations and potentially identify new drilling locations. We commenced the 2021/2022 drilling campaign in December 2021 with the drilling of the Etame 8-H development well. We anticipate the costs of the 2021/2022 drilling program to have an estimated cost of $117.0 million to $143 million gross, or $74.0 million to 91.0 million, net to VAALCO's 63.6% participating interest. In February 2022, we completed the drilling of the Etame 8-H well and moved the drilling rig to the Avouma platform to drill the Avouma 3H-ST1 development well, which is targeting the Gamba reservoir. The initial flow rate of the ETAME 8-H well was 5,000 BOPD, 2,560 BOPD net to VAALCO's 58.8% working interest in 2022.

Production

Production operations in the Etame Marin block include eleven platform wells, plus three subsea wells tied back by pipelines to deliver crude oil and associated natural gas through a riser system to allow for delivery, processing, storage and ultimately offloading the crude oil from a leased FPSO vessel anchored to the seabed on the block. Production from seven of our wells is aided by electric submersible pumps ("ESPs"). We currently have fourteen producing wells. The FPSO can process up to approximately 25,000 BOPD and 30,000 Bbls of total fluids per day. For the years ended December 31, 2021, 2020 and 2019, aggregate production from the block was approximately 5.4 MMBbls (2.6 MMBbls net to us), 6.6 MMBbls (1.8 MMBbls net to us) and 4.7 MMBbls (1.3 MMBbls net to us), respectively. Our net share of barrels produced reflects an allocation of cost oil and profit oil after reduction for a royalty of approximately 13%. Periodically, we perform workovers on our wells to maintain or restore production. For further discussion on workovers see "*Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Recent Developments*."

Hydrogen Sulfide Impact

Four of our wells are currently shut-in for safety and marketability reasons because of high levels of H_2S. These wells have been excluded from the above-referenced well count. H_2S was not encountered in any of the wells or appraisal wellbores drilled in the 2019/2020 drilling campaign and thus far in the 2021/2022 drilling campaign. To re-establish and maximize production from the impacted areas, additional capital investment will be required, including the construction of one or more processing facilities capable of removing H_2S, the recompletion of the temporarily abandoned wells and the potential drilling of additional wells. We have determined that these identified processing facilities are not the most economically attractive use of the Company's resources at current crude oil prices. As of December 31, 2021, we had no proved reserves booked for the wells impacted by high levels of H_2S.

Exploration

At December 31, 2021, we had $13.7 million in undeveloped leasehold costs related to the Etame Marin block. These costs are associated with the exploitation area expansion related to the PSC Extension and acquisition of Sasol's interest in the Sasol Etame Marin block.

Abandonment Costs

Under the Etame PSC terms, the Etame Consortium has agreed to a cash funding arrangement for the eventual abandonment of all offshore wells, platforms and facilities on the Etame Marin block. We are required under the Etame PSC to conduct abandonment studies to update the amounts being funded for the eventual abandonment of the offshore wells, platforms and facilities on the Etame Marin block. The most recent abandonment study was completed in 2021 and resulted in estimated gross abandonment costs of approximately $81.3 million ($47.8 million, net to VAALCO) on an undiscounted basis. Through December 31, 2021, $37.1 million ($21.8 million, net to VAALCO) on an undiscounted basis has been funded. The annual abandonment cost requirements net to VAALCO's 58.8% working interest, are expected to be $5.8 million in 2022 and, once the 2021 abandonment study has been approved by Ministry of Hydrocarbons in Gabon, a revised funding schedule will be established. Amounts paid are reimbursable through a "Cost Account" under the Etame PSC, which accumulates capital costs and operating expenses that are deductible against revenues, net of royalties, in determining taxable profits. These amounts are non-refundable. Our estimated liabilities for the abandonment of these Gabon offshore facilities as of December 31, 2021 and 2020 were $40.7 million and $17.3 million, respectively, which are included in the total "Asset retirement obligation" line item on our consolidated balance sheets as of December 31, 2021 and 2020. Initial recording of this liability is offset by a corresponding capitalization of asset retirement costs reflected under "Crude oil and natural gas properties and equipment – successful efforts method" in the line item "Wells, platforms and other production facilities" on our consolidated balance sheets as of December 31, 2021 and 2020.

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 the Company's 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, as required by the Block P joint operating agreement, assigned the defaulting party's interest to the non-defaulting parties. As a result, VAALCO's working interest will increase to 45.9% once the EG MMH approves a new amendment to the production sharing contract. We have completed a feasibility study of a standalone development concept of the Venus discovery on Block P. We, working closely with the other joint venture owners, are now in the process of finalizing the plan of development before submitting it to the EG MMH for their approval.

As of December 31, 2021 and 2020, we had $10.0 million recorded for the book value of the undeveloped leasehold costs associated with the Block P license.

We and our joint venture owners are evaluating the timing and budgeting for development and exploration activities under a development and production area in the block, including the approval of a development and production plan for the Venus Discovery. 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.

OPEC+ Production Reductions

Near the end of 2019, OPEC had an agreement in place to reduce production by a total of 1.2 MBOPD until March 2020. In April 2020, countries within OPEC+ reached an agreement to cut crude oil production 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 and, as a result, the Minister of Hydrocarbons in Gabon requested that we reduce our production. In response to the request from the Minister of Hydrocarbons, in July 2020 through April 2021, we temporarily reduced production from the Etame Marin block. 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.

DRILLING ACTIVITY

As discussed above, we commenced the 2019/2020 drilling campaign in September 2019. The following table sets forth the total number of completed exploratory and development wells drilled in 2021, 2020 and 2019 on a gross and net basis:

	International					
	Gross			Net		
	2021	2020	2019	2021	2020	2019
Exploratory wells						
Productive	**—**	1	1	**—**	0.3	0.3
Dry	**—**	—	—	**—**	—	—
In progress	**—**	—	—	**—**	—	—
Development wells						
Productive	**—**	2	1	**—**	0.6	0.3
Dry	**—**	—	—	**—**	—	—
In progress	**1**	—	1	**0.6**	—	0.3
Total wells	**1**	3	3	**0.6**	0.9	0.9

In December 2021 we began drilling the ETAME 8-H development well that was completed in February 2022.

ACREAGE AND PRODUCTIVE WELLS

Below is the total acreage under lease or covered by the Etame PSC and Block P and the total number of productive crude oil wells as of December 31, 2021

	Developed		Undeveloped		Total	
Acreage in thousands	Gross	Net	Gross	Net	Gross	Net
Etame	6.9	4.1	39.4	23.1	46.3	27.2
Block P	—	—	57.3	26.3	57.3	26.3
Total acreage	6.9	4.1	96.7	49.4	103.6	53.5
Productive crude oil wells	14.0 (1)	8.2				

(1)Excludes four wells shut-in due to the presence of high levels of H2S. All wells included in the table are Etame Marin block.

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 2021, the average of such price used for our reserve estimates was $69.10 per Bbl for crude oil from Gabon. This compares to the average of such price used for 2020 of $42.46 per Bbl and $63.60 per Bbl for 2019.

Reserves reported below consist of net proved reserves related to the Etame Marin block located offshore Gabon in West Africa. The Company currently has no other proved net crude oil or natural gas reserves. The table below sets forth our estimated net proved reserve quantities for the years ended December 31, 2021, 2020 and 2019 as prepared by our independent petroleum engineering firm, Netherland, Sewell & Associates, Inc. ("NSAI"). 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,		
	2021	2020	2019
		(in thousands)	
Crude oil			
Proved developed reserves (MBbls)	**7,227**	3,216	4,966
Proved undeveloped reserves (MBbls)	**3,991**	—	—
Total proved reserves (MBbls)	**11,218**	3,216	4,966

Standardized Measure and Changes in Proved Reserves

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

Proved Reserves	**Crude Oil (MBbls)**
	(in thousands)
Balance at January 1, 2019	5,370
Production	(1,269)
Revisions of previous estimates	865
Balance at December 31, 2019	4,966
Production	(1,776)
Extensions and discoveries	497
Revisions of previous estimates	(471)
Balance at December 31, 2020	3,216
Production	**(2,599)**
Purchase of reserves	**2,633**
Revisions of previous estimates	**7,968**
Balance at December 31, 2021	**11,218**

	As of December 31,		
	2021	**2020**	**2019**
		(in thousands)	
Standardized measure of discounted future net cash flows	$ **99,258**	$ 14,733	$ 70,431

The information set forth in the foregoing 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. The reserves at the end of the contract 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. At December 31, 2019, the reserves associated with the Etame 9H were reclassified from proved undeveloped reserves to proved developed producing reserves. The reserves associated with the South Tchibala 3H well were removed from proved undeveloped volumes because VAALCO and the Etame joint venture owners decided to remove the well from the 2019 development schedule and instead drill the Etame 11H. Drilling and completing the Etame 11H well resulted in reserve additions classified as proved developed nonproducing reserves at year end 2019. In 2020, we completed the Southeast Etame 4H development whose reserves is included in extensions and discoveries in the December 2020 balance. 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 comparing the net proved reserves of 11.2 MMBbls at December 31, 2021 to the 3.2 MMBbls at December 31, 2020, we added 2.6 MMBbls of reserves due to the acquisition of Sasol's interest in the Etame Marin block and 8.0 MMBbls of reserves through positive revisions of previous estimates. 3.0 MMBbls of the positive revisions were due to price of and 5.0 MMBbls of positives revision through performance and PUDS. The increase of 63% in the average of the first-day-of-the-month prices for each of the twelve months of the year, adjusted for quality, transportation fees and market differentials required by SEC rules to determine reserves, was $69.10 for the 2021 year-end report from $42.46 for the 2020 year-end report.

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 and natural gas 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 and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future crude oil and natural gas 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 and natural gas reserves attributable to our properties.

Historically, we have reviewed on an annual basis all of our proved undeveloped reserves ("PUDs") to ensure an appropriate plan for development exists. At December 31, 2021, we had four PUD well locations included in our reserves which we expect to complete in

2022. At December 31, 2020, we had no PUDs due to current SEC pricing. At December 31, 2019, we had no PUDs because future development wells had not been approved by joint venture owners.

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 and natural gas 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 a 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 Audit Committee of the Board of Directors meets periodically with management to discuss matters and policies related to reserves.

Our controls over reserve estimation include retaining NSAI as our independent petroleum and geological firm for all years presented. We provide information to NSAI about our crude oil and natural gas properties, which includes, but is not limited to, production profiles, ownership and production sharing rights, prices, costs and future drilling plans. NSAI prepares its own estimates of the reserves attributable to our properties. The reserves estimates shown herein have been independently evaluated by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. John R. Cliver and Mr. Zachary R. Long. Mr. 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. He graduated from Rice University in 2004 with a Bachelor of Science Degree in Chemical Engineering and from the University of Texas at Austin in 2008 with a Master of Business Administration Degree. Mr. 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. He graduated from University of Louisiana at Lafayette in 2003 with a Bachelor of Science Degree in Geology and from Texas A&M University in 2005 with a Master of Science Degree in Geophysics.

NET VOLUMES SOLD, PRICES, AND PRODUCTION COSTS

Net volumes sold, average sales prices per unit, and production costs per unit for our 2021, 2020 and 2019 operations are shown in the tables below. All volumes are for crude oil produced from the Etame Marin block.

	Year Ended December 31,		
	2021	**2020**	**2019**
Net crude oil sales (MBbl)	**2,711**	1,627	1,251
Average crude oil sales price ($/Bbl)	$ **70.66**	$ 40.29	$ 65.20
Average production expense ($/Bbl)	$ **29.97**	$ 22.93	$ 30.13

DISCONTINUED OPERATIONS-ANGOLA

On September 30, 2016, we notified Sonangol P&P, our joint venture owners, that we were withdrawing from the joint operating agreement effective October 31, 2016. Further to our decision to withdraw from Angola, we closed our office in Angola and do not intend to conduct future activities in Angola. As a result of this strategic shift, the Angola segment has been classified as discontinued operations in the Financial Statements for all periods presented. In 2019, the Company and Sonangol E.P. entered into a settlement agreement finalizing the Company's rights, liabilities and outstanding obligations for Block 5 in Angola. See "*Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Discontinued Operations - Angola*."

AVAILABLE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC. Our SEC filings are available to the public at the SEC's website at www.sec.gov.

You may also obtain copies of our annual, quarterly and current reports, proxy statements and certain other information filed with the SEC, as well as amendments thereto, free of charge from our website at www.vaalco.com. No information from either the SEC's website or our website is incorporated by reference herein. We have placed on our website copies of charters for our Audit Committee, Compensation Committee and Nominating and Corporate 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 Corporate Secretary, VAALCO Energy, Inc., 9800 Richmond Avenue, Suite 700, Houston, Texas 77042.

CUSTOMERS

For the years ended December 31, 2021, 2020 and 2019, we sold our crude oil production from Gabon under a term contract 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, 2018 through January 31, 2019, the contracted purchaser was Glencore Energy UK Ltd. ("Glencore"). Our contract with Mercuria Energy Trading SA covered crude oil sales from February 2019 through January 2020. Our contract with ExxonMobil Sales and Supply LLC ("ExxonMobil"), covered crude oil sales from February 2020 through January 2021 with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors. In December 2020, the contract with ExxonMobil was amended to extend the date of the contract through the end of July 2021. In July 2021, the contract with ExxonMobil was amended to extend the date of the contract through the end of January 2022. In January 2022, the contract with ExxonMobil was amended to extend the date of the contract through the end of July 2022.

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. 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.

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 the Company and its stockholders by helping our employees attain their highest level of creativity and efficiency.

Demographics

As of December 31, 2021, we had 117 full-time employees, 80 of whom were located in Gabon. 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 the Company's Equal Employment Opportunity policy. Approximately 5% of our management team are female employees and 93.8% of our Gabon workforce is Gabonese.

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 standard medical coverage, we offer eligible employees dental and vision coverage, health savings and flexible spending accounts, paid time off, employee assistance programs, employee loans, 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. Our benefits 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 of the Company 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 the Company's 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.

COVID-19 Pandemic

In response to the COVID-19 pandemic, related government legislation and guidelines and orders issued by key authorities, we implemented changes that we determined were in the best interest of our employees, as well as the communities in which we operate. These changes included quarantining and testing of employees and persons before going to our offshore platforms, having the majority of our employees work from home for several months, and implementing additional safety measures for employees continuing critical on-site work. We continue to maintain a high level of safety protocols and embrace a flexible working arrangement for our employees in Houston.

COMPETITION

The crude oil and natural gas industry is highly competitive. Competition is particularly intense from other independent operators and from major crude oil and natural gas companies with respect to acquisitions and development of desirable crude oil and natural gas 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 and natural gas 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 and natural gas 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 and natural gas 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

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 and natural gas production operations and economics are affected by:

- change in governments;

- civil unrest;
- price and currency controls;
- limitations on crude oil and natural gas 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 and natural gas 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 and natural gas industry, some of which carry substantial penalties for the failure to comply. The regulatory burden on the crude oil and natural gas 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. 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 28 August 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 percent participating interest in the operations, to be carried by the contractor.

The 2019 Hydrocarbons Law also entitles the Gabon Oil Company to acquire a maximum 15 percent 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 percent, at market value, in an operator applying for or already holding an exclusive development and production authorization.

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. The following is a summary of certain 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.

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 percent 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 and Equatorial Guinea, 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 with and are in good standing 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 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 and natural gas 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 and to the lobbying effects of various climate change non-governmental organizations. Legislation and increased regulation 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 and the United States, signed and officially entered into an international climate change accord (the "Paris Agreement"). The Paris Agreement calls for signatory countries to set their own greenhouse gas emissions targets, make these emissions targets more stringent over time and be transparent about the greenhouse gas emissions reporting and the measures each country will use to achieve its greenhouse gas 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 greenhouse gases, to which various countries and regions are parties. In August 2017, the U.S. Department of State officially informed the United Nations of the United States' 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 United States' 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 percent reduction from 2005 levels in economy-wide GHG emissions by 2030. 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 greenhouse gas emissions targets, potential prices on carbon emissions, regulations or other requirements, will affect our financial condition and operating performance. In addition, 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 or impact the marketability of crude oil and natural gas. 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 and storm patterns and 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 developing countries, it is unclear how quickly and to what extent Gabon or Equatorial Guinea will increase their regulation of environmental issues in the future; any significant increase in the regulation or enforcement of environmental issues by Gabon or Equatorial Guinea could have a material effect on us. 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 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 Related to Our Business, Operations and Strategy

Events outside of our control, such as the ongoing COVID-19 pandemic, could adversely impact our business, results of operations, cash flows, financial condition and liquidity.

We face risks related to epidemics, outbreaks or other public health events that are outside of our control. The global or national outbreak of an illness or any other communicable disease, or any other public health crisis, including the COVID-19 pandemic, could significantly disrupt our business and operational plans and adversely affect our results of operations, cash flows, financial condition and liquidity. Although we are not able to enumerate all potential risks to our business resulting from the ongoing COVID-19 pandemic, we believe that such risks include, but are not limited to, the following:

- we may experience disruption to our supply chain for materials essential to our business, including restrictions on importing and exporting products;
- we may receive notices from 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;
- we have experienced a cybersecurity attack and may face cybersecurity issues in the future, as digital technologies may become more vulnerable and experience a higher rate of cyberattacks in the current environment of remote connectivity;
- we may face litigation risk and possible loss contingencies related to COVID-19 and its impact, including with respect to commercial contracts, employee matters and insurance arrangements;
- we may be required to implement reductions of our workforce to adjust to market conditions, including severance payments, retention issues, and we may face an inability to hire employees when market conditions improve;
- we may incur additional asset impairments;
- we have and may continue to experience quarantines involving our employees and other third parties in areas in which we operate, and any such quarantines could result in a well shut-in, temporary closure of offshore platforms or the FPSO charter vehicle or other disruptions in production;
- we have faced and may continue to face 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 FPSO charter vessel or our counterparties are unable to lift crude oil from our FPSO charter vessel;
- we may be subject to actions undertaken by national, regional and local governments and health officials to contain the virus or treat its effects, including travel restrictions and temporary closures of our facilities, that could result in operations and supply chains being interrupted, slowed, or rendered inoperable; and
- we may experience a structural shift in the global economy and its demand for crude oil and natural gas 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 the COVID-19 pandemic and related market 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. For more information, see "*Management's Discussion and Analysis of Financial Condition and Results of Operations – Recent Developments – Impact on Operations of COVID-19 Pandemic and the Current Crude Oil Pricing Environment*".

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 and natural gas 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. In addition, on February 25, 2021, we completed the acquisition of Sasol's 27.8% working interest in the Etame Marin block offshore Gabon. Prior to the completion of the Sasol Acquisition, we relied on the timely payment of cash calls by our joint venture owners to pay for 66.4% of the offshore Gabon budget, but from and after the completion of the Sasol Acquisition, we 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. Further, we acquired an additional working interest of 12% from Atlas Petroleum, thereby increasing our working interest to 43% in 2020. Since we have been appointed, we will rely on the timely payment of cash calls by our joint venture owners to pay for 46.3% (including the 20% carry of GEPetrol's costs) of the Equatorial Guinea budget. 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 and natural gas 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. Our ability to secure additional or replacement financing may be limited. We cannot assure you that 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, 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.

At December 31, 2021, we had four PUDS. As discussed above in "*Item 1. Business — Segment and Geographic Information — Gabon Segment*", we commenced our 2019/2020 drilling program during September 2019 and completed the program with the last well being completed in March 2020. Further, the 2021/2022 program commenced in Etame in December of 2021 with Etame 8H-ST well and is expected to include two development wells and two appraisal wells.

Our future success depends upon our ability to find, develop or acquire additional crude oil and natural gas reserves that are economically recoverable. In general, production from crude oil and natural gas 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 and natural gas 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 and natural gas 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 or natural gas is present or economically producible. Our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including declines in crude oil or natural gas prices and/or prolonged periods of historically low crude oil and natural gas 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 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.

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, 2021, approximately 36 percent of our total estimated proved reserves were undeveloped and we had four PUD well locations included in our 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. Our reserve report at December 31, 2021 includes estimates of total future development costs over the next five years associated with our proved undeveloped reserves of approximately $61 million, net to VAALCO's working interest at December 31, 2021. 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.

All of the value of our current production and reserves is concentrated in a single block offshore Gabon, and any production problems or reductions in reserve estimates related to this property would adversely impact our business.

The Etame Marin block consists of 14 producing wells. Production from the block constituted 100% of our total production for the year ended December 31, 2021. In addition, at December 31, 2021, 100% of our total reserves were attributable to the block. Further, if mechanical problems, storms or other events, including COVID-19 infections and quarantines, curtailed a substantial portion of this production, or if the actual reserves associated with this producing property are less than our estimated reserves, our results of operations, financial condition, and cash flows could be materially adversely affected.

Because our properties are currently concentrated in the same geographic area, many of our rights under the Etame PSC will be affected by the same conditions at the same time, resulting in a relatively greater impact on our results of operations than with respect to companies that have a more diversified portfolio of licenses and properties located across diverse geographic areas.

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 we have an interest in.

On October 11, 2021 we announced our entry into a consortium with BW Energy and Panoro Energy (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. The award is subject to 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 the 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 production facilities are subject to hazards such as capsizing, sinking, grounding, collision and damage from severe weather conditions. The relatively deep offshore drilling conducted by us 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 and natural gas, 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. For example, the production of hydrogen sulfide at certain of our Etame Marin block wells creates unexpected production losses and delays in our development plans; see "*Item 1. Business – Segment and Geographic Information – Hydrogen Sulfide Impact."* 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, cleanup 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 cleanup. 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.

If we are not able to timely implement the transition to the FSO unit before the expiration of the FPSO contract in September 2022, our results of operations could be materially adversely affected.

