ISRAMCO INC
Form 10-K
March 18, 2019

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, 2018

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

COMMISSION FILE NUMBER: 0-12500

ISRAMCO, INC.

(Exact name of registrant as specified in its charter)

Delaware	**13-3145265**
(State or Other Jurisdiction of Incorporation)	(IRS Employer Identification No.)

1001 West Loop South, Suite 750, Houston Texas 77027

(Address of Principal Executive Offices)

713-621-6785

(Registrant's Telephone Number, including Area Code)

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

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

Common Stock, par value $0.01

(Title of Class)

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 15(d) of the Act. Yes No

Indicate by check mark whether the issuer (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the past 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 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 if disclosure of delinquent filers in response to Item 405 of Regulation S-K is not contained in this Form, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or 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 is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act). Yes No

As of March 18, 2019, there were 2,717,648 shares of the Registrant's common stock par value $0.01 per share ("Common Stock") outstanding. The aggregate market value of the Common Stock held by non-affiliates of the Registrant at March 14, 2019, based on the last sale price of such equity reported on Nasdaq Market, was approximately $77.72 million.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Proxy Statement for its 2018 Annual Meeting of Stockholders to be filed not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K are incorporated by reference into Part III of this Form 10-K.

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ISRAMCO, INC.

2018 FORM 10-K ANNUAL REPORT

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Special note regarding forward-looking statements

This report on Form 10-K contains forward-looking statements within the meaning of the federal securities laws. All statements, other than statements of historical facts, concerning, among other things, planned capital expenditures, potential increases in oil and natural gas production, the number of anticipated wells to be drilled in the future, future cash flows and borrowings, pursuit of potential acquisition opportunities, our financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. These forward-looking statements are identified by their use of terms and phrases such as "may," "expect," "estimate," "project," "plan," "believe," "intend," "achiev "anticipate," "will," "continue," "potential," "should," "could" and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. The actual results could differ materially from those anticipated in these forward-looking statements. One should consider carefully the statements under the "Risk Factors" section of this report and other sections of this report that describe factors that could cause our actual results to differ from those set forth in the forward-looking statements, including, but not limited to, the following factors:

the timing and extent of changes in prices for, and demand for, crude oil and condensate, NGLs, natural gas and related commodities;

the possibility that the industry may be subject to future regulatory or legislative actions (including any additional taxes and changes in environmental regulation);

the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs;

the possibility that production decline rates for some of our oil and gas producing properties are greater than we expect;

our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fully develop our undeveloped acreage positions;

the ability to replace oil and natural gas reserves;

our ability to retain skilled operations personnel whom we would need in the event of an upturn in the demand for our services;

environmental risks;

drilling and operating risks;

the loss of one or more of our larger customers;

our ability to implement price increases or maintain pricing on our core services;

exploration and development risks;

competition, including competition for acreage in oil and gas producing areas and for experienced personnel;

management’s ability to execute our plans to meet our goals;

technological advances affecting energy consumption and energy supply;

the collectability of our receivables;

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- our ability to retain key members of senior management and key technical employees;
- industry capacity;
- employee turnover and our ability to replace or add qualified workers;
- severe weather impacts on our business;
- operating risks and the possibility that our insurance may not be adequate to cover all of our losses or liabilities;
- our ability to repay our debt when due;
- changes in domestic and global economic and business conditions that impact the demand for oil, natural gas liquids and natural gas;
- changes in domestic and global supplies of oil, natural gas and natural gas liquids arising from economic and business conditions (including actions by the Organization of the Petroleum Exporting Countries);
- our ability to obtain goods and services, such as drilling rigs and tubulars, and access to adequate gathering systems and pipeline take-away capacity, to execute our drilling and development programs;
- general economic and regulatory conditions, whether internationally, nationally, or in the regional and local market areas in which we do business, may be less favorable than expected; and
- other economic, competitive, governmental, legislative, regulatory, geopolitical and technological factors that may negatively impact our business, operations or commodity prices.

Finally, our future results will depend upon various other risks and uncertainties, including, but not limited to, those detailed in the section entitled “Risk Factors” included in this report. All forward-looking statements are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this document. Other than as required under the securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

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PART I

ITEM 1. BUSINESS

Overview

Isramco, Inc., (NASDAQ: ISRL) is a Delaware corporation incorporated in 1982 (hereinafter, "we", the "Company" or "Isramco"). The Company together with its subsidiaries is an independent oil and natural gas company, engaged in the exploration, development and production of predominately oil and natural gas properties located onshore in the United States and offshore Israel. The Company also operates a production services company that provides a full range of onshore production services to oil companies and independent oil and natural gas production companies conducting operations in the United States.

We currently conduct our operations through two operating segments: our Exploration, Development and Production Segment and our Production Services Segment. The following is a description of these two operating segments. Financial information about our operating segments is included in Note 11, "Segment Information", of the Notes to Consolidated Financial Statements, included in Part II, Item 8, *Financial Statements and Supplemental Data*, of this Annual Report on Form 10-K.

Exploration, Development and Production Segment

At December 31, 2018, our estimated total proved oil, natural gas reserves and natural gas liquids, as prepared by our independent reserve engineering firms, Netherland, Sewell & Associates, Inc. and Cawley, Gillespie & Associates, Inc., were approximately 40,267 thousand barrels of oil equivalent ("MBOE"), consisting of 2,125 thousand barrels (MBbls) of oil, 223,915 million cubic feet (MMcf) of natural gas and 823 thousand barrels (MBbls) of natural gas liquids. Approximately 67.2% of our proved reserves were classified as proved developed (See Note 14, "Supplemental Oil and Gas Information"). Full year 2018 production averaged 3.75 MBOE/d compared to 3.78 MBOE/d in 2017. Tamar Field production share amounted to 2.57 MBOE/d out of total 3.75 MBOE/d compared to 2.46 MBOE/d in 2017.

United States

We, through our wholly-owned subsidiaries, are involved in oil and gas exploration, including the development, production and operation of wells in the United States. We own varying working interests in oil and gas wells in Louisiana, Texas, New Mexico, Oklahoma, Wyoming, Utah and Colorado and currently serve as operator of approximately 422 producing wells located mainly in Texas and in New Mexico.

Israel

In 2007, we closed our branch in Israel in order to focus on our expanding presence in the United States. Despite the closure of that branch we retained certain overriding royalties in three oil and gas licenses located offshore Israel. These licenses granted by the government of Israel are known as the “Michal”, “Matan” and “Shimshon” Licenses.

In 2009, two natural gas discoveries, known as “Tamar” and “Dalit”, were made within the area covered by the Michal and Matan Licenses, respectively. In December 2009, the Israeli Petroleum Commissioner granted Noble Energy, Inc. (“Noble”) and its partners, (the “Tamar Consortium”), two leases (the “Tamar Lease” and the “Dalit Lease”). The Leases are scheduled to expire in December 2038 and cover the Tamar and Dalit gas fields (collectively the “Tamar Field”). The Tamar Field is approximately 95 kilometers off the coast of the Israel, in the Israel exclusive economic zone of the Eastern Mediterranean, with a water depth of approximately 1,700 meters.

We own all ownership units in Tamar Royalties LLC, a Delaware limited liability company. Tamar Royalties LLC owns an overriding royalty interest of 1.5375% before payout which escalates to 2.7375% after payout in the Tamar Field (collectively the “Tamar Royalty”). An overriding royalty interest is an ownership interest in the oil and gas leasehold estate equating to a certain percentage of production or production revenues, calculated free of the costs of production and development of the underlying lease(s), but subject to its proportionate share of certain post production costs. An overriding royalty interest is a non-possessory interest in the oil and gas leasehold estate and, accordingly, we have no control over the operations, drilling, expenses, timing, production, sales, or any other aspect of development or production of the Tamar Field.

Production from the Tamar Field commenced in March 2013. The Tamar Field is now operational and delivering natural gas to Israel. The natural gas flows from the Tamar Field through the world’s longest subsea tieback, more than 90 miles to the Tamar platform, and then to the Ashdod onshore terminal (AOT).

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With regard to the payout of the Tamar Field, a disagreement between the Company and Isramco Negev 2 Limited Partnership has emerged as to what costs should be included in the calculation of payout. In addition to actual costs for the development of the Tamar Field, Isramco, Negev 2 Limited Partnership has asserted that the following costs should be included in the calculation of payout: (i) Isramco Negev 2 Limited Partnership's financing costs; (ii) the general and administrative expenses of Isramco Negev 2 Limited Partnership; (iii) the expected decommissioning costs of the Tamar Field; and (iv) expected future payments to be made in respect of the "Sheshinsky Levy" under Israeli law. In addition to the claim asserted by Isramco Negev 2 Limited Partnership, the Company has asserted counterclaims related to Isramco Negev 2 Limited Partnership's inclusion into the payout calculation of its expenses related to gathering and transportation infrastructure. The disagreements primarily stem from the fact that the agreements governing the creation of the Tamar Royalty were formulated in the 1980s and do not have a clear and unequivocal definition as to what costs should be included in the payout calculation. At the time of initiating arbitration, the Company believed that the total scope of the claim was approximately forty-five million dollars ($45,000,000); however, this amount increases each month based on Isramco Negev 2 Limited Partnership's failure to pay the increased, post-payout overriding royalty to the Company. In addition, certain claims asserted by the Company related to post production costs and pipeline infrastructure have not been quantified. Under the terms of the agreements creating the Tamar Royalty, the dispute is subject to arbitration in Israel. The Company believes that the claims of Isramco Negev 2 Limited Partnership are erroneous and contrary to generally accepted industry practice. The Company expects that the matter will be favorably resolved through this arbitration process; however, the Company cannot be assured of a favorable result in this arbitration process.

The Tamar Consortium currently sells natural gas from the Tamar Field to the Israel Electric Corporation ("IEC") and numerous other Israeli purchasers, including independent power producers, cogeneration facilities, local distribution companies and certain industrial companies. Currently, many of the Tamar Consortium's gas purchase and sale agreements provide for sales at a 7 to 15 year term, while some contracts have extension options of up to 2 years. Depending on the specific contract, prices may vary and are based on an initial base price subject to price adjustment provisions, including price indexation and a price floor. The IEC contract provides for price reopeners (sometimes referred to as "price review" clauses) in the eighth and eleventh years of the contract, subject to limits on the amount of increase or decrease from the existing contractual price.

During year ended December 31, 2018, net sales from the Tamar Field attributable to the Company amounted to 5,591,000 Mcf of natural gas and 7,335 Bbl of condensate with prices of $5.49 per Mcf and $62.95 per Bbl of condensate. Total revenues net of marketing and transportation expenses were $31,036,000. The Israeli Tax Authority withheld $7,138,000 of this revenue.

During year ended December 31, 2017, net sales from the Tamar Field attributable to the Company amounted to 5,343,000 Mcf of natural gas and 6,990 Bbl of condensate with prices of $5.35 per Mcf and $47.46 per Bbl of condensate. Total revenues net of marketing and transportation expenses were $28,781,000. The Israeli Tax Authority withheld $6,907,000 of this revenue.

During year ended December 31, 2016, net sales from the Tamar Field attributable to the Company amounted to 5,102,000 Mcf of natural gas and 6,882 Bbl of condensate with prices of $5.34 per Mcf and $37.48 per Bbl of condensate. Total revenues net of marketing and transportation expenses were $27,462,000. The Israeli Tax Authority withheld $6,866,000 of this revenue.

We have a third party reserve report from independent petroleum engineers, Netherland, Sewell & Associates, Inc. dated March 11, 2019 estimating reserves allocable to the Tamar Royalty as of December 31, 2018 (the "Tamar Reserve Report"). This reserve report estimates that by reason of the Company's ownership of the Tamar Royalty, we have proven reserves estimated at 213.5 million cubic feet of natural gas and 278 thousand barrels of natural gas liquids. The Tamar Reserve Report indicates the undiscounted estimated future net revenue (after deduction of estimated production, ad valorem taxes and levy but before estimated income tax) for such reserves (paid out over time) to be $703.9 million. The Tamar Reserve Report estimates the net present worth of such reserves, discounted at 10% annual discount rate factor, at $321.9 million (See Note 14 to our consolidated financial statements, "Supplemental Oil and Gas Information"). The gas price used to value the reserves in the Tamar Reserve Report is calculated in accordance with SEC rules based on the unweighted arithmetic price for each month within the 12-month period prior to December 31, 2018. The report indicates that there are no commercial oil deposits included as reserves.

The amount of proceeds we receive from the Tamar Royalty is contingent on a variety of factors including the timing of production and the price received. In the event of payout, the Tamar Royalty increases. Payout is the point when all the costs of leasing, drilling, producing and operating the leases have been recovered from lease production proceeds, as defined in the royalty agreements under which we acquired our interest.

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As we do not control any of the factors affecting our rights to payments (time of production, price received, costs incurred) and as a result of the other risk factors as set forth below in "Risk Factors," we cannot determine the amounts or timing of any payments we will receive or when payout is likely to occur, if ever. As discussed above, the determination of the occurrence of payout with respect to the Tamar Royalty is currently the subject of a disagreement with Isramco Negev 2 Limited Partnership. The Company believes that the disagreement will be resolved through a forthcoming arbitration process with Isramco Negev 2 Limited Partnership. Based on the reserves and anticipated production, the income from the Tamar Royalty is currently expected to be very significant to the Company for the foreseeable future.

Commercial production of the Tamar Field reserves is subject to numerous risks, including all of the typical risks associated with offshore oil and gas production. Commercial production of such reserves is also subject to additional risks that may be unique to the Tamar Field. These include:

There has been no previous large-scale production of natural gas from offshore Israel. Therefore, there may be geological, geophysical, or other unforeseen problems unique to offshore Israel that could affect production. In addition, because of the lack of comparable production history for this part of offshore Israel, the length of time that large scale production from offshore Israel can be sustained is uncertain.

There has been significant political upheaval and unrest in the Middle East, particularly in Syria. In addition, there is considerable hostility between Israel and other countries in the region. Accordingly, there is significant risk that production from the Tamar Field may be delayed, diminished, or prevented by virtue of war, acts of terrorism, or other similar or dissimilar events of force majeure.

The market for natural gas in Israel exists, but the financial ability of customers of the Tamar Consortium to take and pay for material amounts of such natural gas remains unclear. It is uncertain that existing customers and markets are capable of buying all of the anticipated production from the Tamar Field.

The Israel Antitrust Authority continues to monitor the Israeli natural gas market, including Noble and the Tamar Consortium, and could impose additional regulations or requirements on the Noble or the Tamar Consortium which could include a requirement to divest of some or all of their ownership or require all or any of them to separately market their proportionate share of production.

As noted above, the Company owns an interest in the Shimshon license located offshore Israel. In April of 2012, a well was drilled in the area covered by the Shimshon license, which has been recognized as a commercial discovery by the Israeli government. The Shimshon partners submitted an application to convert the Shimshon license to a lease. Terms of the lease are in discussion with the Israeli government's Ministry of Energy and Water Resources.

Production Services Segment

The Company began production services operations in September 2011. Our production servicing rig and truck fleet provides a range of production services, including the completion of newly-drilled wells, maintenance and workover of existing wells, fluid transportation, related oilfield services and plugging and abandonment of wells at the end of their useful lives to a diverse group of oil and gas exploration and production companies.

Completion Services. Newly drilled wells require completion services to prepare the well for production. Production servicing rigs are frequently used to complete newly drilled wells to minimize the use of higher cost drilling rigs in the completion process. The completion process may involve selectively perforating the well casing in the productive zones to allow oil or gas to flow into the well bore, stimulating and testing these zones, and installing the production string and other downhole equipment. The completion process typically ranges from a few days to several weeks, depending on the nature and type of the completion, and generally requires additional auxiliary equipment in addition to a production services rigs. The demand for completion services is directly related to drilling activity levels, which are sensitive to fluctuations in oil and gas prices.

Well-servicing/Maintenance Services. We provide maintenance services on the mechanical apparatus used to pump or lift oil from producing wells. These services include, among other activities, repairing and replacing pumps, sucker rods and tubing. We provide the rigs, equipment and crews for these tasks, which are performed on both oil and natural gas wells, but which are more commonly required on oil wells. Maintenance services typically take less than 48 hours to complete. Rigs generally are provided to customers on a call-out basis.

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Workover Services. Producing oil and natural gas wells occasionally require major repairs or modifications, called “workovers.” Workovers may be required to remedy failures, modify well depth and formation penetration to capture hydrocarbons from alternative formations, clean out and recomplete a well when production has declined, repair leaks or convert a depleted well to an injection well for secondary or enhanced recovery projects. Workovers normally are carried out with pumps and tanks for drilling fluids, blowout preventers, and other specialized equipment for servicing rigs. A workover may last anywhere from a few days to several weeks.

Fluid Services. At December 31, 2018, we owned and operated 35 fluid service trucks equipped with an average fluid hauling capacity of up to 130 barrels a piece. Each fluid service truck is equipped to pump fluids from or into wells, pits, tanks and other storage facilities. The majority of our fluid service trucks are also used to transport water to fill frac tanks on well locations, to transport produced salt water to disposal wells, and to transport drilling and completion fluids to and from well locations.

Plugging Services. Production servicing rigs are also used in the process of permanently closing oil and gas wells no longer capable of producing in economic quantities. Many well operators bid this work on a “turnkey” basis, requiring the service company to perform the entire job, including the sale or disposal of equipment salvaged from the well as part of the compensation received, and complying with state regulatory requirements. Plugging and abandonment work can provide favorable operating margins and is less sensitive to oil and gas pricing than drilling and workover activity since well operators must plug a well in accordance with state regulations when it is no longer productive. We perform plugging and abandonment work throughout our core areas of operation in conjunction with equipment provided by us or by other service companies.

We typically bill clients for our production servicing on an hourly basis for the period that the rig is actively working. As of December 31, 2018, our fleet of production servicing rigs totaled 33 rigs, which we operate through 5 locations in Texas and New Mexico. Our fleet is capable of working at depths from 14,000 to 25,000 feet, and as of December 31, 2018, our fleet consists of one 600 series rig, twenty-eight 550 series rigs, and four 300 series rigs.

Derivative Instruments and Hedging Activities

From time to time we utilize derivative contracts to hedge against the variability in cash flows associated with interest rate risk and/or the forecasted sale of our anticipated future oil and natural gas production. We may hedge a substantial, but varying, portion of our anticipated oil and natural gas production current and subsequent. We do not use derivative instruments for trading purposes. We have elected not to apply hedge accounting to derivative contracts, which would potentially allow us to not record the change in fair value of our derivative contracts in the consolidated statements of operations. We carry our derivatives at fair value on our consolidated balance sheets, with the changes in the fair value included in our consolidated statements of operations in the period in which the change occurs.

On June 16, 2015, Tamar Royalties LLC (“Tamar Royalties”), a wholly owned subsidiary of the Company, engaged in an interest rate swap agreement (“IRS Agreement”) with the Deutsche Bank AG London Branch (“DBAG”). An interest rate swap is an agreement between two parties (known as counterparties) where one stream of future interest payments is exchanged for another based on a specified notional principal amount. Interest rate swaps often exchange fixed interest payments for floating interest payments that are linked to interest rates.

As previously disclosed on the Company’s Form 8-K filed May 22, 2015, Tamar Royalties entered into a $120,000,000 credit facility with Deutsche Bank, which facility is discussed further in Note 6 “Long-Term Debt and Interest Expense” to the Company’s consolidated financial statements. Under the terms of this facility, Tamar Royalties, is required to hedge at least seventy-five percent (75%) of the outstanding balance under this facility against fluctuations in LIBOR, with at least thirty-seven and one-half percent (37.5%) of the outstanding balance being hedged through swaps. The notional value of these hedges corresponds to the amortization schedule covering the facility and previously disclosed in the aforementioned Form 8-K. Accordingly, on June 16, 2015, Tamar Royalties and DBAG entered into the IRS Agreement whereby the Company hedged $119,250,000 of the $120,000,000 initial borrowing as follows:

(a) Tamar Royalties hedged 37.5% of the perpetual outstanding balance under the facility, being an initial notional amount of $45,000,000, with a fixed rate swap whereby the Company will pay DBAG a fixed interest rate of 4.63%, and DBAG will pay the Company a monthly floating interest rate of USD-LIBOR-BBA plus a spread of 2.75%.

(b) Tamar Royalties hedged the remaining 62.5% of the perpetual outstanding balance less $750,000, being an initial notional amount of $74,250,000, against fluctuations in LIBOR by capping the fluctuations in LIBOR at 1.50%. Pursuant to the IRS Agreement, the Company will pay DBAG a fixed interest rate of 0.91%, and DBAG will pay the Company the greater of (i) USD-LIBOR-BBA minus a cap strike of 1.5% and (ii) zero.

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Competitive Conditions in the Business

The oil and natural gas industry is highly competitive and we compete with many other companies that have greater financial and other resources. Many of these companies explore for, produce and market oil and natural gas, as well as carry on refining operations and market the resultant products on a worldwide basis. There are also many production services companies that compete for the same customers as we compete. The primary areas in which we encounter substantial competition are in locating and acquiring attractive producing oil and natural gas properties, obtaining purchasers and transporters of the oil and natural gas we produce and hiring and retaining key employees during active times in the oil and gas industry. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the government of the United States and in some instances individual states where we operate. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation.

Our production services customers include major oil companies and mid-range independent oil and natural gas production companies. The markets in which we operate are highly competitive. Competition is influenced by such factors as price, capacity, availability of work crews, and reputation and experience of the service provider. We believe that an important competitive factor in establishing and maintaining long-term customer relationships is having an experienced, skilled and well-trained work force. We believe many of our large customers place increased emphasis on the safety, performance and quality of the crews, equipment and services provided by their contractors. Although we believe customers consider all of these factors, price is often the primary factor in determining which service provider is awarded the work. However, in several instances, we have secured and maintained work for large customers for which efficiency, safety, technology, size of fleet, and availability of other services are of equal importance to price.

Markets and Major Customers

Through our wholly-owned subsidiary, we operate a substantial portion of our domestic oil and natural gas properties. As the operator of a property, the Company makes full payment of the costs associated with each property and seeks reimbursement from the other working interest owners in the property for their share of those costs. Our joint interest partners consist primarily of independent oil and natural gas producers. If the oil and natural gas exploration and production industry in general were adversely affected, the ability of the Company's joint interest partners to reimburse the Company could be adversely affected.

The purchasers of the Company's United States based oil and natural gas production consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. During the year ended December 31, 2018 no purchaser, marketer, or major oil and gas or pipeline company accounted for 10% or more of our consolidated revenues. The Company has not experienced any significant losses from uncollectible accounts as to its sales of oil and gas production. The Company does not believe the loss of any one of its purchasers would materially affect the Company's ability to sell the oil and natural gas it produces. The Company believes other purchasers are available in the Company's areas of operations.

The Company's overriding royalty interest in the Tamar field is paid monthly by Isramco Negev 2 Limited Partnership, a related party. During the twelve months ended December 31, 2018 income from this source accounted for 38% of the Company's consolidated revenues. If Isramco Negev 2 Limited Partnership were to stop receiving revenue from its working interest in the Tamar Field, we would not receive revenue from our overriding royalty interest (the Tamar Royalty). Loss of payments from this source would cause significant financial consequences to the Company.

Our production service subsidiary customers include major oil and natural gas production companies and independent oil and natural gas production companies. We perform credit evaluations of our customers and usually do not require collateral. We maintain reserves for potential credit losses when necessary. During the twelve months ended December 31, 2018, no one individual customer accounted for 10% or more of consolidated revenues. The Company believes the loss of one or more customers of our production service subsidiary would not have a significant effect on this Segment because the Company believes that it can employ its rigs with other existing customers or new customers to the extent it has in the past in such circumstances.

Seasonality of Business

Weather conditions affect the demand for, and prices of, natural gas and can disrupt our overall business plans. Demand for natural gas is typically higher in the fourth and first quarters resulting in higher natural gas prices. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis.

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Operational Risks

Oil and natural gas exploration and development involves a high degree of risk that even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that we will discover or acquire additional oil and natural gas in commercial quantities. Oil and natural gas operations also involve the risk that well fires, blowouts, equipment failure, human error and other circumstances may cause accidental leakage of toxic or hazardous materials, such as petroleum liquids or drilling fluids, into the environment, or cause significant injury to persons or property. Such hazards may also cause damage to or destruction of wells, producing formations, production facilities and pipeline or other processing facilities. In such event, substantial liabilities to third parties or governmental entities may be incurred, the satisfaction of which could substantially reduce available cash and possibly result in loss of oil and natural gas properties.

We carry insurance against such hazards. However, as is common in the oil and natural gas industry, we do not insure fully against all risks associated with our business, either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position and results of operations. For further discussion on risks, see Item 1A. Risk Factors.

Regulations

We do not have any offshore operations in the United States. However, all of the jurisdictions in which we own or operate oil and natural gas properties regulate exploration for and production of oil and natural gas. These laws and regulations include provisions requiring permits to drill wells and requirements that we obtain and maintain a bond or other security as a condition to drilling or operating wells. Regulations also specify the permitted location of and method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the sourcing and disposal of water used in the drilling and completion process, and the plugging and abandonment of wells.

Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in a given area, and the unitization or pooling of oil and natural gas properties, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the establishment of maximum allowable rates of production from fields and individual wells. The effect of these regulations may limit the amount of oil and natural gas that we can produce from our wells and limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability.

Each state in which we operate also imposes some form of production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. We are liable for paying this tax on our production, and are also liable for various real and personal property taxes on our leases and facilities.

Environmental and Occupational Health and Safety Regulations

The oil and gas industry in the United States is subject to stringent federal, state and local laws regulating the discharge of materials into the environment or otherwise relating to health and safety or the protection of the environment. Many governmental agencies, such as the United States Environmental Protection Agency (the "EPA") have issued lengthy and comprehensive regulations to implement and enforce these laws. These laws and regulations often require difficult and costly compliance measures. Failure to comply with these laws and regulations may result in the assessment of substantial administrative, civil and criminal penalties, as well as the issuance of injunctions limiting or prohibiting our activities.

In addition, some laws and regulations relating to protection of the environment may, in certain circumstances, impose strict liability for environmental contamination, rendering a person liable for environmental damages and cleanup costs without regard to negligence or fault on the part of that person. We endeavor to fully comply with these regulatory requirements; however, compliance increases our costs and consequently affects our profitability.

As a part of the overall environmental regulatory policy, the permitting, construction and operations of certain oil and gas facilities are regulated. Many factors, including public perception, can materially impact the ability to secure an environmental construction or operation permit. Once operational, enforcement measures can include significant civil penalties for regulatory violations, regardless of intent. Under appropriate circumstances, an administrative agency can issue a cease and desist order to require termination of operations.

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Environmental regulation is becoming more comprehensive and additional programs, as well as increased obligations under existing programs, are anticipated. In this regard, we expect additional regulation of naturally occurring radioactive materials, oil and natural gas exploration and production operations, waste management, and underground injection of water and waste material. The adoption of additional regulations could have a material adverse effect on our financial condition and results of operations. Environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements could have a material adverse effect on our financial condition and results of operations.

Compliance with environmental laws and regulations increases the Company’s overall cost of business, but has not had, to date, a material adverse effect on its operations, financial condition or results of operations. It is not anticipated, based on current laws and regulations, that Isramco will be required in the near future to expend amounts (whether for environmental control facilities or otherwise) that are material in relation to its total exploration and development expenditure program in order to comply with such laws and regulations. However, given that such laws and regulations are subject to change, Isramco is unable to predict the ultimate cost of compliance or the ultimate effect on its operations, financial condition and results of operations.

Comprehensive Environmental Response, Compensation and Liability Act and Hazardous Substances

In 1980, the United States Congress enacted the federal Comprehensive Environmental Response, Compensation and Liability Act, referred to as CERCLA or the Superfund law. This law, which has been amended since enactment, and comparable state laws impose strict liability, without regard to fault, on certain classes of persons that are considered to be responsible for the release of what are considered to be “hazardous substances” into the environment. These persons include the current or former owners or operators of the sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances released at the site. Under CERCLA, we may be subject to joint and several liability for the costs of investigating and cleaning up hazardous substances that have been released into the environment whether or not we are responsible for the release or even owned an interest in the site at the time of the release, as well as for damages to natural resources and for the costs of health studies. In addition, companies that incur liability frequently confront additional claims because it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment in addition to a CERCLA claim.

