VAALCO ENERGY, INC.

ACHIEVING TRANSFORMATIONAL GROWTH DESPITE CHALLENGING TIMES

2020 Annual Report

VAALCO Energy, Inc. is a Houston-based independent energy company principally engaged in the production, development and acquisition of crude oil properties in the West African region. The Company is an established operator in the Etame Marin block, located offshore Gabon, holding a 58.8% working interest, which to date has produced over 120 million gross barrels of crude oil. The Company also owns and operates an offshore license in Equatorial Guinea that has a discovery and significant upside potential that may be developed in the future.

VAALCO has always focused on safe and environmentally responsible operations and has a long track record of success producing oil resources in West Africa. Our vision is to create sustained growth in shareholder value by maximizing our reserves and production performance in our offshore Gabon Etame Marin block and by leveraging our operational and technical expertise to other areas in West Africa.

VAALCO Energy was founded in 1985 and its common stock trades on the New York Stock Exchange and London Stock Exchange under the symbol "EGY."

CREATING VALUE THROUGH SUCCESSFUL DRILLING AND A HIGHLY ACCRETIVE ACQUISITION

2019/2020 Drilling Program

In September 2019, we commenced our highly successful 2019/2020 Etame drilling campaign which included three development wells, two appraisal wellbores and two workovers. Despite the challenges our industry faced in 2020, we were able to complete the drilling program on time, within budget and with cash on hand. We realized a 40% increase in our net production from 2019 to 2020 due to that capital investment program.

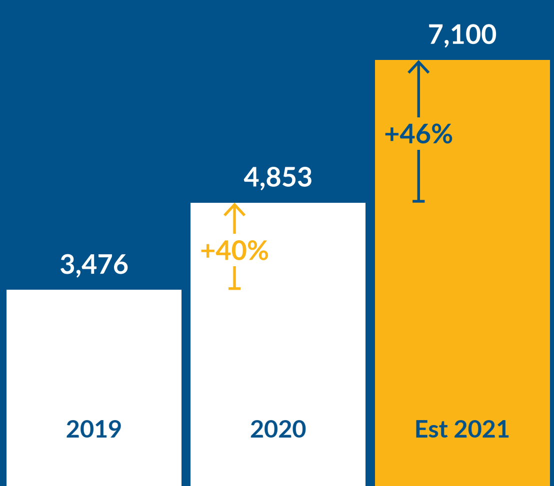
Acquisition of Additional Etame Interest

In late 2020, we announced that we were acquiring our joint-owner Sasol's 27.8% working interest in the Etame field. While the agreed-upon purchase price was $44 million, after closing price adjustments, the total cash paid at closing in late February 2021 was $33.9 million, with a contingent Brent-pricing related payment of $5 million. Our strong free cash flow in 2020 allowed us to fund the acquisition 100% with cash on hand.

We believe the transaction is highly accretive and since we operate the asset, we expect minimal increase in G&A expense, and there is no integration needed. We nearly doubled our proved reserves and our production increased significantly following the closing of the transaction in February. We are forecasting a nearly 50% increase in net production in 2021 which reflects ten months of acquisition production and expected normal decline and field maintenance.

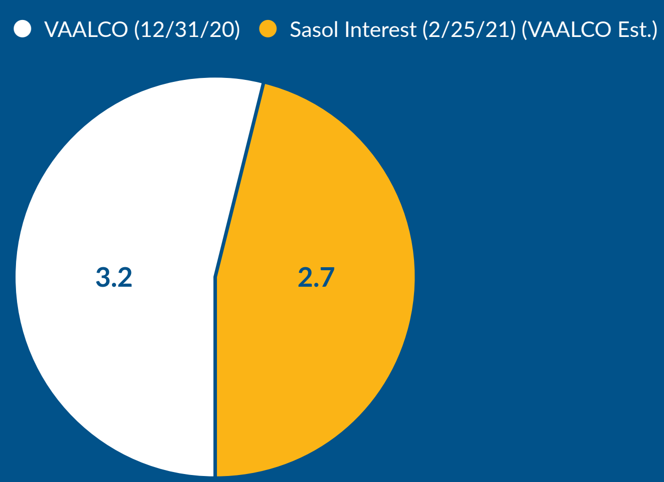
Production Impact from Drilling and Acquisition

(Barrels of oil/day)



Proved Reserves Impact from Acquisition

(Millions of barrels of oil)



A LETTER FROM OUR CHIEF EXECUTIVE OFFICER GEORGE MAXWELL

To Our Fellow Shareholders

When I was asked to join VAALCO's Board in 2020, I was very pleased to accept the position. I have spent the majority of my career based in the U.K focused on the West Africa region and believed that my prior experience in the U.K. and European capital and investor markets would be beneficial to the Company. I had known the Company and its management team for a number of years and developed great respect for its achievements and excellent track record as a respected operator. Recently I was asked to assume the role of Chief Executive Officer to build on the success that our prior CEO, Cary Bounds and his team had achieved, and guide VAALCO through the next chapter of its evolution. That includes expanding our presence in those international capital markets to allow us to further grow the Company in a methodical and accretive manner.

Cary guided VAALCO through some very challenging periods for the industry, oversaw some highly successful initiatives and helped the Company emerge stronger and well positioned to continue to generate free cash flow. VAALCO's accomplishments in 2020 discussed in this letter are a testament to his contribution to the success of the Company. We wish Cary the best in the next phase of his career.

Over the past year, we believe we have materially enhanced both short-term and long-term value at VAALCO as a result of four key initiatives: 1) a highly successful drilling program; 2) a very accretive acquisition; 3) new 3-D seismic over our entire Etame Marin license offshore Gabon; and 4) planning for another drilling campaign expected to begin in late 2021. We remain committed to operational excellence while generating strong financial results and preserving our strong, debt free balance sheet. We generated free cash flow in every quarter in 2020, and with our increased production base in a rising oil price environment, we should generate even greater free cash flow in 2021. This will provide flexibility for the future as we look to continue to grow profitably and meet our long-term goals.

"As we look to the future, I believe it is paramount that businesses are sustainable in order to provide benefits to all stakeholders, with a focus on growth and investor returns."

Over the past several years we had a number of significant accomplishments, all of which were the building blocks allowing us to achieve profitable growth. We negotiated a license extension of up to 20 years in Gabon, we eliminated all debt, we listed on the London Stock Exchange and we have continued to generate free cash flow. In September of 2019, we kicked off our 2019/2020 drilling campaign. which included three successful development wells that materially increased our production and two successful appraisal well bores. We were able to execute the entire drilling program on time, within our initial budget, with no safety or environmental incidents and it was funded with cash on hand and through operational cash flow.

In 2020, we saw oil prices adversely impacted by the global COVID-19 pandemic as well as supply and demand imbalances. We remain fully committed to the health and safety of our employees and as of today, VAALCO has experienced no material impact on its Gabon operations directly associated with COVID-19. Additionally, we were very pleased that we also had hedges in place that provided us good financial protection when oil prices fell in 2020. This allowed us to generate meaningful free cash flow in every quarter in 2020 from our higher production volumes. We increased production 40% year over year as a result of our drilling success when comparing full year 2020 average production of 4,853 net BOPD with our 2019 average of 3,476 net BOPD. This significant production increase allowed us to grow our cash position, provided financial flexibility and gave us the ability to capture value through a very accretive acquisition opportunity that arose in 2020.

In November 2020, we agreed to purchase Sasol's 27.8% working interest in Etame for $44 million, bringing our total working interest in the license to 58.8%. Taking into account closing cost adjustments, the total cash we paid was $33.9 million with a contingent payment of $5 million if Brent oil prices average greater than $60 per barrel for 90 consecutive days from July 1, 2020 through June 30, 2022. We believe the transaction is very accretive to VAALCO as it is improving our margins, increasing production and the price we paid per net barrel of oil was about $14.41 for SEC proved reserves and $4.91 for 2P CPR reserves. Since we already operate the asset, we expect minimal increase in G&A expense, and there is no integration needed. We were able to close the acquisition in February 2021 with cash on hand. Benefiting from the additional production that the transaction brings us, along with the strong recovery in oil pricing, we are projecting significant free cash flow generation going forward. This has provided us with the confidence to announce our next drilling campaign which is expected to start in late 2021. We are planning to drill up to four wells that could add an additional 7,000 to 8,000 gross barrels of oil per day when the drilling program is completed in mid 2022. With our higher working interest in Etame, this could be an additional 3,500 to 4,100 net BOPD to VAALCO.

Our 2020 year-end reserves were significantly impacted by pricing. Despite adding 1.6 MMBO as a result of positive performance revisions and the discovery at SE Etame 4-P, our reserves were down slightly year over year. The downward revisions were driven by 1.8 MMBO in production and a downward pricing revision of 1.6 MMBO. Our net proved SEC reserves at December 31, 2020 were 3.2 MMBO. Regarding our acquisition of Sasol's interest at Etame, the associated reserves were not included in our year-end 2020 reserves. We estimate that approximately 2.7 MMBO of proved SEC net reserves were acquired. Given the recent significant increase in Brent pricing, and assuming that it continues through 2021, we believe that we could see a material increase in reserves not only due to the Sasol acquisition but to pricing as well.

We are excited about the many opportunities that we have identified at Etame. Since its discovery in 1995, we have achieved a 92% success rate on 36 wells drilled and we have produced over 120 million gross barrels thus far. Looking to the future, we believe that the field still has over 100 million gross barrels of resource potential remaining. The 2021/2022 drilling campaign is the next of many future drilling programs focused on profitable growth at Etame.

Turning to our interest in Block P in Equatorial Guinea, in the first quarter of 2020, we acquired additional working interest from a partner, thereby increasing our working interest from 31% to 43%. We are evaluating alternatives to fund the cost to drill an exploratory well targeting over 160 million gross barrels of resources at our SW Grande prospect, as well as evaluating scenarios to develop over 16 million gross barrels of contingent resources at our Venus discovery on Block P. We remain excited about EG and we are working to profitably exploit its resource potential.

Our long track record of success has been underpinned by our commitment to developing and producing oil resources in West Africa in a safe and environmentally responsible manner. Last year, we issued our inaugural Sustainability report which focused on our community involvement, governance practices and environmental commitment. In 2020, we created a committee consisting of the VAALCO executive team and a cross section of employees from across the Company that is charged with the responsibility of monitoring adherence to our ESG standards and formally communicating findings on an ongoing basis to our Board. Also in 2020, our Board's Nominating and Corporate Governance committee amended its charter to include the oversight of the Company's policies and programs on issues of social responsibility and environmental sustainability. Our Board has empowered our management team to create a working environment that assures our success as a trusted operator, a generous partner to the communities where we operate, and as good stewards to the environment. Our 2020 ESG report will be released soon and posted to our web site. It will include three years of key ESG sustainability metrics developed specifically for our industry and give a more in-depth analysis of VAALCO's commitment to ESG.

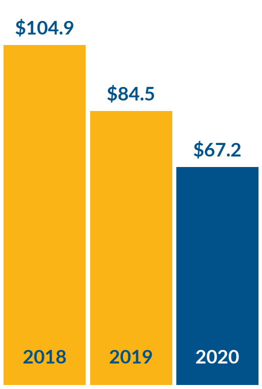
I am especially grateful to our employees for their contributions and commitments this past year to achieving our strong operational and financial results when they had to cope with the many personal issues created by the pandemic. We have a high performing team with a proven history of operating responsibly. The pillars to achieve success are rooted in maintaining our high standards for health, safety, environmental and ethics while stressing operational excellence at all levels. This success has allowed us to build a strong, clean balance sheet and maintain financial flexibility.

As we look to the future, I believe it is paramount that businesses are sustainable in order to provide benefits to all stakeholders, with a focus on growth and investor returns. This is one of the guiding principles I successfully applied in my previous executive role and I believe VAALCO is in an excellent position to ultimately achieve this. I remain wholly committed to our roots and investor base in the U.S., and believe that our expanded presence in the U.K. financial and advisory markets maximizes opportunities for us to achieve our stated strategy.

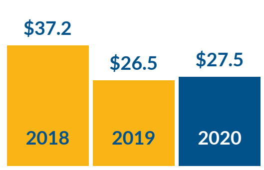
George Maxwell
Chief Executive Officer

FINANCIAL HIGHLIGHTS

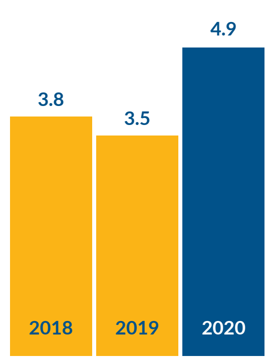
Year Ended December 31,	2020	2019	2018
Income Statement (in thousands)			
Total Revenues	$ 67,176	$ 84,521	$ 104,943
Operating Income (Loss)	$ (27,263)	$ 21,193	$ 51,287
Net Income (Loss)	$ (48,181)	$ 2,563	$ 98,232
Cash Flow Statement (in thousands)			
Operating Activities	$ 27,450	$ 26,472	$ 37,176
Capex (oil and natural gas properties)	$ 24,328	$ 10,348	$ 14,127
Balance Sheet (in thousands)			
Total Assets	$ 141,232	$ 211,537	$ 166,312
Total Debt	—	—	—
Operating Data			
Net Sales:			
Oil (MMBO)	1.63	1.25	1.44
Average Daily Sales (MBOPD)	4.44	3.42	3.94
Averaged Realized Sales Price:			
Oil ($/Bbl)	$ 40.29	$ 65.20	$ 70.32
Net Production:			
Average Daily Production (MBOPD)	4.85	3.48	3.75
Net SEC Proved Reserves			
Oil (MMBO)	3.20	5.00	5.37
Total Proved Developed (MMBO)	3.20	5.00	3.39
Proved Undeveloped (MMBO)	0.00	0.00	1.98
Proved Developed Reserves as a % of Proved Reserves	100.0%	100.0%	63.1%



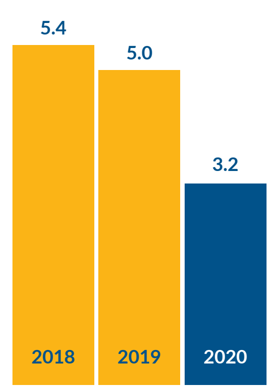
Revenues
(in millions)



Cash Provided by Operating Activities
(in millions)



Production Per Day
(in thousands of barrels)



Net SEC Proved Reserves
(in millions of barrels)

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, 2020

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number: 1-32167

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

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

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

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

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

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

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

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

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

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

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

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

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

Emerging growth company ☐

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

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

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, 2020, the aggregate market value of the voting and non-voting common equity of the registrant held by non-affiliates was approximately $64.5 million based on a closing price of $1.24 on June 30, 2020.