As an offshore producer, we depend on our FPSO to store all of the crude oil we produce prior to sale to our customers. Our current FPSO contract expires in September 2022. On August 31, 2021, we and our Etame co-venturers approved the Bareboat Contract and Operating Agreement with World Carrier Offshore Services Corp. to replace the existing FPSO with a FSO unit at the Etame Marin block offshore Gabon for up to eight years with additional option periods available upon the expiration of the current FPSO contract in September 2022. The transition to the FSO unit will require a significant lead time and may require a capital investment due to the specialized nature of such vessels. To become operational, significant engineering studies, platform modifications, mooring and pipeline surveys as well as installation must be completed. If we are not able to timely implement the transition to the FSO unit as our alternative method of storing the crude oil we produce, then we will not be able to sell crude oil to our customers. Consequently, we would be required to shut in production until such time that we could offload the oil, and our results of operations would be materially adversely affected.

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 and natural gas 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 and natural gas 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 and natural gas;
- 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 and natural gas 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.

We may experience a financial loss if our significant customer fails to pay us for our crude oil or natural gas or reduce the volume of crude oil and natural gas that they purchase from us.

We have been reliant on a small number of significant customers for sales of our crude oil production. Currently, ExxonMobil is our customer, and sales of crude oil to ExxonMobil accounted for approximately 100% of revenues sold to customers for the 2021 fiscal year. In December 2020, our contract with ExxonMobil was extended until July 2021 and in July 2021, the contract with ExxonMobil was subsequently amended to extend the date of the contract through the end of January 2022. In January 2022, our contract with ExxonMobil was extended until July 2022. Our ability to collect payments from the sale of crude oil and natural gas to 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 us for any reason, we could experience a material loss. In addition, if our significant customers cease to purchase our crude oil or natural gas or reduce the volume of the crude oil or natural gas that they purchase from us, 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 and natural gas.

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 and natural gas reserves, including many factors beyond our control. Reserve engineering is a subjective process of estimating the underground accumulations of crude oil and natural gas 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, 2021, and, therefore, are inherently imprecise indications of future net revenues. Actual future production, revenues, taxes, operating expenses, development expenditures and quantities of recoverable crude oil and natural gas 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 and natural gas 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 and natural gas 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.

The estimated future net revenues attributable to our net proved reserves are prepared in accordance with current SEC guidelines and are not intended to reflect the fair market value of our reserves. In accordance with the rules of the SEC, our reserve estimates are prepared using an average of the first day of the month prices received for crude oil and natural gas for the preceding twelve months. Future reductions in prices, below the average calculated for 2021, would result in the estimated quantities and present values of our reserves being reduced.

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 that we will ultimately receive under these arrangements will differ based on numerous factors, including the price of crude oil and natural gas, 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 costs are too low, we could be required to expend greater amounts than expected.

Almost all of our properties, which have future abandonment obligations, are located offshore. The costs to abandon offshore 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 obligation” line item of our consolidated balance sheets.

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 VAALCO's 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. See "*Item 1. Business – Segment and Geographic Information – Gabon Segment — Abandonment Costs*," for further information. 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.

We could lose our interest in Block P 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 joint venture owners are evaluating the timing and budgeting for development and exploration activities in the block, including the approval of a development and production plan. We have completed a feasibility study of a standalone production development opportunity of the Venus discovery on Block P, but 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 $10.0 million associated with Block P interest would be impaired.

Commodity derivative transactions 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 and natural gas, 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. For example, on January 22, 2021 we entered into crude oil commodity swap agreements for a total of 709,262 barrels at a Dated Brent weighted average price of $53.10 per barrel for the period from and including February 2021 through January 2022. On May 6, 2021, the Company entered into commodity swaps at a Dated Brent weighted average price of $66.51 per barrel for the period from and including May 2021 through October 2021 for a quantity of 672,533 barrels. On August 6, 2021, the Company entered into additional commodity swaps at a Dated Brent weighted average price of $67.70 per barrel for the period from and including November 2021 through February 2022 for a quantity of 314,420 barrels. On September 24, 2021, the Company entered into additional commodity swaps at a Dated Brent weighted average price of $72.00 per barrel for the period from and including March 2022 to June 2022 for a quantity of 460,000 barrels.

The following are the hedges outstanding at December 31, 2021:

Settlement Period	Type of Contract	Index	Barrels	Weighted Average Price
January 2022	Swaps	Dated Brent	60,794	$ 53.10
January 2022 to February 2022	Swaps	Dated Brent	191,060	$ 67.70
March 2022 to June 2022	Swaps	Dated Brent	460,000	$ 72.00
			711,854	

The following are the additional hedges entered into in 2022:

Settlement Period	Type of Contract	Index	Barrels	Weighted Average Price
April 2022 to June 2022	Swaps	Dated Brent	234,000	$ 85.01
July 2022 to September 2022	Swaps	Dated Brent	375,000	$ 76.53
			609,000	

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 its contract obligations. Disruptions in the market could also occur that lead to sudden changes in the liquidity of the counterparties to our hedge transactions which in turn limit their ability to perform under their hedging contracts with us. Even if we do 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 nonperformance, 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 we could receive from increases in the prices for crude oil and natural gas and may expose us to cash margin requirements.

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

As a crude oil 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. We rely extensively on information technology systems, including internet sites, computer software, and 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 and natural gas 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;
- data corruption or operational disruption of production infrastructure, which could result in loss of production or accidental discharge;
- 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 protections, 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, to the extent they are in place, will be effective.

In addition, as a result of the COVID-19 pandemic, in the U.S., we adopted a hybrid work-from-home policy in September 2021, and we expect this practice to continue for the foreseeable future. For our Gabon offices our employees are working in the offices on a full time basis and expected to work normal business hours.

Remote work and remote access increase our vulnerability to cybersecurity attacks. We may see an increase in cyberattack volume, frequency and sophistication driven by the global enablement of remote workforces. We seek to detect and investigate unauthorized attempts and attacks against our network, products and services and to prevent their recurrence where practicable through changes to our internal processes and tools and changes or updates to our products and services; however, we remain potentially vulnerable to additional known or unknown threats. In some instances, we could be unaware of an incident or its magnitude and effects.

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.

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 rejoined 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 in July 2020 and continuing through April 30, 2021 in compliance with the OPEC+ mandate, and we took measures to reduce our production. Currently, our production is not impacted by OPEC+ curtailments, however any future reduction in VAALCO's crude oil production or export activities for a substantial period could materially and 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, and added risk in foreign countries may affect our foreign investments.

Our international assets and operations are subject to various political, economic and other uncertainties, including, among other things, the risks of war, expropriation, nationalization, renegotiation or nullification of existing contracts, taxation policies, foreign exchange restrictions, changing political conditions, international monetary fluctuations, currency controls, decisions of international financial institutions such as the International Monetary Fund, CEMAC and the Banking Commission of Central Africa, changes in laws and regulations relating to banking institutions and deposit accounts, requirements to hold funds in government-owned banks and the risk of foreign banking institution failure, possible changes in government personnel, the development of new administrative policies, practices and political conditions that may affect the enforcement or administration of laws and regulations, adoption of new or amendments to regulatory regimes for foreign investment, 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, and foreign governmental regulations that favor or require the awarding of drilling contracts to local contractors or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction.

For example, the Gabonese government's oil company may seek to participate in crude oil and natural gas projects in a manner that could be dilutive to the interest of current license holders and the Gabonese government is under pressure from the Gabonese labor union to require companies to hire a higher percentage of Gabonese citizens. In 2016, the government of Gabon conducted an audit of our operations in Gabon, covering the years 2013 through 2014. We received the findings from this audit and responded to the audit findings in January 2017. Since providing our response, there have been changes in the Gabonese officials responsible for the audit. We are working with the current representatives to resolve the audit findings. Between 2019 and 2021, the government of Gabon conducted an audit of our operations in Gabon, covering the years 2015 and 2016. We have not yet received the findings from this audit. While we do not anticipate that the assessments related to these audits will have a significant, if any, negative impact on our reported earnings or cash flows, we can make no assurances that this will be the case. 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 United States.

In December 2021, 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 was introduced in 2018 that only apply to the extractive industry. This was done by BEAC after prolonged discussions and negotiations with the extractive industries operating in the CEMAC region. 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 2022 and possibly 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 March 5, 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 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 these payments must be denominated in U.S. dollars and the CEMAC FX regulations provide for establishment of a U.S. dollar account with BEAC. Although we requested establishment of such account, BEAC did not comply with our requests until February 2021. As a result, we were not able to make the annual abandonment funding payments in 2019 and 2020. In February 2021, BEAC authorized us to apply for a U.S. dollar denominated escrow account for the abandonment fund at Citibank Gabon ("Citibank"). Working with Citibank, on March 12, 2021 we filed the application to open the account and are currently awaiting the approval of the account from the Central Bank. Accordingly, we were not able to make our funding payment in 2021. In December 2021, as part of the new FX regulations issued by BEAC, they allowed for opening of U.S. dollars escrow accounts for the abandonment funds at BEAC and are currently working with the extractive industry to formulate the agreements which are expected to be finalized in 2022 that regulates these accounts. Accordingly, pursuant to Amendment No. 5 of the Etame PSC that required these funds to be in U.S. dollars, once the account for the U.S. dollars abandonment fund is open at BEAC we will resume our funding of the abandonment fund in compliance with the Etame PSC. For additional information, see "*–Our results of operations, financial conditions and cash flows could be adversely affected by changes in currency exchange rates and regulations*."

Private ownership of crude oil and natural gas reserves under crude oil and natural gas leases in the United States 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 United States may be materially affected by host governments through royalty payments, export taxes and regulations, surcharges, value added taxes, production bonuses and other charges. For instance, 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.

All of our proved reserves are related to the Etame Marin block located offshore Gabon. 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.

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

Our exploration, development and production activities are subject to political and economic 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, redefinition of international boundaries or boundary disputes, foreign exchange restrictions, currency fluctuations, royalty and tax increases and other risks arising out of governmental sovereignty over the areas in which our operations are conducted, as well as risks of loss due to civil strife, acts of war, acts of terrorism, piracy, disease, guerrilla activities, insurrection and other political risks, including tension and confrontations among political parties. Some of these risks may be higher in the developing countries in which we conduct our activities, namely, Gabon and Equatorial Guinea.

Our operations are exposed to risks of war, local economic conditions, political disruption, civil disturbance and governmental policies that may include:

- 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;
- 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;
- inability to deliver our production due to disruption or closing of transportation routes;
- 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;
- 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;
- 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;
- shutdown of a financial system, communications network, or power grid causing a disruption to our business activities; and
- 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.

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 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 United States or may not be successful in subjecting non-U.S. persons to the jurisdiction of courts in the United States or international arbitration, which could adversely affect the outcome of such dispute.

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

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. dollar to Gabon local currency. See the risk factor "*We have less control over our investments in foreign properties than we would have with respect to domestic investments, and added risk in foreign countries may affect our foreign investments*." Hedging foreign currencies can be difficult, especially if the currency is not actively traded.

We are also subject to risks relating to governmental regulation of foreign currency, which may limit our ability to:

- transfer funds from or convert currencies in certain countries;
- repatriate foreign currency received in excess of local currency requirements; and
- repatriate funds held by our foreign subsidiaries to the United States at favorable tax rates.

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

The United States Foreign Corrupt Practices Act and similar worldwide anti-corruption laws generally prohibit companies and their intermediaries from making improper payments to government and other officials for the purpose of obtaining or retaining business. Our internal policies mandate compliance with these anti-corruption laws, and our staff participate in training regarding compliance with these laws. Despite our training and compliance programs, we cannot be assured that our internal control policies and procedures will always protect us from acts of corruption committed by our employees or agents. Any additional expansion outside the United States, including in developing countries, could increase the risk of such violations in the future. Violations of these laws, or allegations of such violations, could disrupt our business and result in a material adverse effect on our financial condition, results of operations and cash flows.

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 was effective as of December 31, 2021, our management does not expect that our 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, in our company have been 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 our 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 and natural gas, including blowouts, cratering and fire, any of which could result in damage to, or destruction of, crude oil and natural gas 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 and natural gas from proved properties and maximizing production from crude oil and natural gas properties. There is competition for qualified personnel in the areas of our activities, and we may be unsuccessful in attracting and retaining these personnel.

Risks Related to Our Industry

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

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

Historically, world-wide crude oil and natural gas prices and markets have been volatile and may continue to be volatile in the future. Prices for crude oil and natural gas are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for crude oil and natural gas, 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 United States shale production, international political conditions, including uprisings and political unrest in the Middle East and Africa, the domestic and foreign supply of crude oil and natural gas, 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, such as the ongoing COVID-19 pandemic. 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 and natural gas production.

A combination of factors, including a substantial decline in global demand for crude oil caused by the COVID-19 pandemic and subsequent mitigation efforts, as well as market concerns about the ability of OPEC+ to agree on a perceived need to implement production cuts in response to weaker worldwide demand, caused an unprecedented decline in crude oil and natural gas prices during the first six months of 2020. Although crude oil prices increased to approximately $77 per barrel for Brent crude as of December 31, 2021 and have further improved since year-end, adverse economic effects caused by the COVID-19 pandemic, as well as the various other factors described above, could result in additional price declines.

In a period of depressed or declining crude oil and natural gas prices, such as the significant declines in crude oil and natural gas prices during the first six months of 2020, 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 and natural gas 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.

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 drilled by us will be productive or that we will recover all or any portion of our investment. Drilling for crude oil and natural gas 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 canceled 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 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.

Material declines in crude oil and natural gas prices have required us, and may require us in the future, to take write-downs in the value of our crude oil and natural gas properties.

The estimated future net revenues attributable to our net proved reserves are prepared in accordance with current SEC guidelines and are not intended to reflect the fair market value of our reserves. In accordance with the rules of the SEC, our reserve estimates are prepared using the average price received for crude oil and natural gas based on closing prices of the average of the first day of the month price over the twelve-month period prior to the end of the reporting period. However, for the purpose of impairment analysis, the estimated future net revenues attributable to our net proved reserves are prepared in accordance with ASC 932 and are priced using forecasted realized prices at the end of the quarter. During 2021 and 2019 no impairments were necessary with respect to the Etame Marin block. However, during the first quarter of 2020, the undiscounted cash flows related to the Etame Marin block was less than the book value, resulting in the Company recording an impairment loss of $30.6 million to write down the Company's investment in the Etame Marin block.

As described elsewhere herein, the COVID-19 pandemic and resulting substantial decline in the demand for crude oil coupled with the current global oversupply of crude oil resulted in a substantial decline in the price of crude oil. If crude oil prices decline further, 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.

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

The crude oil and natural gas industry is intensely competitive. We compete with, and may be outbid by, competitors in our attempts to acquire exploration and production rights in crude oil and natural gas properties. These properties include exploration prospects as well as properties with proved reserves. 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 and natural gas production.

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. These companies may be better able to: competitively bid for and purchase crude oil and natural gas properties; evaluate, bid for and purchase a greater number of properties than our financial or human resources permit; continue drilling during periods of low crude oil and natural gas prices; contract for drilling equipment; and secure trained personnel. Our competitors may also use superior technology that we may be unable to afford or that would require costly investment by us in order to compete.

Competition due to advances in renewable fuels may 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 and natural gas. 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 and natural gas 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 and natural gas activities.

The crude oil and natural gas 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 to us 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.

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 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 to 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 us to toward other industries, which could negatively impact our stock 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.

In addition, ESG and climate chance issues may cause consumer preference to shift toward other alternative sources of energy, lowering demand for our products. In some areas these concerns have caused governments to adopt or consider adopting regulations to transition to a lower-carbon economy. These measures may include adoption of cap-and-trade programs, carbon taxes, increased efficiency standards, prohibitions on the manufacture of certain types of equipment (such as new automobiles with internal combustion engines), and requirements for the use of alternate energy sources such as wind or solar. These types of programs may reduce the demand for our product.

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.

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

Opposition against crude oil and natural gas drilling and development activity has been growing globally. Companies in the crude oil and natural gas 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.

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 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 to engage in exploration and production activities.

Future activist efforts could result in the following:

- delay or denial of drilling permits;
- shortening of lease terms or reduction in lease size;
- restrictions or delays on our ability to obtain additional seismic data;
- restrictions on installation or operation of gathering or processing facilities;
- restrictions on the use of certain operating practices;
- legal challenges or lawsuits;
- damaging publicity about us;
- increased regulation;
- increased costs of doing business;
- reduction in demand for our products; and
- other adverse effects on our ability to develop our properties and/or undertake production operations.

Legal and Regulatory Risks

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

The laws and regulations of the United States, Gabon, and Equatorial Guinea regulate 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 greenhouse gases and the use of hydraulic fracturing fluids, resulting in increased operating costs. In the United States for example, the Environmental Protection Agency continues to focus on requiring additional pollution controls on emissions from oil and gas production facilities. As a result, substantial liabilities to third parties or governmental entities may be incurred, the payment of which could have a material adverse effect on our financial condition, results of operations and liquidity.

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 and natural gas 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 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, and from time to time we may in the future be a defendant or plaintiff in various lawsuits. The nature of our operations exposes us to further possible litigation claims in the future. There is risk that any matter in litigation could be decided unfavorably against us regardless of our belief, opinion, and position, 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 we may have limited influence and control. Private litigation or government proceedings brought against us could also result in significant delays in our operations.

We operate in countries and regions that are subject to legal and regulatory risk.

Investment in companies with assets in developing countries is generally only suitable for sophisticated investors who fully appreciate the significance of the risks involved in, and are familiar with, investing in developing countries. Investors should also note that developing countries could be subject to rapid change and that the information set out in this document may become outdated relatively quickly. Moreover, financial turmoil in developing countries tends to adversely affect prices in equity markets of other developing countries as investors move their money to more stable, developed markets.

Our operations in Etame, Block P and any future opportunistic acquisitions of oil and natural gas reserves may require protracted negotiations with host governments, local governments and communities, local competent authorities, national oil companies and third parties and may be subject to economic, social and political considerations outside of our control, such as the risks of expropriation, nationalization, renegotiation, forced interruption, suspension of operations, curtailment of sales, forced change or nullification of existing contracts or royalty rates, unenforceability of contractual rights, changing taxation policies or interpretations, adverse changes to laws (whether of general application or otherwise) or the interpretation or enforcement of laws, foreign exchange restrictions, inflation, changing political conditions, the death or incapacitation of political leaders, local currency devaluation, currency controls and foreign governmental regulations that favor or require the awarding of contracts to local contractors or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction.

While the laws of each of Gabon and Equatorial Guinea respectively 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 its discretion.

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 the 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.

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 disputes arise in connection with our operations in Gabon, Equatorial Guinea or any future jurisdiction in which we operate, we may be subject to the exclusive jurisdiction of foreign courts or foreign arbitration tribunals or may not be successful in subjecting foreign persons, especially foreign ministries and national companies, to the legal jurisdiction of the United States.

While we are not aware of any activities that would lead to the seizure of any assets, we cannot guarantee that there will not be regulations imposed on any individual or company that is related to our operations or our activities in the relevant region. Such measures, which would be beyond our control, could have a material adverse effect on our business, reputation, results of operations, financial condition and the price of our common stock.

The physical and regulatory impact of climate change could disrupt our business and cause us to incur significant costs in preparing for or responding to their effects.

Climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland, and water availability and quality. If such effects were to occur, our exploration and production operations have the potential to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low-lying areas, disruption of our production activities because of climate-related damages to our facilities, 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 may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change.

In addition, we expect continued and increasing regulatory attention to climate change issues and emissions of greenhouse gases, including methane (a primary component of natural gas) and carbon dioxide (a byproduct of crude oil and natural gas combustion). For example, in April 2016, 195 nations, including Gabon, Equatorial Guinea and the United States, signed and officially entered into an international climate change accord (the “Paris Agreement”). The Paris Agreement calls for signatory countries to set their own greenhouse gas emissions targets, make these emissions targets more stringent over time and be transparent about the greenhouse gas emissions reporting and the measures each country will use to achieve its greenhouse gas 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 greenhouse gases, to which various countries and regions are parties. In August 2017, the U.S. Department of State officially informed the United Nations of the United States’ 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 United States’ intention to rejoin the Paris Agreement, which took effect on February 19, 2021. On April 22, 2021, President Biden announced a target for the US to achieve a 50-52 percent reduction from 2005 levels in economy-wide greenhouse gas emissions by 2030. It cannot be determined at this time what effect the Paris Agreement, and any related greenhouse gas emissions targets, potential prices on carbon emissions, regulations or other requirements, will have on our business, results of operations and financial condition. This regulatory uncertainty, however, could result in a disruption to our business or operations.

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 changes 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 reporting obligations and other regulatory programs that limit or require control of GHG’s from certain sources. These programs may limit our ability to produce crude oil and natural gas, 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.

Risks Related 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 and natural gas 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 in general can experience considerable price and volume fluctuations. Financial markets have experienced significant price and volume fluctuations in the last several years that have particularly affected the market prices of equity securities of companies and that have, in many cases, been unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the market price of the 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 that are deemed to be other than temporary, which may result in impairment losses. Also, certain institutional investors may base their investment decisions on consideration of our environmental, governance and social practices and performance against such institutions' respective investment guidelines and criteria, and failure to meet such criteria may result in a limited or no investment in our common stock by those institutions, which could adversely affect the trading price of our common stock. There is no assurance that continuing 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 the common stock may be adversely affected.

We currently intend to pay dividends on our common stock; however our ability to pay dividends in the future may be limited and no assurance can be given that we will be able to pay dividends to our stockholders in the future at current levels or at all.

On November 3, 2021, we announced that our board of directors adopted of a quarterly cash dividend policy of an expected $0.0325 per common share commencing in the first quarter of 2022. On January 28, 2022, our board of directors declared a quarterly cash dividend of $0.0325 per share of common stock, which is payable on March 18, 2022 to stockholders of record at the close of business on February 18, 2022. To the extent we have adequate cash on hand and cash flows from operations, we will consider paying cash dividends in the future. Payment of future dividends, if any, and the establishment of future record and payment dates 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. As a result, no assurance can be given that we will be able to continue to pay dividends to our stockholders 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 the common stock.

Dual-listing of our common stock will result in differences in liquidity, settlement and clearing systems, trading currencies, prices and transaction costs between the exchanges where the common stock will be quoted. These and other factors may hinder the transferability of the common stock between the two exchanges.