The Solid Waste Disposal Act and Waste Management

The federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, referred to as RCRA, regulates the disposal of solid waste but generally excludes most wastes generated by the exploration and production of oil and natural gas, such as drilling fluids, produced waters and other wastes associated with the exploration, development or production of oil and natural gas from regulation as hazardous wastes. However, these wastes may be regulated by the EPA or state agencies as non-hazardous wastes as long as these wastes are not commingled with regulated hazardous wastes. Moreover, in the ordinary course of our operations, other wastes generated in connection with our exploration and production activities may be regulated as hazardous waste under RCRA or hazardous substances under CERCLA. From time to time, releases of materials or wastes have occurred at locations we own or at which we have operations. These properties and the materials or wastes released thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we have been and may be required to remove or remediate these materials or wastes. At this time, it is not possible to estimate the potential liabilities to which we may be subject from unknown, latent liability risks with respect to any properties where materials or wastes may have been released, but of which we have not been made aware.

The Clean Water Act, wastewater and storm water discharges

The oil and gas industry, generally, and our operations specifically, are also subject to the federal Clean Water Act and analogous state laws. Under the Clean Water Act, the EPA has adopted regulations concerning discharges of storm water runoff. This program requires covered facilities to obtain individual permits, or seek coverage under a general permit. Some of our properties may require permits for discharges of storm water runoff and, as part of our overall evaluation of our current operations, we may apply for storm water discharge permit coverage and updating storm water discharge management practices at some of our facilities. We believe that we will be able to obtain, or be included under, these permits, where necessary, and be required make only minor modifications to existing facilities and operations that we believe would not have a material effect on us. The Clean Water Act and similar state acts regulate other discharges of wastewater, oil, and other pollutants to surface water bodies, such as lakes, rivers, wetlands, and streams. Failure to obtain permits for such discharges could result in civil and criminal penalties, orders to cease such discharges, and costs to remediate and pay natural resources damages.

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These laws also require the preparation and implementation of Spill Prevention, Control, and Countermeasure Plans in connection with on-site storage of significant quantities of oil. More specifically, we are required to develop and maintain a plan applicable to each of our properties at which any significant volume of crude oil or other substance is stored and to ensure the site has sufficient protections (such as berms, etc.) to ensure that any spill will be contained and not reach navigable waters.

The Safe Drinking Water Act, groundwater protection, and the Underground Injection Control Program

The federal Safe Drinking Water Act (SWDA), the Underground Injection Control (UIC) program promulgated under the SWDA and state programs all regulate the drilling and operation of salt water disposal wells. EPA directly administers the UIC program in some states and in others the responsibility for the program has been delegated to the state. This program requires that a permit be obtained before drilling salt water disposal well. Monitoring the integrity of well casing must also be conducted periodically to ensure the casing is not leaking saltwater to groundwater. Violation of these regulations and/or contamination of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs, among other sanctions and liabilities under the SWDA and state laws. In addition, third party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury.

We have engaged in limited hydraulic fracturing or other well stimulation services on the wells for which we are the operator by engaging third parties to conduct these operations on our behalf. For non-operated properties, the operators have applied and may choose to apply in the future hydraulic-fracturing techniques on properties in which we share interest.

The Clean Air Act

The federal Clean Air Act, enacted in 1970, and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. The EPA has developed and continues to develop stringent regulations under the authority of the Clean Air Act governing emissions of toxic air pollutants from specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations.

Some of our operations may be located in areas designated as “non-attainment” areas, which are geographic areas that do not meet the federal air quality standards. Air emission controls and requirements in non-attainment areas are generally more stringent that those imposed in other areas, and the construction of new, or expansion of existing, sources may be restricted.

Climate change

The issue of “global warming” has attracted significant attention and many believe that emissions of certain gases contribute to this problem. Many nations have agreed to limit emissions of “greenhouse gases” pursuant to the United Nations Framework Convention on Climate Change, and the “Kyoto Protocol.” Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas, and refined petroleum products, are considered “greenhouse gases” regulated by the Kyoto Protocol. Although the United States is not participating in the Kyoto Protocol, several states have adopted legislation and regulations to reduce emissions of greenhouse gases. Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect our operations and demand for our products.

In summary, we may be subject to EPA greenhouse gas monitoring and reporting rules, and potentially new EPA permitting rules if adopted, that would apply greenhouse gas permitting obligations and emissions limitations under the federal Clean Air Act. Whether or not any federal greenhouse gas regulations are enacted, more than one-third of the states have begun taking action on their own to control and/or reduce emissions of greenhouse gases. Several multi-state programs have been developed or are in the process of being developed, including the Regional Greenhouse Gas Initiative involving 10 Northeastern states, the Western Climate Initiative involving seven western states, and the Midwestern Greenhouse Gas Reduction Accord involving seven states. The latter two programs have several other states acting as observers and they may join one of the programs at a later date. Any of the climate change regulatory and legislative initiatives described above could have a material adverse effect on our business, financial condition, and results of operations.

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Legislative initiatives and discussions to date have focused on the development of cap-and-trade and/or carbon tax programs. A cap-and-trade program generally would cap overall greenhouse gas emissions on an economy-wide basis and require major sources of greenhouse gas emissions or major fuel producers to acquire and surrender emission allowances. Cap-and-trade programs could be relevant to us and our operations in several ways. First, the equipment we use to explore for, develop, produce and process oil and natural gas emits greenhouse gases. We could therefore be subject to caps, and penalties if emissions exceeded the caps. Second, the combustion of carbon-based fuels, such as the oil, gas and NGLs we sell, emits carbon dioxide and other greenhouse gases. Therefore, demand for our products could be reduced by imposition of caps and penalties on our customers. Carbon taxes could likewise affect us by being based on emissions from our equipment and/or emissions resulting from use of our products by our customers. Application of caps or taxes on companies such as Isramco, based on carbon content of produced oil and gas volumes rather than on consumer emissions, could lead to penalties, fees or tax assessments for which there are no mechanisms to pass them through the distribution and consumption chain where fuel use or conservation choices are made. Moreover, because oil and natural gas are used as chemical feedstocks and not solely as fossil fuel, the Company believes that applying a carbon tax to oil and gas at the production stage would be excessive with respect to actual carbon emissions from petroleum fuels.

The National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions that have the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are potentially subject to the requirements of NEPA. This process has the potential to delay the development of oil and natural gas projects.

Threatened and endangered species, migratory birds, and natural resources

Various state and federal statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds, wetlands, and natural resources. These statutes include the Endangered Species Act, the Migratory Bird Treaty Act, the Clean Water Act and CERCLA. The United States Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or development. Where takings of or harm to species or damages to wetlands, habitat, or natural resources occur or may occur, government entities or at times private parties, may act to prevent oil and gas exploration activities or seek damages for harm to species, habitat, or natural resources resulting from drilling, construction or releases of oil, wastes, hazardous substances or other regulated materials, and may seek compensation for alleged natural resources damages and in some cases, criminal penalties.

Hazard communications and community right to know

We are subject to federal and state hazard communications and community right to know statutes, including, but not limited to, the federal Emergency Planning and Community Right-to-Know Act, and regulations. These regulations govern record keeping and reporting of the use and release of hazardous substances.

Occupational Safety and Health Act

We are subject to the requirements of the federal Occupational Safety and Health Act, commonly referred to as OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and the public.

Hydraulic Fracturing

Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from dense subsurface rock formations. Hydraulic fracturing involves using water, sand or other proppant materials, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore.

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As explained in more detail below, the hydraulic fracturing process is typically regulated by state oil and natural gas agencies, although the EPA, and the Bureau of Land Management of the United States Department of the Interior (“BLM”), and other federal regulatory agencies have taken steps to review or impose federal regulatory requirements. Certain states in which we operate, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. Certain municipalities have already banned hydraulic fracturing, and courts have upheld those moratoria in some instances. In the past several years, dozens of states have approved or considered additional legislative mandates or administrative rules on hydraulic fracturing.

At the federal level, the EPA has issued final Clean Air Act regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; finalized regulations in June 2016 that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants; and issued in May 2014 an Advanced Notice of Proposed Rulemaking seeking comment on its intent to develop regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing. Also, the BLM finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands including, for example, notice to and pre-approval by BLM of the proposed hydraulic fracturing activities; development and pre-approval by BLM of a plan for managing and containing flowback fluids and produced water recovered during the hydraulic fracturing process; implementation of measures designed to protect usable water from hydraulic fracturing activities; and public disclosure of the chemicals used in the hydraulic fracturing fluid. The rule has been challenged in federal court and implementation has been stayed pending a final decision.

In addition, from time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. The adoption of new federal rules or regulations relating to hydraulic fracturing could lead to increased operating costs, delays and curtailment in the pursuit of exploration, development or production activities, which in turn could materially adversely affect our operations. Several governmental reviews are underway that focus on environmental aspects of hydraulic fracturing activities. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources “under some circumstances,” noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. Since the report did not find a direct link between hydraulic fracturing itself and contamination of groundwater resources, we do not believe that this multi-year study report provides any basis for further regulation of hydraulic fracturing at the federal level.

Based on the foregoing, increased regulation and attention given to the hydraulic fracturing process from federal agencies, various states and local governments could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells and increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows.

Employees

As of December 31, 2018, we had approximately 297 full-time employees. We hire independent contractors on an as needed basis. We have no collective bargaining agreements with our employees.

Available Information

We file annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934, as amended. The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers, including Isramco, Inc., that file electronically with the SEC. Information about the Company can be found at our internet address: www.isramcousa.com The public can obtain any document we file with the SEC at www.sec.gov.

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ITEM 1A. RISK FACTORS

In addition to the other information contained in this Annual Report on Form 10-K, investors should consider carefully the following risk factors, which may not be the only risks we face, as our business and operations may also be subject to risks that we do not yet know of, or that we currently believe are immaterial. If any of the events or circumstances described below actually occurs, our business, financial condition or results of operations could be materially and adversely affected and the trading price of our common stock could decline.

Oil, natural-gas and NGLs prices are volatile. A substantial or extended decline in prices could adversely affect our financial condition and results of operations.

Prices for oil, natural gas and NGLs (Natural Gas Liquids) can fluctuate widely. Our revenues, operating results and future growth rates are highly dependent on the prices we receive for our oil, natural gas and NGLs. Historically, the markets for oil, natural gas and NGLs have been volatile and may continue to be volatile in the future.

Factors influencing the prices of oil, natural gas and NGLs are beyond our control. These factors include, among others:

- the worldwide military and political environment, uncertainty or instability resulting from the escalation or additional outbreak of armed hostilities or further acts of terrorism in the United States, or elsewhere, particularly Israel;
- global factors impacting supply quantities of crude oil, natural gas and NGLs, in particular, US crude oil and NGL supply growth resulting from shale oil development;
- the extent to which US shale producers become swing producers, yielding additional non-OPEC crude oil supply;
- political conditions and events (including instability or armed conflict) in hydrocarbon-producing regions;
- actions taken by foreign oil and gas producing nations;
- the level of global crude oil and natural gas inventories;
- further application of horizontal drilling techniques which could increase production and significantly impact both domestic and global supplies of crude oil, natural gas, and NGLs;
- the price and level of foreign imports of oil, natural gas and NGLs;
- the effect of worldwide energy conservation efforts;
- actions by the Organization of Petroleum Exporting Countries, which we refer to as OPEC;
- the price and availability of alternative and competing fuels;
- technology advances that increase crude oil, natural gas and NGL production, thereby increasing supply;
- the cost of exploring for, developing, producing, transporting, and marketing oil, natural gas, and NGLs;
- the availability of pipeline capacity and infrastructure;
- the availability of crude oil transportation and refining capacity;
- consumer demand for oil, gas and NGLs;
- the growth of consumer product demand in emerging markets, such as India and China;

fuel efficiency regulations, such as the Corporate Average Fuel Economy (CAFE) standards, and its impacts on crude oil demand as a transportation fuel;

labor unrest in oil and natural gas producing regions;

regional pricing differentials;

weather conditions;

electricity needs;

the nature and extent of domestic and foreign governmental regulation (including environmental regulation and regulation of derivatives transactions and hedging activities) and taxation; and

the overall economic environment.

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The long-term effect of these and other factors on the prices of oil, natural gas and NGLs are uncertain. Prolonged or substantial declines in these commodity prices may have the following effects on our business:

- adversely affecting our financial condition, liquidity, ability to finance planned capital expenditures and results of operations;
- reducing the amount of oil, natural gas and NGLs that we can produce economically;
- reducing our revenues, profit margins, operating income and cash flows;
- certain properties in our portfolio becoming economically unviable;
- delay or postponement of some of our capital projects;
- reducing the carrying value of our crude oil and natural gas properties;
- reducing the amounts of our estimated proved oil and natural-gas reserves;
- reducing the standardized measure of discounted future net cash flows relating to oil and natural-gas reserves; and
- limiting our access to sources of capital, such as equity and long-term debt; and
- additional counterparty credit risk exposure on commodity hedges.
- asset impairment charges resulting from reductions in the carrying values of our crude oil and natural gas properties at the date of assessment;

Depending on the market prices of oil and gas, oil and gas exploration and production companies may cancel or curtail their drilling programs and may lower production spending on existing wells, thereby reducing demand for our production services. Many factors beyond our control affect oil and gas prices, including:

- the cost of exploring for, producing and delivering oil and gas;
- the discovery rate of new oil and gas reserves;
- the rate of decline of existing and new oil and gas reserves;
- the ability of oil and gas exploration and production companies to raise capital;
- economic conditions in the United States, Israel and elsewhere;
- the price of foreign imports of oil and gas.

Our domestic operations are subject to governmental risks that may impact our operations.

Our domestic operations have been, and at times in the future may be, affected by political developments and are subject to complex federal, state, tribal, local and other laws and regulations such as restrictions on production, permitting, changes in taxes, deductions, royalties and other amounts payable to governments or governmental agencies, price or gathering-rate controls, hydraulic fracturing and environmental protection regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state, tribal and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws, including environmental and tax laws, and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. For example, currently proposed federal legislation, that, if adopted, could adversely affect our business, financial condition and results of operations, includes the following:

Climate Change. A number of state and regional efforts have emerged that are aimed at tracking and/or reducing emissions of green-house gases (GHGs). In addition, the U.S. Environmental Protection Agency (EPA) has made findings that emissions of GHGs present a danger to public health and the environment and, based on these findings, has adopted regulations that restrict emissions of GHGs under existing provisions of the federal Clean Air Act. We may be required to install “best available control technology” to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future if they would otherwise emit large volumes of GHGs.

Taxes. On December 22, 2017, the United States Congress enacted the Tax Cuts and Jobs Act (“Tax Reform Legislation”). The Tax Reform Legislation, among other things, (i) permanently reduces the US corporate income tax rate to 21% beginning in 2018, (ii) repeals the corporate alternative minimum tax (AMT) allowing for corresponding refunds of prior period AMT credits, (iii) provides for a five year period of 100% bonus depreciation followed by a phase-down of the bonus depreciation percentage, (iv) imposes a new limitation on the utilization of net operating losses generated in taxable years beginning after December 31, 2017, and (v) provides for more general changes to the taxation of corporations, including changes to the deductibility of interest expense, the adoption of a modified territorial tax system, assessing a repatriation tax or “toll-charge” on undistributed earnings and profits of US-owned foreign corporations, and introducing certain anti-base erosion provisions. The Tax Reform Legislation is complex and far-reaching and could eliminate or postpone certain tax deductions that currently are available with respect to oil and gas development, or increase costs. The ultimate impact of the Tax Reform Legislation may differ from our estimates due to changes in interpretations and assumptions made by us as well as additional regulatory guidance that may be issued, and our business and financial condition could be adversely affected.

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In addition, from time to time, legislation has been proposed that, if enacted into law, would make significant changes to US federal and state income tax laws, including (i) the elimination of the immediate deduction for intangible drilling and development costs, (ii) the repeal of the percentage depletion allowance for oil and natural gas properties; and (iii) an extension of the amortization period for certain geological and geophysical expenditures. While these specific changes are not included in the Tax Reform Legislation, no accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future, or the timing of any such action. The elimination of such US federal tax deductions, as well as any other changes to or the imposition of new federal, state, local or non-US taxes (including the imposition of, or increases in production, severance or similar taxes) could adversely affect our business and financial condition.

Hydraulic Fracturing. This process is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from dense subsurface rock formations. With regard to our non-operated properties, the operators may choose to apply hydraulic-fracturing techniques in many of our U.S. onshore oil and natural-gas drilling and completion programs. Hydraulic fracturing involves using water, sand or other proppant materials, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore.

As explained in more detail below, the hydraulic fracturing process is typically regulated by state oil and natural gas agencies, although the EPA, the BLM and other federal regulatory agencies have taken steps to review or impose federal regulatory requirements. Certain states in which we operate, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. Certain municipalities have already banned hydraulic fracturing, and courts have upheld those moratoria in some instances. In the past several years, dozens of states have approved or considered additional legislative mandates or administrative rules on hydraulic fracturing.

At the federal level, the EPA has taken numerous actions, including the following: final federal Clean Air Act regulations in 2012 and, more recently, in June 2016 governing performance standards, including standards for the capture of air emissions released during oil and natural gas hydraulic fracturing, leak detection, and permitting; published in June 2016 an effluent limitation final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants; and issued in May 2014 an Advanced Notice of Proposed Rulemaking seeking comment on its intent to develop regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing. Also, the BLM finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands including, for example, notice to and pre-approval by BLM of the proposed hydraulic fracturing activities; development and pre-approval by BLM of a plan for managing and containing flowback fluids and produced water recovered during the hydraulic fracturing process; implementation of measures designed to protect usable water from hydraulic fracturing activities; and public disclosure of the chemicals used in the hydraulic fracturing fluid. Some of these rules are subject to pending challenges and, on March 28, 2017, an executive order was signed directing the EPA and the BLM to review their rules and, if appropriate, to initiate rulemaking to rescind or revise them consistent with the stated policy of promoting clean and safe development of the nation’s energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production. Accordingly, the EPA and the BLM have taken actions to delay or rescind certain requirements related to hydraulic fracturing activities. In addition, from time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. The adoption of new federal rules or regulations relating to hydraulic fracturing could require us to obtain additional permits or approvals or to install expensive pollution control equipment for our operations, which in turn could lead to increased operating costs, delays and curtailment in the pursuit of exploration, development or production activities, which in turn could materially adversely affect our operations.

In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources “under some circumstances,” noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. Since the report did not find a direct link between hydraulic fracturing itself and contamination of groundwater resources, we do not believe that this multi-year study report provides any basis for further regulation of hydraulic fracturing at the federal level.

Based on the foregoing, increased regulation and attention given to the hydraulic fracturing process from federal agencies, various states and local governments could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil, natural gas and NGLs, including from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells and increased compliance costs and time, which could adversely affect our business, financial position, results of operations and cash flows.

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The federal Clean Water Act, as amended by the Oil Pollution Act, the federal Clean Air Act, the federal Resource Conservation and Recovery Act, the federal Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, the Safe Drinking Water Act, or SDWA, the federal Outer Continental Shelf Lands Act, the Occupational Safety and Health Act, or OSHA, and their state counterparts and similar statutes are the primary statutes that impose the requirements and provide for civil, criminal and administrative penalties and other sanctions for violation of their requirements. The OSHA hazard communication standard, the Environmental Protection Agency "community right-to-know" regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require us to organize and report information about the hazardous materials we use in our operations to employees, state and local government authorities and local citizens. In addition, CERCLA, also known as the "Superfund" law, and similar state statutes impose strict liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered responsible for the release or threatened release of hazardous substances into the environment. These persons include the current owner or operator of a facility where a release has occurred, the owner or operator of a facility at the time a release occurred, and companies that disposed of or arranged for the disposal of hazardous substances found at a particular site. This liability may be joint and several. Such liability, which may be imposed for the conduct of others and for conditions others have caused, includes the cost of removal and remedial action as well as damages to natural resources. Few defenses exist to the liability imposed by environmental laws and regulations. It is also common for third parties to file claims for personal injury and property damage caused by substances released into the environment.

The enactment of derivatives legislation could have an adverse effect on the Company's ability to use derivative instruments to reduce the effect of commodity-price, interest-rate, and other risks associated with its business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), enacted in 2010, establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as the Company, that participate in that market. The Dodd-Frank Act requires the Commodities Futures Trading Commission (CFTC) and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. In its rulemaking under the Dodd-Frank Act, the CFTC issued a final rule on position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions are exempt from these position limits. The position-limits rule was vacated by the U.S. District Court for the District of Colombia in September 2012 and the CFTC recently stated that it will appeal the District Court's decision. The CFTC also finalized other regulations, including critical rulemakings on the definition of "swap," "swap dealer," and "major swap participant." Some regulations, however, remain to be finalized and it is not possible at this time to predict when this will be accomplished. Depending on the Company's classification and the particular nature of its derivative activities, the Dodd-Frank Act and regulations may require the Company to comply with margin requirements and with certain clearing and trade-execution requirements in connection with its derivative activities. The Dodd-Frank Act and regulations may also require the counterparties to the Company's derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The Dodd-Frank Act and regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks the Company encounters, reduce the Company's ability to monetize or restructure its existing derivative contracts, and increase the Company's exposure to less-creditworthy counterparties. If the Company reduces its use of derivatives as a result of the Dodd-Frank Act and regulations, the Company's results of operations may become more volatile and its cash flows may be less predictable, which could adversely affect the Company's ability to plan for and fund capital expenditures. Finally, the Dodd-Frank

Act was intended, in part, to reduce the volatility of oil and natural-gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. The Company's revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on the Company's consolidated financial position, results of operations, or cash flows.

Drilling crude oil and natural gas wells is a high-risk activity and subjects us to a variety of risks that we cannot control.

Drilling crude oil and natural gas wells, including development wells, involves numerous risks, including the risk that we may not encounter commercially productive crude oil and natural gas reserves (including "dry holes"). As a result, we may not recover all or any portion of our investment in new wells.

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Specifically, we often are uncertain as to the future cost or timing of drilling, completing and operating wells, and our drilling operations and those of our third-party operators may be curtailed, delayed or canceled, the cost of such operations may increase and/or our results of operations and cash flows from such operations may be impacted, as a result of a variety of factors, including

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions, such as winter storms, flooding and hurricanes, and changes in weather patterns;
- compliance with, or changes in, environmental laws and regulations relating to air emissions, hydraulic fracturing and disposal of produced water, drilling fluids and other wastes, laws and regulations imposing conditions and restrictions on drilling and completion operations and other laws and regulations, such as tax laws and regulations;
- the availability and timely issuance of required governmental permits and licenses;
- the availability of, costs associated with and terms of contractual arrangements for properties, including mineral licenses and leases, pipelines, rail cars, crude oil hauling trucks and qualified drivers and related facilities and equipment to gather, process, compress, transport and market crude oil, natural gas and related commodities; and
- the costs of, or shortages or delays in the availability of, drilling rigs, hydraulic fracturing services, pressure pumping equipment and supplies, tubular materials, water, sand, disposal facilities, qualified personnel and other necessary equipment, materials, supplies and services.

Our failure to recover our investment in wells, increases in the costs of our drilling operations or those of our third-party operators, and/or curtailments, delays or cancellations of our drilling operations or those of our third-party operators in each case due to any of the above factors or other factors, may materially and adversely affect our business, financial condition and results of operations. For related discussion of the risks and potential losses and liabilities inherent in our crude oil and natural gas operations generally, see the immediately following risk factor.

Our oil and natural gas activities are subject to various risks that are beyond our control and expose us to potential losses and liabilities, and insurance may not fully protect us against these risks and potential losses and liabilities.

Our operations are subject to many risks and hazards incident to exploring and drilling for, producing, transporting, marketing and selling oil and natural gas. Although we may take precautionary measures, many of these risks and hazards are beyond our control and unavoidable under the circumstances. Many of these risks or hazards could materially and adversely affect our revenues and expenses, the ability of certain of our wells to produce oil and natural gas in commercial quantities, the rate of production and the economics of the development of, and our investment in the prospects in which we have or will acquire an interest. Any of these risks and hazards could materially and adversely affect our financial condition, results of operations and cash flows. Such risks and hazards include:

human error, accidents, labor force and other factors beyond our control that may cause personal injuries or death to persons and destruction or damage to equipment and facilities;
blowouts, fires, explosions, loss of well control, hurricanes, pollution and equipment failures that may result in damage to or destruction of wells, producing formations, production facilities and equipment;
unavailability of materials and equipment;
engineering and construction delays;
unanticipated transportation costs and delays;
adverse weather conditions, such as winter storms, flooding and hurricanes, and other natural disasters;
hazards resulting from unusual or unexpected geological or environmental conditions;
environmental regulations and requirements;
accidental leakage of toxic or hazardous materials, such as petroleum liquids or drilling fluids, into the environment;
changes in laws and regulations, including laws and regulations applicable to oil and natural gas activities or markets for the oil and natural gas produced;
fluctuations in supply and demand for oil and natural gas causing variations of the prices we receive for our oil and natural gas production;
hazards resulting from the presence of hydrogen sulfide (H_2S) or other contaminants in gas we produce;
the availability of alternative fuels and the price at which they become available; and
terrorism, vandalism and physical, electronic and cyber security breaches.

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To mitigate financial losses resulting from these operating hazards, we maintain insurance coverage, including insurance coverage for certain physical damage, comprehensive general liability, and worker's compensation and employer's liability. However, our insurance coverage may not be sufficient to cover us against all of potential losses arising as a result of the foregoing, and for certain risks, such as political risk, 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. The occurrence of a significant event against which we are not fully insured could have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

The high cost or unavailability of drilling rigs, equipment, supplies, personnel, and other oilfield services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget, which could have a material adverse effect on our business, financial condition, or results of operations.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies, or qualified personnel. During these periods, the costs of rigs, equipment, supplies, and personnel are substantially greater and their availability to us may be limited. Additionally, these services may not be available on commercially reasonable terms. The high cost or unavailability of drilling rigs, equipment, supplies, personnel, and other oilfield services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget, which could have a material adverse effect on our business, financial condition, or results of operations.

A portion of our crude oil and natural gas production may be subject to interruptions that could have a material and adverse effect on us.

A portion of our crude oil and natural gas production may be interrupted, or shut in, from time to time for various reasons, including, but not limited to, as a result of accidents, weather conditions, loss of gathering, processing, compression or transportation facility access or field labor issues, or intentionally as a result of market conditions such as crude oil or natural gas prices that we deem uneconomic. If a substantial amount of our production is interrupted, our cash flows and, in turn, our financial condition and results of operations could be materially and adversely affected.

Failure to fund continued capital expenditures could adversely affect our properties.

Our acquisition, exploration, and development activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations and loans from commercial banks and related parties. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of crude oil and natural gas, and our success in finding, developing and producing new reserves. If revenues were to decrease as a result of lower crude oil and natural gas prices or decreased production, and our access to capital were limited, we would have a reduced ability to replace our reserves, resulting in a decrease in production over time. If our cash flows from operations are not sufficient to meet our obligations and fund our capital budget, we may not be able to access debt, equity or other methods of financing on an economic basis to meet these requirements, particularly in the current economic environment. If we are not able to fund our capital expenditures, interests in some properties might be reduced or forfeited as a result.

Reserve estimates depend on many interpretations and assumptions that may turn out to be inaccurate. Any significant inaccuracies in these interpretations and assumptions could cause the reported quantities and the value of our reserves to be materially misstated.

Estimating quantities of crude oil, NGLs and natural gas reserves and future net cash flows from such reserves is a complex, inexact process. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors, made by our management and our independent reserve engineering firms; Netherland, Sewell & Associates, Inc. and Cawley, Gillespie & Associates, Inc. Any significant inaccuracies in these interpretations or assumptions could cause the reported quantities of our reserves and future net cash flows from such reserves to be overstated or understated. Also, the data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions.

To prepare estimates of our economically recoverable crude oil, NGLs and natural gas reserves and future net cash flows from our reserves, we analyze many variable factors, such as historical production from the area compared with production rates from other producing areas. We also analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also involves economic assumptions relating to commodity prices, production costs, severance and excise taxes, capital expenditures and workover and remedial costs, many of which factors are or may be beyond our control.

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Estimates of reserves based on risk of recovery and estimates of expected future net cash flows prepared by different engineers, or by the same engineers at different times, may vary substantially. Actual production, revenues, and expenditures with respect to our reserves will likely vary from estimates, and the variance may be material. The discounted cash flows included in this report should not be construed as the fair value of the estimated oil, natural-gas, and NGLs reserves attributable to our properties. The estimated discounted future net cash flows from proved reserves are based on average 12-month sales prices using the average beginning-of-month price. Actual future prices and costs may differ materially from the SEC regulation-compliant prices used for purposes of estimating future discounted net cash flows from proved reserves.

Discoveries or Acquisitions of reserves are needed to avoid a material decline in reserves and production.