As of February 28, 2021, there were outstanding 57,663,188 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

- *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.
- *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.
- *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 reserves* — 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.

SPECIAL NOTE 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 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 the sharp decline in the global demand for crude oil, which resulted in a significant global oversupply of crude oil and steep decline in 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 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;
- 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 find a replacement for the FPSO or to renew the FPSO charter;
- 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, disruption in financial markets and the availability 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 in their entirety by this "Special Note 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.

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 options to extend up to an additional ten years ("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. 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.

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.

As discussed below, 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").

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 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.

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 will be 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. 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*."

On March 11, 2020, the World Health Organization classified the COVID-19 outbreak as a pandemic, based on the rapid increase in global exposure to the virus. The COVID-19 pandemic and related economic repercussions have created significant volatility, uncertainty, and turmoil in the oil and gas industry, and the full impact of the outbreak continues to evolve. The adverse economic effects of the COVID-19 outbreak have 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 addition, in early March 2020, crude oil prices declined significantly, ending at approximately $15 per barrel for Brent crude, as of March 31, 2020, primarily as a result of market concerns about the ability of OPEC and Russia to agree on a perceived need to implement further production cuts in response to weaker worldwide demand. While OPEC and Russia were able to reach an agreement to cut production in April 2020, crude oil prices continued to be depressed for several months. Although crude oil prices increased to approximately $51 per barrel for Brent crude as of December 31, 2020 and have further improved since year-end, the adverse economic effects caused by the COVID-19 pandemic, as well as the various other factors described above, could result in additional price declines and volatility. 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. Our options include securing a new storage vessel, either under a charter agreement or a purchase, purchasing the vessel under the current FPSO charter pursuant to an option in the charter contract or extending the charter agreement for the current FPSO. Execution of any of these options requires significant lead time and may require a capital investment due to the specialized nature of such vessels. We are currently evaluating our alternatives so that we will be in position to have an alternative in place when the current charter expires.

SEGMENT AND GEOGRAPHIC INFORMATION

For operating segment and geographic financial information, see Note 5 to the 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. The Etame, Avouma/South Tchibala, Ebouri, Southeast Etame and North Tchibala fields are included in the block. Currently, our working interest in the Etame Marin block is 58.8%, and we are designated as the operator on behalf of the Consortium. The fields are 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%.

Fields in the Etame Marin block. There are currently five producing fields in the Etame Marin block: the Etame field, which has seven producing wells; the Avouma/South Tchibala field, which has three producing wells; the Ebouri field, which has one producing well; the Southeast Etame field, which has two producing wells and the North Tchibala field, which has one producing well.

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 field 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).

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 field. 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), in early January 2020.

We drilled the SE Etame 4P appraisal wellbore to evaluate a Gamba step out area in the Southeast Etame field 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 we expect all the data to be fully processed and analyzed 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 plan to commence the next drilling campaign at Etame in late 2021 or early 2022 with two development wells and two appraisal wells at an estimated cost of $115.0 million to $125 million gross, or $73.0 million to 79.0 million, net to VAALCO's 63.6% participating interest. The locations of these wells will be determined in conjunction with the new seismic processing and interpretation.

Production. Production operations in the Etame Marin block include eleven platform wells, plus three subsea wells across all fields 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, 2020, 2019 and 2018, aggregate production from the block was approximately 6.6 MMBbls (1.8 MMBbls net to us), 4.7 MMBbls (1.3 MMBbls net to us) and 5.1 MMBbls (1.4 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. 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 economically attractive at current crude oil prices. As of December 31, 2020, we had no proved reserves booked for the wells impacted by high levels of H_2S.

Exploration

At December 31, 2020, we had $11.5 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.

Abandonment Costs

Under the Etame PSC terms, the 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 November 2018 and resulted in estimated gross abandonment costs of approximately $61.8 million ($19.2 million, net to VAALCO) on an undiscounted basis. Through December 31, 2020, $40.2 million ($12.5 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 $4.3 million in 2021 and $1.4 million per year for 2022 through 2028. 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, 2020 and 2019 were $17.3 million and $15.8 million, respectively, which are included in the total "Asset retirement obligation" line item on our consolidated balance sheets as of December 31, 2020 and 2019. 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, 2020 and 2019.

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 operator for the Block P interest 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 Atlas Petroleum in the event that there is commercial production from Block P, and the EG MMH has approved this assignment. 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.

As of December 31, 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 future 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. 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. We are seeking to farm down our interest in Block P in exchange for funding a substantial portion of an appraisal well. We continue to evaluate alternatives to funding the cost to drill an exploratory well in 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.

Organization of Petroleum Exporting Countries ("OPEC") Production Reductions

During 2018, Gabon, as a member of OPEC, agreed to reduce its production by up to 9,000 Bbl per day. As a result of natural production declines, our 2018 production was not impacted by this agreement. As of December 31, 2018, OPEC decided to further reduce overall production by 0.8 MBOPD for the first six months of 2019 compared to the October 2018 levels. 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 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 the request from the Minister of Hydrocarbons, in July 2020 we temporarily reduced production from the Etame Marin block. Based on informal communications with the Gabonese government, this reduction is expected to continue through March 31, 2021. Should production curtailments continue after March 31, 2021, we anticipate that these reductions will be attained through natural production declines. However, there can be no assurance that this will be the case.

DRILLING ACTIVITY

We had no drilling activity during 2018. As discussed above, we commenced the 2019/2020 drilling campaign in September 2019. The following table sets forth the total number of exploratory and development wells drilled in 2020, 2019 and 2018 on a gross and net basis:

	International					
	Gross			Net		
	2020	2019	2018	2020	2019	2018
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	—	**—**	0.3	—
Total wells	**3**	3	—	**0.9**	0.9	—

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 and natural gas wells as of December 31, 2020

	Developed		Undeveloped		Total	
Acreage in thousands	Gross	Net	Gross	Net	Gross	Net
Etame	6.9	2.2	39.4	12.2	46.3	14.4
Block P	—	—	57.3	24.6	57.3	24.6
Total acreage	6.9	2.2	96.7	36.8	103.6	39.0
Productive crude oil wells	14.0 (1)	4.3				

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

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 2020, the average of such price used for our reserve estimates was $42.46 per Bbl for crude oil from Gabon. This compares to the average of such price used for 2019 of $63.60 per Bbl and $70.83 per Bbl for 2018.

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, 2020, 2019 and 2018 as prepared by our independent petroleum engineering firm, Netherland, Sewell & Associates, Inc. ("NSAI"). Because the Sasol Acquisition did not close until February 25, 2021, the estimated net proved reserve quantities below do not include those attributable to the Sasol interest acquired.

	As of December 31,		
	2020	2019	2018
		(in thousands)	
Crude oil			
Proved developed reserves (MBbls)	**3,216**	4,966	3,388
Proved undeveloped reserves (MBbls)	—	—	1,982
Total proved reserves (MBbls)	**3,216**	4,966	5,370

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, 2018	3,049
Production	(1,369)
Extensions and discoveries	2,235
Revisions of previous estimates	1,455
Balance at December 31, 2018	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**

	As of December 31,		
	2020	2019	2018
		(in thousands)	
Standardized measure of discounted future net cash flows	$ **14,733**	$ 70,431	$ 80,056

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. The proved undeveloped reserves at December 31, 2018 in the table above were primarily related to the Etame 9H and the South Tchibala 3H wells. 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 comparing the net proved reserves of 5.0 MMBbls at December 31, 2019 to the 3.2 MMBbls at December 31, 2020, we 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 in negative revisions reflecting the decrease in crude oil prices and a 1.1 MMBbls increase due to improvements in well performance.

The decrease 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 from $63.60 for the 2019 year-end report to $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, 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. At December 31, 2018, we had PUDs associated with two wells. For the first of these two wells, we completed drilling during the last half of 2019 and the second well was replaced by a development well in a different field, which was completed during the first quarter of 2020.

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 2020, 2019 and 2018 operations are shown in the tables below. All volumes are for crude oil produced from the Etame Marin block.

	Year Ended December 31,					
	2020		2019		2018	
Net crude oil sales (MBbl)		**1,627**		1,251		1,442
Average crude oil sales price ($/Bbl)	$	**40.29**	$	65.20	$	70.32
Average production expense ($/Bbl)	$	**22.93**	$	30.13	$	28.03

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, 2020, 2019 and 2018, 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"). Sales of crude oil to Glencore were approximately 100% of revenues sold to customers for 2018. 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.

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, 2020, we had 102 full-time employees, 71 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 43% of our management team are female employees and 93.7% 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 a majority of our employees.

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, Compania Nacional de Petroleos de Guinea Equatorial ("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. 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 may face cybersecurity issues, 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, 2020, we had no 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 we expect the 2021/2022 program to begin in Etame in late 2021 or early 2022 with 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.

All of the value of our 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 five fields with 14 producing wells. Production from these fields constituted 100% of our total production for the year ended December 31, 2020. In addition, at December 31, 2020, 100% of our total reserves were attributable to these fields. 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 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.

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. 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 secure a method of storing the crude oil we produce 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. Our options include securing a new storage vessel, either under a charter agreement or a purchase, purchasing the vessel under the current FPSO charter pursuant to an option in the charter contract or extending the charter agreement for the current FPSO. Execution of any of these options requires 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 secure an 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 86% of revenues sold to customers for the 2020 fiscal year. In November 2020, our contract with ExxonMobil was extended until July 2021. 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, 2020, 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 2020, 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 2018, the abandonment cost estimate used for this purpose is approximately $61.8 million ($19.2 million net to VAALCO's 31.1% working interest prior to the Sasol Acquisition, and $36.3 million, net to VAALCO's 58.8% working interest, after the Sasol Acquisition) 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 potential future 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 are also seeking to farm down our interest in Block P in exchange for funding a substantial portion of an appraisal well. We continue to evaluate alternatives to funding the cost to drill an exploratory well in 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. Our derivatives program may be inadequate to protect us from significant and prolonged declines in the price of crude oil.

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.

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 March 31, 2021 in compliance with the OPEC+ mandate, and we took measures to reduce our production. A 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. While we do not anticipate that the assessments related to this audit 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.

As part of securing the first of two five-year extensions to the Etame PSC, 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 transferred the funds to the 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. 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 have requested establishment of such account, the Central Bank has not complied with our requests. As a result, we were not able to make the annual abandonment funding payments in 2019 and 2020. Pursuant to Amendment No. 5 to the Etame PSC, in the event that the Gabonese bank fails for any reason to reimburse all of the principal and interest due, we shall no longer be held liable for the resulting shortfall in funding the obligation to remediate the sites. 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" can 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, 2020, 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 $51 per barrel for Brent crude as of December 31, 2020 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 for all or portions of 2021; 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 2019 and 2018 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, Avouma, Ebouri and South East Etame/North Tchibala fields were less than the book values for these fields 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.

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. 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. 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.

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 do not currently intend to pay dividends on our common stock and our ability to pay dividends in the future may be limited; consequently, the only opportunity for investors to achieve a return on their investment is if the price of our common stock appreciates.

We have never declared or paid dividends on our common stock. To the extent we have adequate cash on hand and cash flows from operations, we will consider paying cash dividends. Payment of future dividends, if any, would 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. Consequently, investors must primarily rely on sale of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment.