The common stock is quoted on the NYSE and on the LSE. Consequently, the trading in and liquidity of the common stock is split between these two exchanges. The price of the common stock may fluctuate and may at any time be different on the NYSE and the LSE. Investors could seek to sell or buy 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 common stock available for trading on either market. This could adversely affect the trading of the common stock on these exchanges and increase their price volatility and/or adversely affect the price and liquidity of the common stock on these exchanges. In addition, holders of 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.

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

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

Our stockholders do not have preemptive rights and we, without stockholder consent, may issue additional 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 common stock in connection with those acquisitions. We also issue 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 preemptive rights are granted, stockholders in certain jurisdictions may experience difficulties or may be unable to exercise their preemptive 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 with us.

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 Company's 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 the Company's 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 the Company consents in writing to the selection of an alternative forum, the federal district courts of the United States 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 capital stock of the Company will be deemed to have notice of and have consented to the provisions of our 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.

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

We cannot predict what effect, if any, future sales of common stock, or the availability of common stock for future sale, or the offer of additional common stock in the future, will have on the market price of common stock. Sales or an additional offering of substantial numbers of 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 common stock and may make it more difficult for stockholders to sell their common stock at a time and price which 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 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 common shares with respect to payment of dividends, liquidation, and other matters.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

The location and general character of our principal crude oil and natural gas assets, production facilities, and other important physical properties have been described by segment under Item 1. "*Business*." Information about crude oil and natural gas 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 March 1, 2022, based upon information received from our transfer agent and brokers and nominees, there were approximately 47 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 November 3, 2021, we announced that our board of directors adopted a quarterly cash dividend policy of an expected $0.0325 per common share commencing in the first quarter of 2022. On January 28, 2022, our board of directors declared a quarterly cash dividend of $0.0325 per share of common stock, which is payable on March 18, 2022 to stockholders of record at the close of business on February 18, 2022.

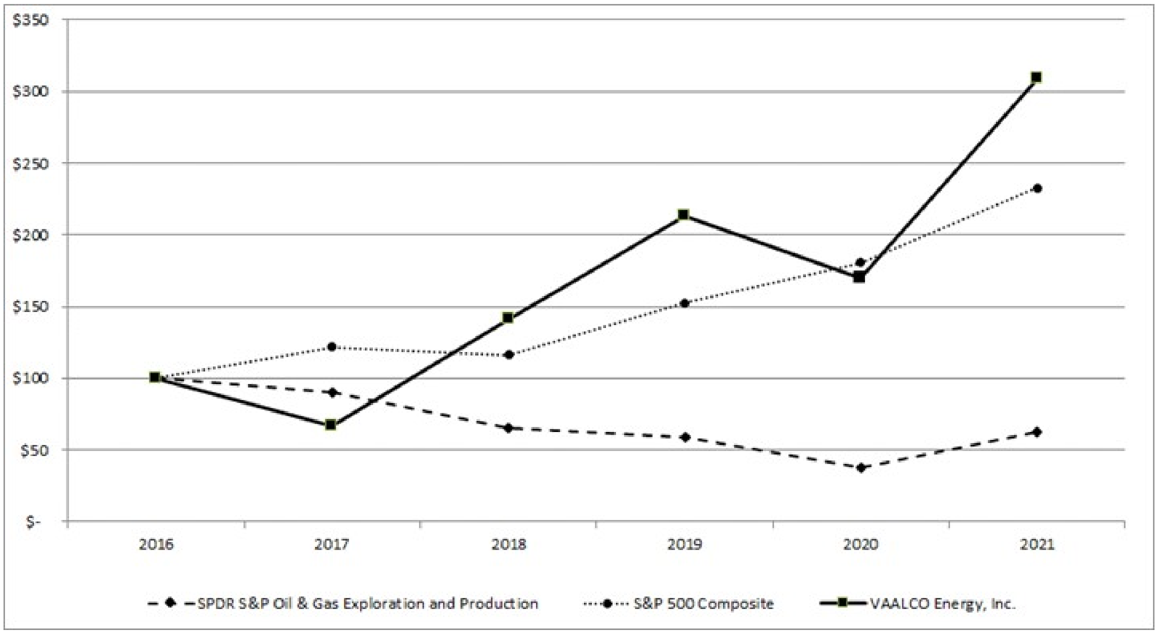
To the extent we have adequate cash on hand and cash flows from operations, we will consider paying additional cash dividends on a quarterly basis; however, any future dividend payments, if any, will be at the discretion of the board of directors after taking into account various factors, including current 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.

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 30, 2016 in our common stock and in each index, and that all dividends, in any, are reinvested. Stockholder returns over the indicated period may not be indicative of future stockholder returns.



	2016	2017	2018	2019	2020	2021
SPDR S&P Oil & Gas Exploration and Production	$ 100	$ 91	$ 65	$ 59	$ 37	$ 63
S&P 500 Composite	$ 100	$ 122	$ 116	$ 153	$ 181	$ 233
VAALCO Energy, Inc.	$ 100	$ 67	$ 141	$ 213	$ 170	$ 309

Unregistered Sales of Equity Securities and Use of Proceeds

None.

Issuer Purchases of Equity Securities

We did not repurchase any of our equity securities during the fourth quarter of the fiscal year ended December 31, 2021.

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 2020 as compared with 2019, refer to Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2020 Form 10-K, which was filed with the SEC on March 9, 2021. 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

VAALCO is a Houston, Texas based independent energy company engaged in the acquisition, exploration, development and production of crude oil. As operator, we have production operations and conduct exploration activities in Gabon, West Africa. We also have opportunities to participate in development and exploration activities in Equatorial Guinea, West Africa. For further discussion of our two operating segments see "*Item 1. Business – Segment and Geographical Information – "Gabon Segment" and "Equatorial Guinea Segment".* As discussed further in Note 4 to the Financial Statements, we have discontinued operations associated with our activities in Angola, West Africa.

RECENT DEVELOPMENTS

On March 11, 2020, the World Health Organization classified the outbreak of a new strain of coronavirus ("COVID-19") as a pandemic, based on the rapid increase in global exposure. The COVID-19 pandemic and related economic repercussions have created significant volatility, uncertainty, and turmoil in the oil and gas industry. The adverse economic effects of the COVID-19 outbreak materially decreased demand for crude oil based on the restrictions in place by governments trying to curb the outbreak and changes in consumer behavior. This led to a significant global oversupply of oil and consequently a substantial decrease in crude oil prices in 2020. In April 2020, countries within OPEC+, which includes Gabon, reached an agreement to cut crude oil production to reduce the gap between excess supply and demand, in an effort to stabilize the international oil market. Gabon has undertaken measures to comply with such OPEC+ production quota agreement and, as a result, the Minister of Hydrocarbons in Gabon requested that we reduce our production. In response to such request from the Minister of Hydrocarbons, beginning in July 2020 and continuing through April 2021, we temporarily reduced production from the Etame Marin block. Currently, our production is not impacted by OPEC+ curtailments. Reductions in production have significantly improved the demand/supply imbalance, and crude oil prices have improved from the lows seen in March and April of 2020. As a result, in July 2021, OPEC+ agreed to increase production beginning in August 2021 to phase out a portion of the prior production cuts. The decision to increase in production was reaffirmed by an OPEC+ meeting held on February 2, 2022. See "*Liquidity*" below for discussion of the unexpired commodity swaps we have in place.

We considered the impact of the COVID-19 pandemic and the substantial decline in crude oil prices on the assumptions and estimates used for preparation of the financial statements. As a result, we recognized a number of material charges during the three months ended March 31, 2020, including impairments to our capitalized costs for proved crude oil and natural gas properties and valuation allowances on its deferred tax assets. These are discussed further in the notes to our consolidated financial statements included in this report.

The spread of COVID-19, including vaccine-resistant strains, or repeated deterioration in crude oil and natural gas prices could result in future adverse impacts on our results of operations, cash flows and financial position, including asset impairments. The health of our employees, contractors and vendors, and our ability to meet staffing needs in our operations and certain critical functions cannot be predicted and is vital to our operations. We are unable to predict the extent of the impact that the continuing spread of COVID-19 throughout Gabon may have on our ability to continue to conduct our operations. Further, the impacts of a potential worsening of global economic conditions and the continued disruptions to, and volatility in, the credit and financial markets as well as other unanticipated consequences remain unknown. In addition, we cannot predict the impact that COVID-19 will have on our customers, vendors and contractors; however, any material effect on these parties could adversely impact our business. The situation surrounding COVID-19 remains fluid and unpredictable, and we are actively managing our response and assessing potential impacts to our financial position and operating results, as well as any adverse developments that could impact our business.

In response to the COVID-19 outbreak and the current pricing environment, we took the following measures:

- put in place social distancing measures at our work sites;
- actively screened and monitored employees and contractors that come on to our facilities including testing and quarantines with onsite medical supervision;
- engaged in regular company-wide COVID-19 updates to keep employees informed of key developments; and
- implemented sharing certain costs, such as supply vessels, helicopter, and personnel with other operators in the region.

We expect to continue to take proactive steps to manage any disruption in our business caused by COVID-19 and to protect the health and safety of our employees. However, the health and safety measures we and our vendors have taken have resulted in us incurring higher costs. As a result of these factors and the conditions described above, 2020 was one of the most uncertain and disruptive years that the industry has ever seen.

For the year ended December 31, 2021, crude oil prices have improved, there were no disruptions to operations as a result of COVID-19 or any strain thereof, global economic activity has steadily increased, and oil demand has stabilized over multiple quarters removing much of the uncertainty and instability in the industry. Therefore, no additional charges or impairments were required for the twelve months ended December 31, 2021. Crude oil prices have continually increased and are currently at the highest levels seen in recent years. The average annual Brent price per barrel for the year ended December 31, 2020 was $41.96 and increased 69% to $70.86 for the year ended December 31, 2021. At the end of 2021 and continuing into 2022, travel-related restrictions have lessened, access to vaccines that reduce the spread and impact of COVID-19 and its variants have become more accessible and the global economy appears more flexible to continuing to effectively operate in a COVID-19 environment. However, while the business environment in 2021 improved, the COVID-19 situation and effects thereof remain fluid. A prolonged outbreak may have a material adverse impact on our financial results and business operations, including the timing and ability of us to complete future drilling campaigns and other efforts required to advance the development of our crude oil and natural gas properties.

Recent Operational Updates

Provisional Award of Two Offshore Blocks in Gabon

The BWE Consortium of VAALCO, BW Energy and Panoro Energy were provisionally awarded two blocks in the 12th Offshore Licensing Round in Gabon. The award is subject to concluding the terms of production sharing contracts ("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.

Charter Agreement for the Floating Storage and Offloading Unit

We are currently a party to an FPSO charter for the storage of all of the crude oil that we produce. This contract will expire in September 2022. In August of 2021, we and our co-venturers at Etame approved the Bareboat Contract and Operating Agreement (collectively, the "FSO Agreements") with World Carrier Offshore Services Corp. ("World Carrier") to replace the existing FPSO with an FSO. The FSO Agreements require a prepayment of $2 million gross ($1.3 million net) in 2021 and $5 million gross ($3.2 million net) in 2022 of which $6 million will be recovered against future rentals. Current total capital conversion estimates are $40 to $50 million gross ($26 to $32 million net to VAALCO).

In December 2020, we completed the acquisition of approximately 1,000 square kilometers of new dual-azimuth proprietary 3-D seismic data over the entire Etame Marin block and have now processed the new 3-D seismic which has allowed us to optimize drilling locations for the 2021/2022 drilling campaign. The seismic data enhanced sub-surface imaging by merging legacy data with newly acquired seismic allowing for the first continuous 3-D seismic over the entire block. In conjunction with the 2021/2022 drilling program, that began in December 2021, we executed a contract with Borr Jack-Up XIV Inc., an affiliate of Borr Drilling Limited, to drill a minimum of three wells with options to drill additional wells. On October 4, 2021, we novated the Borr Jack-Up XIV Inc contract with Borr West Africa Assets, Inc. In December of 2021, we spudded the Etame 8H sidetrack, the first well of the 2021/2022 drilling program. In February of 2022 we completed the drilling of the Etame 8-H well and moved the drilling rig to the Avouma platform to drill the Avouma 3H-ST1 development well, which is targeting the Gamba reservoir. The initial flow rate of the ETAME 8-H well was 5,000 BOPD, 2,560 BOPD net to VAALCO's 58.8% working interest in 2022.

We estimate the range of cost of the 2021/2022 drilling program with four wells to be between $117.0 million to $143.0 million gross, or $74.0 million to $91.0 million, net to VAALCO's 63.6% participating interest with about $26 million to about $31 million gross expected in 2021, or about $16 million to $20 million net to VAALCO.

Acquisition of Additional Working Interest at Etame Marin Block

In November 2020, we signed a SPA to acquire Sasol's 27.8% working interest in the Etame Marin block offshore Gabon. On February 25, 2021, we completed the acquisition of Sasol's 27.8% working interest in the Etame Marin block offshore Gabon pursuant to the SPA. The effective date of the transaction was July 1, 2020. Prior to the Sasol Acquisition, we owned and operated a 31.1% working interest in Etame. The Sasol Acquisition increased our working interest to 58.8%. As a result of the Sasol Acquisition, the net portion of production and costs relating to our Etame operations increased from 31.1% to 58.8%. Reserves, production and financial results for the interests acquired have been included in our results for periods after February 25, 2021. All assets and liabilities associated with Sasol's interest in Etame Marin block, including crude oil and natural gas properties, asset retirement obligations and working capital items were recorded at their fair value. As a result of comparing the purchase price to the fair value of the assets acquired and liabilities assumed, a $7.7 million bargain purchase gain was recognized. A bargain purchase gain of $5.2 million is included in "*Other, net*" under "*Other income (expense)*" in the consolidated statements of operations. An income tax benefit of $2.5 million, related to the bargain purchase gain, is also included in the consolidated statements of operations. The reason for the bargain purchase gain is mainly due to the lower crude oil price outlook used when the SPA was signed, November 17, 2020, and the higher oil price outlook on February 25, 2021, when the fair value of the reserves associated with the Sasol Acquisition were determined.

The actual impact of the Sasol Acquisition was an increase to "*Crude oil and natural gas sales*" in the condensed consolidated statement of operations of $84.6 million for the year ended December 31, 2021and a $29.3 million increase to "*Net income*" in the condensed consolidated statement of operations. Under the terms of the SPA, a contingent payment of $5.0 million was payable to Sasol should the average Dated Brent price over a consecutive 90-day period from July 1, 2020 to June 30, 2022 exceed $60.00 per barrel. Included in the purchase consideration was the fair value, at closing, of the contingent payment due to Sasol. The conditions related to the contingent payment were met and on April 29, 2021, we paid the $5.0 million contingent amount to Sasol in accordance with the terms of the SPA.

Workovers

In October 2021, we completed two workovers on the Ebouri 2-H and the Etame 12-H wells. The workover on the Ebouri 2-H well increased production from about 500 gross barrels of oil per day ("BOPD") (255 BOPD, net) prior to the workover to approximately 1,400 gross BOPD (715 BOPD, net). For the Etame 12-H well, we replaced both the upper and lower electrical submersible pumps ("ESP") and reconfigured the ESP design resulting in restored production of about 1,800 gross BOPD (920 BOPD, net).

DISCONTINUED OPERATIONS-ANGOLA

In November 2006, we signed a production sharing contract for Block 5 offshore Angola ("PSA"). Our working interest is 40%, and we carried Sonangol P&P, for 10% of the work program. On September 30, 2016, we notified Sonangol P&P that we were withdrawing from the joint operating agreement effective October 31, 2016. On November 30, 2016, we notified the national concessionaire, Sonangol E.P. that we were withdrawing from the PSA. Further to our decision to withdraw from Angola, we have closed our office in Angola and do not intend to conduct future activities in Angola. As a result of this strategic shift, the Angola segment has been classified as discontinued operations in the Financial Statements for all periods presented. See Note 4 to the Financial Statements. In the first quarter of 2019, the Company and Sonangol E.P. entered into a settlement agreement finalizing the Company's rights, liabilities and outstanding obligations for Block 5 in Angola. Pursuant to the settlement agreement, the Company agreed to pay $4.5 million to Angola National Agency of Petroleum, Gas, and Biofuels, as National Concessionaire, and to eliminate the $3.3 million receivable from Sonangol P&P. The receivable was related to joint interest billings and was reflected as current assets from discontinued operations at year-end 2018. As a result, the Company adjusted a previously accrued liability and recognized a net of tax non-cash benefit from discontinued operations of $5.7 million in the first quarter of 2019. In July 2019, subsequent to the publication of an executive decree from the Ministry of Mineral Resources and Petroleum, the Company paid the $4.5 million due under the settlement agreement. For the twelve months ended December 31, 2021 or December 31, 2020, the Angola segment did not have a material impact on the Company's financial position, results of operations, cash flows and related disclosures.

CAPITAL RESOURCES AND LIQUIDITY

Cash Flows

Our cash flows for the years 2021 and 2020 are as follows:

	Year Ended December 31,		
	2021	**2020**	**Increase (Decrease) in 2021 over 2020**
		(in thousands)	
Net cash provided by operating activities before changes in operating assets and liabilities	**$ 61,622**	$ 20,468	$ 41,154
Net change in operating assets and liabilities	**(11,413)**	7,423	(18,836)
Net cash provided by continuing operating activities	**50,209**	27,891	22,318
Net cash used in discontinued operating activities	**(92)**	(441)	349
Net cash provided by operating activities	**50,117**	27,450	22,667
Net cash used in investing activities	**(39,063)**	(24,328)	(14,735)
Net cash used in financing activities	**(57)**	(929)	872
Net change in cash, cash equivalents and restricted cash	**$ 10,997**	$ 2,193	$ 8,804

The increase in net cash provided by our operating activities for the year ended December 31, 2021 compared to the same period of 2020 includes a $41.2 million increase in cash generated by continuing operations before change in operating assets and liabilities, which was mainly due to higher revenue as referenced below in Results of Operations. The decrease in cash resulting from the net change in operating assets and liabilities of $18.8 million for the year ended December 31, 2020 reflects an increase of $25.6 million in trade receivables and an increase of $11.1 million in other receivables partially offset by increases in foreign income taxes payable and accrued liabilities of $10.2 million.

Property and equipment expenditures have historically been our most significant use of cash in investing activities. Net cash used in investing activities during the year ended December 31, 2021 included $22.5 million paid for the completion of the Sasol Acquisition as discussed in Note 4 to our consolidated financial statements. In addition, we incurred on a cash basis $16.6 million for property and equipment primarily related to equipment and enhancements as well as expenditures related to the 2021/2022 drilling program as discussed in "*Recent Operational Updates*" above. See "*— Capital Expenditures and Capital Resources, Liquidity, and Cash*

Requirements" below for further discussion. For 2020, the $20.0 million cash basis expenditures consisted of $19.7 million related to the 2019/2020 drilling program and $0.3 million paid for equipment and enhancements.

For the year ended December 31, 2021, net cash used in financing activities included $1.4 million for treasury stock as a result of tax withholding on options exercised and vested restricted stock as discussed in Note 16 to our condensed consolidated financial statements, partially offset by $1.3 million in proceeds from options exercised. Net cash used in financing activities during the year ended December 31, 2020 included $1.1 million for treasury stock purchases primarily made under the Company's stock repurchase plan.

Capital Expenditures

At December 31, 2018, pursuant to the PSC Extension, we had commitments for capital expenditures related to the drilling of two wells and two appraisal wellbores by September 16, 2020. In February 2020, these commitments were fully met as a result of drilling the Etame 9P and SE Etame 4P appraisal wellbores in 2019 and 2020, respectively, as well as the completion of the Etame 9H and Etame 11H development wells in 2019 and 2020, respectively. See "— *Capital Expenditures and Capital Resources, Liquidity, and Cash Requirements*" below for further discussion.

During 2021, we had accrual basis capital expenditures attributable to continuing operations of $79.2 million, that includes the Sasol Acquisition, compared to $10.5 million accrual basis capital expenditures in 2020. 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 2021 are attributable to expenditures related to the 2021/2022 drilling program and Sasol acquisition and the 2020 capital expenditures were attributable to expenditures related to the 2019/2020 drilling program, a portion of seismic acquisition costs and equipment and enhancements. See table below in "*Capital Resources, Liquidity and Cash Requirements"* for further information.

Regulatory and Joint Interest Audits

We are subject to periodic routine audits by various government agencies in Gabon, 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 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 transactions is a major oil company's trading subsidiary, and our derivative positions are generally reviewed on a monthly basis. 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 statement of operations. 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.

For the period from January to June 2019, we had commodity swap contracts for approximately 172,000 barrels of crude oil. On May 6, 2019, we entered into commodity swaps at a Dated Brent weighted average price of $66.70 per barrel for the period from and including July 2019 through June 2020 for an approximate quantity of 500,000 barrels. On January 22, 2021, we entered into commodity swaps at a Dated Brent weighted average price of $53.10 per barrel for the period from and including February 2021 through January 2022 for a quantity of 709,262 barrels. On May 6, 2021, we entered into commodity swaps at a Dated Brent weighted average price of $66.51 per barrel for the period from and including May 2021 through October 2021 for a quantity of 672,533 barrels. On August 6, 2021, we entered into additional commodity swaps at a Dated Brent weighted average price of $67.70 per barrel for the period from and including November 2021 through February 2022 for a quantity of 314,420 barrels. On September 24, 2021, we entered into additional commodity swaps at a Dated Brent weighted average price of $72.00 per barrel for the period from and including March 2022 to June 2022 for a quantity of 460,000 barrels.