The production rates from oil and gas properties generally decline as reserves are depleted, while related per unit production costs generally increase, due to decreasing reservoir pressures and other factors. Therefore, our estimated proved reserves and future oil, gas and NGL production will decline materially as reserves are produced unless we conduct successful exploration and development activities or, through engineering studies, identify additional producing zones in existing wells, secondary or tertiary recovery techniques, or acquire additional properties containing proved reserves. Consequently, our future oil, gas and NGL production and related per unit production costs are highly dependent upon our level of success in finding or acquiring additional reserves.

If we acquire crude oil and natural gas properties, our failure to fully identify existing and potential problems and liabilities, to accurately estimate reserves, production rates or costs, or to effectively integrate the acquired properties into our operations could materially and adversely affect our business, financial condition and results of operations.

From time to time, we seek to acquire crude oil and natural gas properties. Although we perform reviews of properties to be acquired in a manner that we believe is duly diligent and consistent with industry practices, reviews of records and properties may not necessarily reveal existing or potential problems, nor may they permit us to become sufficiently familiar with the properties in order to assess fully their deficiencies and potential. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise in the future. Even when problems with a property are identified, we often may assume environmental and other risks and liabilities in connection with acquired properties pursuant to the acquisition agreements. In addition, there are numerous uncertainties inherent in estimating quantities of crude oil and natural gas reserves (as discussed further above), actual future production rates and associated costs with respect to acquired properties. Actual reserves, production rates and costs may vary substantially from those assumed in our estimates. In addition, an acquisition may have a material and adverse effect on our business and results of operations, particularly during the periods in which the operations of the acquired properties are being integrated into our ongoing operations or if we are unable to effectively integrate the acquired properties into our ongoing operations.

Title to the properties in which we have an interest may be impaired by title defects.

We generally conduct due diligence to review title on significant properties that we drill or acquire. However, there is no assurance that we will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. Generally, under the terms of the operating agreements affecting our properties, any monetary loss is due to title defects is to be borne by all parties to any such agreement in proportion to their interests in such property. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

There is a possibility that we will lose the leases to our oil and gas properties.

Our oil and gas revenues are generated through oil and gas leases. These leases are conditioned on the performance of certain obligations, primarily the obligation to produce oil and/or gas or engage in operations designed to result in the production of oil and gas. If production ceases and operations are not commenced within a specified time, the lease may be lost. The loss of our leases may have a material and adverse impact on our revenues.

In the case of Israeli-based properties, we have interests in licenses that, subject to certain conditions, may result in leases being granted. The leases are subject to certain obligations and are renewable at the discretion of various governmental authorities. As such, if the parties responsible for operations are not able to fulfill their obligations under the leases, the leases may be modified, cancelled, not renewed, or renewed on terms different from the current leases. The modification or cancellation of our leases could eliminate our interests and may have a material and adverse impact on our revenues.

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We are subject to complex laws and regulations relating to environmental protection that can adversely affect the cost, manner, and feasibility of doing business.

Our operations and properties are subject to numerous federal, regional, state, tribal, local, and foreign laws and regulations governing the release of pollutants or otherwise relating to environmental protection. These laws and regulations govern the following, among other things:

- issuance of permits in connection with exploration, drilling and production activities;
- protection of endangered species;
- amounts and types of emissions and discharges;
- generation, management, and disposition of waste materials;
- reclamation and abandonment of wells and facility sites; and
- remediation of contaminated sites.

In addition, these laws and regulations may impose substantial liabilities for our failure to comply or for any contamination resulting from our operations. Future environmental laws and regulations, such as the restriction against emission of pollutants from previously unregulated activities or the designation of previously unprotected species as threatened or endangered in areas where we operate, may negatively impact our industry. The cost of satisfying these requirements may have an adverse effect on our financial condition, results of operations, or cash flows or could result in limitations on our exploration and production activities, which could have an adverse impact on our ability to develop and produce our reserves.

We cannot be certain that the insurance coverage maintained by us will be adequate to cover all losses that may be sustained in connection with all oil and natural gas activities.

We maintain general and excess liability policies, which we consider to be reasonable and consistent with industry standards. These policies generally cover:

- personal injury;
- bodily injury;
- third party property damage;
- medical expenses;
- legal defense costs;
- pollution in some cases;
- loss or damage to equipment;
- well blowouts in some cases; and
- worker’s compensation.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position, results of operations and cash flows. There can be no assurance that the insurance coverage that we maintain will be sufficient to cover claims made against us in the future.

Reduced demand for or excess capacity of production services could adversely affect our profitability.

Our profitability in the future will depend on many factors, but largely on pricing and utilization rates for our production services. An increase in supply of production servicing rigs and equipment, without a corresponding increase in demand, or decrease in demand for production servicing rigs and equipment could decrease the pricing and utilization rates of our production services, which would adversely affect our revenues and profitability.

Our production services business depends on domestic spending by the oil and natural gas industry, and this spending and our business has been in the past, and may in the future be, adversely affected by industry and financial market conditions that are beyond our control.

We depend on our customers' willingness to make operating and capital expenditures to explore for, develop and produce oil and natural gas in the United States. Customers' expectations for lower market prices for oil and natural gas, as well as the availability of capital for operating and capital expenditures, may cause them to curtail spending, thereby reducing demand for our services and equipment.

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Industry conditions are influenced by numerous factors over which we have no control, such as the supply of and demand for oil and natural gas, domestic and worldwide economic conditions, political instability in oil and natural gas producing countries and merger and divestiture activity among oil and gas producers. The volatility of the oil and natural gas industry and the consequent impact on exploration and production activity could adversely impact the level of drilling and workover activity by some of our customers. This reduction may cause a decline in the demand for our services or adversely affect the price of our services. In addition, reduced discovery rates of new oil and natural gas reserves in our market areas also may have a negative long-term impact on our business, even in an environment of stronger oil and natural gas prices, to the extent existing production is not replaced and the number of producing wells for us to service declines.

Limitations on the availability of capital, or higher costs of capital, for financing expenditures may cause oil and natural gas producers to make further reductions to capital budgets in the future even if oil or natural gas prices increase from current levels. Any such cuts in spending will curtail drilling programs as well as discretionary spending on production services, which may result in a reduction in the demand for our services, the rates we can charge and our utilization. In addition, certain of our customers could become unable to pay their suppliers, including us. Any of these conditions or events could adversely affect our operating results.

If oil and natural gas prices remain volatile, or if oil or natural gas prices remain low or decline further, the demand for our production services could be adversely affected.

The demand for our services is primarily determined by current and anticipated oil and natural gas prices and the related general production spending and level of drilling activity in the areas in which we have operations. Volatility or weakness in oil prices or natural gas prices (or the perception that oil prices or natural gas prices will decrease) affects the spending patterns of our customers and may result in the drilling of fewer new wells or lower production spending on existing wells. This, in turn, could result in lower demand for our services and may cause lower rates and lower utilization of our production service equipment. If oil prices or natural gas prices continue to remain low or decline further, or if there is a reduction in drilling activities, the demand for our services and our results of operations could be materially and adversely affected.

Competition in the oil and gas exploration and production industry is intense, and many of our competitors have greater resources than we have.

We compete with national oil companies, major integrated oil and gas companies, independent oil and gas companies and other individual producers for the acquisition of licenses and leases, properties and reserves and the equipment, materials, services and employees and other contract personnel (including geologists, geophysicists, engineers and other specialists) required to explore, develop, produce and market crude oil and natural gas. Some of our competitors may have greater and more diverse resources on which to draw than we do. As a consequence, we may be at a competitive disadvantage in certain respects, such as in bidding for drilling rights, acquisition of licenses and leases, properties and reserves or in acquiring necessary services, equipment, materials and personnel. If we are not successful in our competition for oil and gas reserves or in our marketing of production, our financial condition and results of operations may be adversely affected.

Poor general economic, business, or industry conditions may have a material adverse effect on our results of operations, liquidity, and financial condition.

During the last few years, concerns over inflation, energy costs, geopolitical issues, the availability and cost of credit, the U.S. mortgage market, uncertainties with regard to European sovereign debt, and a declining real estate market in the United States have contributed to increased economic uncertainty and diminished expectations for the global economy. Concerns about global economic conditions have had a significant adverse impact on global financial markets and commodity prices. If the economic recovery in the United States or abroad remains prolonged, demand for petroleum products could diminish or stagnate, which could impact the price at which we can sell our oil, natural gas, and NGLs, affect our vendors', suppliers' and customers' ability to continue operations, and ultimately adversely impact our results of operations, liquidity, and financial condition.

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Our hedging activities may prevent us from benefiting fully from price increases and may expose us to other risks.

In order to manage our exposure to price risks in the marketing of our oil and natural gas production, we sometimes enter into oil and natural gas price hedging arrangements with respect to a portion of our anticipated production and we may enter into additional hedging transactions in the future. While intended to reduce the effects of volatile oil and natural gas prices, such transactions may limit our potential gains and increase our potential losses if oil and natural gas prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which:

- our actual production is less than hedged volumes;
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;
- the counterparties to our hedging agreements fail to perform under the contracts; or
- a sudden unexpected event materially impacts oil and natural-gas prices.

At the time of this report, the Company had no commodity price hedging agreements in place.

The credit risk of financial institutions could adversely affect us.

We have exposure to different counterparties, and we have entered into transactions with counterparties in the financial services industry, including commercial banks, insurance companies and other institutions. These transactions expose us to credit risk in the event of default of our counterparty. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us. We have exposure to these financial institutions through our derivative transactions. In addition, if any lender under our credit facility is unable to fund its commitment, our liquidity will be reduced by an amount up to the aggregate amount of such lender’s commitment under our credit facility. Moreover, to the extent that purchasers of the Company’s production rely on access to the credit or equity markets to fund their operations, there is a risk that those purchasers could default in their contractual obligations to the Company if such purchasers were unable to access the credit or equity markets for an extended period of time.

We have no means to market our oil and gas production without the assistance of third parties.

The marketability of our production depends upon the proximity of our reserves to, and the capacity of, facilities and third party services, including oil and natural gas gathering systems, pipelines, trucking or terminal facilities, and processing facilities. The unavailability or lack of capacity of such services and facilities could impair or delay the production of new wells or the delay or discontinuance of development plans for properties. A shut-in, delay or discontinuance could adversely affect our financial condition. In addition, regulation of oil and natural gas production transportation in the United States or in other countries may affect its ability to produce and market our oil and natural gas on a profitable basis.

Our exploration and development drilling efforts and the operation of our wells may not be profitable or achieve our targeted returns.

We require significant amounts of undeveloped leasehold acreage to further our development efforts. Exploration, development, drilling and production activities are subject to many risks, including the risk that commercially productive reservoirs will not be discovered. We invest in property, including undeveloped leasehold acreage, which we believe will result in projects that will add value over time. However, we cannot guarantee that our leasehold acreage will be profitably developed, that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such leasehold acreage or wells. Drilling for 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 reserves to return a profit after deducting operating and other costs. In addition, wells that are profitable may not achieve our targeted rate of return. Our ability to achieve our target results is dependent upon the current and future market prices for oil and natural gas, costs associated with producing oil and natural gas and our ability to add reserves at an acceptable cost.

In addition, we may not be successful in controlling our drilling and production costs to improve our overall return. The cost of drilling, completing and operating a well is often uncertain and cost factors can adversely affect the economics of a project. We cannot predict the cost of drilling and completing a well, and we may be forced to limit, delay or cancel drilling operations as a result of a variety of factors, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents and shortages or delays in the availability of drilling and completion equipment and services;
- adverse weather conditions, including hurricanes; and
- compliance with governmental requirements.

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We depend on the skill, ability and decisions of third party operators to a significant extent.

The success of the drilling, development and production of the oil and natural gas properties in which we have or expect to have a non-operating working interest is substantially dependent upon the decisions of such third-party operators and their diligence to comply with various laws, rules and regulations affecting such properties. The failure of any third-party operator to make decisions, perform their services, discharge their obligations, deal with regulatory agencies, and comply with laws, rules and regulations, including environmental laws and regulations in a proper manner with respect to properties in which we have an interest could result in material adverse consequences to our interest in such properties, including substantial penalties and compliance costs. Such adverse consequences could result in substantial liabilities to us or reduce the value of our properties, which could negatively affect our results of operations.

We depend substantially on the continued presence of key personnel for critical management decisions and industry contacts.

Our success depends upon the continued contributions of our executive officers and key employees, particularly with respect to providing the critical management decisions and contacts necessary to manage and maintain growth within a highly competitive industry. Competition for qualified personnel can be intense, particularly in the oil and natural gas industry, and there are a limited number of people with the requisite knowledge and experience. Under these conditions, we could be unable to attract and retain these personnel. The loss of the services of any of our executive officers or other key employees for any reason could have a material adverse effect on our business, operating results, financial condition and cash flows.

Our operations in Israel may be adversely affected by unique economic, terrorist activities and political developments.

We have interests in oil and gas leases and in oil and gas licenses in the waters off Israel. These interests are a significant portion of our future production and cash flow and may be adversely affected by terrorist activities, political and economic developments, including the following:

war, terrorist acts and civil disturbances, and other political risks;
changes in taxation policies;
laws and policies of the US and Israel affecting foreign investment, taxation, trade and business conduct;
foreign exchange restrictions;
international monetary fluctuations and changes in the value of the US dollar, such as the decline of the US dollar; and

other hazards arising out of Israeli governmental sovereignty over areas in which we own oil and gas interests.

Oilfield service is a highly competitive, fragmented industry in which price competition could reduce our profitability.

We encounter substantial competition from other oilfield service companies. Our primary market areas are highly fragmented and competitive. The fact that production services equipment are mobile and can be moved from one market to another in response to market conditions heightens the competition in the industry and may result in an oversupply of equipment in an area. Oilfield service companies compete primarily on a regional basis, and the intensity of competition may vary significantly from region to region at any particular time. If demand for drilling or production services improves in a region where we operate, our competitors might respond by moving in suitable rigs and production services equipment from other regions. An influx of equipment from other regions could rapidly intensify competition, reduce profitability and make any improvement in demand for production services short-lived.

Most production services contracts are awarded on the basis of competitive bids, which also results in price competition. In addition to pricing and equipment availability, we believe the following factors are also important to our clients in determining which production services provider to select:

the type and condition of each of the competing production servicing rigs;
the quality of service and experience of the crews;
the safety record of the company providing the services; and
the offering of ancillary services.

We could be adversely affected if shortages of equipment, supplies or personnel occur.

From time to time there have been shortages of production services equipment and supplies during periods of high demand which we believe could recur. Shortages could result in increased prices for production services equipment or supplies that we may be unable to pass on to clients. In addition, during periods of shortages, the delivery times for equipment and supplies can be substantially longer. Any significant delays in our obtaining production services equipment or supplies could limit production services operations and jeopardize our relations with clients. In addition, shortages of production services equipment or supplies could delay and adversely affect our ability to obtain new contracts for our rigs, which could have a material adverse effect on our financial condition and results of operations.

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Our operations require the services of employees having the technical training and experience necessary to achieve the proper operational results. As a result, our operations depend, to a considerable extent, on the continuing availability of such personnel. Shortages of qualified personnel have occurred in our industry. If we should suffer any material loss of personnel to competitors or be unable to employ additional or replacement personnel with the requisite level of training and experience to adequately operate our equipment, our operations could be materially and adversely affected. A significant increase in the wages paid by other employers could result in a reduction in our workforce, increases in wage rates, or both. The occurrence of either of these events for a significant period of time could have a material adverse effect on our financial condition and results of operations.

There are limitations with regard to sales of Tamar Field Production

As noted above, we own an interest in the Tamar Field located offshore Israel. This interest in 2018 accounted for approximately 38% of our consolidated revenues and we expect the interest as a percentage of consolidated revenues to increase significantly if and when payout occurs. We note that the government of Israel allows the owners of Tamar Field production to export fifty percent (50%) of the production that has not yet been committed to supply the Israel domestic market as of the date of the government's decision in this regard. Accordingly, production from Tamar must first satisfy the minimum amount required to supply the Israeli economy.

If our customers delay paying or fail to pay a significant amount of our outstanding receivables, it could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

In most cases, we bill our customers for our services in arrears and are, therefore, subject to our customers delaying or failing to pay our invoices. In weak economic environments, we may experience increased delays and failures due to, among other reasons, a reduction in our customers' cash flow from operations and their access to the credit markets. If our customers delay paying or fail to pay us a significant amount of our outstanding receivables, it could have a material adverse effect on our liquidity, consolidated results of operations, and consolidated financial condition.

We may be unable to implement price increases or maintain existing prices on our core services.

We periodically seek to increase the prices of our services to offset rising costs and to generate higher returns for our stockholders. However, we operate in a very competitive industry and as a result, we are not always successful in raising, or maintaining our existing prices. Additionally, during periods of increased market demand, a significant amount of new service capacity, including new production services rigs may enter the market, which also puts pressure on the pricing of our services and limits our ability to increase or maintain prices. Furthermore, during periods of declining pricing for our services, we may not be able to reduce our costs accordingly, which could further adversely affect our profitability.

Even when we are able to increase our prices, we may not be able to do so at a rate that is sufficient to offset such rising costs. In periods of high demand for oilfield services, a tighter labor market may result in higher labor costs. During such periods, our labor costs could increase at a greater rate than our ability to raise prices for our services. Also, we may not be able to successfully increase prices without adversely affecting our activity levels. The inability to maintain our prices or to increase our prices as costs increase could have a material adverse effect on our business, financial position and results of operations.

A member of Isramco's management team owns a significant amount of common stock, giving him influence or control in corporate transactions and other matters, and the interests of these individuals could differ from those other shareholders.

Haim Tsuff, the Company's President, Co-Chief Executive Officer and Chairman of the Board of Directors, individually and through companies that he beneficially controls own over 73% of our outstanding shares of common stock as of March 18, 2019. As a result, Haim Tsuff is in a position to significantly influence or control the outcome of matters requiring a shareholder vote, including the election of directors, the adoption of an amendment to our certificate of incorporation or bylaws, and the approval of mergers and acquisitions, and other significant corporate transactions.

Our stock price is volatile, could continue to be volatile and has limited liquidity; Accordingly, investors may not be able to sell any significant number of shares of our stock at prevailing market prices.

Investor interest in our common stock may not lead to the development of an active or liquid trading market. The market price of our common stock has fluctuated in the past and is likely to continue to be volatile and subject to wide fluctuations. In addition, the stock market has experienced extreme price and volume fluctuations. The stock prices and trading volumes for our stock has fluctuated widely and the average daily trading volume of our stock continues to be limited and may continue for reasons that may be unrelated to business or results of operations. General economic, market and political conditions could also materially and adversely affect the market price of our common stock and investors may be unable to resell their shares of common stock at or above their purchase price. As a result of the limited trading in our stock, it may be difficult for investors to sell their shares in the public market at any given time at prevailing prices.

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We have not paid dividends on our common stock and do not plan to declare dividends in the foreseeable future, and therefore only appreciation of the price of our common stock will provide a return to our shareholders.

We have not paid or declared any dividends on our common stock and currently intend to retain any earnings to fund our working capital needs, reduce debt and fund growth opportunities. Any future dividends will be at the discretion of our board of directors after taking into account various factors it deems relevant, including our financial condition and performance, cash needs, income tax consequences and restrictions imposed by the Texas Business Organizations Code and other applicable laws.

The Company could be impacted by unfavorable results of legal proceedings.

The Company is subject to various legal proceedings, disputes and claims that have not yet been fully resolved, and additional disputes and claims may arise in the future. Results of legal proceedings are subject to significant uncertainty and, regardless of the merit of the claims, these legal proceedings may be expensive, time-consuming, and disruptive to the Company’s operations and management. The Company may enter into arrangements to settle legal proceedings and other disputes in an attempt to mitigate against the foregoing risks. However, the Company cannot guarantee a favorable result with respect to any resolution of a legal proceeding, whether by settlement or otherwise. If one or more of these legal proceedings were resolved against the Company in a reporting period for amounts in excess of the Company’s expectations, such resolution could result in a material adverse effect on our business, financial position and results of operations.

Uncertainty about the future of the London Interbank Offer Rate (LIBOR) may adversely affect our business and financial results.

LIBOR meaningfully influences market interest rates around the globe. In July 2017, the Chief Executive of the United Kingdom Financial Conduct Authority, which regulates LIBOR, announced its intent to stop persuading or compelling banks to submit rates for the calculation of LIBOR to the administrator of LIBOR after 2021. This announcement indicates that the continuation of LIBOR as currently constructed is not guaranteed after 2021. It is impossible to predict whether and to what extent banks will continue to provide LIBOR submissions to the administrator of LIBOR, whether any additional reforms to LIBOR may be enacted in the United Kingdom or elsewhere, and whether other rate or rates may become accepted alternatives to LIBOR.

In 2014, the FRB and the Federal Reserve Bank of New York convened the Alternative Reference Rates Committee (ARRC) to identify best practices for alternative reference rates, identify best practices for contract robustness, develop an adoption plan, and create an implementation plan with metrics of success and a timeline. The ARRC accomplished its first set of objectives and has identified the Secured Overnight Financing Rate (SOFR) as the rate that represents best practice for use in certain new U.S. dollar derivatives and other financial contracts. The ARRC also published its Paced Transition Plan, with specific steps and timelines designed to encourage adoption of the SOFR. The ARRC was reconstituted in 2018 to help to ensure the successful implementation of the Paced Transition Plan and serve as a forum to coordinate and track planning across cash and derivatives products and market participants currently using LIBOR.

No assurance can be provided that the uncertainties around LIBOR or their resolution will not adversely affect the use, level, and volatility of LIBOR or other interest rates or the value of LIBOR-based securities or other securities or financial arrangements. Further, the viability of SOFR as an alternative reference rate and the availability and acceptance of other alternative reference rates are unclear and also may have adverse effects on market rates of interest and the value of securities and other financial arrangements. These uncertainties, proposals and actions to resolve them, and their ultimate resolution also could negatively impact our funding costs, loan and other asset values, asset-liability management strategies, and other aspects of our business and financial results.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Oil and Gas Exploration and Production - Properties and Reserves

We own varying working interests in oil and gas wells in Louisiana, Texas, New Mexico, Oklahoma, Wyoming, Utah and Colorado. We currently serve as operator of approximately 422 producing wells most of which are located in Texas and New Mexico. Moreover, we own interests in properties operated by third party entities. In many instances, the Company does not have, nor is it entitled to, information pertaining to certain matters such as (i) whether shut-in or temporarily abandoned wells operated by these third parties are mechanically capable of production, (ii) whether third party operators have obtained leases in which the Company would be contractually entitled to participate (being undeveloped acreage), and, in some instances or (iii) the gross and net acreage maintained in the leases included in the contract area under the operative joint operating agreements. Due to the nature of some third party operations (e.g., field wide units), to the Company cannot ascertain the total number of wells drilled within a particular project area and whether each well within such project area is productive. In some instances, third parties operate properties (e.g. field wide units and leases covering a large amount of acreage) where production, revenue and expenses for the property are aggregated and reported as a single property. Accordingly, well information with regard to such properties is not always available to Isramco. In addition, most of the Company's operated wells are legacy assets and, accordingly, were drilled and operated for several years by our predecessors in title. Therefore, at this time, the Company is conducting a review of the terms and conditions of each lease covering our operated assets to determine the acreage held by the underlying oil and gas leases and the Company is also examining shut-in wells to ascertain whether these wells are mechanically capable of production in their current state. Moreover, we are working with the operators of our non-operated assets to obtain similar information with regard to such properties. The Company expects to complete this review in the near future. Currently, we do not own any interest in undeveloped acreage.

Drilling Activities

During the year ended December 31, 2015, we drilled and completed two development wells in North Texas. No new wells were drilled in 2018, 2017, or 2016.

Reserve Information. For estimates of Isramco's net proved reserves of natural gas, crude oil and natural gas liquids, see Note 14 to Consolidated Financial Statements, "Supplemental Oil and Gas Information".

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 control of the producer. The reserve data set forth in Note 14 to Consolidated Financial Statements, “Supplemental Oil and Gas Information”, represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of natural gas, crude oil and condensate and natural gas liquids that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the amount and quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers normally vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of such estimate (upward or downward). Accordingly, reserve estimates are often different from the quantities ultimately recovered. The meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they were based. For related discussion, see ITEM 1A. Risk Factors.

We believe that we have satisfactory title to the properties owned and used in our business, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties, or the use of these properties in our business. We believe that our properties are adequate and suitable for us to conduct business in the future.

Controls Over Reserve Estimates

The Company’s policies and practices regarding internal controls over the recording of reserves are structured to objectively and accurately estimate our oil and gas reserves quantities and present values in compliance with the SEC’s regulations and GAAP. The Company relies on third party professionals to integrate geological, geophysical, engineering and economic data to produce the Company’s reserve reports, which are utilized for its filings with the Commission. Our internal controls over reserves estimates include the following:

- A reserve report covering 100% of our proved reserves in the United States is prepared by Cawley, Gillespie and Associates, Inc., a third-party petroleum consulting firm, on an annual basis;

- A reserve report covering 100% of our interests in Israel is prepared by Netherland, Sewell & Associates, Inc. (“NSAI”), a third-party petroleum consulting firm, on an annual basis; and

- Senior Management of the Company reviews and examines the reserve reports generated by third parties and conducts an internal evaluation of the assumptions underlying material changes to reserves on an annual basis.

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The reserves estimates shown for our U.S. properties have been independently evaluated by Cawley, Gillespie and Associates, Inc. The technical person at Cawley, Gillespie and Associates primarily responsible for preparing the estimates set forth in the reserves report incorporated herein is Mr. Todd Brooker, President. Mr. Brooker joined CG&A in October 1992 as a reservoir engineer. His responsibilities include reserves and economics evaluations, fair market valuations, field studies, pipeline resource studies and acquisition/divestiture analysis. His reserve reports are routinely used for public company SEC disclosures. His experience includes significant projects in both conventional and unconventional resources in every major U.S. producing basin and abroad, including oil and gas shale plays, coalbed methane fields, waterfloods and complex, faulted structures. He is currently President of the firm and has managed the Austin office since its opening in 2002. Prior to joining CG&A, Todd worked in Gulf of Mexico drilling and production engineering at Chevron USA in New Orleans, Louisiana. He graduated Magna Cum Laude from the University of Texas at Austin in 1989 with a BS degree in Petroleum Engineering, and is a registered professional engineer in Texas.

The reserves estimates shown for overriding royalty interest in the Tamar field have been independently evaluated by Netherland, Sewell & Associates, Inc. (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. Richard B. Talley, Jr. and Mr. Zachary R. Long. Mr. Talley, a Licensed Professional Engineer in the State of Texas (No. 102425), has been practicing consulting petroleum engineering at NSAI since 2004 and has over 5 years of prior industry experience. He graduated from University of Oklahoma in 1998 with a Bachelor of Science Degree in Mechanical Engineering and from Tulane University in 2001 with a Master of Business Administration Degree. Mr. Long, a Licensed Professional Geoscientist in the State of Texas, Geology (No. 11792), 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. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

ITEM 3. LEGAL PROCEEDINGS

As noted above, the Company owns an overriding royalty interest of 1.5375% in the Tamar Field, which will increase to 2.7375% after payout (the “Tamar Royalty”). With regard to the payout of the Tamar Field, a disagreement between the Company and Isramco Negev 2 Limited Partnership has emerged as to what costs should be included in the calculation of payout. In addition to actual costs for the development of the Tamar Field, Isramco, Negev 2 Limited Partnership has asserted that the following costs should be included in the calculation of payout: (i) Isramco Negev 2 Limited Partnership’s financing costs; (ii) the general and administrative expenses of Isramco Negev 2 Limited Partnership; (iii) the expected decommissioning costs of the Tamar Field; and (iv) expected future payments to be made in respect of the “Sheshinsky Levy” under Israeli law. The disagreement primarily stems from the fact that the agreements governing the creation of the Tamar Royalty were formulated in the 1980s and do not have a clear and unequivocal definition as to what costs should be included in the payout calculation. At the time of initiating arbitration, the Company believed that the total scope of the disagreement was approximately forty-five million dollars ($45,000,000); however, this amount increases each month based on Isramco Negev 2 Limited Partnership's failure to pay the increased, post-payout overriding royalty of 2.7375%. Under the terms of the agreements creating the Tamar Royalty, the dispute is subject to arbitration in Israel. The Company believes that the claims of Isramco Negev 2 Limited Partnership are erroneous and contrary to generally accepted industry practice. The Company expects that the matter will be favorably resolved through this arbitration process; however, the Company cannot be assured of a favorable result in this arbitration process. On February 26, 2017, Isramco Negev 2 Limited Partnership reported the dispute concerning the Tamar Royalty in its filing with the stock exchange in Israel. As noted above, this dispute will be resolved through arbitration proceedings. The Company and Isramco Negev 2-LP have arranged to conduct the arbitration through the Center for Arbitration and Dispute Resolution (CADR) in Israel and have agreed upon the appointment of retired judge Itzhak Inbar to preside over the proceeding. The preliminary arbitration hearing in the matter occurred on August 13, 2017. On February 25, 2018, the Company submitted as Statement of Claim outlining the Company's position with regard to the matter. Currently, the case is in its early stages with the parties expected to complete the discovery process in the coming months. The next hearing before the arbitrator is scheduled for April 14, 2019. The Company believes that its interpretation of the agreements governing the creation of the Tamar Royalty is the correct interpretation and, accordingly, intends to vigorously pursue its case in the aforementioned arbitration proceedings.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Our common stock is listed on the NASDAQ Capital Market under the symbol "ISRL". The following table sets forth for the periods indicated, the reported high and low closing prices for our common stock. As of March 18, 2019, there were approximately 132 holders of record of our common stock.