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

GENERAL

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

As of February 28, 2021, based upon information received from our transfer agent and brokers and nominees, there were approximately 51 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

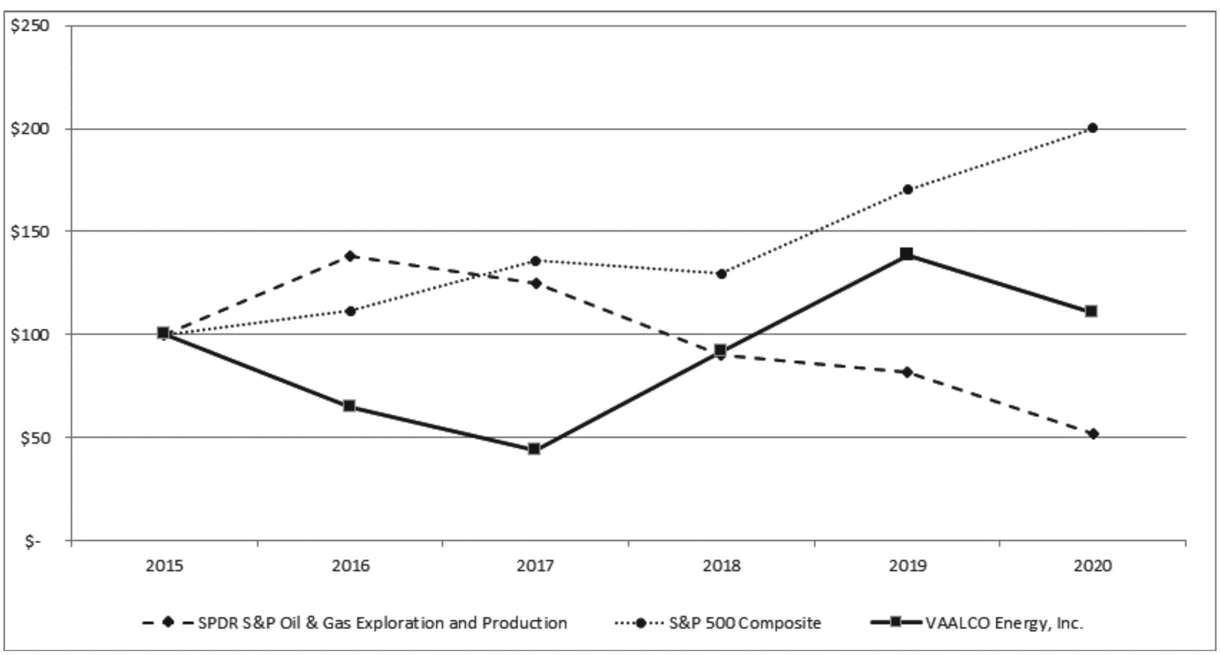
We have not paid cash dividends. To the extent we have adequate cash on hand and cash flows from operations, we will consider paying cash dividends in the future; however, dividend payments, if any, would be at the discretion of the board of directors after taking into account various factors, including 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 31, 2015 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.



	2015	2016	2017	2018	2019	2020
SPDR S&P Oil & Gas Exploration and Production	$ 100	$ 138	$ 125	$ 90	$ 82	$ 52
S&P 500 Composite	$ 100	$ 112	$ 136	$ 130	$ 170	$ 200
VAALCO Energy, Inc.	$ 100	$ 65	$ 44	$ 92	$ 139	$ 111

Unregistered Sales of Equity Securities and Use of Proceeds

None.

Issuer Purchases of Equity Securities

On June 20, 2019, our Board of Directors authorized and approved a share repurchase program for up to $10.0 million of the then outstanding shares of our common stock over a period of 12 months. Under the stock repurchase program, we repurchased shares through open market purchases, privately negotiated transactions, block purchases or otherwise in accordance with applicable federal securities laws, including Rule 10b-18 of the Exchange Act. 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.

Item 6. Selected Financial Data.

We are a smaller reporting company as defined under Rule 12b-2 of the Exchange Act and are not required to provide the information under this item.

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 2019 as compared with 2018, refer to Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2019 Form 10-K, which was filed with the SEC on March 10, 2020. Our website address is www.vaalco.com. All of our filings with the SEC are available free of charge through our website as soon as reasonably practicable after we file them with, or furnish them to, the SEC. Information on our website does not form part of this Annual Report.

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.

A significant component of our results of operations is dependent upon the difference between prices received for our offshore Gabon crude oil production and the costs to find and produce such crude oil. Historically, crude oil and natural gas prices have been volatile and subject to fluctuations based on a number of factors beyond our control. More recently, crude oil and natural gas prices have been in the midst of an unprecedented decline due to a combination of factors, including a substantial decline in global demand for oil caused by the COVID-19 pandemic and subsequent mitigation efforts. Despite these challenges, we remain committed to generating long-term value for our stockholders by focusing on exploration and development of existing properties, adding value with accretive acquisitions, controlling costs and optimizing production.

RECENT DEVELOPMENTS

Impact on Operations of COVID-19 Pandemic and the Current Crude Oil Pricing Environment

On March 11, 2020, the World Health Organization classified the COVID-19 outbreak 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, and the full impact of the outbreak continues to evolve. The adverse economic effects of the COVID-19 outbreak have 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 has led to a significant global oversupply of oil and consequently a substantial decrease in crude oil prices. 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, we temporarily reduced production from the Etame Marin block beginning in July 2020 and expect such reduction to continue through March 31, 2021. 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. The Company currently has 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 to mitigate the effects of potential future price declines. The Company will consider entering into additional commodity derivative instruments from time to time. However, there can be no assurance when, or upon what terms, the Company may enter into any future commodity derivative instruments.

While we did not incur significant disruptions to operations during the year ended December 31, 2020 as a result of the COVID-19 pandemic, we are unable to predict the impact that the COVID-19 pandemic will have on us in the future, including our financial position, operating results, liquidity and ability to obtain financing in future reporting periods, due to numerous uncertainties. These uncertainties include the severity of the virus, the duration of the outbreak, governmental or other actions taken to combat the virus (which could include limitations on our operations or the operations of our customers and vendors), and the effect that the COVID-19 pandemic and the current crude oil price wars among global suppliers will have on the demand for crude oil. 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 have taken 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;
- implemented cost cutting measures with vendors;
- implemented sharing certain costs, such as shipping vessels, helicopter, and personnel with other operators in the region; and
- ceased or deferred certain discretionary capital spending.

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. Accordingly, the results presented herein are not necessarily indicative of future operating results.

Recent Operational Updates

In September 2019, we commenced our 2019/2020 drilling campaign. During the remainder of 2019, we drilled one development well and one appraisal wellbore, and during the first quarter of 2020, we drilled two development wells and one appraisal wellbore.

In September 2020, we implemented a planned routine full-field maintenance shutdown that took five days to complete. With the exception of this planned shutdown, we maintained field integrity and our crude oil production schedule throughout the year without any material operational disruptions or reportable accidents despite the challenges presented by the COVID-19 pandemic.

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 we expect all the data to be fully processed and analyzed 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 plan to commence the next drilling campaign at Etame in late 2021 or early 2022 with two development wells and two appraisal wells at an estimated cost of $115.0 million to $125.0 million gross, or $73.0 million to $79.0 million, net to VAALCO's 63.6% participating interest. The locations of these wells will be determined in conjunction with the new seismic processing and interpretation.

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. Our options include securing a new storage vessel, either under a charter agreement or a purchase, purchasing the vessel under the current FPSO charter pursuant to an option in the charter contract or extending the charter agreement for the current FPSO. Execution of any of these options requires significant lead time and may require a capital investment due to the specialized nature of such vessels. We are currently evaluating our alternatives so that we will be in position to have an alternative in place when the current charter expires.

Acquisition of Additional Working Interest at Etame Marin Block

In November 2020, the Company signed an SPA to acquire Sasol's 27.8% working interest in the Etame Marin block offshore Gabon (the "Sasol Acquisition"). In conjunction with the signing of the SPA, we paid a $4.3 million deposit as initial consideration. The effective date of the transaction is July 1, 2020. We completed the Sasol Acquisition on February 25, 2021 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 will be 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. Since we previously owned and operated a 31.1% working interest in

Etame, the transaction increased our working interest to 58.8% of total production and reserves. Reserves, production and financial results for the interests acquired will be included in VAALCO's results beginning February 25, 2021.

NYSE Noncompliance Notice

On April 22, 2020, we were notified by the New York Stock Exchange (the "NYSE") that the average closing price of our common stock over the prior 30 consecutive trading days was below $1.00 per share, which is the minimum average closing price required to maintain listing on the NYSE under Section 802.01C of the NYSE Listed Company Manual. On July 1, 2020, we received notification that we regained full compliance with all NYSE continued listing standards.

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

CAPITAL RESOURCES AND LIQUIDITY

Cash Flows

Our cash flows for the years 2020 and 2019 are as follows:

	Year Ended December 31,		
	2020	**2019**	**Increase (Decrease) in 2020 over 2019**
		(in thousands)	
Net cash provided by operating activities before changes in operating assets and liabilities	**$ 20,468**	$ 24,213	$ (3,745)
Net change in operating assets and liabilities	**7,423**	6,945	478
Net cash provided by continuing operating activities	**27,891**	31,158	(3,267)
Net cash used in discontinued operating activities	**(441)**	(4,686)	4,245
Net cash provided by operating activities	**27,450**	26,472	978
Net cash used in investing activities	**(24,328)**	(10,348)	(13,980)
Net cash used in financing activities	**(929)**	(3,655)	2,726
Net change in cash, cash equivalents and restricted cash	**$ 2,193**	$ 12,469	$ (10,276)

The increase in net cash provided by our operating activities for the year ended December 31, 2020 compared to the same period of 2019 includes a $3.7 million decrease in cash generated by continuing operations before change in operating assets and liabilities, which was mainly due to lower revenue as referenced below in Results of Operations, which was more than offset by a $4.2 million decrease in cash used in discontinued operations. The increase in cash resulting from the net change in operating assets and liabilities of $0.5 million for the year ended December 31, 2020 reflects decreases of $22.8 million in trade and other receivables offset by increases of $2.6 million in "Crude oil inventory" as well as decreases of $6.9 million in accounts payable, decreases of $5.5 million in "Accrued liabilities and other" and a $7.3 million decrease in "Foreign taxes payable".

Property and equipment expenditures have historically been our most significant use of cash in investing activities. 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 2019, the $10.3 million in cash basis expenditures consisted of $8.0 million related to the 2019/2020 drilling program and $2.3 million paid for equipment and enhancements. See "—*Capital Expenditures and Capital Resources, Liquidity, and Cash Requirements*" below for further discussion. In addition to property and equipment expenditures, $4.3 million of cash was used in investing activities related to the Sasol Acquisition. This transaction was completed on February 25, 2021, and an additional $29.6 million was paid at closing. An additional $5.0 million will be paid 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. For 2020 and 2019, there were no other significant investing activities.

Net cash used in financing activities during the year ended December 31, 2020 included $1.0 million for treasury stock purchases primarily made under the Company's stock repurchase plan. Net cash used in financing activities during the year ended December 31, 2019 included $3.9 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 2020, we had accrual basis capital expenditures attributable to continuing operations of $10.5 million compared to $22.2 million accrual basis capital expenditures in 2019. 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 2020 and 2019 were attributable to expenditures related to the 2019/2020 drilling program, seismic acquisition costs, equipment and enhancements. See table below in "*Capital Resources, Liquidity and Cash Requirements"* for further information. As discussed above, we anticipate beginning a drilling program late in 2021 which will continue into 2022 which will require significant capital investment in 2021 and 2022. Also, as a result of the FPSO charter expiring in September 2022, securing either the FPSO or a new storage vessel may require a capital investment in 2021 and 2022.

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, 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, we did not have unexpired swaps. On January 22, 2021, we 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 709,262 barrels.

Cash on Hand

At December 31, 2020, we had unrestricted cash of $47.9 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 February 2020 and ends in July 2021. 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

Liquidity is the ability of an enterprise to generate adequate amounts of cash to meet its needs for cash requirements. The table below summarizes by period our estimated material cash requirements net to VAALCO as of December 31, 2020 and based on our 31.1% working interest in the Etame Marin block at this time.

	Note Reference [1]	2021	2022	2023	2024	2025	Total
				(in thousands)			
Operating leases [2][3]	Note 13	$ 13,864	$ 9,685	$ 179	$ —	$ —	$ 23,728
Purchase obligations [2][5]		8,605	6,448	157	—	—	15,210
Capital projects and 3D seismic processing [2][4]		12,174	—	—	—	—	12,174
Sasol acquisition [6]		34,600	—	—	—	—	34,600
Abandonment funding [7]	Note 12	2,290	763	763	763	3,054	7,633
Total cash requirements		$ 71,533	$ 16,896	$ 1,099	$ 763	$ 3,054	$ 93,345

(1) References are to the notes to Financial Statements accompanying *Item 15. Exhibits and Financial Statement Schedules*.
(2) Obligations based on a 31.1% working interest in the Etame as of December 31, 2020. Following the completion of the Sasol Acquisition on February 25, 2021, our obligations will be based on a 58.8% working interest in the Etame, and our obligations will increase accordingly.
(3) Associated with operating leases accounted for under ASC 842 as discussed in Note 13 to the Financial Statements.
(4) Associated with capital expenditures and processing of 3D seismic. This amount does not include capital expenditures for years after 2021 because we do not currently have contractual commitments with respect to such expenditures nor does it include expenditures associated with potentially replacing the FPSO.
(5) Associated with the non-lease components not accounted for under ASC 842 as discussed in Note 13 to the Financial Statements.
(6) See "Acquisition of Additional Working Interest in Etame Marin Block" in Recent Developments above. This amount includes cash payment made on February 25, 2021 upon closing and additional contingent payment of $5.0 million 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.
(7) See "Abandonment funding" in Note 12 to the Financial Statements for further information.