The following are the hedges outstanding at December 31, 2021:

Settlement Period	Type of Contract	Index	Barrels	Weighted Average Price	
January 2022	Swaps	Dated Brent	60,794	$	53.10
January 2022 to February 2022	Swaps	Dated Brent	191,060	$	67.70
March 2022 to June 2022	Swaps	Dated Brent	460,000	$	72.00
			711,854		

The following are the additional hedges entered into in 2022:

Settlement Period	Type of Contract	Index	Barrels	Weighted Average Price	
April 2022 to June 2022	Swaps	Dated Brent	234,000	$	85.01
July 2022 to September 2022	Swaps	Dated Brent	375,000	$	76.53
			609,000		

Cash on Hand

At December 31, 2021, we had unrestricted cash of $48.7 million. 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 term contract that began in January 2020 and ends in July 2022. Pricing under this contract is based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors.

Capital Resources, Liquidity and Cash Requirements

Historically, 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.

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 to support our current cash requirements, including those related to our 2021/2022 drilling program and our ability to fund the FPSO through September 2022 and the FSO charter, through March 2023. However, our ability to generate sufficient cash flow from operations or fund any potential future acquisitions, consortiums, joint ventures or 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.

Cash Requirements

Our material cash requirements generally consist of operating leases, purchase obligations, capital projects and 3D seismic processing, the Sasol Acquisition and abandonment funding, each of which is discussed in further detail below.

Sasol Acquisition – As a result of completing the Sasol Acquisition on February 25, 2021, our obligations with respect to development activities in the Etame have increased based on the increase in our working interest in the Etame from 31.1 % at December 31, 2020, to 58.8%. As a result of the Sasol Acquisition, the net portion of production and costs relating to the Company's Etame operations increased from 31.1% to 58.8%. Reserves, production and financial results for the interests acquired in the Sasol Acquisition have been included in VAALCO's results for periods after February 25, 2021. We expect that part of this increase will be offset by an increase in our operating cash flows based on our increased portion of the Etame production.

FSO Agreements – We are currently a party to an FPSO charter for the production and storage of all of the crude oil that we produce. This contract will expire in September 2022. 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 a FSO unit at the Etame Marin block offshore Gabon. Pursuant to the Bareboat Charter, World Carrier will provide use of the *Cap Diamant* 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.

The FSO Agreements require a prepayment of $2 million gross ($1.2 million net to VAALCO) in 2021 and $5 million gross ($3.2 million net) in 2022 of which $6 million will be recovered against future rentals. In addition, VAALCO Gabon agreed to pay a daily hire rate at certain rates specified therein, with such hire rate being based on the year within the term.

The aggregate amount to be paid to World Carrier under the FSO Agreements during 2022 is approximately $11 million gross (or $6.5 million net to VAALCO based on its participating interest in the Etame block), net of any applicable taxes.

In connection with the implementation of the FSO, we are required to incur certain capital expenses in order to facilitate the FSO. Current total capital conversion estimates are $40 to $50 million gross ($26 to $32 million net to VAALCO).

BWE Consortium – On October 11, 2021 we announced our entry into a consortium with BW Energy and Panoro Energy (the “BWE Consortium”) and that the BWE Consortium has been provisionally awarded two blocks in the 12th Offshore Licensing Round in Gabon. The award is subject to 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 will be held by the BWE Consortium and the PSCs over the blocks will have two exploration periods totaling eight years which may be extended by a further two more years. During the first exploration period, the joint owners 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. In the event the BWE Consortium elects to enter the second exploration period, the BWE Consortium will be committed to drilling at least another one exploration well on each of the awarded blocks.

Drilling Program – We commenced the 2021/2022 drilling campaign in December 2021 with the drilling of the Etame 8-H development well. In February of 2022 we completed the drilling of the Etame 8-H well and moved the drilling rig to the Avouma platform to drill the Avouma 3H-ST1 development well, which is targeting the Gamba reservoir. The initial flow rate of the ETAME 8-H well was 5,000 BOPD, 2,560 BOPD net to VAALCO’s 58.8% working interest in 2022. We expect the campaign to include two development wells and two appraisal wells at an estimated cost of $117.0 million to $143.0 million gross, or $74.0 million to $91.0 million, net to VAALCO’s 63.6% participating interest.

In June 2021, in conjunction with our 2021/2022 drilling program, we entered into a contract with an affiliate of Borr Drilling Limited to drill a minimum of three wells with options to drill additional wells.

Trends and Uncertainties

Sasol Acquisition – At December 31, 2020, we had 3.2 MMBbls of estimated net proved reserves, all of which are related to the Etame Marin block offshore Gabon. In February 2021, as a result of the Sasol acquisition, we increased our working interest in the Etame Marin block from 31.1% to 58.8%. The current term for exploitation of the reserves in the Etame Marin block ends in September 2028 with rights for two five-year extension periods. 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. While both short-term and long-term liquidity are impacted by crude oil prices, our long-term liquidity also depends upon our ability to find, develop or acquire additional crude oil and natural gas reserves that are economically recoverable.

COVID-19 Pandemic – While crude oil prices are currently at the highest levels seen in recent years, the continued spread of COVID-19, including vaccine-resistant strains, or deterioration in crude oil and natural gas prices could result in additional adverse impacts on our results of operations, cash flows and financial position, including asset impairments. The health of our employees, contractors and vendors, and our ability to meet staffing needs in our operations and certain critical functions cannot be predicted and is vital to our operations. We are unable to predict the extent of the impact that the continuing spread of COVID-19 throughout Gabon may have on our ability to continue to conduct our operations.

Further, the impacts of a potential worsening of global economic conditions and the continued disruptions to, and volatility in, the credit and financial markets as well as other unanticipated consequences remain unknown. In addition, we cannot predict the impact that COVID-19 will have on our customers, vendors and contractors; however, any material effect on these parties could adversely impact our business. The situation surrounding COVID-19 remains fluid and unpredictable, and we are actively managing our response and assessing potential impacts to our financial position and operating results, as well as any adverse developments that could impact our business.

Commodity Prices – Historically, the markets for oil and natural gas have been volatile. Oil, natural gas and NGL prices are subject to wide fluctuations in supply and demand. Our cash flows from operations may be adversely impacted by volatility in crude oil prices, a decrease in demand for crude oil and future production cuts by OPEC+. In 2020, crude oil prices experienced a significant decline as a result of the substantial decline in the global demand for crude oil caused by the COVID-19 pandemic and subsequent mitigation efforts. Reductions in production have significantly improved the demand/supply imbalance and crude oil prices have improved from the lows seen in March and April of 2020. Between July 2020 and April 2021, we temporarily reduced production from the Etame Marin block. Currently, our production is not impacted by OPEC+ curtailments. In July 2021, OPEC+ agreed to increase production beginning in August 2021 to phase out a portion of the prior production cuts. Brent crude prices were approximately $77 per barrel as of December 31, 2021. The decision to increase in production was reaffirmed by an OPEC+ meeting held on February 2, 2022.

ESG and Climate Change Effects – ESG matters continue to attract considerable public and scientific attention. In particular, we expect continued regulatory attention on climate change issues and emissions of greenhouse gases (“GHGs”), including methane (a primary component of natural gas) and carbon dioxide (a byproduct of crude oil and natural gas combustion). This increased attention to climate change and environmental conservation may result in demand shifts away from crude oil and natural gas products to alternative forms of energy, 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 investors’ 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 standards, including the reduction of our carbon footprint and measurement of GHG emissions. ESG is important to us, and we are in the process of developing a multi-year plan to establish and document our ESG base currently and developing a systematic plan to monitor and improve matters related to ESG and climate change going forward.

Hedging

We seek to mitigate the impact of volatility in crude oil prices through hedging On January 22, 2021, we entered into commodity swaps at a Dated Brent weighted average price of $53.10 per barrel for the period from and including February 2021 through January 2022 for 709,262 barrels. On May 6, 2021, we entered into commodity swaps at a Dated Brent weighted average price of $66.51 per barrel for the period from and including May 2021 through October 2021 for a quantity of 672,533 barrels. On August 6, 2021, we entered into additional commodity swaps at a Dated Brent weighted average price of $67.70 per barrel for the period from and including November 2021 through February 2022 for a quantity of 314,420 barrels. On September 24, 2021, we entered commodity swaps at a Dated Brent weighted average price of $72.00 per barrel for the period from and including March 2022 to June 2022 for a quantity of 460,000 barrels.

The following are the hedges outstanding at December 31, 2021:

Settlement Period	Type of Contract	Index	Barrels	Weighted Average Price	
January 2022	Swaps	Dated Brent	60,794	$	53.10
January 2022 to February 2022	Swaps	Dated Brent	191,060	$	67.70
March 2022 to June 2022	Swaps	Dated Brent	460,000	$	72.00
			711,854		

The following are the additional hedges entered into in 2022:

Settlement Period	Type of Contract	Index	Barrels	Weighted Average Price	
April 2022 to June 2022	Swaps	Dated Brent	234,000	$	85.01
July 2022 to September 2022	Swaps	Dated Brent	375,000	$	76.53
			609,000		

RESULTS OF OPERATIONS

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020

We reported net income for the year ended December 31, 2021 of $81.8 million, compared to a net loss of $48.2 million for the year ended December 31, 2020. The year-over-year increase in earnings was mainly due to increases in sales volumes and prices received and no impairment and deferred tax valuation adjustments in 2021. Substantially all of our operations are attributable to our Gabon segment. Further discussion of results by significant line item follows.

	Year Ended December 31, 2021	2020	Increase/(Decrease)
	(in thousands except per bbl information)		
Net crude oil sales volume (MBbls)	**2,711**	1,627	1,084
Average crude oil sales price (per Bbl)	**$ 70.66**	$ 40.29	$ 30.37
Net crude oil revenue	**$ 199,075**	$ 67,176	$ 131,899
Operating costs and expenses:			
Production expense	**81,255**	37,315	43,940
Exploration expense	**1,579**	3,588	(2,009)
Depreciation, depletion and amortization	**21,060**	9,382	11,678
Impairment of proved crude oil and natural gas properties	—	30,625	(30,625)
General and administrative expense	**14,766**	10,695	4,071
Bad debt expense	**875**	1,165	(290)
Total operating costs and expenses	**119,535**	92,770	26,765
Other operating expense, net	**(440)**	(1,669)	1,229
Operating income (loss)	**$ 79,100**	$ (27,263)	$ 106,363

The revenue changes between the years ended December 31, 2021 and 2020 identified as related to changes in price or volume are shown in the table below:

(in thousands)

Price [1]	$ 82,333
Volume	43,674
Other	5,892
	$ 131,899

(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.

	Year Ended December 31, 2021	2020
Gabon net crude oil production (MBbls)	2,599	1,776
Gabon net crude oil sales (MBbls)	2,711	1,627
Average realized crude oil price ($/Bbl)	$ 70.66	$ 40.29
Average Dated Brent spot price* ($/Bbl)	70.86	41.96

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

Crude oil revenues increased $131.9 million, or approximately 196.3%, during the year ended December 31, 2021 compared to the same period of 2020. The total barrels lifted for the year ended December 31, 2021 was more than the barrels lifted during the same period in 2020, mainly due to our increased working interest as a result of the Sasol Acquisition partially offset by natural declines in production. The Crude oil sales are a function of the number and size of crude oil liftings in each quarter and thus crude oil sales do not always coincide with volumes produced in any given quarter. We made 11 liftings during both years ended December 31, 2021 and December 31, 2020, respectively. Our share of crude oil inventory, excluding royalty barrels, was approximately 75,680 and 172,276 barrels at December 31, 2021 and 2020, respectively. The crude oil inventory was higher at December 31, 2020 due to the scheduled December 2020 lifting being delayed to January 2021.

Production expenses increased $43.9 million, or approximately 117.8%, in the year ended December 31, 2021 compared to the same period of 2020. The increase in expense was primarily related to costs as a result of our increased working interest as a result of the Sasol Acquisition, increased workover costs and higher marine and personnel costs. On a per barrel basis, production expense, excluding workover expense, for the year ended December 31, 2021 increased to $26.77 per barrel from $21.38 per barrel for the year ended December 31, 2020 primarily as a result of a natural decline in oil production and higher marine and personnel costs. While we have not experienced any significant operational disruptions associated with the current worldwide COVID-19 pandemic, we have incurred approximately $2.9 million, net to VAALCO, for the year ended December 2021 and $1.6 million, net to VAALCO, for the year ended December 2020, in higher costs related to the proactive measures taken in response to the pandemic.

Exploration expenses decreased $2.0 million or approximately 56.0%, in the year ended December 31, 2021 compared to the same period of 2020. The exploration expense in 2020 related to seismic acquisition costs while the expenses in 2021 were due to seismic processing costs. See further information at *Item 1. Business – Segment and Geographic Information – Gabon Segment — Development*.

Depreciation, depletion and amortization increased $11.7 million, or approximately 124.5%, in the year ended December 31, 2021 compared to the same period of 2020 due to higher depletable costs associated with the Sasol Acquisition. Partially offset by an increase in reserve base associated with the positive revisions in reserves.

Impairment of proved crude oil and natural gas properties for the year ended December 31, 2020 of $30.6 million was the result of declining forecasted crude oil prices primarily due to the COVID-19 pandemic. No impairment was recorded for the year ended December 31, 2021.

General and administrative expenses increased $4.1 million, or approximately 38.1% in the year ended December 31, 2021 compared to the same period of 2020. The increase in expense was in part related to a $2.3 million increase in stock-based compensation expense. The change in expense related to stock appreciation rights ("SARs") expense was an increase of $2.1 million. SARs liability awards are fair valued. The primary driver to changes in the fair value of these awards is changes in the Company's stock price. See Note 16 for further discussion. In addition, wages and salaries increased $1.1 million due to severance costs associated with changes in key personnel and legal fees increased $0.3 million due more legal activity in the current year.

Bad debt (recovery) expense and other reflected bad debt expense associated with the VAT allowance for the year ended December 31, 2021. Bad debt expense decreased $0.3 million, or approximately 24.9% in the year ended December 31, 2021 compared to the same period of 2020 mainly due to receipt of $0.5 million, net to VAALCO, in 2021 partially offset by increases in the allowance for bad debt.

Other operating income (expense), net decreased $1.2 million, or approximately 73.6%, in the year ended December 31, 2021 compared to the same period of 2020. The $0.4 million balance for the year ended December 31, 2021 is primarily comprised of the difference between the fair value of the contingent consideration paid to Sasol in April 2021, $5.0 million, and the fair value of the contingent consideration on the closing date of the Sasol Acquisition, $4.6 million. For the year ended December 31, 2020 other operating income (expense) is primarily related to a $0.8 million payment to resolve claims made by one of the Etame Marin block joint venture owners related to audits for the years 2017 and 2018 as well as $0.9 million in inventory obsolescence.

Derivative instruments gain (loss), net is attributable to our commodity swaps as discussed in Note 10 to the Financial Statements. The $22.8 million loss for the year ended December 31, 2021 is a result of the increase in the price of Dated Brent crude oil above the weighted average swap price of our derivative instruments during the year ended December 31, 2021 as compared to a decrease in the price of Dated Brent crude oil that resulted in a $6.6 million gain during the comparable period in 2020. Our derivative instruments currently cover a portion of our production through September 2022.

Interest income (expense), net for the years ended December 31, 2020 and 2019 relate to interest income on cash balances and are not material to the financial statements.

Other, net for the year ended December 31, 2021 is primarily attributable to $5.2 million for the bargain purchase gain offset by $1.0 million for an acquisition success fee and foreign currency losses. Other, net was not significant for the year ended December 31, 2020.

Income tax expense (benefit) for the year ended December 31, 2021 was $(22.1) million. This is comprised of $42.4 million of deferred tax benefit and a current tax provision of $20.3 million. The income tax expense for the year ended December 31, 2020 was $27.7 million. This is comprised of $ 24.2 million of deferred tax expense and a current tax provision of $3.5 million. The deferred income tax expense for the year ended December 31, 2020 included a $41.6 million charge to increase the valuation allowances on U.S. and Gabon deferred tax assets due to a decrease in future estimated taxable earnings primarily as a result of lower crude oil prices as well as the overall economic conditions of the industry. The current tax provision in both periods is primarily attributable to our operations in Gabon and is higher in 2021 than income tax for the comparable 2020 period as a result of higher revenues. See Note 8 to the Financial Statements for further discussion.

Income (loss) from discontinued operations, net of tax for the years ended December 31, 2021 and 2020 are attributable to our Angola segment as discussed further in Note 4 to the Financial Statements. The loss from discontinued operations for the year ended December 31, 2021 and December 31,2020, respectively, was related to Angola administration costs.

CRITICAL ACCOUNTING POLICIES AND 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 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 and natural gas 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, 2021, the Company had deferred tax assets of $86.9 million primarily attributable to Gabon and U.S. federal taxes related to basis differences in fixed assets, foreign tax credit carryforwards, and U.S. and foreign net operating loss carryforwards. A valuation allowance of $46.9 million has been established against the deferred tax assets as of December 31, 2021, 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 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 and natural gas 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 and natural gas 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 and natural gas 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 and natural gas prices and costs change.

Management is responsible for estimating the quantities of proved crude oil and natural gas 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.

Our senior executives and reserve engineers oversee the review of our crude oil and natural gas reserves and related disclosures by our appointed independent reserve engineers. The 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 and natural gas 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 and Natural Gas Producing Activities (unaudited).*"

Successful Efforts Method of Accounting for Crude Oil and Natural Gas Activities

We use the successful efforts method to account for our crude oil and natural gas activities. Management believes that this method is preferable, as we have focused on exploration activities wherein there is risk associated with future success and as such earnings are best represented by drilling results. 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.

Geological and geophysical costs are expensed as incurred. Costs of seismic studies that are utilized in development drilling within an area of proved reserves are capitalized as development costs. Amounts of seismic costs capitalized are based on only those blocks of data used in determining development well locations. To the extent that a seismic project covers areas of both developmental and exploratory drilling, those seismic costs are proportionately allocated between development costs and exploration expense.

We capitalize interest, if debt is outstanding, during drilling operations in our exploration and development activities.

We review the crude oil and natural gas 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 and natural gas 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 Financial Statements.

Impairment of Unproved Property

We evaluate our undeveloped crude oil and natural gas 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 and natural gas 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.

Future Dismantlement, Restoration, and Abandonment Costs

We have significant obligations to remove tangible equipment and restore land and seabed at the end of crude oil and natural gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells, removing and disposing of all or a portion of offshore crude oil and natural gas platforms, and capping pipelines. Estimating the future restoration and removal costs is difficult and 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 an asset retirement obligation (“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 our crude oil and natural gas properties. We use current retirement costs to estimate the expected cash outflows for asset 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 and natural gas properties. 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 asset balance or income statement, 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 and natural gas production facilities, while accretion escalates over the lives of the assets to reach the expected settlement value. See Note 11 to the Financial Statements for disclosures regarding the asset retirement obligations.

Derivative instruments and hedging activities

We use derivative financial instruments to achieve a more predictable cash flow from crude oil sales by reducing the exposure to price fluctuations. For more information regarding our use of derivative instruments, see Note 10 to the Financial Statements for disclosures.

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 significant inputs used to estimate fair value are crude oil prices, volatility, discount rate and the contract terms of the derivative instruments. 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. 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” and “Cash settlements received on matured derivative contracts, net” lines items located as adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities on the statements of consolidated cash flows. For further discussion, see Note 10 to the Financial Statements.

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 and natural gas 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. See Note 4 under “Acquisitions and dispositions” for further discussion.

NEW ACCOUNTING STANDARDS

See Note 3 to the 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, 2021, we had net monetary assets of $25.2 million (XAF 14,610.91 million) denominated in XAF. A 10% weakening of the CFA relative to the U.S. dollar would have a $(2.3) million reduction in the value of these net assets. For the year ended December 31, 2021, we had expenditures of approximately $24.9 million denominated in XAF.

Commodity Price Risk

Our major market risk exposure continues to be the prices received for our crude oil and natural gas production. Sales prices are primarily driven by the prevailing market prices applicable to our production. Market prices for crude oil and natural gas have been volatile and unpredictable in recent years, and this volatility may continue. Sustained low crude oil and natural gas prices or a resumption of the decreases in crude oil and natural gas 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 2,711 MBbls, a $5 per Bbl decrease in crude oil price would be expected to cause a $13.6 million decrease per year in revenues and operating income (loss) and a $12.2 million decrease per year in net income (loss).

As of December 31, 2021, we had unexpired derivative instruments outstanding covering 712 MBbls of production through June 2022. During the years ended December 31, 2021 and 2020, 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 "*Derivative instruments and hedging activities*" 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, 2021 at the reasonable assurance level.

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 (the "COSO Framework").

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, 2021.

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.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There have been no changes in our internal control over financial reporting during the three months ended December 31, 2021 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

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 2022 annual meeting, which will be filed with the SEC within 120 days of December 31, 2021, 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 2022 annual meeting, which will be filed with the SEC within 120 days of December 31, 2021, 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 2022 annual meeting, which will be filed with the SEC within 120 days of December 31, 2021, and which is incorporated herein by reference. Please see "*Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*" for information on securities that may be issued under our stock incentive plans.

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

Information required by this item will be included in the proxy statement for our 2022 annual meeting, which will be filed with the SEC within 120 days of December 31, 2021, 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 2022 annual meeting, which will be filed with the SEC within 120 days of December 31, 2021, 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.

(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).
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).
3.2	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 Nonstatutory 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).
10.22*	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).
10.23*	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).
10.24*	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).
10.25*	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).
10.26	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).
10.27	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 by reference herein).
10.28	Deed of Guarantee and Indemnity, by and between VAALCO Energy, Inc. and VAALCO Gabon S.A., 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 by reference herein).
10.29	Deed of Guarantee and Indemnity, by and between VAALCO Energy, Inc. and VAALCO Gabon S.A., 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 by reference herein).
21.1(a)	List of subsidiaries of the Company.
23.1(a)	Consent of BDO USA, LLP.
23.2(a)	Consent of Netherland, Sewell & Associates, Inc. — 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.
99.1(a)	Report of Netherland, Sewell & Associates, Inc. (International Properties).
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

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 10, 2022

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on the 9th day of March 2022, 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

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 sheets of VAALCO Energy, Inc. (the “Company”) as of December 31, 2021 and 2020, the related consolidated statements of operations, shareholders’ equity, and cash flows for each of the three years ended in the period ended December 31, 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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion.