We have never paid cash dividends on our common stock. We intend to retain earnings for use in the operation and expansion of our business and therefore do not anticipate declaring cash dividends on our common stock in the foreseeable future. Any future determination to pay dividends on common stock will be at the discretion of the board of directors and will be dependent upon then existing conditions, including other factors, as the board of directors deems relevant.

ITEM 6. SELECTED FINANCIAL DATA

The table below contains selected consolidated financial data derived from our Consolidated Financial Statements. The data should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our Consolidated Financial Statements and the related notes included elsewhere in this report.

	Year Ended December 31,				
(thousands, except share and per share amounts)	**2018**	**2017**	**2016**	**2015**	**2014**
Revenues and Income (Loss)					
Total Revenues	81,339	65,947	54,942	74,509	93,898
Net Income (Loss)	17,934	(24,310)	6,745	(17,310)	5,162
Per Share Data					
Earnings (Loss) Per Share - Basic	6.60	(8.95)	2.48	(6.37)	1.90
Earnings (Loss) Per Share - Diluted	6.60	(8.95)	2.48	(6.37)	1.90
Cash Dividends Per Share	-	-	-	-	-
Year-End Stock Price Per Share	118.50	104.65	124.30	89.31	138.00
Weighted Average Shares Outstanding	2,717,648	2,717,648	2,717,648	2,717,648	2,717,648
Basic	2,717,648	2,717,648	2,717,648	2,717,648	2,717,648
Diluted	2,717,648	2,717,648	2,717,648	2,717,648	2,717,648
Total Assets	111,614	108,797	141,272	146,957	158,864

Long-term Obligations	78,365	99,039	116,289	124,567	92,674
Long-Term Debt & Long-Term Accrued Interest	56,193	77,369	95,441	104,252	72,628

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ITEM 7. MANAGEMENT DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

THE FOLLOWING COMMENTARY SHOULD BE READ IN CONJUNCTION WITH THE CONSOLIDATED FINANCIAL STATEMENTS AND RELATED NOTES CONTAINED ELSEWHERE IN THIS FORM 10-K. THE DISCUSSION CONTAINS FORWARD-LOOKING STATEMENTS THAT INVOLVE RISKS AND UNCERTAINTIES. THESE STATEMENTS RELATE TO FUTURE EVENTS OR OUR FUTURE FINANCIAL PERFORMANCE. IN SOME CASES, YOU CAN IDENTIFY THESE FORWARD-LOOKING STATEMENTS BY TERMINOLOGY SUCH AS “MAY,” “WILL,” “SHOULD,” “EXPECT,” “PLAN,” “ANTICIPATE,” “BELIEVE,” “ESTIMA “PREDICT,” “POTENTIAL,” “INTEND,” OR “CONTINUE,” AND SIMILAR EXPRESSIONS. THESE STATEMENTS ARE ONLY PREDICTIONS. OUR ACTUAL RESULTS MAY DIFFER MATERIALLY FROM THOSE ANTICIPATED IN THESE FORWARD-LOOKING STATEMENTS AS A RESULT OF A VARIETY OF FACTORS, INCLUDING, BUT NOT LIMITED TO, THOSE SET FORTH UNDER “RISK FACTORS” AND ELSEWHERE IN THIS FORM 10-K.

Overview

We are an independent oil and natural gas company engaged in the exploration, development, and production of oil and natural gas properties located onshore in the United States and an owner of various royalty interests offshore Israel. Our properties are primarily located in Texas, New Mexico and Oklahoma. We act as the operator of most of our U.S. properties. Historically, we have grown through acquisitions, with a focus on properties within our core operating areas that we believe have significant development and exploration opportunities and where we can apply our technical experience and economies of scale to increase production and proved reserves while lowering lease operating costs. In August, 2011 we created a new production services subsidiary that began operations in October 2011. As of December 2018, the subsidiary had 33 deployed production services rigs and various trucks that operate primarily in Texas and New Mexico. The Company provides a full range of production services such as well completion and wellbore maintenance, workover, fluid transportation and plugging and abandonment services.

Oil and Gas Exploration and Production Segment

Our financial results depend upon many factors, but are largely driven by the volume of our oil and natural gas production and the price that we receive for that production. Our production volumes will decline as reserves are depleted unless we expend capital in successful development and exploration activities or acquire additional properties with existing production. The amount we realize for our production depends predominantly upon commodity prices, which are affected by changes in market demand and supply, as impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, quality, basis differentials and other factors, and secondarily upon our commodity price hedging activities. Accordingly, finding and developing oil and natural gas reserves at economical costs is critical to our long-term success. Our future drilling plans are subject to change based upon various factors, some of which are beyond our control, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. To the extent these factors lead to reductions in our drilling plans and associated capital budgets in future periods, our financial position, cash flows and operating results could be adversely impacted.

We own all ownership units in Tamar Royalties, LLC, which owns an overriding royalty interest of 1.5375% before payout which escalates to 2.7375% after payout in the Tamar Field (collectively the “Tamar Royalty”). An overriding royalty interest is an ownership interest in the oil and gas leasehold estate equating to a certain percentage of production or production revenues, calculated free of the costs of production and development of the underlying lease(s), but subject to its proportionate share of certain post production costs. An overriding royalty interest is a non-possessory interest in the oil and gas leasehold estate and, accordingly, we have no control over the operations, drilling, expenses, timing, production, sales, or any other aspect of development or production of the Tamar Field.

The Tamar Field project began production in March 2013 and is now operational and delivering natural gas to Israel. The natural gas flows from the Tamar Field through the world’s longest subsea tieback, more than 90 miles to the Tamar platform, and then to the Ashdod onshore terminal.

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With regard to the payout of the Tamar Field, a disagreement between the Company and Isramco Negev 2 Limited Partnership has emerged as to what costs should be included in the calculation of payout. In addition to actual costs for the development of the Tamar Field, Isramco, Negev 2 Limited Partnership has asserted that the following costs should be included in the calculation of payout: (i) Isramco Negev 2 Limited Partnership's financing costs; (ii) the general and administrative expenses of Isramco Negev 2 Limited Partnership; (iii) the expected decommissioning costs of the Tamar Field; and (iv) expected future payments to be made in respect of the "Sheshinsky Levy" under Israeli law. In addition to the claim asserted by Isramco Negev 2 Limited Partnership, the Company has asserted counterclaims related to Isramco Negev 2 Limited Partnership's inclusion into the payout calculation of its expenses related to gathering and transportation infrastructure. The disagreements primarily stem from the fact that the agreements governing the creation of the Tamar Royalty were formulated in the 1980s and do not have a clear and unequivocal definition as to what costs should be included in the payout calculation. At the time of initiating arbitration, the Company believed that the total scope of the claim was approximately forty-five million dollars ($45,000,000); however, this amount increases each month based on Isramco Negev 2 Limited Partnership's failure to pay the increased, post-payout overriding royalty to the Company each month. In addition, certain claims asserted by the Company related to post production costs and pipeline infrastructure have not been quantified. Under the terms of the agreements creating the Tamar Royalty, the dispute is subject to arbitration in Israel. The Company believes that the claims of Isramco Negev 2 Limited Partnership are erroneous and contrary to generally accepted industry practice. The Company expects that the matter will be favorably resolved through this arbitration process; however, the Company cannot be assured of a favorable result in this arbitration process.

During year ended December 31, 2018, net sales from the Tamar Field attributable to the Company amounted to 5,591,000 Mcf of natural gas and 7,335 Bbl of condensate with prices of $5.49 per Mcf and $62.95 per Bbl of condensate. Total revenues net of marketing and transportation expenses were $31,036,000. The Israeli Tax Authority withheld $7,138,000 of this revenue.

During year ended December 31, 2017, net sales from the Tamar Field attributable to the Company amounted to 5,343,000 Mcf of natural gas and 6,990 Bbl of condensate with prices of $5.35 per Mcf and $47.46 per Bbl of condensate. Total revenues net of marketing and transportation expenses were $28,781,000. The Israeli Tax Authority withheld $6,907,000 of this revenue.

During year ended December 31, 2016, net sales from the Tamar Field attributable to the Company amounted to 5,102,000 Mcf of natural gas and 6,882 Bbl of condensate with prices of $5.34 per Mcf and $37.48 per Bbl of condensate. Total revenues net of marketing and transportation expenses were $27,462,000. The Israeli Tax Authority withheld $6,866,000 of this revenue.

At December 31, 2018, our estimated total proved oil, natural gas reserves and natural gas liquids, as prepared by our independent reserve engineering firms, Netherland, Sewell & Associates, Inc. and Cawley, Gillespie & Associates, Inc., were approximately 40,267 thousand barrels of oil equivalent ("MBOE"), consisting of 2,125 thousand barrels (MBbls) of oil, 223,915 million cubic feet (MMcf) of natural gas and 823 thousand barrels (MBbls) of natural gas liquids. Approximately 67.2% of our proved reserves were classified as proved developed (See Note 14, "Supplemental

Oil and Gas Information”). Full year 2018 production averaged 3.75 MBOE/d compared to 3.78 MBOE/d in 2017. Tamar Field production share amounted to 2.57 MBOE/d out of total 3.75 MBOE/d compared to 2.46 MBOE/d in 2017.

Production Services Segment

Our core businesses depend on our customers’ willingness to make expenditures to produce, develop and explore for oil and natural gas in the United States. Industry conditions are influenced by numerous factors, such as the supply of and demand for oil and natural gas, domestic and worldwide economic conditions, political instability in oil producing countries and merger and divestiture activity among oil and natural gas producers. The volatility of the oil and natural gas industry, and the consequent impact on exploration and production activity, could adversely impact the level of workover activity by some of our customers. This volatility also affects the demand for our services and the price of our services. In addition, the discovery rate of new oil and natural gas reserves in our market areas also may have an impact on our business, even in an environment of stronger oil and natural gas prices.

We derive a majority of our revenues from services supporting production from existing oil and natural gas operations including in moderate oil and natural gas price environments, ongoing maintenance spending is generally required to sustain production. However, in a low commodity price environment our customers may reduce their budgets resulting in reduced demand for our services. As oil and natural gas prices reach higher levels, demand for all of our services generally increases as our customers engage in more well servicing activities relating to existing wells to maintain or increase oil and natural gas production from those wells. Because our services are required to support drilling and workover activities, our revenues will vary based on changes in capital spending by our customers as oil and natural gas prices increase or decrease.

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The production services market is highly competitive. Competition is influenced by such factors as price, capacity, availability of work crews, and reputation and experience of the service provider. We believe that an important competitive factor in establishing and maintaining long-term customer relationships is having an experienced, skilled and well-trained work force. We believe many of our larger customers place increased emphasis on the safety, performance and quality of the crews, equipment and services provided by their contractors. Although we believe customers consider all of these factors, price is often the primary factor in determining which service provider is awarded the work. However, in numerous instances, we secure and maintain work from large customers for which efficiency, safety, technology, size of fleet and availability of other services are of equal importance to price.

The demand for our services fluctuates, primarily in relation to the price (or anticipated price) of oil and natural gas, which, in turn, is driven primarily by the supply of, and demand for, oil and natural gas. Generally, as supply of those commodities decreases and demand increases, service and maintenance requirements increase as oil and natural gas producers attempt to maximize the productivity of their wells in a higher priced environment. However, in a lower oil and natural gas price environment, demand for service and maintenance generally decreases as oil and natural gas producers decrease their activity. In particular, the demand for new or existing field drilling and completion work is driven by available investment capital for such work. Oil and natural gas producers generally tend to be less risk tolerant when commodity prices are low or volatile, we may experience a more rapid decline in demand for well maintenance services compared with demand for other types of oilfield services. Further, in a low commodity price environment, fewer production services rigs are needed for completions, as these activities are generally associated with drilling activity. The plugging and abandonment work is less affected by prices and generally driven by state regulations and have smaller variations in demand.

The level of our revenues, earnings and cash flows are substantially dependent upon, and affected by, the level of U.S. oil and natural gas exploration, development and production activity, as well as the equipment capacity in any particular region.

Critical Accounting Policies

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our consolidated financial statements requires us to make estimates and assumptions that affect our reported results of operations and the amount of reported assets, liabilities and proved oil and natural gas reserves. Some accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. Actual results may differ from the estimates and assumptions used in the preparation of our consolidated financial statements. Described below are the most significant policies we apply in preparing our consolidated financial statements, some of which are subject to alternative treatments under accounting principles generally accepted in the United States. We also describe the most significant estimates and assumptions we make in applying these policies.

Oil and Natural Gas Activities

Accounting for oil and natural gas activities is subject to unique rules. Two generally accepted methods of accounting for oil and natural gas activities are available - successful efforts and full cost. The most significant differences between these two methods are the treatment of unsuccessful exploration costs and the manner in which the carrying value of oil and natural gas properties are amortized and evaluated for impairment. The successful efforts method requires unsuccessful exploration costs to be expensed as they are incurred upon a determination that the well is uneconomical, while the full cost method provides for the capitalization of these costs. Both methods generally provide for the periodic amortization of capitalized costs based on proved reserve quantities. Impairment of oil and natural gas properties under the successful efforts method is based on an evaluation of the carrying value of individual oil and natural gas properties against their estimated fair value, while impairment under the full cost method requires an evaluation of the carrying value of oil and natural gas properties included in a cost center against the net present value of future cash flows from the related proved reserves, using period-end prices and costs and a 10% discount rate. We account for our natural gas and crude oil exploration and production activities under the successful efforts method of accounting.

Proved Oil and Natural Gas Reserves

Isramco estimates its proved oil and gas reserves as defined by the SEC and the FASB. This definition includes crude oil, natural gas, and NGLs that geological and engineering data demonstrate with reasonable certainty to be economically producible in future periods from known reservoirs under existing economic conditions, operating methods, government regulations, etc., i.e., at prices and costs as of the date the estimates are made. Prices include consideration of price changes provided only by contractual arrangements, and do not include adjustments based upon expected future conditions.

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The Company's estimates of proved reserves are made using available geological and reservoir data, as well as production performance data. These estimates are reviewed annually by our independent reserve engineering firm, Cawley, Gillespie & Associates, Inc and Netherland, Sewell & Associates, Inc. and revised, either upward or downward, as warranted by additional data. Revisions are necessary due to changes in, among other things, reservoir performance, prices, economic conditions, and governmental restrictions, as well as changes in the expected recovery associated with infill drilling. Decreases in prices, for example, may cause a reduction in some proved reserves due to reaching economic limits earlier. A material adverse change in the estimated volumes of proved reserves could have a negative impact on depreciation, depletion and amortization expense (DD&A) and could result in property impairments.

Depreciation, Depletion and Amortization

Our rate of recording DD&A is primarily dependent upon our estimate of proved reserves, which is utilized in our unit-of-production method calculation. If the estimates of proved reserves were to be reduced, the rate at which we record DD&A expense would increase, reducing net income. Such a reduction in reserves may result from lower market prices, which may make it non-economic to drill for and produce higher cost reserves.

Our production services equipment and tools are carried at cost less accumulated depreciation. Depreciation is provided for our assets over the estimated depreciable lives of the assets using the straight-line method. We depreciate our operational assets over their depreciable lives to their salvage value, which is a fair value higher than the assets' value as scrap. When we scrap an asset, we accelerate the depreciation of the asset down to its salvage value. When we dispose of an asset, a gain or loss is recognized.

Impairment

We review our property and equipment in accordance with Accounting Standards Codification (ASC) 360, *Property, Plant, and Equipment* (ASC 360). ASC 360 requires us to evaluate property and equipment as an event occurs or circumstances change that would more likely than not reduce the fair value of the property and equipment below the carrying amount. If the carrying amount of property and equipment is not recoverable from its undiscounted cash flows, then we would recognize an impairment loss for the difference between the carrying amount and the current fair value. Further, we evaluate the remaining useful lives of property and equipment at each reporting period to determine whether events and circumstances warrant a revision to the remaining depreciation periods.

Asset Retirement Obligations

We have significant obligations to remove tangible equipment and facilities associated with our oil and gas wells and to restore land at the end of oil and gas production operations. Our removal and restoration obligations are most often associated with plugging and abandoning wells. Estimating the future restoration and removal costs is difficult and requires us to make estimates and judgments because most of the removal obligations we have will be take effect in the future. Additionally, these operations are subject to private contracts and government regulations that often have vague descriptions of what is required. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Inherent in the present value calculations are numerous assumptions and judgments including the ultimate removal cost amounts, inflation factors, credit adjusted discount rates, timing of obligations and changes in the legal, regulatory, environmental and political environments.

Accounting for Derivative Instruments and Hedging Activities

We have and may utilize derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our anticipated future oil and natural gas production. We may generally hedge a substantial, but varying, portion of our anticipated oil and natural gas production for the next years. We do not use derivative instruments for trading purposes. We have elected not to apply hedge accounting to our derivative contracts, which would potentially allow us to not record the change in fair value of our derivative contracts in the consolidated statements of operations. We carry our derivatives at fair value on our consolidated balance sheets, with the changes in the fair value included in our consolidated statements of operations in the period in which the change occurs.

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Environmental Obligations, Litigation and Other Contingencies

Management makes judgments and estimates in accordance with applicable accounting rules when it establishes reserves for environmental remediation, litigation, and other contingent matters. Provisions for such matters are charged to expense when it is probable that a liability is incurred and reasonable estimates of the liability can be made. Estimates of environmental liabilities are based on a variety of matters, including, but not limited to, the stage of investigation, the stage of the remedial design, evaluation of existing remediation technologies, and presently enacted laws and regulations. In future periods, a number of factors could significantly change the Company's estimate of environmental-remediation costs, such as changes in laws and regulations, changes in the interpretation or administration of laws and regulations, revisions to the remedial design, unanticipated construction problems, identification of additional areas or volumes of contaminated soil and groundwater, and changes in costs of labor, equipment, and technology. Consequently, it is not possible for management to reliably estimate the amount and timing of all future expenditures related to environmental or other contingent matters and actual costs may vary significantly from the Company's estimates. The Company's in-house legal counsel regularly assesses these contingent liabilities and, in certain circumstances, consults with third-party legal counsel or consultants to assist in forming the Company's conclusion.

Income Taxes and Impact of Tax Reform Legislation

The Company follows ASC 740, Income Taxes, (ASC 740), which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the consolidated financial statements or tax returns. Under this method, deferred tax assets and liabilities are computed using the liability method based on the differences between the financial statement and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse.

A valuation allowance is provided, if necessary, to reserve the amount of net operating loss and net deferred tax assets which the Company may not be able to use because of the expiration of maximum carryover periods allowed under applicable tax codes.

On December 22, 2017, the US Congress enacted the Tax Cuts and Jobs Act (Tax Reform Legislation), which made significant changes to US federal income tax law affecting us. See Note 6. Income Taxes.

Liquidity and Capital Resources

Our primary source of cash during the year ended December 31, 2018, was net cash flow from operating activities. We continuously monitor our liquidity and evaluate our development plans in light of a variety of factors, including, but not limited to, our cash flows, capital resources and drilling success.

Our future capital resources and liquidity may depend, in part, on our success in developing the leasehold interests that we have acquired. Cash is required to fund capital expenditures necessary to offset inherent declines in production and proven reserves, which is typical in the capital-intensive oil and gas industry. Future success in growing reserves and production will be highly dependent on the capital resources available and our success in finding and acquiring additional reserves. Our production services subsidiary also requires capital resources to acquire and maintain equipment. We expect to fund our future capital requirements through internally generated cash flows, and borrowings under loans and the credit facility described below. Long-term cash flows are subject to a number of variables, including the level of production, prices, amount of work orders received, and our commodity price hedging activities, as well as various economic conditions that have historically affected the oil and natural gas industry.

On May 18, 2015, Tamar Royalties LLC (“Tamar Royalties”), a newly formed, wholly-owned, special purpose subsidiary of the Company entered into a term loan credit agreement (the “DB Facility”) with Deutsche Bank Trust Company Americas (“Deutsche Bank”) in the amount of $120,000,000 secured by the Company’s interest in the Tamar field. Interest on the borrowing is subject to fluctuations in LIBOR. The Company entered into interest rate swap agreements in relation to this borrowing. The terms of the agreement and swaps are disclosed in Notes 4 and 5.

On June 30, 2015, the Company obtained a credit facility (the “SG Facility”) with The Société Générale. The SG facility provided for a commitment by The Société Générale of $150,000,000, subject to an initial borrowing base of $40,000,000. The tenure of the SG Facility was four (4) years and it was secured by certain onshore United States oil and gas properties. Interest on borrowing was variable as disclosed in Note 5 “Long-Term Debt and Interest Expense”. On February 28, 2017 the SG Facility was terminated.

During the year ended December 31, 2018, our cash (including restricted cash) decreased by $6,494,000. Specifically, net cash from operating activities of $17,167,000, was offset by cash used in investing activities of $7,394,000 and cash used in financing activities of $16,267,000.

(See Item 1A “Risk Factors”).

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Commitments and Contingencies

As is common within the oil and natural gas industry, we have entered into various commitments and operating agreements related to the exploration and development of and production from proved oil and natural gas properties. It is our belief that such commitments will be met without a material adverse effect on our financial position, results of operations or cash flows.

Contractual Obligations: Aggregate maturities of contractual obligations at December 31, 2018 are due in future years as follows (in thousands):

Principal Payments on Long-term debt:

2019	$21,900
2020	17,100
2021	14,700
2022	14,400
2023	11,400
Total	$79,500

Debt

	As of December 31,		
	2018	**2017**	**2016**
	(In thousands except percentage)		
Long – term debt net of discount and bank fees	56,193	77,369	95,441
Short – term debt – related party *(1)*	3,671	-	-
Current maturities of long-term debt, short-term debt, net of current portion of discount and debt cost and bank overdraft	21,739	18,517	9,147
Total debt	81,603	95,886	104,588
Stockholders’ equity (deficit)	(7,359)	(23,818)	2,016
Debt to capital ratio	110 %	133 %	98 %

(1) The amounts are inclusive of accrued interest due to related party.

At year-end 2018, our total debt was $81,603,000 compared to total debt of $95,886,000 at year-end 2017 and $104,588,000 at year-end 2016.

Bank Loan and Credit Facility

The Deutsche Bank Facility

On May 18, 2015, Tamar Royalties LLC (“Tamar Royalties”), a newly formed, wholly-owned, special purpose subsidiary of the Company, entered into a term loan credit agreement (the “DB Facility”) with Deutsche Bank Trust Company Americas (“Deutsche Bank”), as facility agent for the lenders and as collateral agent for the secured parties, and with the lenders party thereto. The DB Facility provides for borrowings in the amount of $120,000,000 on a committed basis and is secured by, among other things, an overriding royalty interest in the Tamar Field, a natural gas field in the Mediterranean Sea, equal to 1.5375% before payout increasing to 2.7375% after payout in the Tamar Field (the “Royalty Interest”). In connection with the DB Facility, and pursuant to a royalties sale and contribution agreement, the Company contributed the Royalty Interest to Tamar Royalties in exchange for all of the ownership units of Tamar Royalties. Pursuant to the terms of its governing documents, Tamar Royalties will be managed by N.M.A. Energy Resources Ltd, a related party of the Company, and an independent manager, Donald J. Puglisi.

Pursuant to the terms of the DB Facility, Tamar Royalties borrowed $120,000,000 in its initial borrowing under this facility. The initial borrowing under the DB Facility bears annual interest based on the LIBOR for a three-month interest period plus a spread of 2.75%. The $120,000,000 initial borrowing under the DB Facility will be repaid over eight (8) years commencing July 1, 2015, in accordance with an amortization profile based on projected cash flows from the Royalty Interest. Tamar Royalties' obligations under the Facility are secured by a first ranking pledge of the shares of Tamar Royalties, first ranking pledge of all rights under the agreements creating the Royalty Interest, and a first priority security interest over the accounts created under the DB Facility.

So long as any amounts remain outstanding to the Lenders under the DB Facility, Tamar Royalties must, from and after the end of the Availability Period (as defined in the DB Facility), have a Historical Debt Service Coverage Ratio (as defined in the DB Facility) of not less than 1.00:1.00, a Loan Life Coverage Ratio (as defined in the DB Facility) of at least 1.1:1.00, and maintain a Required Reserve Amount (as defined in the DB Facility). In addition, Tamar Royalties is required under the DB facility to hedge against fluctuations in LIBOR as reflected in Note 4 "Financial Instruments and Fair Value".

The amortization schedule under the DB Facility was based on the projection that the Investment Repayment Date (as defined therein) would occur at some point before the end of the first quarter of 2018 and therefore, commencing from the Payment Date occurring on 1st April 2018, the amounts to be repaid on each payment date under the credit agreement increase to reflect the expected increase in the Royalties Receivables (as defined therein) as a result of the increase in the royalty percentage following the Investment Repayment Date.

As noted above with regard to the payout of the Tamar Field, a disagreement between Tamar Royalties and Isramco Negev 2 Limited Partnership has emerged as to whether certain items may be included in the calculation of payout. The disagreement largely stems from the fact that the agreements governing the creation of the Tamar Royalty were formulated in the 1980s and do not have a clear and unequivocal definition as to what costs should be included in the payout calculation. At the time of initiating arbitration, the Company believed that the total scope of the claim was approximately forty-five million dollars ($45,000,000); however, this amount increases each month based on Isramco Negev 2 Limited Partnership's failure to pay the increased, post-payout overriding royalty to the Company. Under the terms of the agreements creating the Tamar Royalty, the dispute is subject to arbitration in Israel. The Company expects that the matter will be resolved through this arbitration process. However, the Company cannot be assured of a favorable result resulting from this arbitration process. Accordingly, the Company continues to receive royalty payments at the lower rates as if the Investment Repayment Date has not occurred.

Therefore, as a result of the dispute with the Isramco Negev 2, Tamar Royalties has a shortfall in its Royalties Receivables for the period (or part of the period) between 1st April 2018 and 1st April 2019, by which time, even if the Isramco Negev 2's claims regarding the Investment Repayment Date are accepted, the Investment Repayment Date is expected to occur.

As a result, the Company believes Tamar Royalties required an additional $15,600,000 USD to cover payments under the amortization schedule of the DB Facility (the “Shortfall”), and the Company believes that curing the Shortfall was in the best interest of both Isramco Inc. and Tamar Royalties. Therefore, Isramco Inc. contributed the expected amount of the Shortfall, being $15,600,000 USD, to Tamar Royalties as an additional capital contribution and such contribution was made pursuant to the terms and conditions of that certain Consent and Agreement dated February 27, 2018, between and among Tamar Royalties, as Borrower, Deutsche Bank Trust Company Americas, as Facility Agent and Collateral Agent, and the Lenders party thereto. As a result of the aforementioned contribution, together with the terms and conditions of the aforementioned consent and assignment, Tamar Royalties remains in compliance with all covenants of the DB Facility.

In 2015 the Company incurred debt costs in obtaining the facility in the amount of $2,011,000 and $2,959,000 in fees were retained by the lenders. These costs totaling $4,970,000 were recorded as a reduction of the principal loan balance and are being amortized over the life of the loan using the effective interest method. Amortization of these costs for the twelve months ended December 31, 2018, 2017, and 2016 totaled $828,000, $789,000, and $820,000 respectively.

In connection with the DB Facility, the Company and Tamar Royalties entered into an Intercompany Loan Agreement dated May 18, 2015 (the “Intercompany Loan Agreement”). Pursuant to the terms of the Intercompany Loan Agreement, Tamar Royalties LLC provided a loan to the Company in an aggregate principal amount of $108,000,000 USD. The purpose of the Intercompany Loan was to repay indebtedness owed by the Company to related parties, to enable acquisitions and capital expenditures by the Company, and for other general corporate purposes of the Company.