Historically, our primary source of liquidity has been cash flows from operations and our primary uses of cash has been to fund capital expenditures for development activities in the Etame Marin block. 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%. 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. 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. In early March 2020, crude oil prices declined significantly ending at approximately $15 per barrel for Brent crude, as of March 31, 2020, as a result of market concerns about the ability of OPEC and Russia to agree on a perceived need to implement further production cuts in response to weaker worldwide demand. While OPEC and Russia were able to reach an agreement to cut production in April 2020, crude oil prices continued to decline below $20 per barrel for Brent crude as a result of the substantial decline in the global demand for crude oil caused by the COVID-19 pandemic and subsequent mitigation efforts. The reduced demand for crude oil as a result of measures taken to prevent the spread of COVID-19 led to a surplus in the global supply of crude oil. 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. Brent crude prices were approximately $51 per barrel as of December 31, 2020. On January 22, 2021, we 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 709,262 barrels.

Despite the lower Brent crude oil prices, based on current expectations, we believe we have sufficient liquidity through our existing cash balances and cash flow from operations to support our cash requirements, including those related to the Sasol Acquisition, through March 2022. We are continuing to evaluate all uses of cash and whether to pursue growth opportunities or preserve our resources in light of ongoing economic conditions.

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. 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.

RESULTS OF OPERATIONS

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019

We incurred a net loss for the year ended December 31, 2020 of $(48.2) million, compared to net income of $2.6 million for the year ended December 31, 2019. The year-over-year decrease in earnings was mainly due to a $30.6 million impairment and lower revenues as a result of receiving lower crude oil prices. Substantially all of our operations are attributable to our Gabon segment. Further discussion of results by significant line item follows.

	Year Ended December 31,		
	2020	**2019**	**Increase/(Decrease)**
	(in thousands except per bbl information)		
Net crude oil sales volume (MBbls)	**1,627**	1,251	376
Average crude oil sales price (per Bbl)	**$ 40.29**	$ 65.20	$ (24.91)
Net crude oil revenue	**$ 67,176**	$ 84,521	$ (17,345)
Operating costs and expenses:			
Production expense	**37,315**	37,689	(374)
Exploration expense	**3,588**	—	3,588
Depreciation, depletion and amortization	**9,382**	7,083	2,299
Impairment of proved crude oil and natural gas properties	**30,625**	—	30,625
Gain on revision of asset retirement obligations	**—**	(379)	379
General and administrative expense	**10,695**	14,855	(4,160)
Bad debt expense	**1,165**	(341)	1,506
Total operating costs and expenses	**92,770**	58,907	33,863
Other operating expense, net	**(1,669)**	(4,421)	2,752
Operating income (loss)	**$ (27,263)**	$ 21,193	$ (48,456)

Crude oil revenues decreased $17.3 million, or approximately 20.5%, during the year ended December 31, 2020 compared to the same period of 2019. The decrease in revenue is primarily attributable to lower prices as described below partially offset by higher sales volumes. While sales volumes increased as a result of additional production from the new wells drilled during the 2019/2020 drilling program, the increase in sales volume was partially offset by curtailments mandated by Gabon to meet OPEC+ production cuts as well as a delay to January 2021 in the lifting scheduled for December 2020.

The revenue changes between the years ended December 31, 2020 and 2019 identified as related to changes in price or volume are shown in the table below:

(in thousands)

Price	$ (40,529)
Volume	24,515
Other	(1,331)
	$ (17,345)

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

	Year Ended December 31,	
	2020	**2019**
Gabon net crude oil production (MBbls)	1,776	1,269
Gabon net crude oil sales (MBbls)	1,627	1,251
Average realized crude oil price ($/Bbl)	$ 40.29	$ 65.20
Average Dated Brent spot price* ($/Bbl)	41.96	64.65

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

Crude oil sales are a function of the number and size of crude oil liftings in each year from the FPSO, and as a result, crude oil sales do not always coincide with volumes produced in any given year. We made eleven liftings for the year ended December 31, 2020 and fifteen liftings for the year ended December 31, 2019. Production volumes for the year ended December 31, 2020 were higher than the comparable 2019 period due to new development wells brought onto production. The increase from new wells was partially offset by production curtailments. Sales volumes were higher in 2020 as compared to 2019 due to the new development wells brought onto production. Our share of crude oil inventory aboard the FPSO, excluding royalty barrels, was approximately 172,276 and 38,476 barrels at December 31, 2020 and 2019, respectively. The crude oil inventory was higher at December 31, 2020 due to the scheduled December 2020 lifting being delayed to January 2021, as discussed above.

Production expenses decreased $0.4 million, or approximately 1.0%, in the year ended December 31, 2020 compared to the same period of 2019. The decrease in expense was associated with an increase in crude inventory levels as discussed above offset by higher workover expense related to two workovers. On a per barrel basis, production expense, excluding workover expense, for the year ended December 31, 2020 decreased to $21.38 per barrel from $29.70 per barrel for the year ended December 31, 2019 primarily as a result of an increase in sales volumes. While we have not experienced any significant operational disruptions associated with the current worldwide COVID-19 pandemic, we have incurred approximately $1.6 million in higher costs related to the proactive measures taken in response to the pandemic.

Exploration expenses of $3.6 million were related to the acquisition of proprietary 3-D seismic data over the entire Etame Marin block as discussed in *Item 1. Business – Segment and Geographic Information – Gabon Segment — Development*.

Depreciation, depletion and amortization increased $2.3 million, or approximately 32.5%, in the year ended December 31, 2020 compared to the same period of 2019 due to higher sales volumes and higher depletable costs associated with the new development wells.

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. See Note 9 to the Financial Statements for further discussion.

Gain on revision of asset retirement obligations for the year ended December 31, 2019 resulted from a downward revision of $0.4 million as discussed in Note 11 to the Financial Statements.

General and administrative expenses decreased $4.2 million, or approximately 28.0% in the year ended December 31, 2020 compared to the same period of 2019. The decrease in expense was in part related to a $3.3 million decrease in stock appreciation rights ("SARs") expense. 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 17 to the Financial Statements for further discussion. Other expense categories that decreased during the year ended December 31, 2020 compared to the same period in 2019 were accounting and audit fees and travel costs, which were higher in the prior year as a result of our listing on the London Stock Exchange in September 2019.

Bad debt (recovery) expense and other reflected bad debt expense associated with the VAT allowance for the year ended December 31, 2020 compared to the bad debt recoveries during 2019.

Other operating income (expense), net for the year ended December 31, 2020 is primarily related 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. related to audits for the years 2017 and 2018 as well as $0.9 million in inventory obsolescence. During the year ended December 31, 2019, we incurred costs related to a $4.4 million agreement to resolve a legacy issue related to findings from Etame joint ventures owners' audits for the periods from 2007 through 2016.

Derivative instruments gain (loss), net is attributable to our commodity swaps as discussed in Note 10 to the Financial Statements and the $6.6 million gain is a result of a decrease in the price of Dated Brent crude oil during the year ended December 31, 2020 as compared to an increase in the price of Dated Brent crude oil that resulted in a $0.4 million loss during the comparable prior year.

Interest income (expense), net for the years ended December 31, 2020 and 2019 relate to interest income on cash balances.

Other, net for the year ended December 31, 2020 and 2019 consists primarily of foreign currency gains (losses) as discussed in Note 1 to the Financial Statements.

Income tax expense (benefit) 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 income tax expense of $23.9 million for the year ended December 31, 2019 is comprised of $14.5 million of deferred income tax expense and a current tax provision of $9.4 million. The deferred income tax expense for the year ended December 31, 2019 included a $3.1 million benefit to decrease the valuation allowances on deferred tax assets due to a decrease in future estimated taxable earnings primarily as a result of lower crude oil prices. The current tax provision in both periods is primarily attributable to our operations in Gabon and is lower in 2020 than income tax for the comparable 2019 period as a result of lower 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, 2020 and 2019 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, 2020 was related to Angola administration costs. The gain from discontinued operations for the year ended December 31, 2019 is primarily related to recording a $5.7 million after tax gain on the finalized Angola settlement.

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, 2020, the Company had deferred tax assets of $126.3 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 $126.3 million has been established against the deferred tax assets as of December 31, 2020, as management has concluded that it was more-likely-than-not that no 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

The Company uses derivative financial instruments to achieve a more predictable cash flow from crude oil sales by reducing the exposure to price fluctuations. While we had derivative instruments which settled during the years ended December 31, 2020 and 2019, as of December 31, 2020, we did not have unexpired derivative instruments. On January 22, 2021, we 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 an approximate quantity of 709,262 barrels.

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.

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, 2020, we had net monetary assets of $5.5 million (XAF 2,924 million) denominated in XAF. A 10% weakening of the CFA relative to the U.S. dollar would have a $0.5 million reduction in the value of these net assets. For 2020, we had expenditures of approximately $13.1 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 1,627 MBbls, a $5 per Bbl decrease in crude oil price would be expected to cause a $8.1 million decrease per year in revenues and operating income (loss) and a $7.3 million decrease per year in net income (loss).

As of December 31, 2020, we did not have any unexpired derivative instruments outstanding. During the years ended December 31, 2020 and 2019, 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, 2020.

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, 2020.

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, 2020 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information required by this item will be included in the proxy statement for our 2021 annual meeting, which will be filed with the SEC within 120 days of December 31, 2020, 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 2021 annual meeting, which will be filed with the SEC within 120 days of December 31, 2020, and that is incorporated herein by reference.

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

Except as set forth below, information required by this item will be included in the proxy statement for our 2021 annual meeting, which will be filed with the SEC within 120 days of December 31, 2020, and that is incorporated herein by reference.

The following tables provide information as of December 31, 2020 regarding the number of shares of common stock that may be issued under our compensation plans. Please refer to Note 16 to the Financial Statements for additional information on stock-based compensation.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants, and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issues under equity compensation plans (excluding securities reflected in the first column)
Equity compensation plans approved by security holders	2,449,186	$ 1.34	3,744,737
Total	2,449,186	$ 1.34	3,744,737

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

Information required by this item will be included in the proxy statement for our 2021 annual meeting, which will be filed with the SEC within 120 days of December 31, 2020, 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 2021 annual meeting, which will be filed with the SEC within 120 days of December 31, 2020, and that is incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules

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

VAALCO ENERGY, INC. AND SUBSIDIARIES

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

(a) 3. Exhibits:

2.1(a)	Sale and Purchase Agreement, dated as of November 17, 2020, by and between Sasol Gabon S.A. and VAALCO Gabon S.A.
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*	Amended and Restated Executive Employment Agreement between VAALCO Energy, Inc. and Cary Bounds, effective as of December 29, 2016 (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K filed on January 3, 2017, and incorporated herein by reference).
10.14	Settlement Agreement, dated as of December 22, 2015, among VAALCO Energy, Inc., Group 42, Inc. Paul A. Bell, Michael Keane, BLR Partners LP, BLRPart, LP, BLRGP Inc., Fondren Management, LP, FMLP Inc., The Radoff Family Foundation and Bradley L. Radoff (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K filed on December 23, 2015, and incorporated herein by reference).
10.15*	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).
10.16*	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).

10.17*	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).
10.1	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).
10.19	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).
10.2	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).
10.2	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).
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/ CARY BOUNDS
Cary Bounds

Chief Executive Officer

Dated March 9, 2021

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on the 9th day of March 2021, by the following persons on behalf of the registrant and in the capacities indicated.

Signature	Title
By: /s/ CARY BOUNDS Cary Bounds	Chief Executive Officer (Principal Executive Officer) and Director
By: /s/ ELIZABETH D. PROCHNOW Elizabeth D. Prochnow	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/ GEORGE W.M. MAXWELL George W.M. Maxwell	Director
By: /s/ BRADLEY L. RADOFF Bradley L. Radoff	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. and its subsidiaries (the "Company") as of December 31, 2020 and 2019, the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years ended in the period ended December 31, 2020, 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 VAALCO Energy, Inc. and its subsidiaries as of December 31, 2020 and 2019, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2020, 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 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 discussed in Note 8 to the consolidated financial statements, the Company records a valuation allowance based on the assessment of the realizability of the Company's deferred tax assets. During the year ended December 31, 2020, the Company recorded a valuation allowance of $41.6 million and as of December 31, 2020 had fully valued deferred tax assets of $126.3 million.

We identified the assessment of the realizability of deferred tax assets as a critical audit matter. Auditing management's assessment of the recoverability of deferred tax assets in the U.S. and non-U.S. jurisdictions involved significant estimation and complex auditor judgments, including the need for specialized knowledge and skill, in determining whether sufficient future taxable income will be generated to support the realization of the existing deferred tax assets.

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

- Evaluating the reasonableness of 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 personnel with specialized knowledge and skill in domestic and international tax matters to assist in analyzing management's projections of future taxable income and evaluating the appropriateness and accuracy of the gross deferred tax assets and liabilities and permanent tax differences in the various tax jurisdictions.

Estimate of 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 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 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 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, 2020 was $37.0 million, which includes net proved crude oil and natural gas properties of $9.5 million.

We identified the estimation of oil and natural gas reserves, due to its impact on depletion expense and impairment evaluation, as a critical audit matter. The principal consideration for our determination that the estimation of oil and natural gas reserves is a critical audit matter is that it requires a high degree of subjectivity necessary to estimate the oil and natural gas reserves 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 impairment expense. In turn, auditing those 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 oil and gas price assumptions against third-party forecasts, peer information and relevant market data to determine whether the Company's price forecasts were within range of such third-party forecasts.

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

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

- Reviewing reports provided by external experts and assessing the scope of work and findings.

- Assessing the competence, capability and objectivity of the Company's internal and external reserve experts through an understanding of their relevant professional qualifications and experience as a basis for using this work.