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.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate 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 critical audit matters 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 matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Accounting for Income Taxes - Assessment of the Realizability of Deferred Tax Assets

As described in Notes 2 and 8 to the consolidated financial statements, the Company 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 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. During the year ended December 31, 2021, the Company determined it was more likely than not that it would realize a portion of their deferred taxes and reversed a portion of the valuation allowance of the previously fully valued deferred tax assets. After the reversal, the Company had net deferred tax assets of $40 million.

We identified the assessment of the realizability of deferred tax assets as a critical audit matter. Auditing management’s judgments with respect to the recoverability of deferred tax assets in the United States and Gabon tax jurisdictions, including whether sufficient future taxable income will be generated, required increased audit effort including the need for professionals with specialized knowledge and skill in taxation.

The primary procedures we performed to address this critical audit matter included:

- Evaluating the assumptions used by management in developing projections of future taxable income by income tax jurisdiction, testing the completeness and accuracy of the underlying data used in the projections and assessing the consistency of underlying data and assumptions with evidence obtained in other areas of the audit.

- Utilizing professionals with specialized knowledge and skill in domestic and international tax matters to assist in evaluating the appropriateness and accuracy of the gross deferred tax assets and liabilities and permanent tax differences in the various tax jurisdictions.

Estimate of Crude Oil and Natural Gas Reserves

As described in Notes 2 and 9 to the consolidated financial statements, the Company accounts for its crude oil and natural gas properties using the successful efforts method of accounting, which requires management to make estimates of crude oil and natural gas reserve volumes and future revenues to record depletion expense and measure its crude oil and natural gas properties for potential impairment. To estimate the volume of crude oil and natural gas reserves and future revenues, management makes significant estimates and assumptions, including forecasting the production decline rate of producing properties and forecasting the timing and volume of production associated with the Company's development plan for proved undeveloped properties. In addition, the estimation of crude oil and natural gas reserves is also impacted by management's judgments and estimates regarding the financial performance of wells to determine if wells are expected, with reasonable certainty, to be economical under the appropriate pricing assumptions required in the estimation of depletion expense and potential impairment measurements. The net crude oil and natural gas properties and equipment balance as of December 31, 2021 was $94.3 million.

We identified the estimation of crude oil and natural gas reserves, due to its impact on depletion expense and potential impairment evaluation, as a critical audit matter. The estimation of crude oil and natural gas reserves requires a high degree of judgment by a qualified petroleum engineer and relatively minor changes in certain inputs and assumptions, as described above, could have a significant impact on the measurement of depletion expense or the recognition of potential impairment expense. In turn, auditing these inputs and assumptions required subjective and complex auditor judgment.

The primary procedures we performed to address this critical audit matter included:

- Comparing the Company's crude oil and gas price assumptions to third-party forecasts, peer information and relevant market data to determine whether the Company's price forecasts were within range of such third-party data.

- Testing estimated future capital and operational costs by comparison to historically realized amounts, approved budgets and current economic conditions.

- Performing a look-back analysis to identify indications of potential management bias over time in estimating decline curves and volumes.

- Reviewing reserve reports provided by an external reserve engineer and assessing the scope of work and findings.

- Assessing the competence, capability and objectivity of the Company's internal and external reserve experts involved in preparing the reserve reports through an understanding of their relevant professional qualifications and experience as a basis for management's reliance on their work.

Valuation and Recognition of Crude Oil and Natural Gas Properties Acquired in Sasol Acquisition

As described in Notes 2 and 4 to the consolidated financial statements, the Company completed its acquisition of Sasol Gabon S.A.'s ("Sasol") working interest in the Etame Marin block for consideration of $38.6 million during the first quarter of 2021. All assets and liabilities associated with Sasol's interest in the Etame Marin block were recorded at their fair values. As a result of the acquisition, the Company recognized crude oil and natural gas properties of $37.2 million, based on the fair value on the acquisition date.

We identified the determination of fair value of crude oil and natural gas properties acquired from Sasol as a critical audit matter. The Company, with the assistance of outside consultants, used significant judgment to develop estimates of reserve quantities factoring in specific risk adjustments based on reserve category and the Company's weighted average cost of capital used to determine their fair value at closing. Auditing these assumptions involved especially subjective auditor judgment and effort, including the need for professionals with specialized knowledge and skill in valuation.

The primary procedures we performed to address this critical audit matter included:

- Assessing the competence, capability and objectivity of the outside valuation consultants engaged by the Company to measure the fair value of the acquired crude oil and natural gas properties including the valuation methodology selected.
- Testing management's estimate of reserve quantities by applying procedures consistent with our testing of the Company's existing crude oil and natural gas reserves.
- Utilizing personnel with specialized knowledge and skill with valuation to assist in assessing the reasonableness of reserve risk adjustments and the weighted average cost of capital utilized by management.

/s/BDO USA, LLP

We have served as the Company's auditor since 2016.

Houston, TX

March 10, 2022

VAALCO ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	As of December 31, 2021	As of December 31, 2020
ASSETS	*(in thousands)*	
Current assets:		
Cash and cash equivalents	**$ 48,675**	$ 47,853
Restricted cash	**79**	86
Receivables:		
Trade, net	**22,464**	—
Accounts with joint venture owners, net of allowance of $0.0 million in both periods presented	**345**	3,587
Other, net	**9,977**	4,331
Crude oil inventory	**1,593**	3,906
Prepayments and other	**5,156**	4,215
Total current assets	**88,289**	63,978
Crude oil and natural gas properties, equipment and other - successful efforts method, net	**94,324**	37,036
Other noncurrent assets:		
Restricted cash	**1,752**	925
Value added tax and other receivables, net of allowance of $5.7 million and $2.3 million, respectively	**5,536**	4,271
Right of use operating lease assets	**10,227**	22,569
Deferred tax assets	**39,978**	—
Abandonment funding	**21,808**	12,453
Other long-term assets	**1,176**	—
Total assets	**$ 263,090**	$ 141,232
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	**$ 18,797**	$ 16,690
Accounts with joint venture owners	**3,233**	4,945
Accrued liabilities and other	**49,444**	17,184
Operating lease liabilities - current portion	**9,642**	12,890
Foreign income taxes payable	**3,128**	860
Current liabilities - discontinued operations	**13**	7
Total current liabilities	**84,257**	52,576
Asset retirement obligations	**33,949**	17,334
Operating lease liabilities - net of current portion	**587**	9,671
Other long-term liabilities	—	193
Total liabilities	**118,793**	79,774
Commitments and contingencies (Note 12)		
Shareholders' equity:		
Preferred stock, $25 par value; 500,000 shares authorized, none issued	—	—
Common stock, $0.10 par value; 100,000,000 shares authorized, 69,562,774 and 67,897,530 shares issued, 58,623,451 and 57,531,154 shares outstanding, respectively	**6,956**	6,790
Additional paid-in capital	**76,700**	74,437
Less treasury stock, 10,939,323 and 10,366,376 shares, respectively, at cost	**(43,847)**	(42,421)
Retained earnings	**104,488**	22,652
Total shareholders' equity	**144,297**	61,458
Total liabilities and shareholders' equity	**$ 263,090**	$ 141,232

See notes to consolidated financial statements.

VAALCO ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2021	**2020**	**2019**
	(in thousands, except per share amounts)		
Revenues:			
Crude oil and natural gas sales	**$ 199,075**	$ 67,176	$ 84,521
Operating costs and expenses:			
Production expense	**81,255**	37,315	37,689
Exploration expense	**1,579**	3,588	—
Depreciation, depletion and amortization	**21,060**	9,382	7,083
Impairment of proved crude oil and natural gas properties	—	30,625	—
Gain on revision of asset retirement obligations	—	—	(379)
General and administrative expense	**14,766**	10,695	14,855
Bad debt expense and other	**875**	1,165	(341)
Total operating costs and expenses	**119,535**	92,770	58,907
Other operating income (expense), net	**(440)**	(1,669)	(4,421)
Operating income (loss)	**79,100**	(27,263)	21,193
Other income (expense):			
Derivative instruments gain (loss), net	**(22,826)**	6,577	(446)
Interest income, net	**10**	155	733
Other, net	**3,494**	129	(438)
Total other income (expense), net	**(19,322)**	6,861	(151)
Income (loss) from continuing operations before income taxes	**59,778**	(20,402)	21,042
Income tax expense (benefit)	**(22,156)**	27,681	23,890
Income (loss) from continuing operations	**81,934**	(48,083)	(2,848)
Income (loss) from discontinued operations, net of tax	**(98)**	(98)	5,411
Net income (loss)	**$ 81,836**	$ (48,181)	$ 2,563
Basic net income (loss) per share:			
Income (loss) from continuing operations	**$ 1.38**	$ (0.83)	$ (0.05)
Loss from discontinued operations, net of tax	—	—	0.09
Net income (loss) per share	**$ 1.38**	$ (0.83)	$ 0.04
Basic weighted average shares outstanding	**58,230**	57,594	59,143
Diluted net income (loss) per share:			
Income (loss) from continuing operations	**$ 1.37**	$ (0.83)	$ (0.05)
Loss from discontinued operations, net of tax	—	—	0.09
Net income (loss) per share	**$ 1.37**	$ (0.83)	$ 0.04
Diluted weighted average shares outstanding	**58,755**	57,594	59,143

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	Treasury Stock	Retained Earnings	Total
				(in thousands)			
Balance at January 1, 2019	67,168	(7,572)	$ 6,717	$ 72,358	$ (37,827)	$ 68,579	$ 109,827
Shares issued - stock-based compensation	506	(10)	50	206	—	—	256
Stock-based compensation expense	—	—	—	985	—	—	985
Treasury stock	—	(2,067)	—	—	(3,602)	(309)	(3,911)
Net income	—	—	—	—	—	2,563	2,563
Balance at December 31, 2019	67,674	(9,649)	6,767	73,549	(41,429)	70,833	109,720
Shares issued - stock-based compensation	223	(44)	23	40	—	—	63
Stock-based compensation expense	—	—	—	848	—	—	848
Treasury stock	—	(673)	—	—	(992)	—	(992)
Net loss	—	—	—	—	—	(48,181)	(48,181)
Balance at December 31, 2020	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**

See notes to consolidated financial statements.

VAALCO ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2021	2020	2019
	(in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ **81,836**	$ (48,181)	$ 2,563
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Loss from discontinued operations, net of tax	**98**	98	(5,411)
Depreciation, depletion and amortization	**21,060**	9,382	7,083
Bargain purchase gain	**(7,651)**	—	—
Impairment of proved crude oil and natural gas properties	—	30,625	—
Gain on revision of asset retirement obligations	—	—	(379)
Other amortization	—	181	241
Deferred taxes	**(39,978)**	24,159	14,480
Unrealized foreign exchange (gain) loss	**(291)**	91	(50)
Stock-based compensation	**2,459**	114	3,506
Cash settlements paid on exercised stock appreciation rights	**(3,271)**	(275)	(491)
Derivative instruments (gain) loss, net	**22,826**	(6,577)	446
Cash settlements received (paid) on matured derivative contracts, net	**(18,020)**	7,216	2,439
Bad debt expense and other	**875**	1,165	(341)
Other operating loss, net	**440**	869	58
Operational expenses associated with equipment and other	**2,415**	1,601	69
Cash advance for other long-term assets	**(1,176)**	—	—
Change in operating assets and liabilities:			
Trade receivables	**(11,308)**	14,335	(2,428)
Accounts with joint venture owners	**1,594**	4,016	(2,075)
Other receivables	**(9,736)**	1,405	(94)
Crude oil inventory	**5,022**	(2,834)	(287)
Prepayments and other	**1,617**	(1,126)	(1,014)
Value added tax and other receivables	**(1,593)**	(1,268)	275
Accounts payable	**(922)**	(842)	6,011
Foreign income taxes receivable/payable	**2,268**	(4,880)	2,396
Accrued liabilities and other	**1,645**	(1,383)	4,161
Net cash provided by continuing operating activities	**50,209**	27,891	31,158
Net cash used in discontinued operating activities	**(92)**	(441)	(4,686)
Net cash provided by operating activities	**50,117**	27,450	26,472
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property and equipment expenditures	**(16,558)**	(20,008)	(10,348)
Acquisition of crude oil and natural gas properties	**(22,505)**	(4,320)	—
Net cash used in continuing investing activities	**(39,063)**	(24,328)	(10,348)
Net cash used in discontinued investing activities	**—**	—	—
Net cash used in investing activities	**(39,063)**	(24,328)	(10,348)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from the issuances of common stock	**1,369**	63	256
Treasury shares	**(1,426)**	(992)	(3,911)
Net cash used in continuing financing activities	**(57)**	(929)	(3,655)
Net cash used in discontinued financing activities	**—**	—	—
Net cash used in financing activities	**(57)**	(929)	(3,655)
NET CHANGE IN CASH, CASH EQUIVALENTS AND RESTRICTED CASH	**10,997**	2,193	12,469
CASH, CASH EQUIVALENTS AND RESTRICTED CASH AT BEGINNING OF PERIOD	**61,317**	59,124	46,655
CASH, CASH EQUIVALENTS AND RESTRICTED CASH AT END OF PERIOD	$ **72,314**	$ 61,317	$ 59,124

See notes to consolidated financial statements.

VAALCO ENERGY, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS SUPPLEMENTAL DISCLOSURES

	Year Ended December 31,		
	2021	**2020**	**2019**
		(in thousands)	
Supplemental disclosure of cash flow information:			
Income taxes received in cash	**$ —**	$ (696)	$ (674)
Income taxes paid in-kind with crude oil	**$ 20,103**	$ 8,738	$ 7,268
Supplemental disclosure of non-cash investing and financing activities:			
Property and equipment additions incurred but not paid at end of period	**$ 15,021**	$ 3,966	$ 13,646
Recognition of right-of-use operating lease assets and liabilities	**$ 581**	$ 1,478	$ 44,681
Recognition of right-of-use operating lease liabilities	**$ 581**	$ 1,478	$ 44,656
Asset retirement obligations	**$ 21,733**	$ 359	$ 595
Restricted stock issued out of treasury	**$ —**	$ —	$ 309

See notes to 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. As operator, the Company has production operations and conducts exploration activities in Gabon, West Africa. The Company has opportunities to participate in development and exploration activities in Equatorial Guinea, West Africa. As discussed further in Note 4 below, VAALCO has discontinued operations associated with activities in Angola, West Africa.

The Company's consolidated subsidiaries are 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) and VAALCO Energy (USA), Inc.

With respect to the novel strain of coronavirus ("COVID-19"), a global pandemic was declared by the World Health Organization on March 11, 2020. The adverse economic effects of the COVID-19 outbreak materially decreased demand for crude oil based on the restrictions in place by governments trying to curb the outbreak and changes in consumer behavior. This led to a significant global oversupply of crude oil and consequently a substantial decrease in crude oil prices.

In response to the oversupply of crude oil, global crude oil producers, including the Organization of Petroleum Exporting Countries and other oil producing nations ("OPEC+"), reached agreement in April 2020 to cut crude oil production. Further, in connection with the OPEC+ agreement, the Minister of Hydrocarbons in Gabon requested that the Company reduce its production. In response to such request from the Minister of Hydrocarbons, between July 2020 and April 2021, the Company temporarily reduced production from the Etame Marin block. Currently, the Company's production is not impacted by OPEC+ curtailments. 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.

The Company considered the impact of the COVID-19 pandemic and the substantial decline in crude oil prices on the assumptions and estimates used for preparation of the financial statements. As a result, the Company recognized a number of material charges during the three months ended March 31, 2020, including impairments to its capitalized costs for proved crude oil and natural gas properties and valuation allowances on its deferred tax assets. These are discussed further in the following notes.

For the year ended December 31, 2021, crude oil prices have improved, there were no disruptions to operations as a result of COVID-19 or any strain thereof, global economic activity has steadily increased, and oil demand has stabilized over multiple quarters removing much of the uncertainty and instability in the industry. Therefore, no additional charges or impairments were required for the twelve months ended December 31, 2021. Crude oil prices have continually increased and are currently at the highest levels seen in recent years. The average annual Brent price per barrel for the year ended December 31, 2020 was $41.96 and increased 69% to $70.86 for the year ended December 31, 2021. At the end of 2021 and continuing into 2022, travel-related restrictions have lessened, access to vaccines that reduce the spread and impact of COVID-19 and its variants have become more accessible and the global economy appears more flexible to continuing to effectively operate in a COVID-19 environment. However, while the business environment in 2021 improved, the COVID-19 situation and effects thereof remain fluid. A prolonged outbreak may have a material adverse impact on financial results and business operations of the Company, including the timing and ability of the Company to complete future drilling campaigns and other efforts required to advance the development of its crude oil and natural gas properties.

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 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 United States ("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 and natural gas reserves used to estimate depletion expense and impairment charges require extensive 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 become 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.

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 time duration. Current amounts in restricted cash at December 31, 2021 and 2020 each include an escrow amount representing bank guarantees for customs clearance in Gabon. Long-term amounts at December 31, 2021 and 2020 include a charter payment escrow for the FPSO offshore Gabon as discussed in Note 12. 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,	
	2021	**2020**
	(in thousands)	
Cash and cash equivalents	**$ 48,675**	$ 47,853
Restricted cash - current	**79**	86
Restricted cash - non-current	**1,752**	925
Abandonment funding	**21,808**	12,453
Total cash, cash equivalents and restricted cash	**$ 72,314**	$ 61,317

The Company conducts regular abandonment studies to update the estimated costs to abandon the offshore wells, platforms and facilities on the Etame Marin block. This cash funding is reflected under “Other noncurrent assets” as “Abandonment funding” on 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. See Note 11 for further discussion.

On February 28, 2019, the Gabonese branch of the international commercial bank holding the abandonment funds in a U.S. dollar denominated account advised that the bank regulator required transfer of the funds to the Central Bank for African Economic and Monetary Community (“CEMAC”) of which Gabon is one of the six member states, for conversion to local currency with a credit back to the Gabonese branch in local currency. The Etame PSC provides these payments must be denominated in U.S. dollars and the CEMAC regulations provide for establishment of a U.S. dollar account with the Central Bank. Although we requested establishment of such account, the Central Bank did not comply with our requests until February 2021. As a result, we were not able to make the annual abandonment funding payment in 2019, 2020 or 2021 totaling $4.3 million, net to VAALCO based on the 2018 abandonment study. In February 2021, BEAC authorized us to apply for a U.S. dollar denominated escrow account for the abandonment fund at Citibank. Working with Citibank, on March 12, 2021 we filed the application to open the account and are currently awaiting the approval of the account from the Central Bank. Accordingly, we were not able to make our funding payment in 2021. In December 2021, as part of the new FX regulations issued by BEAC, they allowed for opening of U.S. dollars escrow accounts for the abandonment funds at BEAC and are currently working with the extractive industry to formulate the agreements which are expected to be finalized in 2022 that regulates these accounts. Accordingly, pursuant to Amendment No. 5 of the Etame PSC that required these funds to be in U.S. dollars, once the account for the U.S. dollars abandonment fund is open at BEAC we will resume our funding of the abandonment fund in compliance with the Etame PSC.

Accounts with joint venture owners – 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.

Accounts Receivable and Allowance for Doubtful Accounts – The Company’s accounts receivable results from sales of crude oil production, joint interest billings to its joint interest owners for their share of expenses on joint venture projects for which the Company is the operator, and receivables from the government of Gabon for reimbursable Value-Added Tax (“VAT”). Collection efforts, including remedies provided for in the contracts, are pursued to collect overdue amounts owed to the Company. Portions of the Company’s costs in Gabon (including the Company’s VAT receivable) are denominated in the local currency of Gabon, the Central African CFA Franc (“XAF”). Most of these receivables have payment terms of 30 days or less. The Company monitors the creditworthiness of the counterparties, and it has obtained credit enhancements from some parties in the form of parental guarantees or letters of credit. Joint owner receivables are secured through cash calls and other mechanisms for collection under the terms of the joint operating agreements.

The Company routinely assesses the recoverability of all material receivables to determine their collectability. The Company accrues a reserve on a receivable when, based on management’s judgment, it is probable that a receivable will not be collected and the amount of such reserve may be reasonably estimated. When collectability is in doubt, the Company records an allowance against the accounts receivable and a corresponding income charge for bad debts, which appears in the “Bad debt expense and other” line item of the consolidated statements of operations.

As of December 31, 2021, the outstanding VAT receivable balance, excluding the allowance for bad debt, was approximately $14.5 million ($9.6 million, net to VAALCO). As of December 31, 2021, the exchange rate was XAF 578.2 = $1.00. As of December 31, 2020, the exchange rate was XAF 534.8 = $1.00. 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 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, net" line item of the consolidated statements of operations.

The following table provides an analysis of the change in the allowance:

	Year Ended December 31,		
	2021	2020	2019
		(in thousands)	
Allowance for bad debt			
Balance at beginning of period	**$ (2,273)**	$ (1,508)	$ (2,535)
Bad debt (charge) income, net of receipts	**(875)**	(1,165)	341
Adjustment associated with reversal of allowance on Mutamba receivable	**—**	593	623
Adjustment associated with Sasol Acquisition	**(2,879)**	—	—
Foreign currency gain (loss)	**286**	(193)	63
Balance at end of period	**$ (5,741)**	$ (2,273)	$ (1,508)

Other receivables– Under the terms of the Etame PSC, the Company can be required to contribute to meeting domestic market needs of the Republic of Gabon by delivering to it, or another entity designated by the Republic of Gabon, an amount of crude oil proportional to the Company's share of production to the total production in Gabon over the year. In 2021, the Company was notified by the Republic of Gabon to deliver to a refinery its proportionate share of crude oil to meet the domestic market need as per the terms of the Etame PSC. The Company is entitled, per the Etame PSC, to a fixed selling price for the oil delivered. Since the crude-oil produced by the Company was not compatible with the crude-oil requirements of the refinery, the Company entered into 2 contracts to fulfill its domestic market needs obligation under the Etame PSC. One contract was to purchase oil from another producer that was more compatible to the refinery and another contract with the refinery itself to deliver the crude oil to. Under the contract with another producer, the producer is entitled to a selling price consistent with the price the Company receives under the terms of the Etame PSC. As a result of these contracts and timing differences between when the oil is procured and when it is delivered to and paid by the refinery, included in the Company's December 31, 2021 consolidated balance sheet is other receivables of approximately $10.0 million for amounts due to the Company from the refinery and a $5.4 million liability included in accounts payable and a $4.6 million liability included in accrued liabilities in the December 31, 2021 consolidated balance sheet for amounts due to the oil supplier.