As of December 31, 2018, Tamar Royalties was in compliance with the financial covenants required under the DB Facility.

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The Société Générale Facility

On June 30, 2015, Isramco Onshore LLC (“Isramco Onshore”), a newly formed, wholly-owned, subsidiary of Isramco, Inc. (the “Company”), entered into a secured Credit Agreement (the “SG Facility”) with The Société Générale, as Administrative Agent and Issuing Lender, SG Americas Securities LLC, as Sole Bookrunner, Lead Arranger and Documentation Agent, and the lenders party thereto from time to time, as Lenders. The SG Facility provides for a commitment by The Société Générale of $150,000,000, subject to an initial borrowing base of $40,000,000. The tenure of the SG Facility was four (4) years and the SG Facility was secured by certain onshore United States oil and gas properties. Pricing under the SG Facility was as follows: (i) for EuroDollar Rate (as defined in the SG Facility) loans range from the EuroDollar rate plus 1.75% to the EuroDollar rate plus 2.75% depending on borrowing base utilization; and (ii) for Reference Rate (as defined in the SG Facility) loans ranges from the Reference Rate plus 0.75% to the Reference Rate Spread plus 1.75% based on borrowing base utilization; (iii) a quarterly commitment fee (as defined in the SG Facility) ranging from an annual rate of 0.38% to 0.5% of the undrawn borrowing base.

The SG Facility provided that Isramco Onshore hedge at least seventy-five percent (75%) of its crude oil production before borrowing under the SG Facility. As of December 31, 2018 and as of the date of issuance Isramco Onshore has not entered into such hedge agreements nor has it made a draw under the SG Facility. The Company incurred $478,000 of financing costs in relation to this credit facility which were capitalized as a long-term asset and amortized over the term on the agreement on a straight-line basis until December 31, 2016 at which time the remaining balance totaling $299,000 was expensed.

Isramco Onshore had various financial and operating covenants required by the SG Facility, including, among other things, the requirement that, during the term of the SG Facility, Isramco Onshore must have a Minimum Current Ratio (as defined in the SG Facility) of not less than 1.00:1.00, a Maximum Leverage Ratio (as defined in the SG Facility) of not less than 4.00:1.00 and a Minimum Interest Coverage Ratio (as defined in the SG Facility) of at least 2.50:1.00. In addition, the SG Facility provided for customary events of default, including, but not limited to, payment defaults, breach of representations or covenants, bankruptcy events and change of control.

On August 18, 2016 as a result of semi-annual borrowing base redetermination the borrowing base under SG Facility was reduced to zero. On February 28, 2017 the SG Facility was terminated.

Short-term related party debt

In September 2018 the Company issued an unsecured promissory note dated effective September 11, 2018, to I.O.C - Israel Oil Company LTD (“IOC”) a related party in which the company may borrow up to $7,000,000 at a rate of interest equal to seven and one-half percent (7.5%) and with a maturity date of September 2019. The company received $3,600,000 under this related party note in 2018 attendant with the creation of a new subsidiary, Arrow Midstream LLC. Amounts received under the aforementioned promissory note are dedicated to working capital and the purchase of equipment for Arrow Midstream LLC, a new wholly owned subsidiary of Isramco Inc. Arrow Midstream is focused on the transportation of liquefied petroleum products including, but not limited to, butane, propane, and similar products.

Mr. Haim Tsuff, Isramco's Co-Chief Executive Officer and Chairman and is a controlling shareholder of IOC.

Isramco also had related party payables of $165,000 and $60,000 as of December 31, 2018 and 2017 respectively which are included with short term related party debt on the balance sheets.

Off-Balance Sheet Arrangements

At December 31, 2018, we did not have any off-balance sheet arrangements.

Cash Flow

Our primary source of cash in 2018 was cash flow from operating activities. In 2018, cash received from operations and proceeds from sale of oil and gas properties was primarily used for repayment of long-term debt, short-term debt, investments in equipment.

Our primary source of cash in 2017 was cash flow from operating activities. In 2017, cash received from operations and proceeds from sale of oil and gas properties was primarily used for repayment of long-term debt, short-term debt, investments in equipment

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Our primary source of cash in 2016 was cash flow from operating activities. In 2016, cash received from operations and proceeds from sale of oil and gas properties was primarily used for repayment of long-term debt, short-term debt, investments in equipment.

Operating cash flow fluctuations were substantially driven by changes in commodity prices and changes in our production volumes. Working capital was substantially influenced by these variables. Fluctuation in commodity prices and our overall cash flow may result in an increase or decrease in our future capital expenditures. Prices for oil and natural gas have historically been subject to seasonal fluctuations characterized by peak demand and higher prices in the winter heating season; however, the impact of other risks and uncertainties have influenced prices throughout recent years. See Results of Operations below for a review of the impact of prices and volumes on sales.

	Years Ended December 31,		
	2018	**2017**	**2016**
	(In thousands)		
Cash flows provided by operating activities	$17,167	$18,552	$15,510
Cash flows (used in) investing activities	(7,394)	(1,461)	(250)
Cash flows (used in) financing activities	(16,267)	(10,519)	(10,691)
Net increase (decrease) in cash	$(6,494)	$6,572	$4,569

Operating Activities, Net cash flows provided by operating activities were $17,167,000, $18,552,000, and $15,510,000 for the years ended December 31, 2018, 2017 and 2016, respectively. Key drivers of net operating cash flows are commodity prices, production volumes, operating costs, proceeds from an overriding royalty interest in the Tamar Field and activities of our production services subsidiary.

During the year ended December 31, 2018, compared to the same period in 2017, net cash flow provided by operating activities decreased by $1,385,000 to $17,167,000.

During the year ended December 31, 2017, compared to the same period in 2016, net cash flow provided by operating activities increased by $3,042,000 to $18,552,000.

We are unable to predict future production levels, future commodity prices, future proceeds from our Tamar Field royalties, and future revenues generated by our production services segment; therefore, we cannot predict future levels of net cash provided by operating activities.

Investing Activities, Net cash flows used in investing activities for the twelve months ended December 31, 2018 and 2017 were $7,394,000 and $1,461,000, respectively. During 2018 and 2017 the Company invested in equipment and oil and gas properties in amounts equal to $8,997,000 ($796,000 in oil and gas properties and $8,201,000 in production services equipment) and $4,184,000 ($615,000 in oil and gas properties and $3,569,000 in production services equipment) respectively. During 2018 the Company received $1,435,000 from the sale of oil and gas properties and received $168,000 from the sale of equipment.

Net cash flows used in investing activities for the twelve months ended December 31, 2017 and 2016 were $1,461,000 and $250,000, respectively. During 2017 and 2016 the Company invested in equipment and oil and gas properties in amounts equal to $4,184,000 ($615,000 in oil and gas properties and $3,569,000 in production services equipment) and $794,000 ($157,000 in oil and gas properties and $637,000 in production services equipment), respectively. During 2017 the Company received $2,705,000 from the sale of oil and gas properties, invested $31,000 in a LLC, and received $49,000 from the sale of equipment.

Financing Activities, Net cash flows used in financing activities were $16,267,000 and $10,519,000 for the year ended December 31, 2018 and 2017, respectively. In 2018, the Company made $18,900,000 in principal loan payments. The Company also repaid short-term insurance financing of $950,000, received $3,600,000 from related party financing, and paid $17,000 to non-controlling interests.

Net cash flows used in financing activities were $10,519,000 and $10,691,000 for the year ended December 31, 2017 and 2016, respectively. In 2017, the Company made $9,600,000 in principal loan payments. The Company also repaid short-term insurance financing of $911,000.

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Results of Continuing Operations

Selected Data

	Years Ended December 31, 2018	2017	2016
	(In thousands except per share and MBOE amounts)		
Financial Results			
Oil and Gas sales			
United States	$15,932	$15,109	$12,947
Israel	31,036	28,781	27,462
Production services	31,825	18,265	12,752
Gain on divestiture	1,452	2,703	600
Other	1,094	1,089	1,181
Total revenues and other	81,339	65,947	54,942
Cost and expenses	53,426	41,321	40,875
Other expense	4,299	4,815	5,544
Income tax expense	7,138	45,637	3,634
Net income (loss) attributable to common shareholders	16,476	(25,826)	4,889
Net loss attributable to noncontrolling interests	(1,458)	(1,516)	(1,856)
Net income (loss) attributable to Isramco	17,934	(24,310)	6,745
Earnings (loss) per common share – basic	$6.60	$(8.95)	$2.48
Earnings (loss) per common share –diluted	$6.60	$(8.95)	$2.48
Weighted average number of shares outstanding-basic	2,717,648	2,717,648	2,717,648
Weighted average number of shares outstanding- diluted	2,717,648	2,717,648	2,717,648
Operating Results			
Adjusted EBITDAX (1)	$35,319	$31,970	$24,847
Total proved reserves (MBOE)	40,267	38,653	34,582
Sales volumes United States (MBOE)	430	483	528
Sales volumes Israel (MBOE)	939	897	857
Average cost per BOE - United States:			
Production (excluding transportation and taxes)	$18.11	$15.79	$13.76
General and administrative	$13.55	$9.65	$8.49
Depletion of oil and gas properties	$4.39	$5.08	$6.58

(1) See Adjusted EBITDAX for a description of Adjusted EBITDAX, which is not a Generally Accepted Accounting Principles (GAAP) measure, and a reconciliation of Adjusted EBITDAX to income from operations before income taxes, which is presented in accordance with GAAP.

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Financial Results

Net Income (Loss)

In 2018 our net income was $17,934,000, or $6.60 per share. This compares to net loss of $(24,310,000), or $(8.95) per share for the year ended December 31, 2017.

In 2017 the Company had a one-time increase in allowance for foreign tax credit and deferred tax assets. We fully allowed for our accumulated future tax credit related to the taxes withheld by the Israeli taxing authorities. The valuation allowance amounted to $28,677,000. Total foreign tax credit balance was written off in 2018 after the passing of new tax legislation in the United States which lowered the corporate tax rate to a level that eliminated the forecasted usage of the accumulated foreign tax credit. Likewise, we increased our allowance to fully allow for our deferred tax assets (see Note 6 – Income Tax to the Company's consolidated financial statements). Net income comparatively increased in 2018 because we had no such increase in the allowance in 2018. In addition, the average commodity prices in 2018 were more than those of 2017, increasing our production revenues despite lower production volumes in the United States.

In 2017 our net loss was $(24,310,000), or $(8.95) per share. This compares to net income of $6,745,000, or $2.48 per share for the year ended December 31, 2016.

This decrease in income is primarily due to the increase in allowance for foreign tax credit and deferred tax assets. We fully allowed for our accumulated future tax credit related to the taxes withheld by the Israeli taxing authorities. The valuation allowance amounted to $28,677,000. Total foreign tax credit balance was written off after the passing of new tax legislation in the United States which lowered the corporate tax rate to a level that eliminated the forecasted usage of the accumulated foreign tax credit. Likewise we increased our allowance to fully allow for our deferred tax assets (see Note 6 – Income Taxes to the Company's consolidated financial statements). Income Tax. This increase in tax expense was partially offset by increased revenues from our United States based production operations, increased revenues from the Tamar field, increased revenues from production service activities, and an increased in gain on divestiture.

Revenues, Volumes and Average Prices Oil and Gas Segment - Israel

During year ended December 31, 2018, net sales from the Tamar Field attributable to the Company amounted to 5,591,000 Mcf of natural gas and 7,335 Bbl of condensate with prices of $5.49 per Mcf and $62.95 per Bbl of condensate. Total revenues net of marketing and transportation expenses were $31,036,000. The Israeli Tax Authority withheld $7,138,000 of this revenue.

During year ended December 31, 2017, net sales from the Tamar Field attributable to the Company amounted to 5,343,000 Mcf of natural gas and 6,990 Bbl of condensate with prices of $5.35 per Mcf and $47.46 per Bbl of condensate. Total revenues net of marketing and transportation expenses were $28,781,000. The Israeli Tax Authority withheld $6,907,000 of this revenue.

During the year ended December 31, 2016, net sales from the Tamar Field attributable to the Company amounted to 5,102,000 Mcf of natural gas and 6,882 Bbl of condensate with prices of $5.34 per Mcf and $37.48 per Bbl of condensate. Total revenues net of marketing and transportation expenses were $27,462,000. The Israeli Tax Authority withheld $6,866,000, of this revenue.

Revenues, Volumes and Average Prices Oil and Gas Segment - United States

Sales Revenues

	Years Ended December 31,				
In thousands except percentages	**2018**	**2017**	**Dvs. 2017**	**2016**	**D vs. 2016**
Gas sales	$3,133	$3,955	(21)%	$3,209	23 %
Oil sales	11,195	9,558	17	8,506	12
Natural gas liquid sales	1,604	1,596	1	1,232	30
Total	$15,932	$15,109	5 %	$12,947	17 %

Our sales revenues for the year ended December 31, 2018 increased by 5% when compared to the same period of 2017, due to increase in prices for crude oil and natural gas liquids partially offset by reduced production volumes and reduced prices for natural gas. Our sales revenues for the year ended December 31, 2017 increased by 17% when compared to the same period of 2016, primarily due to increase in prices for natural gas, crude oil, and natural gas liquids partially offset by reduced production volumes.

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Volumes and Average Prices

	Years Ended December 31,				
	2018	2017	D vs. 2017	2016	D vs. 2016
Natural Gas					
Sales volumes Mmcf	1,119	1,320	(15)%	1,417	(7)%
Price per Mcf	$2.80	$3.00	(7)	$2.26	33
Total gas sales revenues (thousands)	$3,133	$3,955	(21)%	$3,209	23 %
Crude Oil					
Sales volumes MBbl	184	196	(6)%	215	(9)%
Price per Bbl	$60.84	$48.77	25	$39.56	23
Total oil sales revenues (thousands)	$11,195	$9,558	17 %	$8,506	12 %
Natural gas liquids					
Sales volumes MBbl	59	67	(12)%	77	(13)%
Price per Bbl	$27.19	$23.82	14	$16.00	49
Total natural gas liquids sales revenues (thousands)	$1,604	$1,596	1 %	$1,232	30 %

The Company's natural gas sales volumes decreased by 15%, crude oil sales volumes decreased by 6% and natural gas liquids sales volumes decreased by 12% for the year ended December 31, 2018 compared to the same period of 2017.

Our average natural gas price for the year ended December 31, 2018 decreased by 7%, or $0.20 per Mcf, when compared to the same period of 2017. Our average crude oil price for the year ended December 31, 2018 increased by 25%, or $12.07 per Bbl, when compared to the same period of 2017. Our average natural gas liquids price for the year ended December 31, 2018 increased by 14%, or $3.37 per Bbl, when compared to the same period of 2017.

The Company's natural gas sales volumes decreased by 7%, crude oil sales volumes decreased by 9% and natural gas liquids sales volumes decreased by 13% for the year ended December 31, 2017 compared to the same period of 2016.

Our average natural gas price for the year ended December 31, 2017 increased by 33%, or $0.74 per Mcf, when compared to the same period of 2016. Our average crude oil price for the year ended December 31, 2017 increased by 23%, or $9.21 per Bbl, when compared to the same period of 2016. Our average natural gas liquids price for the year ended December 31, 2017 increased by 49%, or $7.82 per Bbl, when compared to the same period of 2016.

Analysis of Oil and Gas Operations Sales Revenues

The following table provides a summary of the effects of changes in volumes and prices on Isramco's sales revenues for the year ended December 31, 2018 compared to 2017 and 2016.

In thousands	**Natural Gas**	**Oil**	**Natural gas liquids**
2016 sales revenues	$ 3,209	$ 8,506	$ 1,232
Changes associated with sales volumes	(220)	(752)	(160)
Changes in prices	966	1,804)	524
2017 sales revenues	$ 3,955	$ 9,558	$ 1,596
Changes associated with sales volumes	(602)	(585)	(191)
Changes in prices	(220)	2,222	199
2018 sales revenues	$ 3,133	$ 11,195	$ 1,604

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Operating Expenses (excluding production services segment)

	Years Ended December 31,				
In thousands except percentages	**2018**	**2017**	**D vs. 2017**	**2016**	**D vs. 2016**
Lease operating expense, transportation and taxes	$9,381	$9,478	(1)%	$8,925	6 %
Depreciation, depletion and amortization of oil and gas properties	1,886	2,454	(23)	3,474	(29)
Impairments of oil and gas assets	1,252	1,682	(26)	4,529	(63)
Accretion expense	869	913	(5)	897	2
Loss from plug and abandonment	281	26	NM	(3)	NM
General and administrative	5,821	4,662	25	4,485	4
	$19,490	$19,215	1 %	$22,307	(14)%

NM – Not Meaningful

During 2018, our operating expenses increased by 1% when compared to 2017 as highlighted below:

Lease operating expense, transportation cost and taxes decreased by 1%, or $97,000 in 2018 when compared to 2017. On a per unit basis, lease operating expenses (excluding transportation and taxes) increased by $2.32 per MBOE to $18.11 per MBOE in 2018 from $15.79 per MBOE in 2017. The increase was a result of an increase in repair and maintenance activity.

Depreciation, Depletion & Amortization (DD&A) of the cost of proved oil and gas properties is calculated using the unit-of-production method. Our DD&A rate and expense are the composite of numerous individual field calculations. There are several factors that can impact our composite DD&A rate and expense, including but not limited to field production profiles, drilling or acquisition of new wells, disposition of existing wells, and reserve revisions (upward or downward) primarily related to well performance and commodity prices, and impairments. Changes in these factors may cause our composite DD&A rate and expense to fluctuate from period to period. DD&A decreased by 23%, or $568,000, in 2018 when compared to 2017. On a per unit basis, depletion expenses decreased by $0.69 per MBOE to $4.39 per MBOE in 2018 from $5.08 per MBOE in 2017 due to a lower beginning balance resulted from previous years impairments and lower production volumes compared to 2017.

Impairments of oil and gas assets of $1,252,000 in 2018 were primarily the result of lower estimated future production in several fields which reduced the projected value in those fields from prior estimates and resulted in a projected value lower than the carrying value of those fields which triggered impairment.

Loss from plugging and abandonment expenses increased by $255,000 in 2018 when compared to 2017, primarily due to larger than planned costs to plug non-operated wells.

General and administrative expenses increased by 25% or $1,159,000 primarily as a result of increased professional fees in 2018 as compared to 2017.

During 2017, our operating expenses decreased by 14% when compared to 2016 as highlighted below:

Lease operating expense, transportation cost and taxes increased by 6%, or $553,000 in 2017 when compared to 2016. On a per unit basis, lease operating expenses (excluding transportation and taxes) increased by $2.03 per MBOE to $15.79 per MBOE in 2017 from $13.76 per MBOE in 2016. The increase was a result of an increase in repair and maintenance activity as oil, natural gas and NGLs prices increased.

Depreciation, Depletion &Amortization (DD&A) of the cost of proved oil and gas properties is calculated using the unit-of-production method. Our DD&A rate and expense are the composite of numerous individual field calculations. There are several factors that can impact our composite DD&A rate and expense, including but not limited to field production profiles, drilling or acquisition of new wells, disposition of existing wells, and reserve revisions (upward or downward) primarily related to well performance and commodity prices, and impairments. Changes in these factors may cause our composite DD&A rate and expense to fluctuate from period to period. DD&A decreased by 29%, or $1,020,000, in 2017 when compared to 2016. On a per unit basis, depletion expenses decreased by $1.50 per MBOE to $5.08 per MBOE in 2017 from $6.58 per MBOE in 2016 due to a lower beginning balance resulted from previous years impairments and lower production volumes compared to 2016.

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Impairments of oil and gas assets of $1,682,000 in 2017 were primarily the result of lower estimated future production in several fields which reduced the projected value in those fields from prior estimates and resulted in a projected value lower than the carrying value of those fields which triggered impairment.

Loss from plugging and abandonment expenses increased by $29,000 in 2017 when compared to 2016, primarily due to an increase in the wells plugged in 2017.

General and administrative expenses increased as a result of increased professional fees. This increase was partially offset by a lesser increase in allowance for doubtful accounts and no write off of deferred financing costs as had occurred in 2016.

Production Services Segment

	Years Ended December 31,							
In thousands except percentages	**2018**	**2017**	**D vs. 2017**		**2016**	**D vs. 2016**	
Production Services *(1)*	$32,164	$18,265	76	%	$12,752	43	%
Operating expenses	29,725	18,241	63		14,494	26	
Depreciation	3,657	3,072	19		3,193	(4	)
General and administrative *(1)*	1,013	913	11		1,001	(9	)
Operating income	$(2,231)	$(3,961)	44	%	$(5,936)	33	%

(1) Production Services revenue includes intersegment revenues and expenses.

The revenues from production services operations in 2018 increased by 76% or $13,899,000 when compared to 2017 primarily due to a continued rebound in crude oil prices which resulted in growth in our trucking services through customer acquisition. The revenues from production services operations in 2017 increased by 43% or $5,513,000 when compared to 2016 primarily due to a rebound in crude oil prices which resulted in growth in our trucking services through customer acquisition.

Operating expenses from production services operations for the year ended December 31, 2018 has increased by 63% or $11,484,000 when compared to the same period in 2017. The increase was primarily associated with an increase in payroll, fuel, and other related expenses as a result of increase in trucking services. Operating expenses from production services operations for the year ended December 31, 2017 has increased by 26% or $3,747,000 when compared to the same period in 2016. The increase was primarily associated with an increase in payroll, fuel, and other related expenses as a result of increase in trucking services.

Production service equipment depreciation – the amounts represent depreciation for our production services rigs and auxiliary equipment. The depreciation expense for the year ended December 31, 2018 increased by $585,000 compared to 2017 as a result of increased investment in equipment. The depreciation expense for the year ended December 31, 2017 decreased by $121,000 compared to 2016.

For the year ended December 31, 2018 general and administrative expenses increased by 11% or $100,000 from 2017 primarily as a result of increased professional fees and increase in the allowance for doubtful accounts partially offset by decreased legal fees. For the year ended December 31, 2017 general and administrative expenses decreased by 9% or $88,000 from 2016 primarily as a result of lesser increase in the allowance for doubtful accounts partially offset by increased legal fees.

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Other expenses

	Years Ended December 31,				
In thousands except percentages	**2018**	**2017**	**D vs. 2017**	**2016**	**D vs. 2016**
Interest expense net	$4,921	$4,784	3 %	$4,817	(1)%
Interest expense – related party, net	71	-	NM	-	0
Loss (gain) from derivative contracts, net	(680)	176	486	657	(73)
Capital (gain) loss	(13)	(145)	(91)	70	307
	$4,299	$4,815	(11)%	$5,544	(13)%

Net interest expense. Isramco's interest expense increased, by $208,000 for the twelve months ended December 31, 2018 compared to the same period of 2017 as indexed interest rate on the DB Facility increased with increased LIBOR rates. Also, the Company secured additional related party financing which increased the principal outstanding under the DB Facility. These increases were partially offset by the reduced principal balance on the DB Facility from principal payments.

Net Interest expense. Isramco's interest expense decreased only slightly, by $33,000 for the twelve months ended December 31, 2017 compared to the same period of 2016 as increased interest income from investment and the reduced principal balance on loans was partially offset by the increase in the indexed interest rate.

Net loss on derivative contracts. During 2015 we entered into interest rate cap and swap agreements. These agreements are considered derivative and are accounted for with mark-to-market valuation. The loss in fair value of these contracts is recorded in the statement of operations. The loss from derivative contracts decreased from $657,000 in 2016 and to $176,000 in 2017 and turned to a gain of $680,000 in 2018 primarily as a result of an increase in the estimated future LIBOR rate which is a factor in determining the market value of the derivatives.

Income Taxes and Impact of Tax Reform Legislation

Income tax expense for the year ended December 31, 2018 was $7,138,000. The tax expense was primarily due to the tax withheld by the Israel taxation authorities on Tamar Field proceeds.

Income tax expense for the year ended December 31, 2017 was $45,637,000. The tax expense was primarily due to the full allowance of amounts previously in deferred tax assets as future tax credits related to tax withheld by the Israel taxation authorities on Tamar Field proceeds and the full allowance of other deferred tax assets. On December 22, 2017, the US Congress enacted the Tax Reform Legislation, which made significant changes to US federal income tax law, including a reduction in the federal corporate tax rate to 21% effective January 1, 2018. Under US GAAP, we are required to recognize the effect of a rate change on deferred tax assets and liabilities in the period in which the tax rate change is enacted. At the lower tax rate, we projected that we would not be able to recover accumulated foreign tax credits balance to reduce our future tax burden and therefore recorded a full valuation allowance of $31,091,000. In addition, a full valuation allowance was recorded to reduce deferred tax assets balances as of December 31, 2017 due to uncertainty in their future recoverability - see Note 6 Income Taxes. Our pre-tax income of $19,811,000 for 2017 increased by $11,288,000 from pre-tax income in 2016 of $8,523,000. This increase in pre-tax income from 2016 to 2017 was primarily the result of a $5,513,000 increase in production services revenues, a $2,162,000 increase revenues from United States based oil and gas assets, a $2,103,000 increase in gain on divestiture, and a $1,319,000 increase in Tamar Field proceeds. This increase was partially offset by increased operating expenses.

The effective tax rates for the years ended December 31, 2018, 2017 and 2016 were 30.2%, 230.4% and 42.6%, respectively.

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Adjusted EBITDAX

To assess the operating results of Isramco, management analyzes income from operations before income taxes, interest expense, exploration expense, unrealized gain (loss) on derivative contracts and DD&A expense and impairments ("Adjusted EBITDAX"). Adjusted EBITDAX is not a GAAP measure. Isramco's definition of Adjusted EBITDAX excludes exploration expense because exploration expense is not an indicator of operating efficiency for a given reporting period, but rather is monitored by management as a part of the costs incurred in exploration and development activities. Similarly, Isramco excludes DD&A expense and impairments from Adjusted EBITDAX as a measure of segment operating performance because capital expenditures are evaluated at the time capital costs are incurred. The Company's definition of Adjusted EBITDAX also excludes interest expense to allow for assessment of segment operating results without regard to Isramco's financing methods or capital structure. Adjusted EBITDAX is a widely accepted financial indicator of a company's ability to incur and service debt, fund capital expenditures and make payments on its long term loans. Management believes that the presentation of Adjusted EBITDAX provides information useful in assessing the Company's financial condition and results of operations.

However, Adjusted EBITDAX, as defined by Isramco, may not be comparable to similarly titled measures used by other companies. Therefore, Isramco's consolidated Adjusted EBITDAX should be considered in conjunction with income (loss) from operations and other performance measures prepared in accordance with GAAP, such as operating income or cash flow from operating activities. Adjusted EBITDAX has important limitations as an analytical tool because it excludes certain items that affect income from continuing operations and net cash provided by operating activities. Adjusted EBITDAX should not be considered in isolation or as a substitute for an analysis of Isramco's results as reported under GAAP. Below is a reconciliation of consolidated Adjusted EBITDAX to income (loss) from operations before income taxes.

	Years Ended December 31,		
In thousands	**2018**	**2017**	**2016**
Income from operations before income taxes *(1)*	$23,614	$19,811	$8,523
Depreciation, depletion, amortization and impairment expense	6,795	7,208	11,196
Interest expense, net	4,992	4,784	4,817
(Gain) on derivative contract	(951)	(746)	(586)
Accretion Expenses	869	913	897
Consolidated Adjusted EBITDAX	$35,319	$31,970	$24,847

(1) Including net gain on divestiture of $1,452,000 in 2018, $2,703,000 in 2017, and $600,000 in 2016.

Recently Issued Accounting Pronouncements

We discuss recently adopted and issued accounting standards in Item 8. Consolidated Financial Statements and Supplemental Data–Note 1, “Summary of Significant Accounting Policies.”

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk and Derivative Instruments

We are exposed to various risks, including energy commodity price risk. If oil and natural gas prices decline significantly our ability to finance our capital budget and operations could be adversely impacted. We expect energy prices to remain volatile and unpredictable, therefore we have adopted a risk management policy which provides for the use of derivative instruments to provide partial protection against declines in oil and natural gas prices by reducing the risk of price volatility and the affect it could have on our operations. The type of derivative instrument that we typically utilize is swaps. The total volumes which we hedge through the use of our derivative instruments vary from period to period.

During the year ended December 31, 2015, Tamar Royalties LLC, a wholly owned subsidiary of the Company, entered into certain swap and cap agreements with Deutsche Bank AG London Branch to hedge the risk of interest rate volatility loan balances. See Note 4 “Financial Instruments and Fair Value” for details.

We may be exposed to market risk on our open derivative contracts of non-performance by our counterparties. However, we do not expect such non-performance because our contracts are with major financial institutions with investment grade credit ratings.