/s/BDO USA, LLP

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

Houston, TX
March 9, 2021

VAALCO ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31, 2020	As of December 31, 2019
	(in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 47,853**	$ 45,917
Restricted cash	**86**	911
Receivables:		
Trade	**—**	14,335
Accounts with joint venture owners, net of allowance of $0.0 million and $0.5 million, respectively	**3,587**	2,714
Other	**4,331**	1,517
Crude oil inventory	**3,906**	1,072
Prepayments and other	**4,215**	3,292
Total current assets	**63,978**	69,758
Crude oil and natural gas properties, equipment and other - successful efforts method, net	**37,036**	68,258
Other noncurrent assets:		
Restricted cash	**925**	925
Value added tax and other receivables, net of allowance of $2.3 million and $1.0 million, respectively	**4,271**	3,683
Right of use operating lease assets	**22,569**	33,383
Deferred tax assets	—	24,159
Abandonment funding	**12,453**	11,371
Total assets	**$ 141,232**	$ 211,537
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	**$ 16,690**	$ 15,897
Accounts with joint venture owners	**4,945**	—
Accrued liabilities and other	**17,184**	29,773
Operating lease liabilities - current portion	**12,890**	11,990
Foreign income taxes payable	**860**	5,740
Current liabilities - discontinued operations	**7**	350
Total current liabilities	**52,576**	63,750
Asset retirement obligations	**17,334**	15,844
Operating lease liabilities - net of current portion	**9,671**	21,371
Other long-term liabilities	**193**	852
Total liabilities	**79,774**	101,817
Commitments and contingencies (Note 12)		
Shareholders' equity:		
Preferred stock, $25 par value; 500,000 shares authorized, none issued	—	—
Common stock, $0.10 par value; 100,000,000 shares authorized, 67,897,530 and 67,673,787 shares issued, 57,531,154 and 58,024,571 shares outstanding, respectively	**6,790**	6,767
Additional paid-in capital	**74,437**	73,549
Less treasury stock, 10,366,376 and 9,649,216 shares, respectively, at cost	**(42,421)**	(41,429)
Retained earnings	**22,652**	70,833
Total shareholders' equity	**61,458**	109,720
Total liabilities and shareholders' equity	**$ 141,232**	$ 211,537

See notes to consolidated financial statements.

VAALCO ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2020	**2019**	**2018**
	(in thousands, except per share amounts)		
Revenues:			
Crude oil and natural gas sales	**$ 67,176**	$ 84,521	$ 104,943
Operating costs and expenses:			
Production expense	**37,315**	37,689	40,415
Exploration expense	**3,588**	—	14
Depreciation, depletion and amortization	**9,382**	7,083	5,596
Impairment of proved crude oil and natural gas properties	**30,625**	—	—
Gain on revision of asset retirement obligations	—	(379)	(3,325)
General and administrative expense	**10,695**	14,855	11,398
Bad debt (recovery) expense and other	**1,165**	(341)	(77)
Total operating costs and expenses	**92,770**	58,907	54,021
Other operating income (expense), net	**(1,669)**	(4,421)	365
Operating income (loss)	**(27,263)**	21,193	51,287
Other income (expense):			
Derivative instruments gain (loss), net	**6,577**	(446)	4,264
Interest income (expense), net	**155**	733	(145)
Other, net	**129**	(438)	68
Total other income (expense), net	**6,861**	(151)	4,187
Income (loss) from continuing operations before income taxes	**(20,402)**	21,042	55,474
Income tax expense (benefit)	**27,681**	23,890	(43,254)
Income (loss) from continuing operations	**(48,083)**	(2,848)	98,728
Income (loss) from discontinued operations, net of tax	**(98)**	5,411	(496)
Net income (loss)	**$ (48,181)**	$ 2,563	$ 98,232
Basic net income (loss) per share:			
Income (loss) from continuing operations	**$ (0.83)**	$ (0.05)	$ 1.65
Income (loss) from discontinued operations, net of tax	**0.00**	0.09	(0.01)
Net income (loss) per share	**$ (0.83)**	$ 0.04	$ 1.64
Basic weighted average shares outstanding	**57,594**	59,143	59,248
Diluted net income (loss) per share:			
Income (loss) from continuing operations	**$ (0.83)**	$ (0.05)	$ 1.63
Income (loss) from discontinued operations, net of tax	**0.00**	0.09	(0.01)
Net income (loss) per share	**$ (0.83)**	$ 0.04	$ 1.62
Diluted weighted average shares outstanding	**57,594**	59,143	59,997

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, 2018	66,444	(7,581)	$ 6,644	$ 71,251	$ (37,953)	$ (29,653)	$ 10,289
Shares issued - stock-based compensation	724	35	73	287	177	—	537
Stock-based compensation expense	—	—	—	820	—	—	820
Treasury stock	—	(26)	—	—	(51)	—	(51)
Net income	—	—	—	—	—	98,232	98,232
Balance at December 31, 2018	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**

See notes to consolidated financial statements.

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

	Year Ended December 31,		
	2020	**2019**	**2018**
		(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	**$ (48,181)**	$ 2,563	$ 98,232
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
(Income) loss from discontinued operations	**98**	(5,411)	496
Depreciation, depletion and amortization	**9,382**	7,083	5,596
Impairment of proved crude oil and natural gas properties	**30,625**	—	—
Gain on revision of asset retirement obligations	**—**	(379)	(3,325)
Other amortization	**181**	241	417
Deferred taxes	**24,159**	14,480	(56,907)
Unrealized foreign exchange gain	**91**	(50)	834
Stock-based compensation	**114**	3,506	2,388
Cash settlements paid on exercised stock appreciation rights	**(275)**	(491)	(82)
Derivative instruments (gain) loss, net	**(6,577)**	446	(4,264)
Cash settlements received on matured derivative contracts, net	**7,216**	2,439	744
Bad debt expense and other	**1,165**	(341)	(77)
Other operating loss, net	**869**	58	(570)
Operational expenses associated with equipment and other	**1,601**	69	1,604
Change in operating assets and liabilities:			
Trade receivables	**14,335**	(2,428)	(8,351)
Accounts with joint venture owners	**4,016**	(2,075)	2,747
Other receivables	**1,405**	(94)	(1,330)
Crude oil inventory	**(2,834)**	(287)	2,478
Prepayments and other	**(1,126)**	(1,014)	1,164
Value added tax and other receivables	**(1,268)**	275	(777)
Accounts payable	**(842)**	6,011	(3,409)
Foreign income taxes receivable/payable	**(4,880)**	2,396	2,751
Accrued liabilities and other	**(1,383)**	4,161	(2,131)
Net cash provided by continuing operating activities	**27,891**	31,158	38,228
Net cash used in discontinued operating activities	**(441)**	(4,686)	(1,052)
Net cash provided by operating activities	**27,450**	26,472	37,176
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property and equipment expenditures	**(20,008)**	(10,348)	(14,127)
Acquisition of crude oil and natural gas properties	**(4,320)**	—	—
Net cash used in continuing investing activities	**(24,328)**	(10,348)	(14,127)
Net cash used in discontinued investing activities	**—**	—	—
Net cash used in investing activities	**(24,328)**	(10,348)	(14,127)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from the issuances of common stock	**63**	256	544
Debt repayments	**—**	—	(9,166)
Treasury shares	**(992)**	(3,911)	(58)
Net cash used in continuing financing activities	**(929)**	(3,655)	(8,680)
Net cash used in discontinued financing activities	**—**	—	—
Net cash used in financing activities	**(929)**	(3,655)	(8,680)
NET CHANGE IN CASH, CASH EQUIVALENTS AND RESTRICTED CASH	**2,193**	12,469	14,369
CASH, CASH EQUIVALENTS AND RESTRICTED CASH AT BEGINNING OF YEAR	**59,124**	46,655	32,286
CASH, CASH EQUIVALENTS AND RESTRICTED CASH AT END OF YEAR	**$ 61,317**	$ 59,124	$ 46,655

See notes to consolidated financial statements.

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

	Year Ended December 31,		
	2020	**2019**	**2018**
		(in thousands)	
Supplemental disclosure of cash flow information:			
Interest expense paid in cash	**$ —**	$ —	$ 257
Income taxes (received) paid in cash	**$ (696)**	$ (674)	$ 2,720
Income taxes paid in-kind with crude oil	**$ 8,738**	$ 7,268	$ 9,385
Supplemental disclosure of non-cash investing and financing activities:			
Property and equipment additions incurred but not paid at end of period	**$ 3,966**	$ 13,646	$ 2,138
Crude oil and natural gas property additions paid with non-cash assets	**$ —**	$ —	$ 4,197
Gross-up of crude oil and natural gas properties by establishment of deferred tax liability	**$ —**	$ —	$ 18,613
Recognition of right-of-use operating lease assets and liabilities	**$ 1,478**	$ 44,681	$ —
Recognition of right-of-use operating lease liabilities	**$ 1,478**	$ 44,656	$ —
Asset retirement obligations	**$ 359**	$ 595	$ (6,527)
Restricted stock issued out of treasury	**$ —**	$ 309	$ 177

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 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. As a result of the pandemic, many companies have experienced disruptions in their operations and in markets served. The Company has instituted some and may take additional temporary precautionary measures intended to help ensure the well-being of its employees and minimize business disruption. Such measures include social distancing measures and actively screening and monitoring employees and contractors that come on to the Company's facilities. The adverse economic effects of the COVID-19 outbreak have 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 has 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, beginning in July 2020 and continuing through March 31, 2021, the Company has temporarily reduced production from the Etame Marin block.

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. Crude oil prices improved somewhat by December 31, 2020, and therefore no further material charges or impairments were required in the year end impairment analysis done at December 31, 2020. The full extent of the future impacts of COVID-19 on the Company's operations is uncertain. 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, 2020 and 2019 each include an escrow amount representing bank guarantees for customs clearance in Gabon. Long-term amounts at December 31, 2020 and 2019 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,	
	2020	**2019**
	(in thousands)	
Cash and cash equivalents	**$ 47,853**	$ 45,917
Restricted cash - current	**86**	911
Restricted cash - non-current	**925**	925
Abandonment funding	**12,453**	11,371
Total cash, cash equivalents and restricted cash	**$ 61,317**	$ 59,124

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 and 2020. In February 2021, the Central Bank authorized the Company to apply for a USD escrow account for the Abandonment Fund at Citibank Gabon. The Company is working with Citibank to complete the documentation required for the account. Amendment No. 5 to the Etame PSC also provides that in the event that the Gabonese bank fails for any reasons to reimburse all of the principal and interest due, the Contractor shall no longer be held liable for the obligation to remediate the sites.

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, 2020, the outstanding VAT receivable balance, excluding the allowance for bad debt, was approximately $13.4 million ($4.5 million, net to VAALCO). As of December 31, 2020, the exchange rate was XAF 534.8 = $1.00. As of December 31, 2019, the exchange rate was XAF 585.7 = $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,		
	2020	2019	2018
		(in thousands)	
Allowance for bad debt			
Balance at beginning of period	**$ (1,508)**	$ (2,535)	$ (7,033)
Bad debt charge	**(1,165)**	341	77
Adjustment associated with reversal of allowance on Mutamba receivable	**593**	—	—
Adjustment associated with settlement of customs audit	**—**	623	—
Reclassification to leasehold costs related to signing bonus	**—**	—	4,197
Foreign currency gain (loss)	**(193)**	63	224
Balance at end of period	**$ (2,273)**	$ (1,508)	$ (2,535)

Crude oil inventory – Crude oil inventories are carried at the lower of cost or market 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 field-by-field basis under the unit-of-production method based upon estimates of proved developed reserves. Depletion of developed leasehold acquisition costs are provided on a field-by-field 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 field-by-field 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 a field contains lower than anticipated reserves or if commodity prices fall below a level that significantly effects anticipated future cash flows on the field. 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.

Capitalized interest – Interest costs and commitment fees from external borrowings are capitalized on exploration and development projects that are not subject to current depletion. Interest and commitment fees are capitalized only for the period that activities are in progress to bring these projects to their intended use. Capitalized interest is added to the cost of the underlying asset and is depleted on the unit-of-production method in the same manner as the underlying assets.

The Company capitalized no interest costs during the years ended December 31, 2020, 2019 and 2018.

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. See Note 11 for disclosures regarding the asset retirement obligations. 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 17 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 gains on foreign currency transactions of $0.2 million in 2020, while the Company recognized losses on foreign currency transactions of $0.2 million and $0.1 million in 2019, and 2018, respectively.

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).

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 guarantee. 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 derivative asset commodity swaps referenced below are reported in “Prepayments 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, 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**

		As of December 31, 2019			
	Balance Sheet Line	**Level 1**	**Level 2**	**Level 3**	**Total**
			(in thousands)		
Assets					
Derivative asset commodity swaps	Prepayments and other	$ —	$ 636	$ —	$ 636
		$ —	$ 636	$ —	$ 636
Liabilities					
SARs liability	Accrued liabilities	$ —	$ 2,638	$ —	$ 2,638
SARs liability	Other long-term liabilities	—	852	—	852
		$ —	$ 3,490	$ —	$ 3,490

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 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 the fiscal years beginning after December 15, 2020, with early adoption permitted. The adoption of this guidance is not expected to have a material impact on the Company's financial statements.

In June 2016, the FASB issued 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 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. The Company plans to defer the implementation of ASU 2016-13, and related updates, until January 2023.