Crude oil inventory – Crude oil inventories are carried at the lower of cost or net realizable value and represent the share of crude oil produced and stored on the FPSO, but unsold at the end of the period.

Materials and supplies – Materials and supplies, which are included in the "Prepayments and other" line item of the consolidated balance sheet, are primarily used for production related activities. These assets are valued at the lower of cost, determined by the weighted-average method, or net realizable value.

Crude Oil and natural gas properties, equipment and other – The Company uses the successful efforts method of accounting for crude oil and natural gas producing activities. Management believes that this method is preferable, as the Company has focused on exploration activities wherein there is risk associated with future success and as such earnings are best represented by drilling results.

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. Geological and geophysical costs are expensed as incurred. Costs of seismic studies that are utilized in development drilling within an area of proved reserves are capitalized as development costs. Amounts of seismic costs capitalized are based on only those blocks of data used in determining development well locations. To the extent that a seismic project covers areas of both developmental and exploratory drilling, those seismic costs are proportionately allocated between development costs and exploration expense.

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 proved developed reserves. Depletion of developed leasehold acquisition costs are provided on a block basis under the unit-of-production method based upon estimates of proved reserves. Support equipment (other than equipment inventory) and leasehold improvements related to crude oil and natural gas producing activities, as well as property, plant and equipment unrelated to crude oil and natural gas 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.

Impairment – The Company reviews the crude oil and natural gas producing properties 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 if commodity prices fall below a level that significantly effects anticipated future cash flows. 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 and natural gas 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 and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future crude oil and natural gas sales prices may all differ from those assumed in these estimates. Capitalized equipment inventory is reviewed regularly for obsolescence. When undeveloped crude oil and natural gas leases are deemed to be impaired, exploration expense is charged. Unproved property costs consist of acquisition costs related to undeveloped acreage in the Etame Marin block in Gabon and in Block P in Equatorial Guinea. See Note 9 for further discussion.

Purchase Accounting – On February 25, 2021, VAALCO Gabon S.A., a wholly owned subsidiary of the Company, completed the acquisition of Sasol Gabon S.A.’s (“Sasol’s”) 27.8% working interest in the Etame Marin block offshore Gabon pursuant to the sale and purchase agreement (“SPA”) dated November 17, 2020 (the “Sasol Acquisition”). The Company made various assumptions in determining the fair values of acquired assets and liabilities assumed. In order to allocate the purchase price, the Company developed fair value models with the assistance of outside consultants. These fair value models were used to determine the fair value associated with the reserves and applied discounted cash flows to expected future operating results, considering expected growth rates, development opportunities, and future pricing assumptions. The fair value of working capital assets acquired and liabilities assumed were transferred at book value, which approximates fair value due to the short-term nature of the assets and liabilities. The fair value of the fixed assets acquired was based on estimates of replacement costs and the fair value of liabilities assumed was based on their expected future cash outflows. See Note 4 for further discussion.

Lease commitments – The Company leases office buildings, warehouse and storage facilities, equipment and corporate housing under leasing agreements that expire at various times. All leases are characterized as operating leases and are expensed either as production expenses or general and administrative expenses. See Note 13 for further discussion.

Asset retirement obligations (“ARO”) – The Company has significant obligations to remove tangible equipment and restore land or seabed at the end of crude oil and natural gas production operations. The removal and restoration obligations are primarily associated with plugging and abandoning wells, removing and disposing of all or a portion of offshore crude oil and natural gas platforms, and capping pipelines. Estimating the future restoration and removal costs is difficult and 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 and natural gas properties. 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 and natural gas properties. 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 asset balance or income statement, 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 and natural gas 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. See Note 11 for further discussion.

Revenue recognition– Revenues from contracts with customers are generated from sales in Gabon pursuant to crude oil sales and purchase agreements. 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. 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. 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. See Note 7 for further discussion.

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, 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 requisite or derived service period, using the straight-line attribution method over the service period for each separately vesting portion of the award as if the award was, in-substance, multiple awards.

Unless the awards contain a market condition, previously recognized expense related to forfeited awards is reversed in the period in which the forfeiture occurs. For awards containing a market condition, previously recognized stock-based compensation expense is not reversed when the awards are forfeited. See Note 16 for further discussion.

Foreign currency transactions – The U.S. dollar is the functional currency of the Company's foreign operating subsidiaries. Gains and losses on foreign currency transactions are included in income. Within the consolidated statements of operations line item "Other income (expense)—Other, net," the Company recognized losses on foreign currency transactions of $0.7 million in 2021, while the Company recognized gains on foreign currency transactions of $0.2 million in 2020 and losses on foreign currency transactions of $0.2 million in 2019.

Income taxes – The annual 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 and natural gas 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. We also record as income tax expense the increase or decrease in the value of the government's allocation of Profit Oil which results due to changes in value from the time the allocation is originally produced to the time the allocation is actually lifted.

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.

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

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. 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. See Note 10 for further discussion.

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 represent quoted prices in active markets for identical assets or liabilities (for example, exchange-traded commodity derivatives).

Level 2 – Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (for example, quoted market prices for similar assets or liabilities in active markets or quoted market prices for identical assets or liabilities in markets not considered to be active, inputs other than quoted prices that are observable for the asset or liability, or market-corroborated inputs).

Level 3 – Inputs that are not observable from objective sources, such as internally developed assumptions used in pricing an asset or liability (for example, an estimate of future cash flows used in the internally developed present value of future cash flows model that underlies the fair-value measurement).

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 and natural gas properties, asset retirement assets and liabilities and other long-lived assets and assets acquired and liabilities assumed in a business combination. Generally, a cash flow model is used in combination with inflation rates and credit-adjusted, risk-free discount rates or industry rates to determine the fair value of the assets and liabilities. Based upon our review of the fair value hierarchy, the inputs used in these fair value measurements are considered Level 3 inputs.

Fair value of financial instruments – The Company’s current assets and liabilities include financial instruments such as cash and cash equivalents, restricted cash, accounts receivable, derivative assets and liabilities, accounts payable, liabilities for SARs and guarantees. As discussed further in Note 10, derivative assets and liabilities are measured and reported at fair value each period with changes in fair value recognized in net income. The derivatives referenced below are reported in “Accrued liabilities and other” on the consolidated balance sheet. SARs liabilities are measured and reported at fair value using level 2 inputs each period with changes in fair value recognized in net income. The current portion of the SARs liabilities is reported in “Accrued liabilities and other” on the consolidated balance sheet while the long-term portion is reported in “Other long-term liabilities”. With respect to the other financial instruments included in current assets and liabilities, the carrying value of each financial instrument approximates fair value primarily due to the short-term maturity of these instruments.

		As of December 31, 2021			
	Balance Sheet Line	**Level 1**	**Level 2**	**Level 3**	**Total**
		(in thousands)			
Liabilities					
SARs liability	Accrued liabilities	**$ —**	**$ 609**	**$ —**	**$ 609**
Derivative liability - crude oil swaps	Accrued liabilities	**—**	**4,806**	**—**	**4,806**
		$ —	**$ 5,415**	**$ —**	**$ 5,415**

		As of December 31, 2020			
	Balance Sheet Line	**Level 1**	**Level 2**	**Level 3**	**Total**
		(in thousands)			
Liabilities					
SARs liability	Accrued liabilities	$ —	$ 2,289	$ —	$ 2,289
SARs liability	Other long-term liabilities	—	193	—	193
		$ —	$ 2,482	$ —	$ 2,482

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. See Note 6 for further discussion.

Other, net – "Other, net" in non-operating income and expenses includes gains and losses from foreign currency transactions as discussed above as well as taxes other than income taxes.

3. NEW ACCOUNTING STANDARDS

Not Yet 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 will be 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. Initially, ASU 2016-13 was effective for all public companies for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years and will be applied with a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. The FASB subsequently issued ASU No. 2019-04 ("ASU 2019-04"): *Codification Improvements to Topic 326, Financial Instruments-Credit Losses, Topic 815, Derivatives, and Topic 825, Financial Instruments and ASU No. 2019-05 ("ASU 2019-05"*): Financial Instruments-Credit Losses (Topic 326) - Targeted Transition Relief. ASU 2019-04 and ASU 2019-05 provide certain codification improvements related to implementation of ASU 2016-13 and targeted transition relief consisting of an option to irrevocably elect the fair value option for eligible instruments. In November 2019, the FASB issued ASU No. 2019-10, *Financial Instruments—Credit Losses (Topic 326), Derivatives and Hedging (Topic 815), and Leases (Topic 842): Effective Dates*. This amendment deferred the effective date of ASU No. 2016-13 from January 1, 2020 to January 1, 2023 for calendar year end smaller reporting companies, which includes the Company. The Company plans to defer the implementation of ASU 2016-13, and related updates, until January 2023.

Adopted

In December 2019, the Financial Accounting Standards Board ("FASB") issued ASU No. 2019-12, *Income Taxes (Topic 740: Simplifying the Accounting for Income Taxes* ("ASU 2019-12"), which removes certain exceptions to the general principles in Topic 740. ASU 2019-12 is effective for fiscal years beginning after December 15, 2020, with early adoption permitted. The adoption of this guidance did not have a material impact on the Company's financial statements.

4. ACQUISITIONS AND DISPOSITIONS

Acquisition of Sasol Gabon S.A.'s Interest in Etame

On February 25, 2021, VAALCO Gabon S.A. completed the acquisition of Sasol's 27.8% working interest in the Etame Marin block offshore Gabon pursuant to the SPA. The effective date of the transaction was July 1, 2020. Prior to the Sasol Acquisition, the Company owned and operated a 31.1% working interest in Etame. The Sasol Acquisition increased the Company's working interest to 58.8%. As a result of the Sasol Acquisition, the net portion of production and costs relating to the Company's Etame operations increased from 31.1% to 58.8%. Reserves, production and financial results for the interests acquired in the Sasol Acquisition have been included in VAALCO's results for periods after February 25, 2021.

The following amounts represent the preliminary allocation of the purchase price to the assets acquired and liabilities assumed in the Sasol Acquisition. The final determination of fair value for certain assets and liabilities will be completed as soon as the information necessary to complete the analysis is obtained. These amounts will be finalized as soon as possible, but no later than one year from the date of the acquisition. The final determination of fair value for certain assets and liabilities (VAT and accrued liabilities) could differ materially from the amounts set forth below:

		February 25, 2021
		(in thousands)
Purchase Consideration		
Cash	$	33,959
Fair value of contingent consideration		4,647
Total purchase consideration	$	38,606

		February 25, 2021
		(in thousands)
Assets acquired:		
Wells, platforms and other production facilities	$	37,176
Equipment and other		5,568
Value added tax and other receivables		1,234
Abandonment funding		11,781
Accounts receivable - trade		11,220
Other current assets		3,963
Liabilities assumed:		
Asset retirement obligations		(14,564)
Accrued liabilities and other		(10,121)
Bargain purchase gain		(7,651)
Total purchase price	$	38,606

All assets and liabilities associated with Sasol's interest in Etame Marin block, including crude oil and natural gas 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, February 25, 2021, 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 the Company's 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 risk adjusted discount rates. Other significant estimates were used by the Company to determine the fair value of assets acquired and liabilities assumed. The Company has one year from the date of closing to record purchase price adjustments as a result of changes in such estimates. As a result of comparing the purchase price to the fair value of the assets acquired and liabilities assumed a $7.7 million bargain purchase gain was recognized. A bargain purchase gain of $5.2 million is included in "*Other, net*" under "*Other income (expense)*" in the consolidated statements of operations. An income tax benefit of $4.1 million, related to the bargain purchase gain, is also included in the consolidated statements of operations. The bargain purchase gain is primarily attributable to the increase in crude oil price forecasts from the date the SPA was signed, November 17, 2020, to the closing date, February 25, 2021, when the fair value of the reserves associated with the Sasol Acquisition were determined.

The impact of the Sasol Acquisition was an increase to "*Crude oil and natural gas sales*" of $84.6 million and $29.3 million of "Net income" in the consolidated statements of operations for the year ended December 31, 2021.

The unaudited pro forma results presented below have been prepared to give the effect to the Sasol Acquisition discussed above on the Company's results of operations for the years ended December 31, 2021 and 2020, as if the Sasol Acquisition had been consummated on January 1, 2020. The unaudited pro forma results do not purport to represent what the Company's actual results of operations would have been if the Sasol Acquisition 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,	
	2021	2020
	(in thousand)	
Pro forma (unaudited)		
Crude oil and natural gas sales	$ **216,848**	$ 127,199
Operating income (loss)	**89,782**	(16,902)
Net income (loss)	**66,001** (a)	(36,508) (b)
Basic net income (loss) per share:		
Income (loss) from continuing operations	$ **1.14**	$ (0.63)
Loss from discontinued operations, net of tax	**(0.01)**	—
Net income (loss) per share	$ **1.13**	$ (0.63)
Basic weighted average shares outstanding	**58,230**	57,594
Diluted net income (loss) per share:		
Income (loss) from continuing operations	$ **1.12**	$ (0.63)
Loss from discontinued operations, net of tax	—	—
Net income (loss) per share	$ **1.12**	$ (0.63)
Diluted weighted average shares outstanding	**58,755**	57,594

(a) 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.

(b) The unaudited pro forma net loss for the year ended December 31, 2020 includes 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.

Under the terms of the SPA, a contingent payment of $5.0 million was payable to Sasol should the average Dated Brent price over a consecutive 90-day period from July 1, 2020 to June 30, 2022 exceed $60.00 per barrel. Included in the purchase consideration was the fair value, at closing, of the contingent payment due to Sasol. The conditions related to the contingent payment were met and on April 29, 2021, the Company paid the $5.0 million contingent amount to Sasol in accordance with the terms of the SPA.

Discontinued Operations - Angola

In November 2006, the Company signed a production sharing contract for Block 5 offshore Angola (“Block 5 PSA”). The Company’s working interest was 40%, and the Company carried Sonangol P&P, for 10% of the work program. On September 30, 2016, the Company notified Sonangol P&P that it was withdrawing from the joint operating agreement effective October 31, 2016. On November 30, 2016, the Company notified the national concessionaire, Sonangol E.P., that it was withdrawing from the Block 5 PSA and reduced its activities in Angola. As a result of this strategic shift, the Company classified all the related assets and liabilities as those of discontinued operations in the consolidated balance sheets. The operating results of the Angola segment have been classified as discontinued operations for all periods presented in the Company’s consolidated statements of operations. The Company segregated the cash flows attributable to the Angola segment from the cash flows from continuing operations for all periods presented in the Company’s consolidated statements of cash flows. During the year ended December 31, 2021 and 2020, the Angola segment did not have a material impact on the Company’s financial position, results of operations, cash flows and related disclosures.

5. SEGMENT INFORMATION

The Company’s operations are based in Gabon and Equatorial Guinea. Each of the two reportable operating segments is organized and managed based upon geographic location. The Company’s Chief Executive Officer, who is the chief operating decision maker, and management review and evaluate 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.

Segment activity of continuing operations for the years ended December 31, 2021, 2020 and 2019 and long-lived assets and segment assets at December 31, 2021 and 2020 are as follows:

	Year Ended December 31, 2021			
(in thousands)	**Gabon**	**Equatorial Guinea**	**Corporate and Other**	**Total**
Revenues-crude oil and natural gas sales	**$ 199,075**	**$ —**	**$ —**	**$ 199,075**
Depreciation, depletion and amortization	**20,972**	**—**	**88**	**21,060**
Bad debt expense and other	**875**	**—**	**—**	**875**
Other operating expense, net	**(440)**	**—**	**—**	**(440)**
Operating income (loss)	**93,191**	**(853)**	**(13,238)**	**79,100**
Derivative instruments loss, net	**—**	**—**	**(22,826)**	**(22,826)**
Other, net	**6,925**	**(3)**	**(3,428)**	**3,494**
Income tax expense (benefit)	**12,392**	**1**	**(34,549)**	**(22,156)**
Additions to crude oil and natural gas properties and equipment – accrual (1)	**79,169**	**—**	**52**	**79,221**

(1) Includes assets acquired in the Sasol acquisition.

	Year Ended December 31, 2020			
(in thousands)	**Gabon**	**Equatorial Guinea**	**Corporate and Other**	**Total**
Revenues-crude oil and natural gas sales	$ 67,176	$ —	$ —	$ 67,176
Depreciation, depletion and amortization	9,028	—	354	9,382
Impairment of proved crude oil and natural gas properties	30,625	—	—	30,625
Bad debt expense and other	1,165	—	—	1,165
Other operating expense, net	(1,669)	—	—	(1,669)
Operating loss	(17,261)	(431)	(9,571)	(27,263)
Derivative instruments gain, net	—	—	6,577	6,577
Interest income, net	—	—	155	155
Other, net	194	3	(68)	129
Income tax expense	16,204	1	11,476	27,681
Additions to crude oil and natural gas properties and equipment – accrual	10,503	—	(9)	10,494

	Year Ended December 31, 2019			
(in thousands)	**Gabon**	**Equatorial Guinea**	**Corporate and Other**	**Total**
Revenues-crude oil and natural gas sales	$ 84,521	$ —	$ —	$ 84,521
Depreciation, depletion and amortization	6,825	—	258	7,083
Gain on revision of asset retirement obligations	(379)	—	—	(379)
Bad debt (recovery) expense and other	(341)	—	—	(341)
Other operating expense, net	(4,456)	—	35	(4,421)
Operating income (loss)	35,049	(438)	(13,418)	21,193
Derivative instruments gain, net	—	—	(446)	(446)
Interest income (expense), net	5	—	728	733
Other, net	(230)	(3)	(205)	(438)
Income tax benefit	20,311	12	3,567	23,890
Additions to crude oil and natural gas properties and equipment – accrual	22,116	—	57	22,173

(in thousands)	Gabon	Equatorial Guinea	Corporate and Other	Total
Long-lived assets from continuing operations:				
As of December 31, 2021	**$ 84,156**	**$ 10,000**	**$ 168**	**$ 94,324**
As of December 31, 2020	$ 26,832	$ 10,000	$ 204	$ 37,036

(in thousands)	Gabon	Equatorial Guinea	Corporate and Other	Total
Total assets from continuing operations:				
As of December 31, 2021	**$ 201,748**	**$ 10,548**	**$ 50,794**	**$ 263,090**
As of December 31, 2020	$ 101,399	$ 10,267	$ 29,566	$ 141,232

Information about the Company's most significant customers

The Company currently sells crude oil production from Gabon under term contracts with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors. From February 2019 to January 2020, crude oil sales were to Mercuria Energy Trading SA ("Mercuria"). The Company signed a new contract with ExxonMobil Sales and Supply LLC ("Exxon") that covers sales from February 2020 through January 2022 with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors. In January 2022, the contract with ExxonMobil was amended to extend the date of the contract through the end of July 2022.

During the year ended December 31, 2021, revenues from sales of crude oil to Exxon were 100% of the Company's total revenues from customers.

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:

	Year Ended December 31,		
	2021	**2020**	**2019**
		(in thousands)	
Net income (loss) (numerator):			
Income (loss) from continuing operations	**$ 81,934**	$ (48,083)	$ (2,848)
(Income) loss from continuing operations attributable to unvested shares	**(1,336)**	—	21
Numerator for basic	**80,598**	(48,083)	(2,827)
Income from continuing operations attributable to unvested shares	**—**	—	(21)
Numerator for dilutive	**$ 80,598**	$ (48,083)	$ (2,848)
Income (loss) from discontinued operations, net of tax	**$ (98)**	$ (98)	$ 5,411
(Income) loss from discontinued operations attributable to unvested shares	**2**	—	(39)
Numerator for basic	**(96)**	(98)	5,372
(Income) loss from discontinued operations attributable to unvested shares	**—**	—	39
Numerator for dilutive	**$ (96)**	$ (98)	$ 5,411
Net income (loss)	**$ 81,836**	$ (48,181)	$ 2,563
Net income attributable to unvested shares	**(1,334)**	—	(18)
Numerator for basic	**80,502**	(48,181)	2,545
Net (income) loss attributable to unvested shares	**—**	—	18
Numerator for dilutive	**$ 80,502**	$ (48,181)	$ 2,563
Weighted average shares (denominator):			
Basic weighted average shares outstanding	**58,230**	57,594	59,143
Effect of dilutive securities	**525**	—	—
Diluted weighted average shares outstanding	**58,755**	57,594	59,143
Stock options and unvested restricted stock grants excluded from dilutive calculation because they would be anti-dilutive	**169**	3,545	603

7. REVENUE

Revenues from contracts with customers are generated from sales in Gabon pursuant to crude oil sales and purchase agreements ("COSPAs"). COSPAs with customers are renegotiated near the end of the contract term and may be entered into with a different customer or the same customer going forward. Except for internal costs, which are expensed as incurred, there are no upfront costs associated with obtaining a new COSPA. See Note 5 under "*Information about the Company's most significant customers"* for further discussion.

COSPAs with customers are renegotiated near the end of the contract term and may be entered into with a different customer or the same customer going forward. Except for internal costs, which are expensed as incurred, there are no upfront costs associated with obtaining a new COSPA.

Customer sales generally occur on a monthly basis when the customer's tanker arrives at the FPSO 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 intervals between liftings are generally one month; however, changes in the timing of liftings will impact the number of liftings that occur during the period. Therefore, the performance obligation attributable to volumes to be sold in future liftings are wholly unsatisfied, and there is no transaction price allocated to remaining performance obligations. 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.