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We account for our derivative activities under the provisions of ASC 815, Derivatives and Hedging, (ASC 815). ASC 815 establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. Please refer to Item 8. Consolidated Financial Statements and Supplemental Data—Note 4, “Financial Instruments and Fair Value” for additional information. As of December 31, 2018 and 2017 we did not have open commodity derivative positions.

Interest-Rate Risk

We are exposed to market risk related to adverse changes in interest rates. Our interest rate risk results primarily from fluctuations in short-term rates, which are LIBOR based. If interest rates increase, our interest expense would increase and our available cash flow would decrease. Periodically, we look to utilize interest rate swaps to reduce the exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. During the year ended December 31, 2015, Tamar Royalties LLC, a wholly owned subsidiary of the Company, entered into certain swap and cap agreements with Deutsche Bank AG London Branch to hedge the risk of interest rate volatility loan balances. See Note 4 “Financial Instruments and Fair Value” for details.

We continue to monitor our risk exposure as we incur future indebtedness at variable interest rates and will look to continue our risk management policy as situations present themselves.

Fair Market Value of Financial Instruments

The estimated fair values for financial instruments under ASC 825, *Financial Instruments*, (ASC 825) are determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, cash equivalents, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. See Item 8. Consolidated Financial Statements and Supplemental Data—Note 4 “Financial Instruments and Fair Value” for additional information.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTAL DATA

The information called for by this Item 8 is included following the “Index to Financial Statements” contained in this Annual Report on Form 10-K.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

ITEM 9A. CONTROLS AND PROCEDURES

DISCLOSURE CONTROLS AND PROCEDURES.

We have established disclosure controls and procedures to ensure that material information relating to Isramco, including its consolidated subsidiaries, is made known to the officers who certify Isramco's financial reports and to other members of senior management and the Board of Directors.

Based on their evaluation, Isramco's principal executive and principal financial officers have concluded that Isramco's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were effective as of December 31, 2018 to ensure that the information required to be disclosed by Isramco in the reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms.

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as that term is defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. Our 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.

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

Our management, under the supervision of and with the participation of our Co-Chief Executive Officer and Co-Chief Executive Officer / Chief Financial Officer, conducted an evaluation of our internal control over financial reporting as of December 31, 2017. In making this assessment, management used the criteria set forth in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment using these criteria, our management determined that our internal control over financial reporting was effective as of December 31, 2018.

The effectiveness of our internal control over financial reporting as of December 31, 2018, has been audited by MaloneBailey LLP, an independent registered public accounting firm, as stated in their report which appears herein.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There was no change in Isramco's internal control over financial reporting during the fourth quarter of 2018 that has materially affected, or is reasonably likely to materially affect, Isramco's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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PART III

We will file a definitive Proxy Statement for our 2019 Annual Meeting of Stockholders with the SEC, pursuant to Regulation 14A, not later than 120 days after the end of our fiscal year. Accordingly, certain information required by Part III has been omitted under General Instruction G(3) to Form 10-K. Only those sections of our definitive Proxy Statement that specifically address the items set forth herein are incorporated by reference.

Item 10. Directors, Executive Officers and Corporate Governance

The information required by Item 10 is hereby incorporated by reference from our definitive Proxy Statement relating to our 2019 Annual Meeting of Stockholders, to be filed with the Securities and Exchange Commission within 120 days following the end of our fiscal year.

Item 11. Executive Compensation

The information required by Item 11 is hereby incorporated by reference from our definitive Proxy Statement relating to our 2019 Annual Meeting of Stockholders, to be filed with the Securities and Exchange Commission within 120 days following the end of our fiscal year.

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

The information required by Item 12 is hereby incorporated by reference from our definitive Proxy Statement relating to our 2019 Annual Meeting of Stockholders, to be filed with the Securities and Exchange Commission within 120 days following the end of our fiscal year.

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

The information required by Item 13 is hereby incorporated by reference from our definitive Proxy Statement relating to our 2019 Annual Meeting of Stockholders, to be filed with the Securities and Exchange Commission within 120 days following the end of our fiscal year.

Item 14. Principal Accounting Fees and Services

The information required by Item 14 is hereby incorporated by reference from our definitive Proxy Statement relating to our 2019 Annual Meeting of Stockholders, to be filed with the Securities and Exchange Commission within 120 days following the end of our fiscal year.

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GLOSSARY

“Limited Partnership” means Isramco Negev 2 Limited Partnership, a Limited Partnership founded pursuant to a Limited Partnership Agreement made on the 2nd and 3rd days of March, 1989 (as amended on September 7, 1989, July 28, 1991, March 5, 1992 and June 11, 1992) between the Trustee on part as Limited Partner and Isramco Oil and Gas Ltd., as General Partner on the other part.

“Overriding Royalty” means a percentage interest over and above the base royalty and is free of all costs of exploration and production, which costs are borne by the Grantor of the Overriding Royalty Interest and which is related to a particular Petroleum License.

“Payout” means the point at which all costs of leasing, exploring, drilling and operating have been recovered from production of a well or wells as defined by contractual agreement or otherwise.

“Petroleum” means any petroleum fluid, whether liquid or gaseous, and includes oil, natural gas, natural gasoline, condensates and related fluid hydrocarbons, and also asphalt and other solid petroleum hydrocarbons when dissolved in and producible with fluid petroleum.

“Israel Petroleum Law”

The Company’s business in Israel is subject to regulation by the State of Israel pursuant to the Petroleum Law, 1952. The administration and implementation of the Petroleum Law is vested in the Minister of National Infrastructure (the “Minister”) and an Advisory Council.

The following includes brief statements of certain provisions of the Petroleum Law in effect at the date of this Prospectus. Reference is made to the copy of the Petroleum Law filed as an exhibit to the Registration Statement referred to under “Additional Information” and the description which follows is qualified in its entirety by such reference.

The holder of a preliminary permit is entitled to carry out petroleum exploration, but not test drilling or petroleum production, within the permit areas. The Commissioner determines the term of a preliminary permit and it may not exceed eighteen (18) months. The Minister may grant the holder a priority right to receive licenses in the permit areas and for the duration of such priority right no other Party will be granted a license or lease in such areas.

Drilling for petroleum is permitted pursuant to a license issued by the Commissioner. The term of a license is for three (3) years, subject to extension under certain circumstances for an additional period up to four (4) years. A license holder is required to commence test drilling within two (2) years from the grant of a license (or earlier if required by the terms of the license) and not to interrupt operations between test drillings for more than four (4) months. If any well drilled by the Company is determined to be a Commercial discovery prior to expiration of the license, the Company will be entitled to receive a Petroleum Lease granting it the exclusive right to explore for and produce petroleum in the lease area. The term of a lease is for thirty (30) years, subject to renewal for an additional term of twenty (20) years.

The Company, as a lessee, will be required to pay the State of Israel the royalty prescribed by the Petroleum Law which is presently, and at all times since 1952 has been, 12.5% of the petroleum produced from the leased area and saved, excluding the quantity of petroleum used in operating the leased area.

The Minister may require a lessee to supply at the market price such quantity of petroleum as, in the Minister's opinion, is required for domestic consumption, subject to certain limitations.

As a lessee, the Company will also be required to commence drilling of a development well within six (6) months from the date on which the lease is granted and, thereafter, with due diligence to define the petroleum field, develop the leased area, produce petroleum therefore and seek markets for and market such petroleum.

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PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) Exhibits

3.1	Certificate of Incorporation of Registrant with all amendments filed as an Exhibit to the S-l Registration Statement, File No. 2-83574.
3.2	Amendment to Certificate of Incorporation filed March 17, 1993, filed as an Exhibit with the S-l Registration Statement, File No. 33-57482.
3.3	By-laws of Registrant filed as Exhibit 3(ii) to the 8-K filed January 18, 2012 and incorporated herein by reference.
10.1	Purchase and Sale Agreement, dated as of February 16, 2007, among Five States Energy Company, L.L.C. and each of the other parties listed as a party "Seller" on the signature pages thereof and ISRAMCO, Inc., filed as an Exhibit to the 10-Q for the quarter ended March 31, 2007 and incorporated herein by reference.
10.17	2011 Stock Incentive Plan filed as an Exhibit to the 10-K for the year ended December 31, 2011 and incorporated herein by reference.
10.25	Employment Agreement dated effective November 3, 2017, between Isramco Inc. and Edy Francis, filed as an Exhibit to Form 8-K dated November 9, 2017 and incorporated herein by reference.
10.26	Consulting Agreement dated effective June 1, 2014, between Isramco Inc. and Goodrich Global Ltd., filed as an Exhibit to Form 8-K dated September 11, 2014 and incorporated herein by reference.
10.27	Credit Agreement dated as of May 18, 2015, by and among Tamar Royalties LLC, as Borrower, Deutsche Bank Trust Company Americas, as administrative agent, the lenders party thereto, as Lenders, and Deutsche Bank Trust Company Americas, as collateral agent filed as an Exhibit to 8-K filed by the Company on May 22, 2015 and incorporated herein by reference.
10.28	Royalties Sale and Contribution Agreement dated May 18, 2015, by and between Isramco, Inc., as Seller, and Tamar Royalties, LLC, as Borrower filed as an Exhibit to 8-K filed by the Company on May 22, 2015 and incorporated herein by reference.
10.29	Pledge, Assignment and Security Agreement dated as of May 18, 2015, by and between Tamar Royalties LLC, as Borrower, and Deutsche Bank Trust Company Americas, as collateral agent filed as an Exhibit to 8-K filed by the Company on May 22, 2015 and incorporated herein by reference.

10.30	Intercompany Loan Agreement dated as of May 18, 2015, by and between Isramco, Inc., as Payor, and Tamar Royalties, LLC, as Payee filed as an Exhibit to 8-K filed by the Company on May 22, 2015 and incorporated herein by reference.
10.31	Credit Agreement dated as of June 30, 2015, by and among Isramco Onshore LLC, as Borrower, Société Générale, as Administrative Agent and Issuing Lender, SG Americas Securities LLC, as Sole Bookrunner, Lead Arranger and Documentation Agent, and the lenders party thereto from time to time, as Lenders filed as an Exhibit to 8-K filed by the Company on July 6, 2015 and incorporated herein by reference.
14.1	Code of Ethics, filed as an Exhibit to Form 10-K for the year ended December 31, 2003.

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23.1*	Consent of Cawley, Gillespie & Associates, Inc.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of Co-Chief Executive Officer pursuant to Section 302 of Sarbanes-Oxley Act.
31.2*	Certification of Co-Chief Executive Officer / Chief Financial Officer pursuant to Section 302 of Sarbanes-Oxley Act
31.3*	Certification of Chief Accounting Officer pursuant to Section 302 of Sarbanes-Oxley Act
32.1*	Certification of Chief Executive and Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 Of the Sarbanes-Oxley act of 2002
32.2*	Certification of Co-Chief Executive Officer / Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 Of the Sarbanes-Oxley act of 2002
32.3*	Certification of Chief Accounting Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 Of the Sarbanes-Oxley act of 2002
99.1*	Cawley, Gillespie & Associates, Inc. Reserves Report
99.2*	Netherland, Sewell & Associates, Inc. Reserves Report
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Linkbase
101.LAB	XBRL Taxonomy Extension Label Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase

* Filed Herewith.

+ Management Agreement

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SIGNATURES

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

/S/ HAIM TSUFF

HAIM TSUFF,

CHAIRMAN OF THE BOARD,

CO-CHIEF EXECUTIVE OFFICER

(PRINCIPAL EXECUTIVE OFFICER)

Date: March 18, 2019

/S/ EDY FRANCIS

EDY FRANCIS,

CO-CHIEF EXECUTIVE OFFICER / CHIEF FINANCIAL OFFICER

(PRINCIPAL FINANCIAL OFFICER)

Date: March 18, 2019

/S/ ZEEV KOLTOVSKOY

ZEEV KOLTOVSKOY,

CHIEF ACCOUNTING OFFICER

(PRINCIPAL ACCOUNTING OFFICER)

Date: March 18, 2019

Pursuant to the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the capacities and on the dates indicated.

Signature	***Title***	***Date***
/s/ Haim Tsuff *Haim Tsuff*	*Chairman of the Board &* *Co-Chief Executive Officer*	*March 18, 2019*
/s/ Josef From *Josef From*	*Director*	*March 18, 2019*
/s/ Max Pridgeon *Max Pridgeon*	*Director*	*March 18, 2019*
/s/ Frans Sluiter *Frans Sluiter*	*Director*	*March 18, 2019*
/s/ Nir Hasson *Nir Hasson*	*Director*	*March 18, 2019*
/s/ Asaf Yarkoni *Asaf Yarkoni*	*Director*	*March 18, 2019*

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INDEX TO FINANCIAL STATEMENTS

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Isramco, Inc. (the "Company"), including the Company's Co-Chief Executive Officer, Co-Chief Executive Officer / Chief Financial Officer, and Chief Accounting Officer is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. The Company's internal control system was designed to provide reasonable assurance to the Company's Management and Directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2018.

MaloneBailey, LLP, the Company's independent registered public accounting firm, has issued an attestation report on the effectiveness on our internal control over financial reporting as of December 31, 2018.

/s/ Haim Tsuff	*/s/ Zeev Koltovskoy*	*/s/ Edy Francis*
Haim Tsuff	*Zeev Koltovskoy*	*Edy Francis*
Co-Chief Executive Officer	*Chief Accounting Officer*	*Co-Chief Executive Officer / Chief Financial Officer*

Houston, Texas

March 18, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of

Isramco Inc.

Opinions on the Financial Statements and Internal Control Over Financial Reporting

We have audited the accompanying consolidated balance sheets of Isramco Inc. and its subsidiaries (collectively, the "Company") as of December 31, 2018 and 2017, and the related consolidated statements of operations, changes in shareholders' deficit, and cash flows for each of the years in the three-year period ended December 31, 2018, and the related notes (collectively referred to as the "financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

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

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the financial statements included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that responds to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the 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 financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ MaloneBailey, LLP

www.malonebailey.com

We have served as the Company's auditor since 2005.

Houston, Texas

March 18, 2019

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ISRAMCO INC.

CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share amounts)

As of December 31	**2018**	**2017**
ASSETS		
Current Assets:		
Cash and cash equivalents	$13,857	$30,009
Accounts receivable, net of allowances for doubtful accounts of $2,553 and $2,431	18,920	12,549
Restricted and designated cash	830	802
Inventories	563	475
Derivative asset	293	-
Prepaid expenses and other	2,956	2,711
Total Current Assets	37,419	46,546
Property and Equipment, at cost:		
Oil and Gas properties – successful efforts method	244,450	243,812
Advanced payment for equipment	569	564
Production service equipment and other equipment and property	66,929	59,108
Total Property and Equipment	311,948	303,484
Accumulated depreciation, depletion, amortization and impairment	(257,706)	(251,355)
Net Property and Equipment	54,242	52,129
Derivative asset	388	187
Restricted cash – long term	19,304	9,674
Investments	261	261
Total assets	$111,614	$108,797
LIABILITIES AND SHAREHOLDERS' DEFICIT		
Current liabilities:		
Accounts payable and accrued expenses	$13,976	$13,515
Short term debt and current maturities of long-term debt, net of discount of $724 and $828	21,739	18,517
Short term debt, accrued interest, and payables due to related party	3,836	60
Accrued interest	1,057	1,027
Derivative liability	-	457
Total current liabilities	40,608	33,576
Long term debt, net of discount of $1,407 and $2,131	56,193	77,369
Other Long-term Liabilities:		
Asset retirement obligations	22,172	21,670
Total liabilities	118,973	132,615
Commitments and contingencies (Note 12)		

Shareholders' equity (deficit):		
Common stock $0.01 par value; authorized 7,500,000 shares; issued 2,746,915 shares; outstanding 2,717,648 shares	27	27
Additional paid-in capital	23,853	23,853
Accumulated deficit	(23,036)	(40,970)
Treasury stock, 29,267 shares at cost	(164)	(164)
Total Isramco, Inc. shareholders' equity (deficit)	680	(17,254)
Non controlling interest	(8,039)	(6,564)
Total shareholders' deficit	(7,359)	(23,818)
Total liabilities and shareholders' deficit	$111,614	$108,797

See notes to the consolidated financial statements.

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ISRAMCO INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except share and per share amounts)

Year Ended December 31	**2018**	**2017**	**2016**
Revenues and other			
Oil and gas sales	$46,968	$43,890	$40,409
Production services	31,825	18,265	12,752
Office services	527	554	569
Gain on divestiture	1,452	2,703	600
Other	567	535	612
Total revenues and others	81,339	65,947	54,942
Operating expenses			
Lease operating expense, transportation and taxes	9,381	9,478	8,925
Depreciation, depletion and amortization	5,543	5,526	6,667
Impairments of oil and gas assets and equipment	1,252	1,682	4,529
Accretion expense	869	913	897
Production services	29,386	18,241	14,494
Loss (gain) from plug and abandonment	281	26	(3)
General and administrative	6,714	5,455	5,366
Total operating expenses	53,426	41,321	40,875
Operating income	27,913	24,626	14,067
Other expenses			
Interest expense, net	4,921	4,784	4,817
Interest expense – related party, net	71	-	-
Loss (gain) from derivative contracts, net	(680)	176	657
Capital (gain) loss	(13)	(145)	70
Total other expenses	4,299	4,815	5,544
Income before income taxes	23,614	19,811	8,523
Income tax expense	(7,138)	(45,637)	(3,634)
Net income (loss)	$16,476	$(25,826)	$4,889
Net loss attributable to non-controlling interests	(1,458)	(1,516)	(1,856)
Net income (loss) attributable to Isramco	$17,934	$(24,310)	$6,745
Earnings (loss) per share – basic:	$6.60	$(8.95)	$2.48
Earnings (loss) per share – diluted:	$6.60	$(8.95)	$2.48
Weighted average number of shares outstanding-basic:	2,717,648	2,717,648	2,717,648

Weighted average number of shares outstanding-diluted:	2,717,648	2,717,648	2,717,648

See notes to the consolidated financial statements.

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ISRAMCO INC.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY (DEFICIT)

FOR THE YEARS ENDED DECEMBER 31, 2018, 2017 and 2016

(in thousands, except share amounts)

	Common stock						
	Number of shares	Amount	Additional Paid-In Capital	Accumulated Deficit	Treasury stock	Non-controlling interests	Total Shareholders' Equity (Deficit)
Balance of January 1, 2016	2,717,648	$ 27	$ 23,853	$ (23,405)	$ (164)	$ (3,179)	$ (2,868)
Distribution to non-controlling interests						(5)	(5)
Net income (loss)				6,745		(1,856)	4,889
Balance of December 31, 2016	2,717,648	$ 27	$ 23,853	$ (16,660)	$ (164)	$ (5,040)	$ 2,016
Distribution to non-controlling interests						(8)	(8)
Net loss				(24,310)		(1,516)	(25,826)
Balance of December 31, 2017	2,717,648	$ 27	$ 23,853	$ (40,970)	$ (164)	$ (6,564)	$ (23,818)
Distribution to non-controlling interests						(17)	(17)
Net income (loss)				17,934		(1,458)	16,476
Balance of December 31, 2018	2,717,648	$ 27	$ 23,853	$ (23,036)	$ (164)	$ (8,039)	$ (7,359)

See notes to consolidated financial statements.

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ISRAMCO INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

Year Ended December 31	**2018**	**2017**	**2016**
Cash Flows From Operating Activities:			
Net income (loss)	$16,476	$(25,826)	$4,889
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization	5,543	5,526	6,667
Impairment of oil and gas properties and equipment	1,252	1,682	4,529
Bad debt expense	449	268	551
Accretion expense	869	913	897
Gain on divestiture	(1,452)	(2,703)	(600)
Changes in deferred taxes	-	38,735	(3,239)
Net unrealized gain on derivative contracts	(951)	(746)	(586)
Loss (gain) on sale of equipment and other	(13)	(145)	70
Amortization of debt cost	828	789	940
Write off of debt cost	-	-	299
Changes in components of working capital and other assets and liabilities			
Accounts receivable	(6,820)	(2,915)	2,007
Prepaid expenses and other current assets	823	1,088	639
Due to related party	176	(30)	27
Inventories	(88)	222	174
Accounts payable and accrued expenses	75	1,694	(1,754)
Net cash provided by operating activities	17,167	18,552	15,510
Cash flows from investing activities:			
Addition to oil and gas property and equipment, net	(8,997)	(4,184)	(794)
Proceeds from sale of oil and gas properties	1,435	2,705	600
Proceeds from sale of equipment	168	49	77
Investment in Apache Flats	-	(31)	(133)
Net cash used in investing activities	(7,394)	(1,461)	(250)
Cash flows from financing activities:			
Distributions to non-controlling interests	(17)	(8)	-
Borrowings short-term debt – related parties	3,600	-	-
Repayment of long-term debt	(18,900)	(9,600)	(9,000)
Repayment of short-term debt	(950)	(911)	(1,341)
Borrowings of bank overdraft, net	-	-	(350)
Net cash used in financing activities	(16,267)	(10,519)	(10,691)
Net increase (decrease) in cash, cash equivalents, and restricted cash	(6,494)	6,572	4,569

Cash, cash equivalents, and restricted cash at beginning of year	40,485	33,913	29,344
Cash, cash equivalents, and restricted cash at end of year	$33,991	$40,485	$33,913

See notes to the consolidated financial statements.

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ISRAMCO INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

Isramco, Inc. and its subsidiaries and affiliated companies (together referred to as “We”, “Our”, “Isramco” or the “Company”) is predominately an independent oil and natural gas company engaged in the exploration, development and production of oil and natural gas properties located onshore in the United States and ownership of various royalty interests in oil and gas concessions located offshore Israel. The Company also operates a production services company that provides well maintenance and workover, well completion and recompletion services. The Company’s consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries. All intercompany accounts and transactions have been eliminated. The Company has evaluated events or transactions through the date of issuance of this report in conjunction with the preparation of these consolidated financial statements.

Reclassification of Prior Year Presentation

Certain prior year amounts have been reclassified for consistency with the current period presentation. These reclassifications had no material effect on the reported results of operations.

Use of Estimates

In preparing financial statements in accordance with accounting principles generally accepted in the United States, management makes informed judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. Management evaluates its estimates and related assumptions regularly, including those related to the value of properties and equipment; proved reserves; intangible assets; asset retirement obligations; litigation reserves; environmental liabilities; liabilities, and costs; income taxes; and fair values. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates.

Fair Value Measurements

Certain of Isramco’s assets and liabilities are measured at fair value at each reporting date. Fair value represents the price that would be received to sell the asset or paid to transfer the liability in an orderly transaction between market participants. This price is commonly referred to as the “exit price.” Fair value measurements are classified according to a hierarchy that prioritizes the inputs underlying the valuation techniques. This hierarchy consists of three broad levels:

- Level 1 – Inputs consist of unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. When available, Isramco measures fair value using Level 1 inputs because they generally provide the most reliable evidence of fair value.

- Level 2 – Inputs consist of quoted prices that are generally observable for the asset or liability. Common examples of Level 2 inputs include quoted prices for similar assets and liabilities in active markets or quoted prices for identical assets and liabilities in markets not considered to be active.

- Level 3 – Inputs are not observable from objective sources and have the lowest priority. The most common Level 3 fair value measurement is an internally developed cash flow model.

Cash, cash equivalents and restricted cash

The Company adopted the FASB accounting standard ASU No. 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash (a consensus of the FASB Emerging Issues Task Force) on January 1, 2018 using a full retrospective approach. ASU 2016-18 requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents are included with cash and cash equivalents in reconciling the beginning-of-period and end-of-period total amounts shown on the Company’s consolidated statements of cash flows. We believe the adoption of ASU 2016-18 did not have a material impact on the Company’s Consolidated Financial Statements.

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The Company considers highly liquid investments purchased with a maturity period of three months or less at the date of purchase to be cash equivalents. Restricted cash and restricted cash – long term are included with cash, cash equivalents, and restricted cash on the Company's consolidated statements of cash flows.

Consolidated balance sheets amount included as cash, cash equivalents, and restricted cash on the Company's consolidated statements of cash flows:

	As of December 31, 2018	**As of December 31, 2017**	**As of December 31, 2016**
Cash and cash equivalents	$ 13,857	$ 30,009	$ 26,090
Restricted and designated cash	830	802	701
Restricted cash – long term	19,304	9,674	7,122
Total cash, cash equivalents, and restricted cash	$ 33,991	$ 40,485	$ 33,913

Allowance for Doubtful Accounts

The Company establishes provisions for losses on accounts receivable if it determines that it will not collect all or part of the outstanding balance. The Company regularly reviews collectability and establishes or adjusts the allowance as necessary by using both the specific identification method and/or general allowance as a percentage of outstanding accounts receivable balances.

Oil and Gas Operations

The Company applies the successful efforts method of accounting for oil and gas properties. Under the successful efforts method, exploration costs such as exploratory geological and geophysical costs, delay rentals and exploration overhead are charged against earnings as incurred. Acquisition costs and costs of drilling exploratory wells are capitalized pending determination of whether proved reserves can be attributed to the area as a result of drilling the well. If management determines that commercial quantities of hydrocarbons have not been discovered, capitalized costs associated with exploratory wells are charged to exploration expense. Acquisition costs of unproved leaseholds are assessed for impairment during the holding period and transferred to proved oil and gas properties to the extent associated with successful exploration activities. Significant undeveloped leases are assessed individually for impairment, based on the Company's current exploration plans, and a valuation allowance is provided if impairment is indicated.

Depreciation, depletion and amortization of the cost of proved oil and gas properties are calculated using the unit-of-production method. The reserve base used to calculate depreciation, depletion and amortization is the sum of proved developed reserves and proved undeveloped reserves for leasehold acquisition costs and the cost to acquire proved properties. With respect to lease and well equipment costs, which include development costs and successful exploration drilling costs, the reserve base includes only proved developed reserves. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account.

Amortization rates are updated to reflect: 1) the addition of capital costs, 2) reserve revisions (upwards or downwards) and additions, 3) property acquisitions and/or property dispositions and 4) impairments.

The Company reviews its property and equipment in accordance with Accounting Standard Codification (ASC) 360, *Property, Plant, and Equipment* ("ASC 360"). ASC 360 requires the Company to evaluate property and equipment as an event occurs or circumstances change that would more likely than not reduce the fair value of the property and equipment below the carrying amount. If the carrying amount of property and equipment is not recoverable from its undiscounted cash flows, then the Company would recognize an impairment loss for the difference between the carrying amount and the discounted cash flow.

In 2018, 2017, and 2016, we reported an impairment charge of $1,252,000, $1,682,000, and $4,529,000, respectively, relating to our oil and gas properties. Impairments of oil and gas assets of $1,252,000 in 2018 were a result of lower estimated future production in a few fields. Impairments of oil and gas assets of $1,682,000 in 2017 were a result of lower estimated future production in a few fields. Impairments of oil and gas assets of $4,529,000 in 2016 were a result of lower estimated future production in a few fields.

Gain on divestiture – In 2018, the Company sold oil and gas properties for a net gain of $1,452,000. The gain consists of $1,435,000 cash plus $19,000 in relieved asset retirement obligation, offset by a net book value of $2,000. During the year ended December 31, 2017 the Company sold several leases for a net gain of $2,703,000. The gain consists of $2,705,000 cash plus $18,000 in relieved asset retirement obligation offset by a write off of accounts receivable of $10,000 and a net book value of $10,000. During the year ended December 31, 2016 the Company sold deep rights in one field for a gain of $600,000. The property sold had no net book value.

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Inventory

Inventory is valued at the net realizable value. Cost is determined by using average method. The Company provides a reserve for obsolete and slow-moving inventory. As of December 31, 2018 and 2017 no reserve has been recorded.

Investments

In January 2016, the FASB issued Accounting Standards Update No. 2016-01 (ASU 2016-01) "Financial Instruments-Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities," which amends various aspects of the recognition, measurement, presentation, and disclosure of financial instruments. The Company chooses to follow the provision that allows for measurement of equity investments that do not have readily determinable fair values at cost minus impairment, if any, plus or minus changes resulting from observable price changes in ordinary transaction for the identical or similar investment of the same issuer.

Property, Plant and Equipment Other than Oil and Natural Gas Properties

Property and equipment are carried at cost less accumulated depreciation and impairment. Depreciation is provided for our assets over the estimated depreciable lives of the assets using the straight-line method. Depreciation expense for the years ended December 31, 2018, 2017 and 2016 was $3,657,000, $3,458,000, and $3,569,000, respectively. We depreciate our operational assets over their depreciable lives to their salvage value, which is a fair value higher than the assets' value as scrap. Salvage value approximates 15% of an operational asset's acquisition cost. When an operational asset is stacked or taken out of service, we review its physical condition, depreciable life and ultimate salvage value to determine if the asset is no longer operable and whether the remaining depreciable life and salvage value should be adjusted. When we scrap an asset, we accelerate the depreciation of the asset down to its salvage value. When we dispose of an asset, a gain or loss is recognized.