In March 2020, the FASB issued ASU No. 2020-03 - Codification Improvements to Financial Instruments ("ASU 2020-03"). ASU 2020-03 improves and clarifies various financial instruments topics, including the CECL standard. ASU 2020-03 includes seven different issues that describe the areas of improvement and the related amendments to GAAP, intended to make the standards easier to understand and apply by eliminating inconsistencies and providing clarifications. The amendments in ASU 2020-03 have different effective dates. The adoption of this guidance is not expected to have a material impact on the Company's financial statements.

Adopted

In August 2018, the FASB issued ASU 2018-15, Intangibles - Goodwill and Other - Internal-Use Software (Topic 350): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That is a Service Contract, which requires a customer in a cloud computing arrangement that is a service contract to follow the internal-use software guidance in Accounting Standards Codification ("ASC") 350, Intangibles - Goodwill and Other, in making the determination as to which implementation costs are to be capitalized as assets and which costs are to be expensed as incurred. The new standard is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. Early adoption is permitted, and an entity can elect to apply the new guidance on a prospective or retrospective basis. The Company's adoption of this guidance on January 1, 2020 did not have an impact on its financial position, results of operations, cash flows and related disclosures.

In August 2018, the FASB issued ASU 2018-13, Fair Value Measurement (Topic 820): Disclosure Framework – Changes to the Disclosure Requirements for Fair Value Measurement ("ASU 2018-13"). This ASU modifies the disclosure requirements for fair value measurements. ASU 2018-13 removes the requirement to disclose (1) the amount of and reasons for transfers between Level 1 and Level 2 of the fair value hierarchy, (2) the policy for timing of transfers between levels, and (3) the valuation processes for Level 3 fair value measurements. ASU 2018-13 requires disclosure of changes in unrealized gains and losses for the period included in other comprehensive income (loss) for recurring Level 3 fair value measurements held at the end of the reporting period and the range and weighted average of significant unobservable inputs used to develop Level 3 fair value measurements. ASU 2018-13 applies to all entities and is effective for fiscal years beginning after December 15, 2019. The Company's adoption of this guidance on January 1, 2020 did not have a material impact on its financial position, results of operations, cash flows and related disclosures.

In March 2020, the FASB issued ASU No. 2020-04 - Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting ("ASU 2020-04"). ASU 2020-04 provides optional expedients and exceptions for applying generally accepted accounting principles to contracts, hedging relationships, and other transactions affected by reference rate reform if certain criteria are met. In response to the concerns about structural risks of interbank offered rates (IBORs) and, particularly, the risk of cessation of the London Interbank Offered Rate (LIBOR), regulators in several jurisdictions around the world have undertaken reference rate reform initiatives to identify alternative reference rates that are more observable or transaction based and less susceptible to manipulation. ASU 2020-04 provides companies with optional guidance to ease the potential accounting burden associated with transitioning away from reference rates that are expected to be discontinued. The amendments in ASU 2020-04 are available to be adopted for all entities as of March 12, 2020, the date of issuance of Topic 848, and the relief provided within Topic 848 lasts until December 31, 2022. As the Company currently has no debt instruments or contracts where LIBOR is a material provision of contracts, the adoption of this guidance will 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, 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 effective date of the transaction was July 1, 2020. The final cash settlement payment for the Sasol Acquisition was $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 will be 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. 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%, almost doubling the Company's total production and reserves. As a result of the acquisition, the net portion of production and costs relating to the Company's Etame operations increased from 31.1% to 58.8% on February 25, 2021. Reserves, production and financial results for the interests acquired will be included in VAALCO's results for periods after the February 25, 2021 closing date of the transaction.

Discontinued Operations - Angola

In November 2006, the Company signed a production sharing contract for Block 5 offshore Angola ("PSA"). The working interest is 40%, and the Company carries Sonangol P&P for 10% of the work program. On September 30, 2016, the Company notified Sonangol P&P that the Company 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 the Company was withdrawing from the PSA. Further to the decision to withdraw from Angola, the Company has taken actions to close the office in Angola and reduce future 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 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 consolidated statements of cash flows. The following tables summarize selected financial information related to the Angola segment assets and liabilities as of December 31, 2020 and 2019 and its results of operations for the years ended December 31, 2020, 2019 and 2018.

Summarized Results of Discontinued Operations

	Year Ended December 31,		
	2020	**2019**	**2018**
		(in thousands)	
Operating costs and expenses:			
Gain on settlement of drilling obligation	**$ —**	$ (7,193)	$ —
General and administrative expense	**93**	344	467
Total operating costs, expenses and (recovery)	**93**	(6,849)	467
Operating income (loss)	**(93)**	6,849	(467)
Other expense:			
Other, net	**(5)**	—	(29)
Total other expense	**(5)**	—	(29)
Income (loss) from discontinued operations before income taxes	**(98)**	6,849	(496)
Income tax expense (benefit)	—	1,438	—
Income (loss) from discontinued operations	**$ (98)**	$ 5,411	$ (496)

Assets and Liabilities Attributable to Discontinued Operations

	As of December 31,	
	2020	**2019**
	(in thousands)	
ASSETS		
Accounts with joint venture owners	$ —	$ —
Total current assets	—	—
Total assets	$ —	$ —
LIABILITIES		
Current liabilities:		
Accounts payable	**$ —**	$ 8
Accrued liabilities and other	**7**	342
Total current liabilities	**7**	350
Total liabilities	$ **7**	$ 350

Drilling Obligation

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 a current asset 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.

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, 2020, 2019 and 2018 and long-lived assets and segment assets at December 31, 2020 and 2019 are as follows:

	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 (recovery) 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 loss, net	—	—	(446)	(446)
Interest income, net	5	—	728	733
Other, net	(230)	(3)	(205)	(438)
Income tax expense	20,311	12	3,567	23,890
Additions to crude oil and natural gas properties and equipment – accrual	22,116	—	57	22,173

	Year Ended December 31, 2018			
(in thousands)	**Gabon**	**Equatorial Guinea**	**Corporate and Other**	**Total**
Revenues-crude oil and natural gas sales	$ 104,938	$ —	$ 5	$ 104,943
Depreciation, depletion and amortization	5,176	—	420	5,596
Gain on revision of asset retirement obligations	(3,325)	—	—	(3,325)
Bad debt (recovery) expense and other	(77)	—	—	(77)
Other operating expense, net	365	—	—	365
Operating income (loss)	61,930	(470)	(10,173)	51,287
Derivative instruments gain, net	—	—	4,264	4,264
Interest income (expense), net	(396)	—	251	(145)
Other, net	92	(4)	(20)	68
Income tax benefit	(26,670)	—	(16,584)	(43,254)
Additions to crude oil and natural gas properties and equipment – accrual	38,430	187	17	38,634

(in thousands)	**Gabon**	**Equatorial Guinea**	**Corporate and Other**	**Total**
Long-lived assets from continuing operations:				
As of December 31, 2020	**$ 26,832**	**$ 10,000**	**$ 204**	**$ 37,036**
As of December 31, 2019	$ 57,930	$ 10,000	$ 328	$ 68,258

(in thousands)		Gabon		Equatorial Guinea		Corporate and Other		Total
Total assets from continuing operations:								
As of December 31, 2020	**$**	**101,399**	**$**	**10,267**	**$**	**29,566**	**$**	**141,232**
As of December 31, 2019	$	151,686	$	10,087	$	49,764	$	211,537

Information about the Company's most significant customers

The Company 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 August 2015 through January 2019, the Company sold its crude oil to Glencore Energy UK Ltd. ("Glencore") and from February 2019 through January 2020, crude sales were to Mercuria Energy Trading SA ("Mercuria"). Sales of crude oil to Glencore and Mercuria were approximately 6% and 94%, respectively, of total revenues for the year ended December 31, 2019. The Company signed a new contract with ExxonMobil that covers sales from February 2020 through July 2021 with pricing based upon an average of Dated Brent in the month of lifting, adjusted for location and market factors. Sales of crude oil to Mercuria and ExxonMobil were approximately 14% and 86%, respectively, of the Company's total revenues from customers for the year ended December 31, 2020.

6. EARNINGS PER SHARE

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

	Year Ended December 31,					
		2020		2019		2018
				(in thousands)		
Net income (loss) (numerator):						
Income (loss) from continuing operations	**$**	**(48,083)**	$	(2,848)	$	98,728
(Income) loss from continuing operations attributable to unvested shares		**—**		21		(1,231)
Numerator for basic		**(48,083)**		(2,827)		97,497
(Income) loss from continuing operations attributable to unvested shares		**—**		(21)		—
Numerator for dilutive	**$**	**(48,083)**	$	(2,848)	$	97,497
Income (loss) from discontinued operations, net of tax	**$**	**(98)**	$	5,411	$	(496)
(Income) loss from discontinued operations attributable to unvested shares		**—**		(39)		6
Numerator for basic		**(98)**		5,372		(490)
(Income) loss from discontinued operations attributable to unvested shares		**—**		39		—
Numerator for dilutive	**$**	**(98)**	$	5,411	$	(490)
Net income (loss)	**$**	**(48,181)**	$	2,563	$	98,232
Net (income) loss attributable to unvested shares		**—**		(18)		(1,225)
Numerator for basic		**(48,181)**		2,545		97,007
Net (income) loss attributable to unvested shares		**—**		18		—
Numerator for dilutive	**$**	**(48,181)**	$	2,563	$	97,007
Weighted average shares (denominator):						
Basic weighted average shares outstanding		**57,594**		59,143		59,248
Effect of dilutive securities		**—**		—		749
Diluted weighted average shares outstanding		**57,594**		59,143		59,997
Stock options and unvested restricted stock grants excluded from dilutive calculation because they would be anti-dilutive		**3,545**		603		1,316

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.

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 thirty days after the date of the bill of lading. For each lifting of crude oil, the price is determined based on a formula using published Dated Brent prices as well as market differentials plus a fixed contract differential.

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, 2020, the foreign taxes payable attributable to this obligation is $0.9 million. As of December 31, 2019, the foreign income taxes payable attributable to this obligation was $5.7 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,		
	2020	**2019**	**2018**
Revenue from customer contracts:		*(in thousands)*	
Sales under the COSPA	**$ 67,041**	$ 86,554	$ 104,891
Gabonese government share of Profit Oil	**—**	—	2,193
U.S. crude oil and natural gas revenue	**—**	—	5
Other items reported in revenue not associated with customer contracts:			
Gabonese government share of Profit Oil taken in-kind	**8,738**	7,268	9,385
Carried interest recoupment	**1,631**	2,950	3,545
Royalties	**(10,234)**	(12,251)	(15,076)
Total revenue, net	**$ 67,176**	$ 84,521	$ 104,943

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, 2020, 2019, and 2018 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,		
	2020	**2019**	**2018**
		(in thousands)	
U.S. Federal:			
Current	**$ (337)**	$ (337)	$ (674)
Deferred	**11,814**	3,916	(15,910)
Foreign:			
Current	**3,859**	9,747	14,327
Deferred	**12,345**	10,564	(40,997)
Total	**$ 27,681**	$ 23,890	$ (43,254)

As of December 31, 2020 and 2019, the Company had deferred tax assets of $126.3 million and $108.8 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 than not that some or all of the deferred tax assets will be realized. The ultimate realization of the deferred tax assets is dependent upon the generation of future income in periods in which the deferred tax assets can be utilized. Numerous judgments and assumptions are inherent in this assessment, including the determination of future taxable income, future operating conditions (particularly as related to prevailing crude oil prices).