The Company accounts for production imbalances as a reduction in reserves. 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 existing proved reserves were not adequate to cover an imbalance.

For each lifting completed under a COSPA, 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.

Generally, no significant judgments or estimates are required as of a given filing date with regard to applicable price or volumes sold because all of the parameters are known with certainty related to liftings that occurred in the recently completed calendar quarter. As such, the Company deemed this situation to be characterized as a fixed price situation.

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. Should the government elect to take the production attributable to its royalty in-kind, the Company would no longer have sales to customers associated with production assigned to royalties.

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, 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. Prior to February 1, 2018, the government did not take any of its share of Profit Oil in-kind. These revenues have been included in revenues to customers as the Company entered into the contract with the customer to sell the crude oil and was subject to the performance obligations associated with the contract. For the in-kind sales by the government beginning February 1, 2018, these sales are not considered revenues under a customer contract as the Company is not a party to the contracts with the buyers of this crude oil. However, consistent with the reporting of Profit Oil in prior periods, 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. As of December 31, 2021, the foreign taxes payable attributable to this obligation is $3.1 million. As of December 31, 2020, the foreign income taxes payable attributable to this obligation was $0.9 million.

Certain amounts associated with the carried interest in the Etame Marin block discussed above 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 from contracts with customers as well as revenues associated with the obligations under the Etame PSC:

	Year Ended December 31,		
	2021	**2020**	**2019**
Revenue from customer contracts:			
Sales under the COSPA	**$ 200,321**	$ 67,041	$ 86,554
Other items reported in revenue not associated with customer contracts:			
Gabonese government share of Profit Oil taken in-kind	**20,103**	8,738	7,268
Carried interest recoupment	**7,517**	1,631	2,950
Royalties	**(28,866)**	(10,234)	(12,251)
Crude oil and natural gas sales	**$ 199,075**	$ 67,176	$ 84,521

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.

Income taxes attributable to continuing operations for the years ended December 31, 2021, 2020, and 2019 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:

	Year Ended December 31,		
	2021	**2020**	**2019**
U.S. Federal:		*(in thousands)*	
Current	**$ —**	$ (337)	$ (337)
Deferred	**(34,548)**	11,814	3,916
Foreign:			
Current	**20,282**	3,859	9,747
Deferred	**(7,890)**	12,345	10,564
Total	**$ (22,156)**	$ 27,681	$ 23,890

As of December 31, 2021 and 2020 the Company had deferred tax assets of $86.9 million and $126.3 million, respectively. The deferred tax assets are primarily attributable to Gabon and U.S. federal income taxes related to basis differences in fixed assets, foreign tax credit carryforwards, as well as U.S. and foreign net operating loss carryforwards. In assessing the realizability of the deferred tax assets, the Company considers all available positive and negative evidence and makes a determination whether it is more likely that 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, 2021, due to the increase in future taxable income, the Company determined that it is more likely than not that it would be able to fully utilize its Gabon deferred tax assets and partially utilize its U.S deferred tax assets. Correspondingly, this resulted in a full valuation allowance release of the Gabon deferred tax asset and a partial valuation allowance release of the U.S deferred tax asset. As of December 31, 2020, the Company determined that it is more likely than not that it would not be able to utilize its deferred tax assets. On the basis of these evaluations, a valuation allowance of $46.9 million and $126.3 million were recorded as of December 31, 2021 and 2020, respectively. Valuation allowances reduce the deferred tax assets to the amount that is more likely than not to be realized.

Taxes paid in Gabon with respect to earnings from the Etame Marin block are determined under the provisions of the Etame PSC. In accordance with the Etame PSC, the Etame Consortium maintains a “Cost Account,” which accumulates capital costs and operating expenses that are deductible against revenues, net of royalties, in determining taxable profits. For each calendar year, the Etame Consortium is entitled to receive a percentage of the production (“Cost Recovery Percentage”) remaining after deducting royalties so long as there are amounts remaining in the Cost Account. Prior to the PSC Extension, the Cost Recovery Percentage was 70%. As a result of the PSC Extension, the Cost Recovery Percentage has been increased to 80% for the period from September 17, 2018 through September 16, 2028. See Note 9 for further discussion of the PSC Extension. After September 16, 2028, the Cost Recovery Percentage returns to 70%. The difference between revenues, net of royalties, and the costs recovered for the period is “Profit Oil.” 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%. The percentage of Profit Oil paid to the government as tax is a function of production rates. When the Cost Account is less than the entitled recovery percentage (either 70% or 80%, depending on the period), Profit Oil as a percentage of revenues increases and Gabon taxes paid increase as a percentage of revenues. We also record as income tax expense the increase or decrease in the value of the government’s allocation of Profit Oil which results due to change in value from the time the allocation is originally produced to the time the allocation is actually lifted.

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, 2021 and 2020 are as follows:

	As of December 31,	
(in thousands)	**2021**	**2020**
Deferred tax assets:		
Basis difference in fixed assets	**$ 20,133**	$ 27,995
Foreign tax credit carryforward	**20,084**	34,144
Alternative minimum tax credit carryover	**—**	—
U.S. federal net operating losses	**25,182**	32,579
Foreign net operating losses	**8,693**	24,602
Asset retirement obligations	**8,546**	3,640
Operating leases	**1,750**	**1,472**
Basis difference in accrued liabilities	**402**	368
Basis difference in receivables	**454**	331
Other	**1,683**	1,121
Total deferred tax assets	**86,927**	126,252
Valuation allowance	**(46,949)**	(126,252)
Net deferred tax assets	**$ 39,978**	$ —

Foreign tax credits will expire between the years 2021 and 2025. Foreign net operating losses ("NOLs") are not subject to expiry dates. The NOLs for the Gabon subsidiaries are included in the respective subsidiaries' cost oil accounts, which will be offset against future taxable revenues. All of the Company's U.S. federal NOLs that were incurred prior to 2018 will expire between 2035 and 2037. 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. 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 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, 2021 and 2020. 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)	**2021**	**2020**	**2019**
U.S.	**$ (38,867)**	$ (2,908)	$ (13,330)
Foreign	**98,645**	(17,494)	34,372
	$ 59,778	$ (20,402)	$ 21,042

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)	**2021**	**2020**	**2019**
Tax provision computed at U.S. statutory rate	**$ 12,553**	$ (4,284)	$ 4,386
Foreign taxes not offset in U.S. by foreign tax credits	**35,306**	(9,801)	16,015
Recognition of foreign deferred tax assets, net of U.S. impact	**—**	—	—
Unrealizable foreign deferred tax assets	**—**	—	—
Permanent differences	**(703)**	97	180
Foreign tax credit expirations	**14,060**	—	9,616
Increase/(decrease) in valuation allowance	**(83,372)**	41,635	(6,307)
Other	**—**	34	—
Total income tax expense (benefit)	**$ (22,156)**	$ 27,681	$ 23,890

For the years ended December 31, 2021, 2020, and 2019, 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.	2012-2021
Gabon	2017-2021

9. CRUDE OIL AND NATURAL GAS PROPERTIES AND EQUIPMENT

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

	As of December 31, 2021	As of December 31, 2020
	(in thousands)	
Crude oil and natural gas properties and equipment - successful efforts method:		
Wells, platforms and other production facilities	**$ 488,756**	$ 441,879
Work-in-progress	**13,515**	169
Undeveloped acreage	**23,735**	21,476
Equipment and other	**23,478**	9,276
	549,484	472,800
Accumulated depreciation, depletion, amortization and impairment	**(455,160)**	(435,764)
Net crude oil and natural gas properties, equipment and other	**$ 94,324**	$ 37,036

Extension of Term of Etame Marin Block PSC

On September 25, 2018, VAALCO, together with the other joint venture owners in the Etame Marin block (the "Etame Consortium"), received an implementing Presidential Decree from the government of Gabon authorizing an extension for additional years ("PSC Extension") to the Etame Consortium to operate in the Etame Marin block. The Company's subsidiary, VAALCO Gabon S.A., currently has a 63.575% participating interest (working interest including the working interest attributable to the carried interest owner) in the Etame Marin block.

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. Prior to the PSC Extension, the exploitation periods for the three exploitation areas in the Etame Marin block would expire beginning in June 2021. The PSC Extension also grants the Etame Consortium the right for two additional extension periods of five years each. The PSC Extension further allows the Etame Consortium to explore the potential for resources within the area of each Exclusive Exploitation Authorization as defined in the PSC Extension.

In consideration for the PSC Extension, the Etame Consortium agreed to a signing bonus of $65.0 million ($21.8 million, net to VAALCO) payable to the government of Gabon (the "signing bonus"). The Etame Consortium paid $35.0 million ($11.8 million, net to VAALCO) in cash on September 26, 2018 and paid $25.0 million ($8.4 million, net to VAALCO) through an agreed upon reduction of the VAT receivable owed by the government of Gabon to the Etame Consortium as of the effective date. An additional $5.0 million ($1.7 million, net to VAALCO) was to be paid in cash by the Etame Consortium following the end of the drilling activities described below.

As required under the PSC Extension, the Etame Consortium completed drilling two development wells and two appraisal wellbores during the 2019/2020 drilling campaign with the last appraisal wellbore completed in February 2020. During September 2020, the Etame Consortium completed the two technical studies at a cost of $1.5 million gross ($0.5 million, net to VAALCO).

In accordance with the Etame Marin block PSC, the Etame Consortium maintains a "Cost Account," which accumulates capital costs and operating expenses that are deductible against revenues, net of royalties, in determining taxable profits. Under the PSC Extension, the Cost Recovery Percentage 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%. The government of Gabon will acquire from the Etame Consortium an additional 2.5% gross working interest carried by the Etame Consortium effective June 20, 2026. VAALCO's share of this interest to be transferred to the government of Gabon is 1.6%.

Proved Properties

The Company reviews the crude oil and natural gas 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 and natural gas 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. The fair value of the asset is measured using a discounted cash flow model relying primarily on Level 3 inputs into 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.

There was no triggering event in the year ended December 31, 2021 that would cause the Company to believe the value of crude oil and natural gas producing properties should be impaired. Factors considered included higher forward price curves for the fourth quarter of 2021 and capital expenditures in the period related to the Etame Marin block.

Declining forecasted oil prices in the first quarter of 2020 caused the Company to perform an impairment review during this period. The impairment test was performed using the year end 2019 independently prepared reserve report, estimated reserves for the South East Etame 4H well completed in March 2020 and forward price curves. The Company performed a recoverability test as defined under ASC 932 and ASC 360, noting that the undiscounted cash flows related to the Etame Marin block were less than the book value for the block, resulting in the Company recording a $30.6 million impairment loss to write down the Company's investment to its fair value of $15.6 million.

Undeveloped Leasehold Costs

VAALCO acquired a 31% working interest in an undeveloped portion of a block ("Block P") offshore Equatorial Guinea in 2012. The Ministry of Mines and Hydrocarbons ("EG MMH") approved our appointment as the operator of Block P on November 12, 2019. The Company acquired an additional working interest of 12% from Atlas Petroleum, thereby increasing its 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 the Company's 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 of Block P. On April 12, 2021, the non-defaulting parties assigned the defaulting party's interest to the non-defaulting parties as required by the Joint Operating Agreement. As a result, VAALCO's working interest will increase to 45.9% once the EG MMH approves a new amendment to the production sharing contract. As of December 31, 2021, the Company had $10.0 million recorded for the book value of the undeveloped leasehold costs associated with the Block P license. The Company has completed a feasibility study of a standalone development concept of the Venus discovery on Block P. VAALCO, working closely with tis other joint venture owners, is now in the process of formalizing the plan of development before submitting it to the EG MMH for their 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.

As a result of the PSC Extension discussed above, the exploitation area for the Etame Marin block was expanded to include previously undeveloped acreage. The Company allocated $6.7 million of the share of the signing bonus and $7.1 million of the $18.6 million resulting from the deferred tax impact for the difference between book basis and tax basis to unproved leasehold costs using the acreage attributable to the previous exploitation areas and the additional acreage in the expanded exploitation areas. Exploitation of this additional area is permitted throughout the term of the Etame Marin block PSC. As a result of discovering reserves in connection with drilling the South East Etame 4H development well in March 2020, $2.3 million of costs were transferred to proved leasehold costs leaving a remaining $11.5 million in unproved leasehold costs. In connection with the Sasol Acquisition discussed under Note 4, $2.2 million of reserves were attributed to undeveloped properties. The balance of undeveloped leasehold costs related to the Etame Marin block at December 31, 2021 was $13.7 million.

Capitalized Equipment Inventory

Capitalized equipment inventory is reviewed regularly for obsolescence. Adjustments for inventory obsolescence are recorded in the "Other operating income (expense), net" line item of the consolidated statements of operations. During the years ended December 31, 2021 and 2019, adjustments for inventory obsolescence were not material. For the year ended December 31, 2020, the Company recorded $0.9 million in adjustments for inventory obsolescence.

10. DERIVATIVES AND FAIR VALUE

The Company uses derivative financial instruments from time to time to achieve a more predictable cash flow from crude oil production by reducing the exposure to price fluctuations. See Note 2 for further information.

Commodity swaps - In June 2018, the Company entered into commodity swaps at a Dated Brent weighted average of $74.00 per barrel for the period from and including June 2018 through June 2019 for a quantity of approximately 400,000 barrels. On May 6, 2019, the Company entered into commodity swaps at a Dated Brent weighted average of $66.70 per barrel for the period from and including July 2019 through June 2020 for an approximate quantity of 500,000 barrels. As of December 31, 2020, the Company did not have any unexpired commodity swaps.

On January 22, 2021, the Company entered into commodity swaps at a Dated Brent weighted average of $53.10 per barrel for the period from and including February 2021 through January 2022 for a quantity of 709,262 barrels. On May 6, 2021, the Company entered into commodity swaps at a Dated Brent weighted average price of $66.51 per barrel for the period from and including May 2021 through October 2021 for a quantity of 672,533 barrels. On August 6, 2021, the Company entered into additional commodity swaps at a Dated

Brent weighted average price of $67.70 per barrel for the period from and including November 2021 through February 2022 for a quantity of 314,420 barrels. On September 24, 2021, the Company entered into additional commodity swaps at a Dated Brent weighted average price of $72.00 per barrel for the period from and including March 2022 to June 2022 for a quantity of 460,000 barrels. See the table below for the unexpired barrels as of December 31, 2021.

Settlement Period	Type of Contract	Index	Barrels	Weighted Average Price
January 2022	Swaps	Dated Brent	60,794	$ 53.10
January 2022 to February 2022	Swaps	Dated Brent	191,060	$ 67.70
March 2022 to June 2022	Swaps	Dated Brent	460,000	$ 72.00
			711,854	

The following are the additional swaps entered into in 2022:

Settlement Period	Type of Contract	Index	Barrels	Weighted Average Price
April 2022 to June 2022	Swaps	Dated Brent	234,000	$ 85.01
July 2022 to September 2022	Swaps	Dated Brent	375,000	$ 76.53
			609,000	

While these commodity swaps are intended to be an economic hedge to mitigate the impact of a decline in crude oil prices, the Company has not elected hedge accounting. The contracts are being measured at fair value each period, with changes in fair value recognized in net income. The Company does not enter into derivative instruments for speculative or trading proposes.

The crude oil swaps are measured at fair value using the Income Method. Level 2 observable inputs used in the valuation model include market information as of the reporting date, such as prevailing Brent crude futures prices, Brent crude futures commodity price volatility and interest rates. The determination of the swaps' fair value includes the impact of the counterparty's non-performance risk.

To mitigate counterparty risk, the Company enters into such derivative contracts with creditworthy financial institutions deemed by management as competent and competitive market makers.

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

		Year Ended December 31,		
Derivative Item	**Statement of Operations Line**	**2021**	**2020**	**2019**
			(in thousands)	
Crude oil swaps	Realized gain (loss) - contract settlements	**$ (18,020)**	$ 7,216	$ 2,439
	Unrealized loss	**(4,806)**	(639)	(2,885)
	Derivative instruments gain (loss), net	**$ (22,826)**	$ 6,577	$ (446)

11. ASSET RETIREMENT OBLIGATIONS

The following table summarizes the changes in the Company's asset retirement obligations:

(in thousands)	As of December 31, 2021	As of December 31, 2020
Beginning balance	**$ 17,334**	$ 15,844
Accretion	**1,627**	893
Additions	**14,564**	359
Revisions	**7,169**	238
Ending balance	**$ 40,694**	$ 17,334

Accretion is recorded in the line item "Depreciation, depletion and amortization" on the consolidated statements of operations.

In connection with the Sasol Acquisition in February 2021, as discussed in Note 4, the Company added $14.6 million of asset retirement obligations as a result of increasing its interest in the Etame Marin block

The Company is required under the Etame PSC for the Etame Marin block in Gabon to conduct abandonment studies to update the amounts being funded for the eventual abandonment of the offshore wells, platforms and facilities on the Etame Marin block. The current abandonment study was prepared in November 2021. At December 31, 2021, associated with the study, the Company recorded an upward revision of $7.2 million to the asset retirement obligation primarily as a result of increased costs expected with the abandonment of the Etame Marin block and a change in the expected timing of the abandonment costs associated with the termination of the FPSO charter, as discussed further in Note 12. As a result of the expected timing of the abandonment of the FPSO, included in accrued liabilities in the consolidated balance sheet is $6.7 million of costs associated with the retirement obligation associated with the FPSO.

In 2020, the Company recorded $0.4 million in additions associated with the Southeast Etame 4H development well and $0.2 million in revisions associated with a U.S. property.

12. COMMITMENTS AND CONTINGENCIES

Abandonment funding

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 periods from 2018 through 2028, under the 2018 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 will be presented to the Gabonese Directorate of Hydrocarbons as required by the PSC. Through December 31, 2021, $37.1 million ($21.8 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.

On March 5, 2019, in accordance with certain foreign currency regulatory requirements, the Gabonese branch of an international commercial bank holding the abandonment funds in a U.S. dollar denominated account transferred the funds to the Central Bank for CEMAC, of which Gabon is one of the six member states. The U.S. dollars were converted to local currency with a credit back to the Gabonese branch. During the year ended December 31, 2021, the Company has recorded a $1.6 million foreign currency loss associated with the abandonment funding account. During the year ended December 31, 2020, the Company has recorded a $1.1 million foreign currency gain associated with the abandonment funding account. In December 2021, as part of the new FX regulations issued by BEAC, they allowed for opening of U.S. dollars escrow accounts for the abandonment funds at BEAC and are currently working with the extractive industry to formulate the agreements which are expected to be finalized in 2022 that regulates these accounts. Accordingly, pursuant to Amendment No. 5 of the Etame PSC that required these funds to be in U.S. dollars, once the account for the U.S. dollars abandonment fund is open at BEAC we will resume our funding of the abandonment fund in compliance with the Etame PSC.

FPSO charter

In connection with the charter of the FPSO, the Company, as operator of the Etame Marin block, guaranteed all of the charter payments under the charter through its contract term. At the Company’s election, the charter could be extended for two one-year periods beyond September 2020. These elections have been made, and the charter has been extended through September 2022. The Company obtained guarantees from each of the Company’s joint venture owners for their respective shares of the payments. The Company’s net share of the charter payment is 58.8%, or approximately $19.4 million per year. Although the Company believes the need for performance under the charter guarantee is remote, the Company recorded a liability of $0.1 million and $0.4 million as of December 31, 2021 and 2020 representing the guarantee’s estimated fair value.

Estimated future minimum obligations as of December 31, 2021 through the end of the FPSO charter in September 2022 are approximately $24.2 million ($14.2 million, net to VAALCO).

The FPSO charter payment includes a $0.93 per barrel charter fee for production up to 20,000 barrels of crude oil per day and a $2.50 per barrel charter fee for those barrels produced in excess of 20,000 barrels of crude oil per day. VAALCO’s net share of payments was $22.1 million, $13.1 million and $12.1 million for the years ended December 31, 2021, 2020 and 2019, respectively.

Regulatory and Joint Interest Audits and Related Matters

The Company is subject to periodic routine audits by various government agencies in Gabon, including audits of the Company’s petroleum cost account, customs, taxes and other operational matters, as well as audits by other members of the contractor group under the Company’s joint operating agreements.

In 2016, the government of Gabon conducted an audit of the Company’s operations in Gabon, covering the years 2013 through 2014. The Company received the findings from this audit and responded to the audit findings in January 2017. Since providing the Company’s response, there have been changes in the Gabonese officials responsible for the audit. The Company is working with the newly appointed representatives to resolve the audit findings. The Company does not anticipate that the ultimate outcome of this audit will have a material effect on the Company's financial condition, results of operations or liquidity.

Between 2019 and 2021, the government of Gabon conducted an audit of the operations in Gabon, covering the years 2015 and 2016. The Company has not yet received the findings from this audit.

In 2019, the Etame joint venture owners conducted audits for the years 2017 and 2018. In June 2020, the Company agreed to a $0.8 million payment to resolve claims made by one of the Etame Marin block joint venture owners, Addax Petroleum Gabon S.A. There are now no unresolved matters related to the joint venture owner audits for these years.

FSO

On August 31, 2021, VAALCO and its co-venturers at Etame approved the Bareboat Contract and Operating Agreement (collectively, the "FSO Agreements") with World Carrier Offshore Services Corp. to replace the existing FPSO with a Floating Storage and Offloading unit ("FSO"). The FSO Agreements require a prepayment of $2 million gross ($1.2 million, net to VAALCO) in 2021 and $5 million gross ($3.2 million net) in 2022 of which $6 million will be recovered against future rentals. Current total capital conversion estimates are $40 to $50 million gross ($26 to $32 million net to VAALCO). No other prepayments are required under the FSO Agreements until the vessel is accepted by the Company at the Etame Marin Block location. The Bareboat Contract contains purchase provisions and termination provisions. The Company does not expect to utilize the terminations provision under the FSO Agreements.