As of December 31, 2018, the estimated useful lives of our asset classes are as follows:

Description	**Years**
Production services rigs and components	15
Oilfield trucks, vehicles and related equipment	5 - 10
Production services auxiliary equipment	7 - 15
Furniture and equipment	3 - 7

A long-lived asset or asset group should be tested for recoverability whenever events or changes in circumstances indicate that its carrying amount may not be recoverable. For purposes of testing for impairment, we group our long-lived assets along our lines of business based on the services provided, which is the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. We record an impairment charge, reducing the net carrying value to an estimated fair value, if the asset group's estimated future cash flows were less than its net carrying value. Events or changes in circumstance that cause us to evaluate our fixed assets for recoverability and possible impairment may include changes in market conditions, such as adverse movements in the prices of oil and natural gas, or changes of an asset group, such as its expected future life, intended use or physical condition, which could reduce the fair value of certain of our property and equipment. The development of future cash flows and the determination of fair value for an asset group involves significant judgment and estimates. We had no impairment loss in 2018, 2017, or 2016.

Asset Retirement Obligation

ASC 410, *Asset Retirement and Environmental Obligations* (ASC 410) requires that the fair value of an asset retirement cost, and corresponding liability, should be recorded as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. The Company records asset retirement obligations to reflect the Company's legal obligations related to future plugging and abandonment of its oil and natural gas wells and gas gathering systems. The Company estimates the expected cash flow associated with the obligation and discounts the amounts using a credit-adjusted, risk-free interest rate. At least annually, the Company reassesses the obligation to determine whether a change in the estimated obligation is necessary. The Company evaluates whether there are indicators that suggest the estimated cash flows underlying the obligation have materially changed. Should those indicators suggest the estimated obligation may have materially changed on an interim basis (quarterly), the Company will accordingly update its assessment. Additional retirement obligations increase the liability associated with new oil and natural gas wells as these obligations are incurred. See Note 13 "Asset Retirement Obligations."

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Concentrations of Credit Risk

Through our wholly-owned subsidiary, we operate a substantial portion of our domestic oil and natural gas properties. As the operator of a property, the Company makes full payment of the costs associated with each property and seeks reimbursement from the other working interest owners in the property for their share of those costs. Isramco's joint interest partners consist primarily of independent oil and natural gas producers. If the oil and natural gas exploration and production industry in general were adversely affected, the ability of the Company's joint interest partners to reimburse the Company could be adversely affected.

The purchasers of the Company's oil and natural gas production consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. During the years ended December 31, 2018, 2017, and 2016, no purchaser, marketer, or major oil and gas or pipeline company accounted for 10% or more of Isramco's consolidated revenues. The Company has not experienced any significant losses from uncollectible accounts as to its sales of oil and gas production. The Company does not believe the loss of any one of its purchasers would materially affect the Company's ability to sell the oil and natural gas it produces. The Company believes other purchasers are available in the Company's areas of operations.

The Company's overriding royalty interest in the Tamar field is paid monthly by Isramco Negev 2 Limited Partnership, a related party. During the twelve months ended December 31, 2018, 2017, and 2016, income from this source accounted for 38%, 44%, and 50%, respectively of the Company's consolidated revenues. If Isramco Negev 2 Limited Partnership were to stop receiving revenue from its working interest in the Tamar Field, we would not receive revenue from our overriding royalty interest. Loss of payments from this source would have significant financial consequences on the Company.

Our production service subsidiary customers include major oil and natural gas production companies and independent oil and natural gas production companies. We perform credit evaluations of our customers and usually do not require collateral. We maintain reserves for potential credit losses when necessary. During the twelve months ended December 31, 2018, 2017 and 2016, no one individual customer accounted for 10% or more of consolidated revenues. The Company believes the loss of one or more customers of our production service subsidiary would not have a significant effect on this Segment because the Company believes that it can employ its rigs with other existing customers or new customers to the extent it has in the past in such circumstances.

Revenue Recognition

Effective January 1, 2018, we adopted ASU 2014-09, Revenue from Contracts with Customers (Topic 606). Under the new standard, we recognize revenues when the following criteria are met: (i) persuasive evidence of a contract with a customer exists, (ii) identifiable performance obligations under the contract exist, (iii) the transaction price is determinable for each performance obligation, (iv) the transaction price is allocated to each performance obligation, and (v) when the performance obligations are satisfied. See note 3. *Revenue from Contracts with Customers.*

Price Risk Management Activities

The Company follows ASC 815, *Derivatives and Hedging*. From time to time, the Company may hedge a portion of its forecasted oil and natural gas production. Derivative contracts entered into by the Company consist of transactions in which the Company hedges the variability of cash flow related to a forecasted transaction. The Company elected to not designate any of its positions for hedge accounting. Accordingly, the Company records the net change in the mark-to-market valuation of these positions, as well as payments and receipts on settled contracts, in “Net gain (loss) on derivative contracts” on the Company’s consolidated statements of operations.

As of the date of this report there are no open hedge positions related to commodity prices.

Deferred Financing Costs

Deferred financing costs are amortized over the life of the underlying credit agreement or the expected remaining life of the underlying credit agreement.

Income Taxes and Impact of Tax Reform Legislation

We account for deferred income taxes using the asset and liability method and provide deferred taxes for all significant temporary differences. Management determines our current tax liability as well as taxes incurred as a result of current operations, but which are deferred until future periods. Current taxes payable represent our liability related to our income tax returns for the current year, while net deferred tax expense or benefit represents the change in the balance of deferred tax assets and liabilities reported on our consolidated balance sheets. Management estimates the changes in both deferred tax assets and liabilities using the basis of assets and liabilities for financial reporting purposes and for enacted rates that management estimates will be in effect when the differences reverse. Further, management makes certain assumptions about the timing of temporary tax differences for the differing treatments of certain items for tax and accounting purposes or whether such differences are permanent. The final determination of our tax liability involves the interpretation of local tax laws, tax treaties, and related authorities in each jurisdiction as well as the significant use of estimates and assumptions regarding the scope of future operations and results achieved and the timing and nature of income earned and expenditures incurred.

We establish valuation allowances to reduce deferred tax assets if we determine that it is more likely than not (e.g., a likelihood of more than 50%) that some portion or all of the deferred tax assets will not be realized in future periods. To assess the likelihood, we use estimates and judgment regarding our future taxable income, as well as the jurisdiction in which this taxable income is generated, to determine whether a valuation allowance is required. Such evidence can include our current financial position, our results of operations, both actual and forecasted results, the reversal of deferred tax liabilities, and tax planning strategies as well as the current and forecasted business economics of our industry. Additionally, we record uncertain tax positions at their net recognizable amount, based on the amount that management deems is more likely than not to be sustained upon ultimate settlement with the tax authorities in the domestic and international tax jurisdictions in which we operate.

On December 22, 2017, the US Congress enacted the Tax Cuts and Jobs Act (Tax Reform Legislation), which made significant changes to US federal income tax law affecting us. See “Note 6 Income Taxes” for further discussion of accounting for income taxes, changes in our valuation allowance, components of our tax rate reconciliation and realization of loss carryforwards.

Legal Contingencies

When estimating our liabilities related to litigation, we take into account all available facts and circumstances in order to determine whether a loss is probable and reasonably estimable.

Various suits and claims arising in the ordinary course of business are pending against us. We conduct business throughout the continental United States and offshore Israel and may be subject to jury verdicts or arbitrations that result in outcomes in favor of the plaintiffs. We continually assess our contingent liabilities, including potential litigation liabilities, as well as the adequacy of our accruals and our need for the disclosure of these items. We establish a provision for a contingent liability when it is probable that a liability has been incurred and the amount is reasonably estimable.

Earnings per Share

The Company’s basic earnings per share (EPS) amounts have been computed based on the average number of shares of common stock outstanding for the period and include the effect of any participating securities as appropriate. Diluted EPS includes the effect of the Company’s outstanding stock options, restricted stock awards, restricted stock units and performance-based stock awards if the inclusion of these items is dilutive.

For the years ended December 31, 2018, 2017, & 2016, Isramco did not have any outstanding stock options, restrictive stock awards, restricted stock units, or performance-based awards.

Noncontrolling Interests

Noncontrolling interests represent third-party ownership in the net assets of the Company’s consolidated subsidiary and are presented as a component of equity.

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Environmental

The Company accrues for losses associated with environmental remediation obligations when such losses are probable and can be reasonably estimated. Accruals for estimated losses from environmental remediation obligations are recognized no later than the time of the completion of the remediation feasibility study or remediation plan. These accruals are adjusted as additional information becomes available or as circumstances change. Costs of future expenditures for environmental remediation obligations are not discounted to their present value.

Recently Issued Accounting Pronouncements

In May 2014, the FASB issued guidance regarding the accounting for revenue from contracts with customers. In April 2016, May 2016 and December 2016, the FASB issued additional guidance, addressed implementation issues and provided technical corrections. The guidance may be applied retrospectively or using a modified retrospective approach to adjust retained earnings (deficit). The guidance is effective for interim and annual periods beginning after December 15, 2017. The Company adopted the new revenue recognition and presentation guidance on January 1, 2018, using a full retrospective transition approach. We believe that adoption of the new guidance had no cumulative effect on the Company’s retained earnings at January 1, 2018.

In January 2016, the FASB issued Accounting Standards Update No. 2016-01 (ASU 2016-01) "Financial Instruments-Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities," which amends various aspects of the recognition, measurement, presentation, and disclosure of financial instruments. The Company adopted ASU 2016-01 as of January 1, 2018 using the modified retrospective method for marketable equity securities. This adoption had no affect the Company’s consolidated financial statements.

In November 2016, the FASB issued ASU No. 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash (a consensus of the FASB Emerging Issues Task Force). ASU 2016-18 requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. ASU 2016-18 is effective for all interim and annual reporting periods beginning after December 15, 2017. The Company adopted this guidance effective January 1, 2018 using a full retrospective approach. We believe the adoption did not have a material impact on the Company’s Consolidated Financial Statements.

In February 2016, the FASB issued guidance regarding the accounting for leases. The guidance requires recognition of most leases on the balance sheet. The guidance requires lessees and lessors to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. The guidance is effective for interim and annual periods beginning after December 15, 2018. Isramco will adopt this ASU on January 1, 2019. Isramco has concluded that the adoption of this ASU will not have a material impact on its consolidated financial statements.

In January 2018, the Company early-adopted Accounting Standards Update ("ASU") No. 2017-09, "Compensation - Stock Compensation (Topic 718): Scope of Modification Accounting." ASU No. 2017-09 provides guidance concerning which changes to the terms or conditions of a share-based payment award require an entity to apply modification accounting in Topic 718. The adoption of ASU 2017-09 did not have a material impact on the Company's consolidated financial statements.

In August 2018, the FASB issued ASU 2018-13, Fair Value Measurement (Topic 820) – Disclosure Framework – Changes to the Disclosure Requirements for Fair Value Measurements ("ASU 2018-13"). ASU 2018-13 adds, modifies, or removes certain disclosure requirements for recurring and nonrecurring fair value measurements based on the FASB's consideration of costs and benefits. The amendments in this ASU are effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years, and early adoption is permitted. Entities must adopt the amendments on changes in unrealized gains and losses, the range and weighted average of significant unobservable inputs used to develop Level 3 fair value measurements, and the narrative description of measurement uncertainty prospectively, and all other amendments should be applied retrospectively to all periods presented. The adoption of ASU 2018-13 is currently not expected to have a material effect on our consolidated financial statements but may require enhanced footnote disclosures.

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2. Transactions with Affiliates and Related Parties

The Company and Goodrich entered into a Consulting Agreement dated effective June 1, 2014 (the "2014 Consulting Agreement"). The 2014 Consulting Agreement will pay Goodrich $360,000 per annum in installments of $30,000 per month, in addition to reimbursing Goodrich for all reasonable business expenses, including automobile expenses, incurred by Mr. Tsuff in connection with services rendered on behalf of the Company, in exchange for management services performed by Mr. Tsuff as the Company's Chairman, Co-Chief Executive Officer and President. These payments of $360,000 constitute the salary of Mr. Tsuff. The 2014 Consulting Agreement had an initial term through May 31, 2017, and was automatically extended by its terms for an additional three-years. The Consulting Agreement also contains certain customary confidentiality and non-compete provisions which are identical to those contained in the Goodrich Agreement.

As previously disclosed, on May 18, 2015, Tamar Royalties LLC, a newly formed, wholly-owned, special purpose subsidiary of the Company, entered into a term loan credit agreement with Deutsche Bank Trust Company Americas, as facility agent for the lenders and as collateral agent for the secured parties, and with the lenders party thereto. Pursuant to the terms of the transaction, the Amended and Restated Borrower LLC Agreement of Tamar Royalties LLC requires management by N.M.A. Energy Resources Ltd, a related party of the Company, and an independent manager, Donald J. Puglisi. As consideration for its management of Tamar Royalties LLC, the Company pays twenty thousand dollars ($20,000) per month to N.M.A. Energy Resources Ltd. As noted herein, Isramco Inc. owns all ownership interests in Tamar Royalties LLC, subject to its management by the aforementioned parties. All overriding royalty payments received in Tamar Royalties LLC are paid by Isramco Negev 2 Limited Partnership, a company affiliated by common ownership.

In September 2018 the Company issued an unsecured promissory note dated effective September 11, 2018, to I.O.C - Israel Oil Company LTD, a related party, in which the Company may borrow up to $7,000,000 at a rate of interest equal to seven and one-half percent (7.5%) and with a maturity date of September 2019. The Company received $3,600,000 under this related party note in2018 attendant with the creation of a new subsidiary, Arrow Midstream LLC. Amounts received under the aforementioned promissory note are dedicated to working capital and the purchase of equipment for Arrow Midstream LLC, a new wholly owned subsidiary of Isramco Inc. Arrow Midstream is focused on the transportation of liquefied petroleum products including, but not limited to, butane, propane, and similar products. Mr. Haim Tsuff, Isramco's Co-Chief Executive Officer and Chairman and is a controlling shareholder of IOC.

3. Revenue from Contracts with Customers

Adoption of new revenue recognition and disclosure guidance

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606), which generally requires an entity to identify performance obligations in its contracts, estimate the amount of consideration to be received in the transaction price, allocate the transaction price to each separate performance obligation, and recognize revenue as obligations are satisfied. Additionally, the standard requires expanded disclosures related to revenue recognition. Subsequent to the issuance of ASU 2014-09, the FASB issued additional guidance to assist entities with implementation efforts, including the issuance of ASU 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net), pertaining to the presentation of revenues on a gross basis (revenues presented separately from associated expenses) versus a net basis. This guidance requires an entity to record revenue on a gross basis if it controls a promised good or service before transferring it to a customer, whereas an entity is required to record revenue on a net basis if its role is to arrange for another entity to provide the goods or services to a customer.

The Company evaluated its natural gas gathering and processing arrangements in place with midstream companies. Under contracts where it is determined that control of the natural gas transfers at the wellhead or the inlet of the midstream processing entity's system, any fees incurred to gather or process the unprocessed natural gas are a reduction of the sales price of unprocessed natural gas, and therefore revenues from such transactions are presented on a net basis. Under contracts where it is determined that control of the natural gas transfers at the tailgate of the midstream entity's processing plant, the Company is the principal and the midstream entity is the agent in the sale transaction with the third party purchaser of processed commodities. In these instances, revenues are presented on a gross basis for amounts expected to be received from the midstream company or third party purchasers through the gathering and treating process and presented as revenue and any fees incurred to gather or process the natural gas are presented as lease operating expenses. The Company previously recognizes both sales at the wellhead or the inlet of the midstream processing entity's system in the same manner as it currently records transactions where the transfer is completed at the tailgate of the midstream entity's processing plant. The difference between the two methods of accounting was not material.

The Company adopted the new revenue recognition and presentation guidance on January 1, 2018, using a full retrospective transition approach. We believe that adoption of the new guidance had no material cumulative effect on the Company's retained earnings at January 1, 2018.

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The new guidance does not have a material impact on the timing of the Company's revenue recognition or its financial position, results of operations, net income, or cash flows.

Below is a discussion of the nature, timing, and presentation of revenues arising from the Company's major revenue-generating arrangements:

Oil and Gas Sales United Sates – Revenues on sales of oil, natural gas liquids ("NGLs"), gas and purchased oil and gas are recognized when control of the product is transferred to the purchaser and payment can be reasonably assured. Sales prices for oil, NGL and gas production are negotiated based on factors normally considered in the industry, such as an index or spot price, distance from the well to the pipeline or market, commodity quality and prevailing supply and demand conditions. As such, the prices of oil, NGLs and gas generally fluctuate based on the relevant market index rates. Sales under the Company's oil contracts are generally considered performed when the Company sells oil production at the wellhead and receives an agreed-upon index price, net of any price differentials. The Company recognizes revenue when control transfers to the purchaser at the wellhead based on the net price received. Sales under the Company's gas processing contracts are recognized when the Company delivers gas to a midstream processing entity at the wellhead or the inlet of the midstream processing entity's system. The midstream processing entity gathers and processes the gas and remits proceeds to the Company for the resulting sales of NGLs and gas.

In a few cases, the Company elects to take its NGLs and residue gas in-kind at the tailgate of the midstream entity's processing plant and subsequently market the products itself. When the Company elects to take-in-kind, it delivers NGLs and gas to a third-party purchaser at a contractually agreed-upon delivery point and receives a specified index price from the purchaser.

Natural Gas Sales Israel – We own all ownership units in Tamar Royalties LLC, a Delaware limited liability company. Tamar Royalties LLC owns an overriding royalty interest of 1.5375% before payout and increasing to 2.7375% after payout in the Tamar Field (collectively the "Tamar Royalty") offshore Israel. An overriding royalty interest is an ownership interest in the oil and gas leasehold estate equating to a certain percentage of production or production revenues, calculated free of the costs of production and development of the underlying lease(s), but subject to its proportionate share of certain post production costs. An overriding royalty interest is a non-possessory interest in the oil and gas leasehold estate and, accordingly, we have no control over the operations, drilling, expenses, timing, production, sales, or any other aspect of development or production of the Tamar Field.

Natural gas from the Tamar Field is currently sold to the Israel Electric Corporation ("IEC") and numerous other Israeli purchasers, including independent power producers, cogeneration facilities, local distribution companies and certain industrial companies. Currently, many of the Tamar's gas purchase and sale agreements provide for sales at a 7 to 15-year term, while some contracts have extension options of up to 2 years. Depending on the specific contract, prices may vary and are based on an initial base price subject to price adjustment provisions, including price indexation and a price floor. The IEC contract provides for price reopeners (sometimes referred to as "price review" clauses) in the eighth and eleventh years of the contract, subject to limits on the amount of increase or decrease from the existing contractual price.

Revenues from natural gas sales in Israel are recognized when control of the product is transferred to a purchaser and payment can reasonably be assured. The Company receives monthly overriding royalty payments from Isramco Negev 2 Limited Partnership, a related party. We generally receive payment two months after the hydrocarbons have been produced. The revenue is recognized in the month that the hydrocarbons are produced.

Production Services – Our production services business earns revenues for well servicing, plugging and abandonment services, workover and fluid hauling services pursuant to master service agreements based on purchase orders or other contractual arrangements with the client. Production services jobs are generally short-term (less than 30 days) and are charged at current market rates for the labor, equipment and materials necessary to complete the job. Production services jobs are varied in nature, but typically represent a single performance obligation, either for a particular job, a series of distinct jobs, or a period of time during which we stand ready to provide services as our client needs them. Generally, the Company accounts for production services as a single performance obligation satisfied at a certain point in time. Revenue for certain jobs spanning multiple days is recognized upon the completion of each day's work based upon a completed field ticket, which includes the charges for the services performed, mobilization of the equipment to the location and personnel. Additional revenue is generated through labor charges and the sale of consumable supplies that are incidental to the service being performed. Such amounts are recognized ratably over the period during which the corresponding goods and services are consumed.

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Disaggregation of revenues (in thousands):

	Years Ended December 31,		
	2018	2017	2016
Oil and Gas sales			
United States	$15,932	$15,109	$12,947
Israel	31,036	28,781	27,462
Production Services	31,825	18,265	12,752
Total revenues from contracts with customers	$78,793	$62,155	$53,161

Performance obligations

The Company satisfies the performance obligations under its crude oil and natural gas sales contracts upon delivery of its production and related transfer of title to customers. Upon delivery of production, the Company has a right to receive consideration from its customers in amounts that correspond with the value of the production transferred. The Company satisfies the performance obligations under production services arrangements by completing the contracted job, at which time the Company as the right to receive consideration from its customers in agreed upon amounts.

All of the Company’s outstanding production services and crude oil sales contracts at December 31, 2018 are short-term in nature with contract terms of less than one year. For such contracts, the Company has utilized the practical expedient in Accounting Standards Codification (“ASC”) 606-10-50-14 exempting the Company from disclosure of the transaction price allocated to remaining performance obligations, if any, if the performance obligation is part of a contract that has an original expected duration of one year or less.

The majority of the Company’s operated natural gas production is sold at lease locations to midstream customers under multi-year term contracts. For such contracts having a term greater than one year, the Company has utilized the practical expedient in ASC 606-10-50-14A which indicates an entity is not required to disclose the transaction price allocated to remaining performance obligations, if any, if variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under our sales contracts, whether for crude oil or natural gas, each unit of production delivered to a customer represents a separate performance obligation; therefore, future volumes to be delivered are wholly unsatisfied at period-end and disclosure of the transaction price allocated to remaining performance obligations is not applicable.

Contract balances

Under the Company’s crude oil and natural gas sales contracts or arrangements that give rise to service revenues, the Company recognizes revenue after its performance obligations have been satisfied, at which point the Company has an unconditional right to receive payment. Accordingly, the Company’s commodity sales contracts and service arrangements generally do not give rise to contract assets or contract liabilities under ASC Topic 606. Instead, the Company’s unconditional rights to receive consideration are presented as a receivable within “Accounts receivable, net of allowances for doubtful accounts”, in its consolidated balance sheets.

Revenues from previously satisfied performance obligations

To record revenues for commodity sales in the United States and Israel, at the end of each period the Company estimates the amount of production delivered and sold to customers and the prices to be received for such sales. Differences between estimated revenues and actual amounts received for all prior months are recorded in the month payment is received from the customer and are reflected in our consolidated financial statements within the caption “Oil and gas sales”. Revenues recognized during the year ended December 31, 2018 related to performance obligations satisfied in prior reporting periods were not material.

To record revenues for un-billed production services, at the end of each period the Company estimates the services rendered. Differences between estimated revenues and actual amounts received for all prior months are recorded in the month invoices are created and reflected in our consolidated financial statement with the caption “Production services”. Revenues recognized during the year ended December 31, 2018 related to performance obligations satisfied in prior reporting periods were not material.

4. Financial Instruments and Fair Value

Pursuant to ASC 820, Fair Value Measurements and Disclosures (ASC 820) the Company's determination of fair value incorporates not only the credit standing of the counterparties involved in transactions with the Company resulting in receivables on the Company's consolidated balance sheets, but also the impact of the Company's nonperformance risk on its own liabilities. ASC 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The Company classifies fair value balances based on the observability of those inputs.

On June 16, 2015, Tamar Royalties LLC, a wholly owned subsidiary of the Company, engaged in an interest rate swap agreement ("IRS Agreement") with the Deutsche Bank AG London Branch ("DBAG"). An interest rate swap is an agreement between two parties (known as counterparties) where one stream of future interest payments is exchanged for another based on a specified notional principal amount. Interest rate swaps often exchange fixed interest payments for floating interest payments that are linked to interest rates.

As previously disclosed on the Company's Form 8-K filed May 22, 2015, Tamar Royalties LLC entered into a $120,000,000 credit facility with Deutsche Bank, which facility is discussed further in Note 5 "Long-Term Debt and Interest Expense". Under the terms of this facility, Tamar Royalties LLC, is required to hedge at least seventy-five percent (75%) of the outstanding balance under this Facility against fluctuations in LIBOR, with at least thirty-seven and one-half percent (37.5%) of the outstanding balance being hedged through swaps. The notional value of these hedges corresponds to the amortization schedule covering the facility and previously disclosed in the aforementioned Form 8-K. Accordingly, on June 16, 2015, Tamar Royalties LLC and DBAG entered into the IRS Agreement whereby Tamar Royalties LLC hedged $119,250,000 of the $120,000,000 initial borrowing as follows:

(a) Tamar Royalties LLC hedged 37.5% of the perpetual outstanding balance under the facility, being an initial notional amount of $45,000,000, with a fixed rate swap whereby the Company will pay DBAG a fixed interest rate of 4.63%, and DBAG will pay the Company a monthly floating interest rate of USD-LIBOR-BBA plus a spread of 2.75%.

(b) Tamar Royalties hedged the remaining 62.5% of the perpetual outstanding balance less $750,000, being an initial notional amount of $74,250,000, against fluctuations in LIBOR by capping the fluctuations in LIBOR at 1.50%. Pursuant to the IRS Agreement, the Company will pay DBAG a fixed interest rate of 0.91%, and the Bank will pay the Company the greater of (i) USD-LIBOR-BBA minus a cap strike of 1.5% and (ii) zero.

Financial Instruments as of December 31, 2018 and December 31, 2017 consisted of the following (in thousands):

Financial Instrument	Fair Value Input Level	December 31, 2018 Carrying Value	December 31, 2018 Fair Value	December 31, 2017 Carrying Value	December 31, 2017 Fair Value
ST (Liabilities)/Assets:					
Interest rate swaps	Level 2	$293	$293	$(457)	$(457)
LT Assets:					
Interest rate swaps	Level 2	388	388	187	187
		$681	$681	$(270)	$(270)

Level 2 Financial Instruments

Our interest rate swaps are measured at fair value using Level 2 inputs. The fair of our interest rate swaps is based on the net present value of expected future cash flows related to both variable and fixed-rate legs of the swap agreement. This measurement is computed using the forward London Interbank Offered Rate ("LIBOR") yield curve, a market-based observable input.

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5. Long-Term Debt and Interest Expense

Long-term debt as of December 31, 2018 and December 31, 2017 consisted of the following (in thousands):

	As of December 31, 2018	As of December 31, 2017
Bank loan		
Principal amount	$ 79,500	$ 98,400
Less: unamortized discount and debt costs	(2,131)	(2,959)
Total long-term debt	77,369	95,441
Less: current maturities and current discount amortization	(21,176)	(18,072)
Long-term debt, net of current maturities	$ 56,193	$ 77,369

Bank Loan and Credit Facility

The Deutsche Bank Facility

On May 18, 2015, Tamar Royalties LLC ("Tamar Royalties"), a newly formed, wholly-owned, special purpose subsidiary of the Company, entered into a term loan credit agreement (the "DB Facility") with Deutsche Bank Trust Company Americas ("Deutsche Bank"), as facility agent for the lenders and as collateral agent for the secured parties, and with the lenders party thereto. The DB Facility provides for borrowings in the amount of $120,000,000 on a committed basis and is secured by, among other things, an overriding royalty interest in the Tamar Field, a natural gas field in the Mediterranean Sea, equal to 1.5375% before payout increasing to 2.7375% after payout in the Tamar Field (the "Royalty Interest"). In connection with the DB Facility, and pursuant to a royalties sale and contribution agreement, the Company contributed the Royalty Interest to Tamar Royalties in exchange for all of the ownership units of Tamar Royalties. Pursuant to the terms of its governing documents, Tamar Royalties will be managed by N.M.A. Energy Resources Ltd, a related party of the Company, and an independent manager, Donald J. Puglisi.

Pursuant to the terms of the DB Facility, Tamar Royalties borrowed $120,000,000 in its initial borrowing under this facility. The initial borrowing under the DB Facility bears annual interest based on the LIBOR for a three-month interest period plus a spread of 2.75%. The $120,000,000 initial borrowing under the DB Facility will be repaid over eight (8) years commencing July 1, 2015, in accordance with an amortization profile based on projected cash flows from the Royalty Interest. Tamar Royalties' obligations under the Facility are secured by a first ranking pledge of the shares of Tamar Royalties, first ranking pledge of all rights under the agreements creating the Royalty Interest, and a first priority security interest over the accounts created under the DB Facility.