As of December 31, 2020, the Company determined it is more likely than not that it would not be able to utilize its deferred tax assets. As of December 31, 2019, the Company had anticipated it would not be able to fully utilize its deferred tax assets. On the basis of these evaluations, a valuation allowance of $126.3 million and $84.6 million were recorded as of December 31, 2020 and 2019, 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 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 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 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, 2020 and 2019 are as follows:

(in thousands)	As of December 31, 2020	As of December 31, 2019
Deferred tax assets:		
Basis difference in fixed assets	**$ 27,995**	$ 26,590
Foreign tax credit carryforward	**34,144**	34,144
Alternative minimum tax credit carryover	**—**	337
U.S. federal net operating losses	**32,579**	30,572
Foreign net operating losses	**24,602**	11,770
Asset retirement obligations	**3,640**	3,407
Operating leases	**1,472**	—
Basis difference in accrued liabilities	**368**	676
Basis difference in receivables	**331**	171
Other	**1,121**	1,120
Total deferred tax assets	**126,252**	108,787
Valuation allowance	**(126,252)**	(84,628)
Net deferred tax assets	**$ —**	$ 24,159

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 nor the utilization of NOLs and has recorded a full valuation allowance on both of 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, 2020 and 2019. 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:

(in thousands)	Year Ended December 31, 2020	2019	2018
U.S.	**$ (2,908)**	$ (13,330)	$ (5,672)
Foreign	**(17,494)**	34,372	61,146
	$ (20,402)	$ 21,042	$ 55,474

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:

(in thousands)	Year Ended December 31, 2020	2019	2018
Tax provision computed at U.S. statutory rate	**$ (4,284)**	$ 4,386	$ 11,650
Foreign taxes not offset in U.S. by foreign tax credits	**(9,801)**	16,015	24,840
Recognition of foreign deferred tax assets, net of U.S. impact	**—**	—	(45,751)
Unrealizable foreign deferred tax assets	**—**	—	24,176
Permanent differences	**97**	180	(104)
Foreign tax credit expirations	**—**	9,616	4,311
Increase/(decrease) in valuation allowance	**41,635**	(6,307)	(62,270)
Other	**34**	—	(106)
Total income tax expense (benefit)	**$ 27,681**	$ 23,890	$ (43,254)

For the years ended December 31, 2020, 2019 and 2018, 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.	2011-2020
Gabon	2016-2020

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,	
	2020	2019
	(in thousands)	
Crude oil and natural gas properties and equipment - successful efforts method:		
Wells, platforms and other production facilities	**$ 441,879**	$ 422,651
Work-in-progress	**169**	7,378
Undeveloped acreage	**21,476**	23,771
Equipment and other	**9,276**	11,157
	472,800	464,957
Accumulated depreciation, depletion, amortization and impairment	**(435,764)**	(396,699)
Net crude oil and natural gas properties, equipment and other	**$ 37,036**	$ 68,258

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 "Consortium") received an implementing Presidential Decree from the government of Gabon authorizing an extension for additional years ("PSC Extension") to the Consortium to operate in the Etame Marin block. As of December 31, 2020, the Company's subsidiary, VAALCO Gabon S.A., had 33.575% 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 Consortium the right for two additional extension periods of five years each. The PSC Extension further allows the 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 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 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 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 Consortium following the end of the drilling activities described below. The Company accrued the $1.7 million share of this remaining payment as of December 31, 2019 and the payment was made in February 2020. The amount paid through a reduction in VAT was recorded at $4.2 million, which represented the book value of the receivable, net of the valuation allowance as of the effective date. In addition, the Company recorded an increase of $18.6 million resulting from the deferred tax impact for the difference between book basis and tax basis. A corresponding $18.6 million deferred tax liability was recorded, which reduced the net deferred tax assets. The Company allocated the share of the signing bonus between proved and unproved leasehold costs using the acreage attributable to the previous exploitation areas and the additional acreage in the expanded exploitation areas resulting in $22.5 million being attributed to proved leasehold costs and $13.7 million attributed to unproved leasehold costs.

Under the PSC Extension, by September 16, 2020, the Consortium was required to drill two wells and two appraisal wellbores. The Consortium completed drilling one development well and one appraisal wellbore during the second half of 2019 and completed the remaining development well and appraisal wellbore during the first quarter 2020. The Consortium was also required to complete two technical studies by September 16, 2020. During September 2020, the 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 Consortium maintains a "Cost Account," which accumulates capital costs and operating expenses that are deductible against revenues, net of royalties, in determining taxable profits. Prior to the PSC Extension, the Consortium was entitled to take up to 70% of production remaining after the 13% royalty ("Cost Recovery Percentage") to recover its costs so long as there are amounts remaining in the Cost Account. 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%.

Prior to the PSC Extension, the PSC provided for the government of Gabon to take a 7.5% gross working interest carried by the Consortium. The government of Gabon transferred this interest to a third party. Pursuant to the PSC Extension, the government of Gabon will acquire from the Consortium an additional 2.5% gross working interest carried by the Consortium effective June 20, 2026. VAALCO's share of this interest to be transferred to the government of Gabon is 0.8%.

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.

During the three months ended March 31, 2020, declining forecasted oil prices caused the Company to perform an impairment review. 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, Avouma, Ebouri, Southeast Etame and North Tchibala fields were less than the book values for these fields resulting in the Company recording a $30.6 million impairment loss to write down the Company's investment in each field to their fair value of $15.6 million. There were no triggering events after the three months ended March 31, 2020 or in the year ended December 31, 2019 that would cause the Company to believe the value of crude oil and natural gas producing properties should be impaired.

Undeveloped Leasehold Costs

VAALCO acquired a 31% working interest in an undeveloped portion of a block ("Block P") offshore Equatorial Guinea in 2012. 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 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 Ministry of Mines and Hydrocarbons ("EG MMH"). VAALCO is seeking to farm down its interest in Block P in exchange for funding a substantial portion of an appraisal well. As of December 31, 2020, the Company had $10.0 million recorded for the book value of the undeveloped leasehold costs associated with the Block P license. VAALCO and its 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. 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, the exploitation area on 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 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.

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 year ended December 31, 2020, the Company recorded $0.9 million in adjustments for inventory obsolescence. Adjustments for inventory obsolescence were not material for the years ended December 31, 2019 and 2018.

10. DERIVATIVES AND FAIR VALUE

The Company uses derivative financial instruments 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 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.

While the 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 consolidated statements of operations:

		Year Ended December 31,		
Derivative Item	**Statement of Operations Line**	**2020**	**2019**	**2018**
			(in thousands)	
Crude oil swaps	Realized gain - contract settlements	**$ 7,216**	$ 2,439	$ 744
	Unrealized gain (loss)	**(639)**	(2,885)	3,520
	Derivative instruments gain (loss), net	$ **6,577**	$ (446)	$ 4,264

11. ASSET RETIREMENT OBLIGATIONS

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

	Year ended December 31,	
(in thousands)	**2020**	**2019**
Beginning balance	**$ 15,844**	$ 14,816
Accretion	**893**	812
Additions	**359**	595
Revisions	**238**	(379)
Ending balance	**$ 17,334**	$ 15,844

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

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 completed in November 2018. 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. In 2019, the Company recorded $0.6 million in additions associated with the Etame 9H and Etame 11H development wells. In December 2019, the Company recorded $0.4 million downward revision associated with the Mutamba Iroru block onshore Gabon.

12. COMMITMENTS AND CONTINGENCIES

FPSO charter

In connection with the FPSO charter, the Company, as operator of the Etame Marin block, guaranteed all of the lease payments under the FPSO charter through its contract term. At the Company's election, the charter may 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 joint venture owners for their respective shares of the payments. Although the Company believes the need for performance under the charter guarantee is remote, the Company recorded a liability of $0.4 million as of both December 31, 2020 and 2019 representing the guarantee's estimated fair value.

Estimated future minimum obligations as of December 31, 2020 through the end of the FPSO charter are as follows:

(in thousands)	**Full Charter Payment**	**VAALCO, Net**
Year		
2021	$ 32,988	$ 10,245
2022	23,769	7,382
Total	$ 56,757	$ 17,627

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 $13.1 million, $12.1 million and $10.8 million for the years ended December 31, 2020, 2019 and 2018, respectively.

Gabon domestic market obligation and other investment obligations

Under the terms of the Etame PSC the Consortium is required to provide to the local government refinery a volume of crude oil at a 15% discount to market price (the "Gabon DMO"). The volume required to be furnished is the amount of the Etame Marin block production divided by total Gabon production times the volume of crude oil refined by the refinery per year. In 2020, the Company paid $0.9 million for the share of the 2019 obligation. In 2019, the Company paid $1.2 million for the share of the 2018 obligation. In 2018, the Company paid $1.1 million for the share of the 2017 obligation. The Company accrues an amount for the Gabon DMO based on management's best estimate of the volume of crude oil required because the refinery does not publish throughput figures. The amount accrued at December 31, 2020, for the share of the 2020 obligation was $0.9 million. The amount accrued at December 31, 2019, for the share of the 2019 obligation was $1.1 million. These costs are cost recoverable under the terms of the Etame PSC. Also, the Consortium is required to pay an additional 1% of revenues for provisions for diversified investments ("PID") and for investments in hydrocarbons ("PIH"). The amount accrued at December 31, 2020, for the share of the 2020 obligation was $3.1 million. The amount accrued at December 31, 2019, for the share of the 2019 obligation was $2.2 million. 75% of PID and PIH costs are cost recoverable under the terms of the Etame PSC.

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. The amounts paid will be reimbursed through the Cost Account and are non-refundable. The abandonment estimate used for this purpose is approximately $61.8 million ($19.2 million, net to VAALCO) on an undiscounted basis. Through December 31, 2020, $40.2 million ($12.5 million, net to VAALCO) on an undiscounted basis has been funded. 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, 2020, the Company has recorded a $1.1 million foreign currency gain associated with the abandonment funding account. Amendment No. 5 to the Etame Marin block PSC provides that in the event that the Gabonese bank fails for any reasons to reimburse all of the principal and interest due, the Company and the other joint venture owners shall no longer be held liable for the resulting shortfall in funding the obligation to remediate the sites.

Regulatory and Joint Interest Audits

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

In 2016, the government of Gabon conducted an audit of the 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 response, there have been changes in the Gabonese officials responsible for the audit. The Company is working with the currently 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 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 July 2019, the Company reached an agreement in principle to resolve a legacy issue related to findings from Etame joint venture owners' audits for the periods from 2007 through 2016 for $4.4 million net to VAALCO. The agreement in principle also provides for procedures to minimize the chances of future audit claims. Accordingly, the Company recorded an expense in the consolidated statements of operations in the line item "Other operating income (expense), net". The final settlement agreements were executed by all the joint venture owners effective September 9, 2019. In October 2019, the Company paid $1.1 million of the $4.4 million. The balance of the amount due was paid in February 2020.

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.

Employment agreements

The Company's Chief Executive Officer has an employment agreement, which provides for payments of annual salary, incentive compensation and certain other benefits if their employment is terminated without cause.

13. LEASES

Under the new 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 rental of marine vessels and helicopters, warehouse and storage facilities, equipment and the FPSO. The duration for these agreements range from 21 to 35 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 other leases that contain an option to extend, the Company has concluded that it is not reasonably certain it will exercise the renewal option and the renewal periods have been excluded 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.

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, 2020 and 2019, the components of the lease costs and the supplemental information were as follows:

	Year Ended December 31,	
	2020	2019
Lease cost:	(in thousands)	
Operating lease cost	$ **17,528**	$ 16,428
Short-term lease cost	**1,408**	3,470
Variable lease cost	**7,572**	5,819
Total lease expense	**26,508**	25,717
Lease costs capitalized	**3,456**	3,653
Total lease costs	$ **29,964**	$ 29,370

Other information:		
Cash paid for amounts included in the measurement of lease liabilities:	2020	2019
Operating cash flows attributable to operating leases	$ 26,178	$ 19,229
Weighted-average remaining lease term	1.8 years	2.7 years
Weighted-average discount rate	6.09%	6.18%

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,	
	2020	2019
	(in thousands)	
Production expense	$ **7,904**	$ 7,859
General and administrative expense	**197**	196
Lease costs billed to the joint venture owners	**20,692**	20,181
Total lease expense	**28,793**	28,236
Lease costs capitalized	**1,171**	1,134
Total lease costs	$ **29,964**	$ 29,370

The following table describes the future maturities of the Company's operating lease liabilities at December 31, 2020:

	Lease Obligation
Year	(in thousands)
2021	$ 13,864
2022	9,685
2023	179
	23,728
Less: imputed interest	1,167
Total lease liabilities	$ 22,561

Under the joint operating agreements, other joint venture owners are obligated to fund $16.4 million of the $23.7 million in future lease liabilities as of December 31, 2020.

14. ACCRUED LIABILITIES AND OTHER

Accrued liabilities and other balances were comprised of the following:

	2020	2019
	(in thousands)	
Accrued accounts payable invoices	**$ 4,070**	$ 4,650
Joint venture audit settlement	**—**	3,322
Gabon DMO, PID and PIH obligations	**3,960**	3,314
Capital expenditures	**435**	11,792
Stock appreciation rights – current portion	**2,289**	2,638
Accrued wages and other compensation	**2,108**	1,731
Other	**4,322**	2,326
Total accrued liabilities and other	**$ 17,184**	$ 29,773

15. DEBT

On May 22, 2018, the Company terminated an amended term loan agreement the Company had with the International Finance Corporation (the "IFC") (the "Amended Term Loan Agreement") by prepaying the outstanding principal and accrued interest. The Company did not incur any termination or prepayment penalties as a result of the termination of the Amended Term Loan Agreement.

Interest

The table below shows the components of the "Interest income (expense), net" line item of the consolidated statements of operations and the average effective interest rate, excluding commitment fees, on the borrowings:

	Year Ended December 31,		
	2020	2019	2018
		(in thousands)	
Interest expense related to debt, including commitment fees	**$ —**	$ —	$ (257)
Deferred finance cost amortization	**—**	—	(191)
Interest income	**155**	733	270
Other interest expense not related to debt	**—**	—	33
Interest income (expense), net	**$ 155**	$ 733	$ (145)
Average effective interest rate, excluding commitment fees	**N/A**	N/A	7.09%

16. 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, 2020 or 2019.

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. Under the stock repurchase program, the Company repurchased shares through open market purchases, privately-negotiated transactions, block purchases or otherwise in accordance with applicable federal securities laws, including Rule 10b-18 of the "Exchange Act". The Board of Directors also authorized the Company to enter into written trading plans under Rule 10b5-1 of the Exchange Act.

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 on the date the restricted stock awards vest is net of shares withheld to meet applicable tax withholding requirements. 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 the Financial Statements as they reduce the number of shares that would have been issued upon vesting. See Note 17 for further discussion.

17. STOCK-BASED COMPENSATION AND OTHER BENEFIT PLANS

The stock-based compensation awards have been granted under several stock incentive and long-term incentive plans. The plans authorize the Compensation Committee of the Board of Directors to issue various types of incentive compensation. The Company had previously issued stock options and restricted shares from the 2014 Long-Term Incentive Plan ("2014 Plan") and SARs under the 2016 Stock Appreciation Rights Plan. On June 25, 2020, the Company's stockholders approved the 2020 Long-Term Incentive Plan ("2020 Plan") under which 5,500,000 shares are authorized for future grants. At December 31, 2020, 3,744,737 shares were available for future grants under this plan.