Dividend Policy

On November 3, 2021, the Company announced that the Company's board of directors adopted a cash dividend policy of an expected $0.0325 per common share commencing in the first quarter of 2022. On January 28, 2022, the Company announced that the Company's board of directors had declared a quarterly cash dividend of $0.0325 per share of common stock, payable on March 18, 2022 to stockholders of record at the close of business on February 18, 2022. 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.

Other contractual commitments

In August 2020, the Company entered into an agreement to acquire approximately 1,000 square kilometers of 3-D seismic data in the Company's Etame Marin block. The acquisition was completed in the fourth quarter of 2020 and the processing of the seismic data began in January 2021. The cost, net to VAALCO, is approximately $2.2 million or $3.4 million gross.

In June 2021, the Company entered into a short-term agreement with an affiliate of Borr Drilling Limited to drill a minimum of three wells with options to drill additional wells. The 2021/2022 drilling program commenced in December 2021 and is expected to completed in 2022.

13. 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. The adoption of ASC 842 resulted in a material increase in the Company's total assets and liabilities on the Company's consolidated balance sheet as certain of its operating leases are significant. In addition, adoption resulted in a decrease in working capital as the ROU asset is noncurrent but the lease liability has both long-term and short-term portions. There was no material overall impact on results of operations or cash flows. In the statement of cash flows, operating leases remain an operating activity.

The Company is currently a party to several lease agreements for the corporate office, rental of marine vessels and helicopters, warehouse and storage facilities, equipment and the FPSO. The duration for these agreements range from 6 to 39 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 the FPSO, the marine vessels, helicopter, certain equipment and warehouse and storage facilities used in the joint operations includes the gross amount of the lease components.

For all leases that contain an option to extend the lease, the Company has evaluated whether it will extend the lease beyond the initial lease term those payments have been included in the calculation for the ROU assets and liabilities.

During the third quarter of 2019, the Company notified the lessor of the FPSO of its intent to extend the lease term by the first option that extends the FPSO lease to September 2021. Similarly, during the third quarter of 2020, the Company gave notification to extend the FPSO lease to September 2022.

The FPSO agreement also contains options to purchase the assets during or at the end of the lease term. The Company does not consider these options reasonably certain of exercise and has excluded the purchase price from the calculation of ROU assets and lease liabilities.

The FPSO and helicopter, 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.

In August 2021, the Company signed the FSO agreements to lease a FSO to replace the current FPSO whose term will end in September 2022. Under the terms of the Bareboat Contract, a third party is expected to improve the leased vessel in order to comply with the Company's crude-oil production requirements. The vessel is expected to arrive on location in the Etame Marin block in September 2022 at which time control of the vessel will transfer to the Company.

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, 2021 and 2020, the components of the lease costs and supplemental information was as follows:

	Year Ended December 31,	
	2021	**2020**
Lease cost:	*(in thousands)*	
Operating lease cost	$ **17,692**	$ 17,528
Short-term lease cost	**2,258**	1,408
Variable lease cost	**6,188**	7,572
Total lease expense	**26,138**	26,508
Lease costs capitalized	**232**	3,456
Total lease costs	$ **26,370**	$ 29,964
Other information:		
Cash paid for amounts included in the measurement of lease liabilities:	**2021**	**2020**
Operating cash flows attributable to operating leases	$ **23,925**	$ 26,178
Weighted-average remaining lease term	**0.91 years**	1.8 years
Weighted-average discount rate	**5.91%**	6.09%

The table below describes the presentation of the total lease cost on the Company's consolidated statement of operations. 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.

	Year Ended December 31,	
	2021	**2020**
	(in thousands)	
Production expense	$ **13,457**	$ 7,904
General and administrative expense	**193**	197
Lease costs billed to the joint venture owners	**12,573**	20,692
Total lease expense	**26,223**	28,793
Lease costs capitalized	**147**	1,171
Total lease costs	$ **26,370**	$ 29,964

The following table describes the future maturities of the Company's operating lease liabilities at December 31, 2021:

Year	Lease Obligation (in thousands)
2022	$ 9,867
2023	362
2024	183
2025	46
	10,458
Less: imputed interest	229
Total lease liabilities	$ 10,229

Under the joint operating agreements, other joint venture owners are obligated to fund $4.3 million of the $10.5 million in future lease liabilities as of December 31, 2021.

14. ACCRUED LIABILITIES AND OTHER

Accrued liabilities and other balances were comprised of the following:

	As of December 31, 2021	As of December 31, 2020
	(in thousands)	
Accrued accounts payable invoices	**$ 11,967**	$ 4,070
Gabon DMO, PID and PIH obligations	**9,465**	3,960
Derivative liability - crude oil swaps	**4,806**	—
Capital expenditures	**11,327**	435
Stock appreciation rights – current portion	**609**	2,289
Accrued wages and other compensation	**2,124**	2,108
ARO Obligation	**6,745**	—
Other	**2,401**	4,322
Total accrued liabilities and other	**$ 49,444**	$ 17,184

15. SHAREHOLDERS' EQUITY

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, 2021 or 2020.

Treasury stock – On June 20, 2019, the Board of Directors authorized and approved a share repurchase program for up to $10.0 million of the currently outstanding shares of the Company's common stock over a period of 12 months.

From commencement of the plan in June 2019 through April 13, 2020, the Company purchased 2,740,643 shares of common stock at an average price of $1.70 per share for an aggregate purchase price of $4.7 million under the plan. On April 13, 2020, the Board of Directors approved the termination of the share repurchase program; consequently, no further shares can be repurchased pursuant to the plan.

For the majority of restricted stock awards granted by the Company, the number of shares issued to the participant on the vesting date are net of shares withheld to meet applicable tax withholding requirements. In addition, when options are exercised, the participant may elect to remit shares to the Company to cover the tax liability and the cost of the exercised options. When this happens, the Company adds these shares to treasury stock and pays the taxes on the participant's behalf.

Although these withheld shares are not issued or considered common stock repurchases under the Company's stock repurchase program, they are treated as common stock repurchases in our financial statements as they reduce the number of shares that would have been issued upon vesting. See Note 16 for further discussion.

16. 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, 2021, 7,590,419 shares 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, 2021, 2020 and 2019, the Company settled in cash $3.3 million, $0.3 million and $0.5 million, respectively, for SARs. During the years ended December 31, 2021, 2020 and 2019, the Company received in cash $1.4 million, $0.1 million and $0.3 million, respectively from stock option exercises. Because the Company does not pay significant United States federal income taxes, no amounts were recorded for future tax benefits.

	Year Ended December 31,		
	2021	**2020**	**2019**
		(in thousands)	
Stock-based compensation - equity awards	**$ 1,060**	$ 848	$ 985
Stock-based compensation - liability awards	**1,399**	(734)	2,521
Total stock-based compensation	**$ 2,459**	$ 114	$ 3,506

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 March 2021, the Company granted options to certain employees of the Company that are considered performance stock options to purchase an aggregate of 401,759 shares at an exercise price of $3.14 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 $3.61 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 $4.15 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 $4.78 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.

The Company used the Monte Carlo simulation to calculate the grant date fair value of performance stock option awards. The fair value of these awards will be amortized to expense over the derived service period of the option. During the year ended December 31, 2021, no performance stock option awards issued under the 2020 Plan were exercised.

For options that do not contain a market or performance condition, the Company uses the Black-Scholes model to calculate the grant date fair value of stock option awards. This fair value is then amortized to expense over the service period of the option.

Because the Company has not historically paid cash dividends, no expected dividend yield was input to the Black-Scholes or Monte Carlo models. During the year ended December 31, 2021, 2020 and 2019 the weighted average assumptions shown below were used to calculate the weighted average grant date fair value of option grants under the Monte Carlo model in 2021 and Black-Scholes models.

	Year Ended December 31,		
	2021	**2020**	**2019**
Weighted average exercise price - ($/share)	**$ 3.14**	$ 1.23	$ 2.08
Expected life in years	**6.0**	6.0	3.2
Average expected volatility	**74** %	74 %	73 %
Risk-free interest rate	**0.95** %	0.42 %	2.33 %
Weighted average grant date fair value - ($/share)	**$ 2.07**	$ 0.79	$ 1.06

Stock option activity associated with the Monte Carlo model for the year ended December 31, 2021 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, 2021	644	$	1.23			
Granted	402		3.14			
Exercised	—		—			
Unvested shares forfeited	(687)		1.96			
Vested shares expired	—		—			
Outstanding at December 31, 2021	359	$	1.96	8.75	$	448
Exercisable at December 31, 2021	74	$	1.23	8.49	$	146

Stock option activity associated with the Black-Scholes model for the year ended December 31, 2021 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, 2021	1,804	$	1.38			
Granted	—		—			
Exercised	(1,122)		1.22			
Unvested shares forfeited	(67)		2.33			
Vested shares expired	—		—			
Outstanding at December 31, 2021	615	$	1.58	1.44	$	1,001
Exercisable at December 31, 2021	520	$	1.45	1.31	$	917

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 2021, 2020 and 2019 was $1.6 million, $43 thousand, and $0.3 million, respectively.

As of December 31, 2021, unrecognized compensation cost related to outstanding stock options was $0.3 million, which is expected to be recognized over a weighted average period of 2.0 years.

During the year ended December 31, 2021, 464,671 shares were added to treasury as a result of tax withholding on options exercised. During the year ended December 31, 2020, no shares were added to treasury as a result of tax withholding on options exercised.

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). In March 2021, the Company issued 526,147 shares of service- based restricted stock to employees, with a grant date fair value of $3.14 per share. In June 2021, the Company issued 78,432 shares of service-based restricted stock to directors, with a grant date fair value of $3.06 per share. The vesting of these shares is dependent upon, among other things, the employees' and directors' continued service with the Company.

The following is a summary of activity for the year ended December 31, 2021:

	Restricted Stock	Weighted Average Grant Date Fair Value
	(in thousands)	
Non-vested shares outstanding at January 1, 2021	1,155	$ 1.30
Awards granted	605	3.13
Awards vested	(543)	1.28
Awards forfeited	(476)	2.00
Non-vested shares outstanding at December 31, 2021	741	$ 2.36

The total fair value of vested restricted stock awards during 2021, 2020 and 2019 was $1.8 million, $0.2 million, and $0.6 million, respectively. The weighted average grant date fair value per share of restricted stock awards, which vested during 2021, 2020 and 2019, was $1.28, $1.35 and $2.00, respectively.

As of December 31, 2021, unrecognized compensation cost related to restricted stock totaled $0.8 million and is expected to be recognized over a weighted average period of 1.3 years.

During the year ended December 31, 2021, 68,134 shares were added to treasury as a result of tax withholding on the vesting of restricted shares. During the year ended December 31, 2020, 43,705 shares were added to treasury as a result of tax withholding on the vesting of restricted shares.

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, 2021 and 2020, the Company did not grant SARs to employees or directors. SAR activity for the year ended December 31, 2021 is provided below:

	Number of Shares Underlying SARs	Weighted Average Exercise Price Per Share	Term	Aggregate Intrinsic Value
	(in thousands)		*(in years)*	*(in thousands)*
Outstanding at January 1, 2021	2,940	$ 1.33		
Granted	—	—		
Exercised	(2,450)	1.20		
Unvested SARs forfeited	(128)	2.33		
Vested SARs expired	—	—		
Outstanding at December 31, 2021	362	$ 1.81	1.92	$ 506
Exercisable at December 31, 2021	194	$ 1.57	1.65	$ 319

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.

The Company sponsors a 401(k) plan, with a company match feature, for the employees. Costs of $0.3 million for the year ended December 31, 2021, and costs of $0.4 million for each of the years ended December 31, 2020 and 2019, were incurred for the Company's matching contribution and for administering the plan.

SUPPLEMENTAL INFORMATION ON CRUDE OIL AND NATURAL GAS 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 the state of Texas, and International, which includes the producing properties offshore Gabon (Africa).

Costs Incurred for Acquisition, Exploration and Development Activities

	Year Ended December 31,		
	2021	**2020**	**2019**
Costs incurred during the year:		*(in thousands)*	
International:			
Exploration costs - capitalized	**$ 254**	$ 8,484 (1)	$ 2,952
Exploration costs - expensed	**1,579**	3,588	—
Acquisition of properties	**42,744**	—	—
Development costs	**36,223**	731	15,654
Total	**$ 80,800**	$ 12,803	$ 18,606

(1) Primarily associated with the Southeast Etame 4P appraisal wellbore.

Capitalized Costs Relating to Crude Oil and Natural Gas Producing Activities

Capitalized costs pertain to the producing activities in Gabon and to undeveloped leasehold in Gabon, Equatorial Guinea.

	As of December 31,	
	2021	**2020**
Capitalized costs:	*(in thousands)*	
Properties not being amortized	**$ 55,488**	$ 26,975
Properties being amortized (1)	**488,756**	441,879
Total capitalized costs	**$ 544,244**	$ 468,854
Less accumulated depletion, amortization and impairment	**(451,498)**	(432,431)
Net capitalized costs	**$ 92,746**	$ 36,423

(1) During 2021, the Company recorded $37.2 million of wells, platforms and production facilities and $5.7 million of other equipment associated with the acquisition of Sasol's interest in the Etame Marin block. During 2020, the Company recorded $8.5 million in additions associated with the Southeast Etame 4P appraisal wellbore.

Results of Operations for Crude Oil and Natural Gas Producing Activities

	International			U.S.		
	Year Ended December 31,			Year Ended December 31,		
	2021	**2020**	**2019**	**2021**	**2020**	**2019**
			(in thousands)			
Crude oil and natural gas sales	**$ 199,075**	$ 67,176	$ 84,521	**$ —**	$ —	$ —
Production costs and other expense (1)	**(81,984)**	(38,176)	(38,461)	**—**	(5)	(6)
Depreciation, depletion, amortization	**(20,972)**	(9,028)	(6,825)	**—**	—	—
Exploration expenses	**(1,579)**	(3,588)	—	**—**	—	—
Impairment of proved properties	**—**	(30,625)	—	**—**	—	—
Other operating expense	**(440)**	(1,669)	(4,457)	**—**	—	—
Bad debt recovery (expense)	**(875)**	(1,165)	341	**—**	—	—
Income tax benefit (expense)	**(9,626)**	10,785	(21,702)	**—**	—	—
Results from crude oil and natural gas producing activities	**$ 83,599**	$ (6,290)	$ 13,417	**$ —**	$ (5)	$ (6)

(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 and natural gas 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 and Natural Gas Activities."* For a discussion of the reserve estimation process, including internal controls, see "*Item 1. Business – Reserve Information*."

Proved reserves:	**Oil (MBbls)**
Balance at January 1, 2019	5,370
Production	(1,269)
Revisions of previous estimates	865
Balance at December 31, 2019	4,966
Production	(1,776)
Extensions and discoveries	497
Revisions of previous estimates	(471)
Balance at December 31, 2020	3,216
Production	**(2,599)**
Purchase of reserves	**2,633**
Revisions of previous estimates	**7,968**
Balance at December 31, 2021	**11,218**

Year-end proved developed reserves:	**Oil (MBbls)**
2021	**7,227**
2020	3,216
2019	4,966
Year-end proved undeveloped reserves:	
2021	**3,991**
2020	—
2019	—

The proved developed reserves are located offshore Gabon. In 2021, the Company added 2.6 MMBbls of reserves due the acquisition of Sasol's interest in the Etame Marin block. In addition, the Company added 8.0 MMBbls due to positive revisions. The positive revision of 8.0 MMBbls was due to positive revision of 3.0 MMBbls due to price and positive revisions of 5.0 MMBbls due to performance. In 2020, the Company added 0.5 MMBbls of reserves through extensions and discoveries primarily as a result of the successful Southeast Etame 4P appraisal well. This change between periods was offset by downward revisions of proved reserves of (0.5) MMBbls which was due to (1.6) MMBbls of negative revisions reflecting the decrease in crude oil prices and a 1.1 MMBbls increase due to improvements in well performance.

The Company maintains a policy of not booking 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 and natural gas 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, 2021, 2020 and 2019.

	International		
(In thousands)	**2021**	**2020**	**2019**
Future cash inflows	$ **782,006**	$ 138,328	$ 319,693
Future production costs	**(416,819)**	(99,418)	(193,626)
Future development costs [1]	**(128,984)**	(10,605)	(12,758)
Future income tax expense	**(116,637)**	(13,921)	(36,058)
Future net cash flows	**119,566**	14,385	77,251
Discount to present value at 10% annual rate	**(20,308)**	348	(6,820)
Standardized measure of discounted future net cash flows	$ **99,258**	$ 14,733	$ 70,431

(1) Includes costs expected to be incurred to abandon the properties.

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,		
	2021	**2020**	**2019**
		(in thousands)	
Balance at beginning of period	$ **14,733**	$ 70,431	$ 80,056
Sales of crude oil and natural gas, net of production costs	**(118,358)**	(29,878)	(46,873)
Net changes in prices and production costs	**126,668**	(53,388)	(5,118)
Extensions and discoveries	**—**	10,059	—
Revisions of previous quantity estimates	**158,213**	(10,885)	28,921
Purchases	**9,285**	—	—
Changes in estimated future development costs	**(39,969)**	1,195	(4,033)
Development costs incurred during the period	**2,629**	731	7,185
Accretion of discount	**2,752**	10,086	11,175
Net change of income taxes	**(60,218)**	17,636	1,270
Change in production rates (timing) and other	**3,523**	(1,254)	(2,152)
Balance at end of period	$ **99,258**	$ 14,733	$ 70,431

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 and natural gas 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 and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future crude oil and natural gas 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 and natural gas 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 guidelines of the SEC, estimates of future net cash flow from the properties and the present value thereof are made using an unweighted, arithmetic average of the first-day-of-the-month price for each of the 12 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 2021, the average of such prices reflected a 63% decrease during the year and were $69.10 per Bbl for crude oil from Gabon when compared to the average of such prices for 2020 of $42.46 per Bbl for crude oil from Gabon.

Under the Etame PSC in Gabon, the Gabonese government is the owner of all crude oil and natural gas mineral rights. The right to produce the crude oil and natural gas 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%. At December 31, 2021, there was $23.2 million in the Cost Account, net to the Company's interest. 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, 2021, the Company has no proved reserves related to Block P in Equatorial Guinea.

Exhibit 21.1

Subsidiary Name	Business	Ownership	Date and Place of Incorporation	
VAALCO Energy (USA), Inc.	Energy	100 %	10/16/96	Delaware
VAALCO Gabon (Etame), Inc.	Energy	100 %	6/14/95	Delaware
VAALCO Production (Gabon), Inc.	Energy	100 %	6/14/95	Delaware
VAALCO Angola (Kwanza), Inc.	Energy	100 %	5/15/06	Delaware
VAALCO Energy (EG), Inc.	Energy	100 %	7/3/12	Delaware
VAALCO Energy Mauritius (EG), Limited	Energy	100 %	11/23/12*	Mauritius
VAALCO Gabon S.A.	Energy	100 %	6/4/14	Gabon

* Date of Certificate of Incorporation on Change of Name

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 March 10, 2022, relating to the consolidated financial statements which appears in this Form 10-K.

/s/ BDO USA, LLP

Houston, Texas
March 10, 2022

[Letterhead of Netherland, Sewell & Associates, Inc.]

Exhibit 23.2

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, 2021. 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, 2021, 2020, and 2019 and to the inclusion of our report dated February 4, 2022, as exhibits to the Annual Report on Form 10-K of VAALCO Energy, Inc. for the year ended December 31, 2021. We further consent to the incorporation by reference thereof into VAALCO Energy, Inc.'s Registration Statements on Forms S-8 (Nos. 333-218824, 333-197180, and 333-183515).

NETHERLAND, SEWELL & ASSOCIATES, INC.

/s/ Danny D. Simmons
By: ______________________________
Danny D. Simmons, P.E.
President and Chief Operating Officer

Houston, Texas
March 7, 2022

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 10, 2022

/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 10, 2022

/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, 2021, 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 10, 2022

/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, 2021, 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 10, 2022

/s/ Ronald Bain
Ronald Bain, Chief Financial Officer

February 4, 2022

Mr. George Maxwell
VAALCO Gabon S.A.
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, 2021, to the VAALCO Gabon S.A. (VAALCO) interest in certain oil properties located in the Etame Marin Permit, offshore Gabon. 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 all of the 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 Energy, Inc.'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, 2021, to be:

	Oil Reserves (MBBL)		Future Net Revenue (M$)	
Category	Gross (100%)	Net[(1)]	Total	Present Worth at 10%
Proved Developed Producing	14,125.4	7,226.8	81,172.9	74,588.1
Proved Undeveloped	7,913.3	3,991.0	38,393.3	24,670.4
Total Proved	22,038.6	11,217.8	119,566.3	99,258.5

Totals may not add because of rounding.

(1) Net reserves are prior to deductions for "income tax barrels".

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. Our study indicates that as of December 31, 2021, there are no proved developed non-producing reserves for these properties. 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 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 government's 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 government's share of profit oil multiplied by VAALCO's working interest, net of government 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 Gabonese government. Future net revenue is after deductions for these amounts and VAALCO's share of capital costs, abandonment costs, operating expenses, and production taxes; future net revenue also includes credits for VAALCO's share of state reimbursement. The future net revenue is before consideration of any United States income taxes and 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 Brent spot price for each month in the period January through December 2021. The average price of $69.47 per barrel is adjusted for quality, transportation fees, and market differentials. The adjusted oil price of $69.10 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. It is our understanding that VAALCO is in the process of installing a floating storage and offloading vessel (FSO) to replace the existing floating production, storage and offloading vessel (FPSO) and that VAALCO expects the FSO to be online by September 2022. Operating costs have been divided into permit-level costs, per-well costs, and per-unit-of-production costs and include the cost of recurring electric submersible pump replacements and contractual future changes to the 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 installation of an FSO, 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, 2028. 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

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ John R. Cliver
John R. Cliver, P.E. 107216
Vice President

By: /s/ Zachary R. Long
Zachary R. Long, P.G. 11792
Vice President

Date Signed: February 4, 2022

Date Signed: February 4, 2022

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.

(32) *Unproved properties.* Properties with no proved reserves.