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 2014 Plan and 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 associated with the issuance of stock options, restricted stock, and SARs as general and administrative expense. During the years ended December 31, 2020, 2019 and 2018, the Company settled in cash $0.3 million, $0.5 million, and $0.1 million, respectively, for SARs. During the years ended December 31, 2020, 2019 and 2018, the Company received in cash $0.1 million, $0.3 million, and $0.5 million, respectively from stock option exercises. The Company computes a deferred tax benefit for restricted shares, SARs and stock options expected to generate future tax deductions by applying the U.S. federal statutory income tax rate. For restricted shares, the Company's actual tax deduction is based on the value of the shares at the time of vesting. The Company receives a tax deduction for certain stock option exercises during the period the stock option awards are exercised, generally for the excess of the market value on the exercise date over the exercise price of the stock option awards.

	Year Ended December 31,		
	2020	**2019**	**2018**
		(in thousands)	
Stock-based compensation - equity awards	**$ 848**	$ 985	$ 820
Stock-based compensation - liability awards	**(734)**	2,521	1,568
Total stock-based compensation	**$ 114**	$ 3,506	$ 2,388

Stock options and performance stock options

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 Board of Directors, which in the past has been a five-year life, with the options vesting over a service period of up to five years. In addition, stock options will become exercisable upon a change in control, unless provided otherwise by the Compensation Committee.

In June 2020, the Company granted options that are considered performance stock options to purchase an aggregate of 644,758 shares at an exercise price of $1.23 per share and a life of ten years to its employees. For each performance option award, options with respect to 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 $1.42 per share; 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 $1.63 per share; and 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 $1.88 per share. These awards are option awards that contain a market condition, which has been met. 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, 2020, the assumptions shown below were used to calculate the weighted average grant date fair value of performance stock option awards issued under the 2020 Plan.

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 vesting period of the option. During 2020, 2019 and 2018, the weighted average assumptions shown below were used to calculate the weighted average grant date fair value of option grants. Because the Company has not paid cash dividends historically, no expected dividend yield was input to the Black-Scholes model.

	Year Ended December 31,		
	2020	2019	2018
Weighted average exercise price - ($/share)	**$ 1.23**	$ 2.08	$ 1.05
Expected life in years	**6.0**	3.2	3.5
Average expected volatility	**74 %**	73 %	71 %
Risk-free interest rate	**0.42 %**	2.33 %	2.51 %
Weighted average grant date fair value - ($/share)	**$ 0.79**	$ 1.06	$ 0.68

Performance stock option activity for the year ended December 31, 2020 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, 2020	—	$ —		
Granted	644	1.23		
Exercised	—	—		
Unvested shares forfeited	—	—		
Vested shares expired	—	—		
Outstanding at December 31, 2020	644	1.23	9.49	$ 348
Exercisable at December 31, 2020	—	$ —	—	$ —

Stock option activity that do not contain a market or performance condition for the year ended December 31, 2020 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, 2020	2,834	$ 1.55		
Granted	—	—		
Exercised	(65)	0.96		
Unvested shares forfeited	(60)	1.83		
Vested shares expired	(904)	1.89		
Outstanding at December 31, 2020	1,804	1.38	1.94	$ 968
Exercisable at December 31, 2020	1,364	$ 1.20	1.63	$ 861

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 2020, 2019 and 2018 was $43 thousand, $0.3 million and $0.6 million, respectively.

As of December 31, 2020, unrecognized compensation cost related to outstanding stock options was $0.5 million, which is expected to be recognized over a weighted average period of 2.9 years.

Restricted shares

Restricted stock granted to employees will vest over a period determined by the Compensation Committee, which is generally a three-year period, vesting in three equal parts on the first three anniversaries following the date of the grant. In addition, restricted stock will vest upon a change in control, unless provided otherwise by the Compensation Committee of the Board of Directors. Share grants to directors vest immediately and are not restricted. The following is a summary of activity in unvested restricted stock in 2020.

	Restricted Stock	Weighted Average Grant Date Fair Value
	(in thousands)	
Non-vested shares outstanding at January 1, 2020	343	$ 1.52
Awards granted	971	1.23
Awards vested	(159)	(1.35)
Awards forfeited	—	—
Non-vested shares outstanding at December 31, 2020	1,155	$ 1.30

The total vest-date fair value of restricted stock awards, which vested during 2020, 2019 and 2018 was $0.2 million, $0.6 million, and $0.4 million, respectively. The weighted average grant date fair value per share of restricted stock awards, which vested during the applicable year, was $1.35, $2.00 and $1.71 for the years ended December 31, 2020, 2019 and 2018, respectively.

In June 2020, the Company issued 710,851 and 260,164 shares of service based restricted stock to employees and directors, respectively, with a grant date fair value of $1.23 per share. The vesting of these shares is dependent upon the employees' and directors' continued service with the Company.

As of December 31, 2020, unrecognized compensation cost related to restricted stock totaled $0.8 million and is expected to be recognized over a weighted average period of 1.4 years.

SARs

SARs are granted under the VAALCO Energy, Inc. 2016 Stock Appreciation Rights 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 price per share specified in a SAR award on the date of grant, (which may not be less than the fair market value of the common stock on the date of grant), and the fair market value per share 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 Board of Directors. In addition, SARs will become exercisable upon a change in control, unless provided otherwise by the Compensation Committee of the Board of Directors.

Total compensation expense related to the SARs awards during the year ended December 31, 2020 was $(0.7) million.

SAR activity for the year ended December 31, 2020 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, 2020	3,418	$ 1.30		
Granted	—	—		
Exercised	(357)	0.95		
Unvested SARs forfeited	(60)	1.83		
Vested SARs expired	(61)	1.34		
Outstanding at December 31, 2020	2,940	1.33	2.22	$ 1,688
Exercisable at December 31, 2020	1,758	$ 1.19	1.91	$ 1,144

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.

The Company sponsors a 401(k) plan, with a company match feature, for the employees. Costs incurred in the years ended December 31, 2020, 2019 and 2018 for the Company's matching contribution and for administering the plan were approximately $0.4 million, $0.4 million and $0.3 million, respectively.

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,		
	2020	**2019**	**2018**
Costs incurred during the year:		*(in thousands)*	
International:			
Exploration costs - capitalized	**$ 8,484** [(1)]	$ 2,952	$ —
Exploration costs - expensed	**3,588**	—	14
Acquisition of properties	**—**	—	36,239
Development costs	**731**	15,654	—
Total	**$ 12,803**	$ 18,606	$ 36,253

(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,	
	2020	**2019**
Capitalized costs:	*(in thousands)*	
Properties not being amortized	**$ 26,975**	$ 38,818
Properties being amortized [(1)]	**441,879**	422,651
Total capitalized costs	**$ 468,854**	$ 461,469
Less accumulated depletion, amortization and impairment	**(432,431)**	(393,800)
Net capitalized costs	**$ 36,423**	$ 67,669

(1) Includes $8.8 million of asset retirement costs in both 2020 and 2019. During 2020, the Company recorded $8.5 million in additions associated with the Southeast Etame 4P appraisal wellbore. During 2019, the Company recorded $0.6 million in additions associated with the Etame 9H and Etame 11H development wells at the Etame Marin field.

Results of Operations for Crude Oil and Natural Gas Producing Activities

	International			U.S.		
	Year Ended December 31,			Year Ended December 31,		
	2020	**2019**	**2018**	**2020**	**2019**	**2018**
			(in thousands)			
Crude oil and natural gas sales	**$ 67,176**	$ 84,521	$ 104,938	**$ —**	$ —	$ 5
Production costs and other expense [(1)]	**(38,176)**	(38,461)	(37,865)	**(5)**	(6)	(13)
Depreciation, depletion, amortization	**(9,028)**	(6,825)	(5,176)	**—**	—	(162)
Exploration expenses	**(3,588)**	—	(14)	**—**	—	—
Impairment of proved properties	**(30,625)**	—	—	**—**	—	—
Other operating expense	**(1,669)**	(4,457)	—	**—**	—	—
Bad debt recovery (expense)	**(1,165)**	341	77	**—**	—	—
Income tax benefit (expense)	**10,785**	(21,702)	(37,591)	**—**	—	36
Results from crude oil and natural gas producing activities	**$ (6,290)**	$ 13,417	$ 24,369	**$ (5)**	$ (6)	$ (134)

(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, 2018	3,049
Production	(1,369)
Extensions and discoveries	2,235
Revisions of previous estimates	1,455
Balance at December 31, 2018	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, 20120	**3,216**

Proved developed reserves:	**Oil (MBbls)**
Balance at January 1, 2018	3,049
Balance at December 31, 2018	3,388
Balance at December 31, 2019	4,966
Balance at December 31, 2020	3,216

The proved developed reserves are located offshore Gabon. 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. In 2019, the Company replaced 68% of production by adding 1.1 MMBbls of reserves through reservoir performance additions offset by downward revisions for lower average crude oil prices of 0.2 MMBbls.

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 field, 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, 2020, 2019 and 2018.

(In thousands)	International 2020	International 2019	International 2018
Future cash inflows	$ **138,328**	$ 319,693	$ 387,415
Future production costs	**(99,418)**	(193,626)	(228,999)
Future development costs [1]	**(10,605)**	(12,758)	(27,151)
Future income tax expense	**(13,921)**	(36,058)	(38,512)
Future net cash flows	**14,385**	77,251	92,753
Discount to present value at 10% annual rate	**348**	(6,820)	(12,697)
Standardized measure of discounted future net cash flows	$ **14,733**	$ 70,431	$ 80,056

(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, 2020	2019	2018
		(in thousands)	
Balance at beginning of period	$ **70,431**	$ 80,056	$ 22,490
Sales of crude oil and natural gas, net of production costs	**(29,878)**	(46,873)	(71,962)
Net changes in prices and production costs	**(53,388)**	(5,118)	55,468
Extensions and discoveries	**10,059**	—	—
Revisions of previous quantity estimates	**(10,885)**	28,921	33,344
Purchases	—	—	43,236
Changes in estimated future development costs	**1,195**	(4,033)	1,075
Development costs incurred during the period	**731**	7,185	763
Accretion of discount	**10,086**	11,175	4,530
Net change of income taxes	**17,636**	1,270	(8,889)
Change in production rates (timing) and other	**(1,254)**	(2,152)	1
Balance at end of period	$ **14,733**	$ 70,431	$ 80,056

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 2020, the average of such prices reflected a 33% decrease during the year and were $42.46 per Bbl for crude oil from Gabon when compared to the average of such prices for 2019 of $63.60 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 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, 2020, there was $50.9 million in the Cost Account, net to the Company's interest. As payment of corporate income taxes, the 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 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 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, 2020, the Company has no proved reserves related to Block P in Equatorial Guinea.

BOARD OF DIRECTORS

Andrew L. Fawthrop
Chairman of the Board

George Maxwell
Chief Executive Officer and Director

Bradley Radoff
Director

Cathy Stubbs
Director

CORPORATE OFFICERS

George Maxwell
Chief Executive Officer and Director

David A. DesAutels
Executive Vice President of Corporate Development

Thor Pruckl
Executive Vice President, International Operations

Michael G. Silver
Executive Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer

Jason J. Doornik
Chief Accounting Officer, Controller and Principal Financial Officer

Julie J. Ray
Vice President of Treasury

Annual Meeting

The Annual Meeting of Shareholders of VAALCO Energy, Inc. will be held at the Houston Marriott Westchase, 2900 Briarpark Drive, Houston, Texas 77042 on June 3, 2021 at 9:00 am central time.

Due to ongoing concerns regarding the evolving coronavirus situation, VAALCO may decide to hold the meeting in a different location or solely by means of remote communication (i.e., a virtual-only meeting). If that occurs, VAALCO will issue a press release announcing the decision and post additional information on its website at www.vaalco.com.

Stock Exchanges

The Company's Common Stock is listed on the New York Stock Exchange and the London Stock Exchange and traded under the symbol "EGY."

Investor Relations

Requests for additional information or copies of the Company's Form 10-K filed with the Securities and Exchange Commission should be directed to:

VAALCO Energy, Inc.
Investor Relations
9800 Richmond Avenue
Suite 700
Houston, Texas 77042

Company Website

Information related to Company activities, financials and SEC filings is available at the Company website www.VAALCO.com

Transfer Agent

Communications concerning common stock transfer requirements, lost certificates or changes of address should be directed to:

Computershare
462 South 4th Street, Suite 1600
Louisville, KY 40202
1-800-736-3001 (US, Canada, Puerto Rico)
1-781-575-3100 (Non-US)

Independent Auditors

BDO USA, LLP
Houston, Texas

Corporate Office

9800 Richmond Avenue
Suite 700
Houston, Texas 77042

Branch Offices

VAALCO Gabon S.A.
B.P. 1335
Port-Gentil, Gabon

VAALCO Energy, Inc. has included, as Exhibits 31 and 32 to its 2020 Annual Report on Form 10-K filed with the Securities and Exchange Commission, certificates of the Chief Executive Officer and Principal Financial Officer of the Corporation regarding the quality of the Corporation's public disclosure. The Corporation has also submitted to the New York Stock Exchange (NYSE) a certification of the CEO certifying that he is not aware of any violation by the Corporation of NYSE corporate governance listing standards.

VAALCO ENERGY, INC.

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