So long as any amounts remain outstanding to the Lenders under the DB Facility, Tamar Royalties must, from and after the end of the Availability Period (as defined in the DB Facility), have a Historical Debt Service Coverage Ratio (as defined in the DB Facility) of not less than 1.00:1.00, a Loan Life Coverage Ratio (as defined in the DB Facility) of at least 1.1:1.00, and maintain a Required Reserve Amount (as defined in the DB Facility). In addition, Tamar Royalties is required under the DB facility to hedge against fluctuations in LIBOR as reflected in Note 4 “Financial Instruments and Fair Value”.

On January 2, 2018 the Company made a payment in the amount of $3,427,000 consisting of $2,400,000 and $1,027,000 in principal and interest respectively.

On April 2, 2018, the Company made a payment in the amount of $6,479,000 consisting of $5,400,000 and $1,079,000 in principal and interest respectively.

On July 2, 2018, the Company made a payment in the amount of $6,546,000 consisting of $5,400,000 and $1,146,000 in principal and interest respectively.

On October 2, 2018, the Company made a payment in the amount of $6,796,000 consisting of $5,700,000 and $1,096,000 in principal and interest respectively.

On January 2, 2019, the Company made a payment in the amount of $6,757,000 consisting of $5,700,000 and $1,057,000 in principal and interest respectively.

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The Company incurred debt costs in obtaining the facility in the amount of $2,011,000 and $2,959,000 in fees were retained by the lenders. These costs totaling $4,970,000 are recorded as a reduction of the principal loan balance and are being amortized over the life of the loan using the effective interest method. Amortization of these costs for the period ended December 31, 2017, 2016, and 2015 totaled $828,000, $789,000, and $820,000 respectively.

As of December 31, 2018 and 2017, Tamar Royalties was in compliance with the financial covenants required under the DB Facility.

The Société Générale Facility

On June 30, 2015, Isramco Onshore LLC (“Isramco Onshore”), a newly formed, wholly-owned, subsidiary of Isramco, Inc. (the “Company”), entered into a secured Credit Agreement (the “SG Facility”) with The Société Générale, as Administrative Agent and Issuing Lender, SG Americas Securities LLC, as Sole Bookrunner, Lead Arranger and Documentation Agent, and the lenders party thereto from time to time, as Lenders. The SG Facility provides for a commitment by The Société Générale of $150,000,000, subject to an initial borrowing base of $40,000,000. The tenure of the SG Facility was four (4) years and the SG Facility was secured by certain onshore United States oil and gas properties. Pricing under the SG Facility was as follows: (i) for EuroDollar Rate (as defined in the SG Facility) loans range from the EuroDollar rate plus 1.75% to the EuroDollar rate plus 2.75% depending on borrowing base utilization; and (ii) for Reference Rate (as defined in the SG Facility) loans ranges from the Reference Rate plus 0.75% to the Reference Rate Spread plus 1.75% based on borrowing base utilization; (iii) a quarterly commitment fee (as defined in the SG Facility) ranging from an annual rate of 0.38% to 0.5% of the undrawn borrowing base.

The SG Facility provided that Isramco Onshore hedge at least seventy-five percent (75%) of its crude oil production before borrowing under the SG Facility. As of December 31, 2017 and as of the date of issuance Isramco Onshore has not entered into such hedge agreements nor has it made a draw under the SG Facility. The Company incurred $478,000 of financing costs in relation to this credit facility which were capitalized as a long-term asset and amortized over the term on the agreement on a straight-line basis until December 31, 2016 at which time the remaining balance totaling $299,000 was expensed.

Isramco Onshore had various financial and operating covenants required by the SG Facility, including, among other things, the requirement that, during the term of the SG Facility, Isramco Onshore must have a Minimum Current Ratio (as defined in the SG Facility) of not less than 1.00:1.00, a Maximum Leverage Ratio (as defined in the SG Facility) of not less than 4.00:1.00 and a Minimum Interest Coverage Ratio (as defined in the SG Facility) of at least 2.50:1.00. In addition, the SG Facility provided for customary events of default, including, but not limited to, payment defaults, breach of representations or covenants, bankruptcy events and change of control.

On August 18, 2016 as a result of semi-annual borrowing base redetermination the borrowing base under SG Facility was reduced to zero. On February 28, 2017 the SG Facility was terminated.

Short-Term Debt

As of December 31, 2018 and December 31, 2017 outstanding debt from short-term insurance financing agreements totaled $563,000 and $445,000 respectively. During the year ended December 31, 2018, the Company made cash payments totaling $950,000.

Short-Term Debt – Related Party

In September 2018 the Company issued an unsecured promissory note dated effective September 11, 2018, to I.O.C - Israel Oil Company LTD, a related party, in which the Company may borrow up to $7,000,000 at a rate of interest equal to seven and one-half percent (7.5%) and with a maturity date of September 2019. The Company received $3,600,000 under this related party note in 2018 attendant with the creation of a new subsidiary, Arrow Midstream LLC. Amounts received under the aforementioned promissory note are dedicated to working capital and the purchase of equipment for Arrow Midstream LLC, a new wholly owned subsidiary of Isramco Inc. Arrow Midstream is focused on the transportation of liquefied petroleum products including, but not limited to, butane, propane, and similar products. Mr. Haim Tsuff, Isramco's Co-Chief Executive Officer and Chairman and is a controlling shareholder of IOC. As of December 31, 2018 the balance of the loan was $3,600,000 with accrued interest expense and payable of $71,000.

Isramco also had related party payables of $263,000 and $60,000 as of December 31, 2018 and 2017 respectively which are included with short term related party debt on the balance sheets

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Debt Maturities

Aggregate maturities of long-term debt at December 31, 2018 are due in future years as follows (in thousands):

2019	$21,900
2020	17,100
2021	14,700
2022	14,400
2023	11,400
Total	$79,500

Interest Expense, net

The following table summarizes the amounts included in interest expense for the years ended December 31, 2018, 2017 and 2016:

	Years Ended December 31,		
	2018	**2017**	**2016**
	(In thousands)		
Current debt, long-term debt and other - banks	$4,921	$4,784	$4,817
Long-term debt – related parties	71	-	-
	$4,992	$4,784	$4,817

6. Income Taxes

The Company operates through its various subsidiaries in the United States ("U.S."); accordingly, income taxes have been provided based upon the tax laws and federal and state income tax rates in the U.S. as they apply to the Company's current ownership structure.

On December 22, 2017, H.R. 1, originally known as the Tax Cuts and Jobs Act ("the Tax Reform Act") was enacted. The Tax Reform Act significantly revised the U.S. corporate income tax regime by, among other things, lowering the U.S. corporate tax rate from 35% to 21% effective January 1, 2018, while also repealing the deduction for domestic production activities, implementing a territorial tax system and removing the expiration of net operating losses. U.S.

GAAP requires that the impact of tax legislation be recognized in the period in which the law was enacted. In December 2017, as a result of the Tax Reform Act, the Company recorded a tax expense of $9.2 million due to a remeasurement of deferred tax assets and liabilities.

The Company accounts for income taxes pursuant to Accounting Standards Codification (ASC) 740, *Accounting for Income Taxes,* which requires recognition of deferred income tax liabilities and assets for the expected future tax consequences of events that have been recognized in Isramco's financial statements or tax returns. The Company provides for deferred taxes on temporary differences between the financial statements and tax basis of its assets using the enacted tax rates that are expected to apply to taxable income when the temporary differences are expected to reverse.

The Company adopted Accounting Standards Codification (ASC) 740-10, effective January 1, 2007. The Company recognizes interest and penalties related to unrecognized tax benefits within the provision for income taxes on continuing operations. There were no unrecognized tax benefits that if recognized would affect the tax rate. There were no interest or penalties recognized as of the date of adoption or for the twelve months ended December 31, 2018. The Company's tax years subsequent to 2015 currently remain open and subject to examination by federal tax authorities and the tax authorities in Colorado, Louisiana, Michigan, New Mexico, Oklahoma, Texas, and Utah which are the jurisdictions in which the Company has had its principal operations. In certain of these jurisdictions, the Company operates through more than one legal entity, each of which may have different open years subject to examination. It is important to note that years are technically open for examination until the statute of limitations in each respective jurisdiction expires.

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The income tax provision differs from the amount of income tax determined by applying the Federal Income Tax Rate to pre-tax income from continuing operations due to the following items:

	Years Ended December 31,		
	2018	**2017**	**2016**
	(In thousands)		
Expected tax (benefit) expense	$4,959	$6,934	$2,889
Foreign Tax, net of federal effect	2,388	-	-
US and Foreign Statutory Rate Change (1)	-	9,234	-
Alternative minimum tax conversion	-	57	-
Change in Valuation Allowance	(1,229)	28,677	-
Non-controlling interest in subsidiary	303	531	650
Other	717	204	95
Total tax expense (benefit)	$7,138	$45,637	$3,634

(1) See Recent Changes in US Tax Law, above. Rate decreased to 21.0% for fiscal year 2018

Deferred tax assets at December 31, 2018 and 2017 are comprised primarily of foreign tax credits and book impairment from write downs of assets. Book basis in excess of tax basis for oil and gas properties and equipment primarily results from differing methodologies for recording property costs and depreciation, depletion and amortization under accounting principles generally accepted in the United States and the applicable income tax statutes and regulations in the jurisdictions in which the Company operates.

In assessing the realizability of deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income in the appropriate tax jurisdictions during the periods in which those temporary differences become deductible. We consider the scheduled reversal of deferred tax liabilities, current financial position, results of operations, projected future taxable income and tax planning strategies as well as current and forecasted business economics in the oil and gas industry. Based on the level of historical taxable income and projections for future taxable income, we believe it is unlikely that we will realize the benefits of these foreign tax credits and other deferred tax assets as we do not expect to have a realizable taxable income subject to deduction. Therefore, we have included a full valuation allowance to decrease the deferred tax assets balances to zero.

Effective December 21, 2016, the Israeli government decreased the corporate income tax rate from 25% to 24% for 2017 and further rate decrease from 24% to 23% effective January 2018. A full valuation allowance has been recorded against foreign tax credits based on current interpretation of US Tax Reform law and the expected future utilization of foreign tax credits stems from a lower tax rate of 21% applied on taxable income in United States.

The principal components of the Company’s deferred tax assets as of December 31 were as follows (in thousands):

	2018	2017
Deferred tax assets:		
Allowance for doubtful accounts	$536	$511
Unrealized Hedging Transactions	(143)	57
Foreign tax credit (1)	25,381	23,743
Book-tax differences in property basis	1,657	3,757
Other	17	2
Net operating loss carry-forwards	-	607
Less valuation allowance	(27,448)	(28,677)
Deferred noncurrent tax assets	$-	$-

(1) Total revenues net of marketing and transportation expenses from Tamar Field in 2018 were $31,036,000. The Company paid $7,138,000 in foreign income taxes. As a result a foreign tax credit has been created in the US to be used against future US income tax. The credit will expire in various amounts beginning in 2024 and ending in 2028. Due to Recent Changes in US Tax Law a full valuation allowance has been recorded based on our interpretations of US Tax Law and expectation of future usage of foreign tax credit.

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Components of income (loss) from operations before income taxes are as follows (in thousands):

	2018	2017	2016
Domestic	$(7,422)	$(8,970)	$(18,939)
Foreign	31,036	28,781	27,462
Total	$23,614	$19,811	$8,523

The principal components of the Company's Income Tax Provision for the years indicated below were as follows (in thousands):

	2018	2017	2016
Current income tax:			
Federal	$-	$(57)	$-
Foreign	7,138	6,907	6,866
State	-	-	-
Total current income tax	$7,138	$6,850	$6,866
Deferred income tax			
Federal	$-	$38,787	$(3,232)
Foreign	-	-	-
State	-	-	-
Total deferred income tax	$-	$38,787	$(3,232)
Provision for income tax	$7,138	$45,637	$3,634

7. Earnings Per Share

The following table sets forth the computation of Net Income (Loss) Per Share Available to Common Stockholders for the years ended December 31 (in thousands, except per share data):

	2018	2017	2016
Numerator for Basic and Diluted Earnings per Share - Net Income (loss)	$17,934	$(24,310)	$6,745
Denominator for Basic Earnings per Share - Weighted Average Shares	2,717,648	2,717,648	2,717,648
Potential Dilutive Common Shares -	-	-	-

Adjusted Weighted Average Shares	2,717,648	2,717,648	2,717,648
Net Income (Loss) Per Share Available to Common Stockholders – Basic	$6.60	$(8.95)	$2.48
Net Income (Loss) Per Share Available to Common Stockholders – Diluted	$6.60	$(8.95)	$2.48

8. Stock Options

At the Annual Shareholders Meeting in 2011, the shareholders adopted the 2011 Stock Incentive Plan. That plan will be administered by the Compensation Committee of the Board of Directors and there are 200,000 shares under that plan that may be awarded. Independent members of the board of directors as well as employee of and consultants to the Company are eligible to receive awards. The awards can be in the form of stock options, restricted stock or other stock–based awards. The awards are intended to qualify as performance-based compensation for purposes of Section 162(m) of the Internal Revenue Code. There are no granted awards outstanding under the 2011 Stock Incentive Plan.

No stock options were granted during 2018, 2017 and 2016. Shares of common stock reserved for future issuance under the 2011 plan are 200,000 shares. There are no granted stock options outstanding under the 2011 Plan as of balance sheet date.

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9. Supplemental Cash Flow Information

The Israeli taxing authority withheld taxes of $7,138,000, $6,907,000, and $6,866,000 during the years ended December 31, 2018, 2017, and 2016 respectively.

Cash payments for interest were $4,347,000, $4,012,000, and $3,859,000 for the years ended December 31, 2018, 2017, and 2016 respectively.

The consolidated statements of cash flows for the years ended December 31, 2018, 2017 and 2016 exclude the following non-cash transactions:

Net additions to equipment of $165,000 included in accounts payable in 2018.
Asset retirement obligation relieved of $19,000 due to sale of oil and gas properties in 2018.
Insurance premiums financed through issuance of short term debt of $1,068,000 in 2018.
Net additions to equipment of $33,000 included in accounts payable in 2017.
Addition to prepaid expenses and other of $485,000 from sale of equipment in 2017.
Increase in property and equipment of $28,000 due to additional asset retirement obligation in 2017.
Asset retirement obligation relieved of $18,000 due to sale of oil and gas properties in 2017.
Insurance premiums financed through issuance of short term debt of $835,000 in 2017.
Increase in property and equipment of $1,000 due to additional asset retirement obligation in 2016.
Termination of $487,000 short-term insurance financing reduced prepaid insurance in 2016
Insurance premiums financed through issuance of short-term debt of $742,000 in 2016.
Equipment of $457,000 included in accounts payable in 2016.
Equipment additions were offset by trade-ins valued at $75,000 in 2016.

10. Concentrations of Credit Risk

Financial instruments, which potentially expose Isramco to concentrations of credit risk, consist primarily of cash equivalents, trade and joint interest accounts receivable. Isramco's customer base includes several of the major United States oil and gas operating and production companies as well as major power companies in Israel. Although Isramco is directly affected by the well-being of the oil and gas production industry, management does not believe a significant credit risk existed as of December 31, 2018. Isramco continues to monitor and review credit exposure of its marketing counter-parties.

Our production services segment customers include major oil and natural gas production companies and independent oil and natural gas production companies. We perform ongoing credit evaluations of our customers and usually do not require material collateral. We maintain reserves for potential credit losses when necessary. Our results of operations and financial position should be considered in light of the fluctuations in demand experienced by oilfield service companies as changes in oil and gas producers' expenditures and budgets occur. These fluctuations can impact our results of operations and financial position as supply and demand factors directly affect utilization and hours which are the primary determinants of our net cash provided by operating activities.

Isramco maintains deposits in banks, which may exceed the amount of federal deposit insurance available. Management periodically assesses the financial condition of the institutions and believes that any possible deposit loss is minimal.

11. Segment Information

Isramco's primary business segments are vertically integrated within the oil and gas industry. These segments are separately managed due to distinct operational differences, unique technology, distribution and marketing requirements. The Company's two reporting segments are oil and gas exploration and production and production services. The oil and gas exploration and production segment explores for and produces natural gas, crude oil, condensate, and NGLs. The production services segment is engaged in rig-based and workover services, well completion and recompletion services, plugging and abandonment of wells and other ancillary oilfield services.

Oil and Gas Exploration and Production Segment

Our Oil and Gas segment is engaged in the exploration, development and production of oil and natural gas properties located onshore in the United States and ownership of various royalty interests in oil and gas concessions located offshore Israel. We own varying working interests in oil and gas wells in Louisiana, Texas, New Mexico, Oklahoma, Wyoming, Utah and Colorado and currently serve as operator of approximately 422 producing wells located mainly in Texas in New Mexico.

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Production services Segment

Our rig-based services include the completion of newly drilled wells, workover and recompletion of existing oil and natural gas wells, well maintenance, and the plugging and abandonment of wells at the end of their useful lives.

The completion and recompletion services provided by our rigs prepare a newly drilled well, or a well that was recently extended through a workover, for production. The completion process may involve selectively perforating the well casing to access production zones, stimulating and testing these zones, and installing tubular and downhole equipment. We typically provide a production services rig and may also provide other equipment to assist in the completion process. The completion process usually takes a few days to several weeks, depending on the nature of the completion.

The workover services that we provide are designed to enhance the production of existing wells and generally are more complex and time consuming than normal maintenance services. Workover services can include deepening or extending wellbores into new formations by drilling horizontal or lateral wellbores, sealing off depleted production zones and accessing previously bypassed production zones, converting former production wells into injection wells for enhanced recovery operations and conducting major subsurface repairs due to equipment failures. Workover services may last from a few days to several weeks, depending on the complexity of the workover.

The maintenance services that we provide with our rig fleet are generally required throughout the life cycle of an oil or natural gas well. Examples of these maintenance services include routine mechanical repairs to the pumps, tubing and other equipment, removing debris and formation material from wellbores, and pulling the rods and other downhole equipment from wellbores to identify and resolve production problems. Maintenance services generally take less than 48 hours to complete. Our rig fleet is also used in the process of permanently shutting-in oil or natural gas wells that are at the end of their productive lives. These plugging and abandonment services generally require auxiliary equipment in addition to a production servicing rig. The demand for plugging and abandonment services is not significantly impacted by the demand for oil and natural gas because well operators are required by state and federal regulations to plug wells that are no longer productive.

thousands	**Oil and Gas Exploration & Production**	**Production services**	**Eliminations**	**Total**
Year Ended December 31, 2018:				
Sales revenues				
United States	$ 15,932	$ 31,825	$ -	$47,757

Israel	31,036	-	-	31,036
Intersegment revenues	-	339	(339)	-
Office services and other	2,666	-	(120)	2,546
Total revenues and other	49,634	32,164	(459)	81,339
Operating costs and expenses	16,352	30,738	(459)	46,631
Depreciation, depletion, and amortization	1,886	3,657	-	5,543
Impairment	1,252	-	-	1,252
Interest expenses, net and other	(20)	5,012	-	4,992
Gain on derivative contracts	(680)	-	-	(680)
Other income, net	10	(23)		(13)
Total expenses and other	18,800	39,384	(459)	57,725
Income (loss) before income taxes	$ 30,834	$ (7,220)	$ -	$23,614
Net income (loss)	22,056	(5,580)	-	16,476
Net loss attributable to noncontrolling interests		(1,458)	-	(1,458)
Net income (loss) attributable to Isramco	22,056	(4,122)	-	17,934
Total Assets	$ 63,009	$ 48,605	$ -	$111,614
Expenditures for Long-lived Assets	$ 796	$ 8,201	$ -	$8,997

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thousands	**Oil and Gas Exploration & Production**	**Production services**	**Eliminations**	**Total**
Year Ended December 31, 2017:				
Sales revenues				
United States	$ 15,109	$ 18,265	$ -	$33,374
Israel	28,781	-	-	28,781
Office services and other	3,912	-	(120)	3,792
Total revenues and other	47,802	18,265	(120)	65,947
Operating costs and expenses	15,079	19,154	(120)	34,113
Depreciation, depletion, and amortization	2,454	3,072	-	5,526
Impairment	1,682	-	-	1,682
Interest expenses, net and other	993	3,791	-	4,784
Loss on derivative contracts	176	-	-	176
Other income, net	(33)	(112)		(145)
Total expenses and other	20,351	25,905	(120)	46,136
Income (loss) before income taxes	$ 27,451	$ (7,640)	$ -	$19,811
Net loss	(20,329)	(5,497)	-	(25,826)
Net loss attributable to noncontrolling interests	-	(1,516)	-	(1,516)
Net loss attributable to Isramco	(20,329)	(3,981)	-	(24,310)
Total Assets	$ 67,374	$ 41,423	$ -	$108,797
Expenditures for Long-lived Assets	$ 727	$ 3,457	$ -	$4,184

thousands	**Oil and Gas Exploration & Production**	**Production services**	**Eliminations**	**Total**
Year Ended December 31, 2016:				
Sales revenues				
United States	$ 12,947	$ 12,752	$ -	$25,699
Israel	27,462	-	-	27,462
Office services and other	1,901	-	(120)	1,781
Total revenues and other	42,310	12,752	(120)	54,942
Operating costs and expenses	14,304	15,495	(120)	29,679
Depreciation, depletion, and amortization	3,474	3,193	-	6,667
Impairment	4,529	-	-	4,529

Interest expenses, net and other	1,509	3,308	-	4,817
Loss on derivative contracts	657	-	-	657
Other expense, net	34	36		70
Total expenses and other	24,507	22,032	(120)	46,419
Income (loss) before income taxes	$ 17,803	$ (9,280)	$ -	$ 8,523
Net income (loss)	11,571	(6,682)	-	4,889
Net loss attributable to noncontrolling interests	-	(1,856)	-	(1,856)
Net income (loss) attributable to Isramco	11,571	(4,826)	-	6,745
Total Assets	$ 103,956	$ 37,316	$ -	$ 141,272
Expenditures for Long-lived Assets	$ 233	$ 908	$ -	$ 1,141

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12. Commitments and Contingencies

Commitments

Isramco has a few immaterial lease agreements.

Contingencies

From time to time, the Company may be a plaintiff or defendant in a pending or threatened legal proceeding arising in the normal course of its business. All known liabilities are accrued based on the Company's best estimate of the potential loss. In the opinion of management, Isramco's ultimate liability, if any, in these pending actions would not have a material adverse effect on the financial position, operating results or liquidity of Isramco.

13. Asset Retirement Obligation

If a reasonable estimate of the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells can be made, the Company records a liability (an asset retirement obligation or ARO) on the consolidated balance sheets and capitalizes the asset retirement cost in oil and natural gas properties in the period in which the retirement obligation is incurred. In general, the amount of an ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date that the abandonment obligation was incurred using an assumed cost of funds for the company. After recording these amounts, the ARO is accreted to its future estimated value using the same assumed cost of funds and the additional capitalized costs are depreciated on a unit-of-production basis.

The following table presents the reconciliation of the beginning and ending aggregate carrying amount legal obligations associated with the retirement of oil and gas properties at December 31 (in thousands):

	2018	**2017**	**2016**
Liability for asset retirement obligation at the beginning of the year	$21,670	$20,748	$19,884
Liabilities Incurred	3	28	1
Liabilities settled and divested	(370)	(19)	(34)

Accretion expense	869	913	897
Liability for asset retirement obligation at the end of the year	$22,172	$21,670	$20,748

14. Supplemental Oil and Gas Information (Unaudited)

The following supplemental information regarding the oil and gas activities of Isramco for 2018, 2017 and 2016 is presented pursuant to the disclosure requirements promulgated by the Securities and Exchange Commission and ASC 932, "Disclosures About Oil and Gas Producing Activities." Capitalized costs relating to oil and gas activities and costs incurred in oil and gas property acquisition, exploration and development activities for each year are shown below.

CAPITALIZED COST OF OIL AND GAS PRODUCING ACTIVITIES (IN THOUSANDS)

As of December 31	**2018 United States**	**2017 United States**
Unproved properties not being amortized	$-	$-
Proved property being amortized	244,451	243,812
Accumulated depreciation, depletion amortization and impairment	(226,811)	(224,105)
Net capitalized costs	$17,640	$19,707

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COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION, EXPLORATION, AND DEVELOPMENT ACTIVITIES (IN THOUSANDS)

As of December 31	**2018**	**2017**	**2016**
Property acquisition costs—proved and unproved properties	$ -	$ -	$ -
Exploration costs	$ -	$ -	$ -
Development costs	$ -	$ -	$ -

OIL AND GAS RESERVES

Reserves

Users of this information should be aware that the process of estimating quantities of “proved” and “proved developed” oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

Economic producibility of reserves is dependent on the crude oil and natural gas prices used in the reserves estimate. We based our December 31, 2018, 2017, and 2016 reserves estimates on 12-month average commodity prices, unless contractual arrangements designate the price to be used, in accordance with SEC rules. However, commodity prices are volatile. Declines in crude oil or natural gas prices could result in negative reserves revisions.

The following definitions apply to our categories of proved reserves:

Proved Oil and Gas Reserves Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Developed Oil and Gas Reserves Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well.

Undeveloped Oil and Gas Reserves Proved undeveloped oil and gas reserves (PUDs) 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. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

Our current reserve reports covering United States properties do not reflect any significant or material proved undeveloped reserves ("PUD"). Nevertheless, we note that the Company owns legacy assets, some of which may include some development potential which has not yet been fully evaluated. Accordingly, the Company does not currently have a long-term development plan in place for these assets and, therefore, most major expenditures are made on a case-by-case basis. By rule, reserves cannot be classified as PUDs in the reserve report if a development plan has not been adopted.

For complete definitions of proved natural gas, natural gas liquids and crude oil reserves, refer to SEC Regulation S-X, Rule 4-10(a)(6), (22) and (31).

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Geographic Areas

Our supplemental disclosures are grouped by geographic area, which include the United States and Israel.

The following table illustrates the Company's estimated net proved reserves, including changes, and proved developed reserves for the periods indicated, as estimated by our independent reserve engineering firms, Netherland, Sewell & Associates, Inc. and Cawley, Gillespie & Associates, Inc.

	Oil Bbls United States	**Israel**	**Total**	**Gas Mcf United States**	**Israel**	**Total**
December 31, 2015	1,883,720	-	1,883,720	12,488,852	188,203,034	200,691,886
Revisions of previous estimates	(70,134)	-	(70,134)	(1,298,250)	369,348	(928,902)
Extensions, discoveries, and other additions	11,189	-	11,189	25,057	-	25,057
Acquisition of minerals in place	-	-	-	-	-	-
Sales of minerals in place	-	-	-	-	-	-
Production	(215,256)	-	(215,256)	(1,417,252)	(5,101,795)	(6,519,047)
December 31, 2016	1,609,519	-	1,609,519	9,798,407	183,470,587	193,268,994
Revisions of previous estimates	344,048	-	344,048	1,585,008	28,246,503	29,831,511
Extensions, discoveries, and other additions	7,155	-	7,155	12,853	-	12,853
Acquisition of minerals in place	-	-	-	-	-	-
Sales of minerals in place	-	-	-	-	-	-
Production	(195,850)	-	(195,850)	(1,319,660)	(5,342,855)	(6,662,515)
December 31, 2017	1,764,872	-	1,764,872	10,076,608	206,374,235	216,450,843
Revisions of previous estimates	529,546	-	529,546	1,398,946	12,763,295	14,162,241
Extensions, discoveries, and other additions	14,985	-	14,985	12,645	-	12,645
Acquisition of minerals in place	-	-	-	-	-	-
Sales of minerals in place	(1,126)	-	(1,126)	-	-	-
Production	(183,623)	-	(183,623)	(1,119,667)	(5,591,031)	(6,710,698)
December 31, 2018	2,124,654	-	2,124,654	10,368,532	213,546,499	223,915,031
Proved Developed Reserves						
December 31, 2018	2,124,654	-	2,124,654	10,368,532	134,876,499	145,245,031
December 31, 2017	1,764,872	-	1,764,872	10,076,608	174,252,235	184,328,843
December 31, 2016	1,609,519	-	1,609,519	9,798,407	138,511,587	148,309,994
Proved Undeveloped Reserves						

December 31, 2018	-	-	-	-	78,670,000	78,670,000
December 31, 2017	-	-	-	-	32,122,000	32,122,000
December 31, 2016	-	-	-	-	44,959,000	44,959,000

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	NGL Bbls			Total BOE		
	United States	Israel	Total	United States	Israel	Total
December 31, 2015	642,773	244,586	887,359	4,607,968	31,611,758	36,219,726
Revisions of previous estimates	(42,316)	(1,944)	(44,260)	(328,824)	59,614	(269,210)
Extensions, discoveries, and other additions	1,334	-	1,334	16,699	-	16,699
Acquisition of minerals in place	-	-	-	-	-	-
Sales of minerals in place	-	-	-	-	-	-
Production	(76,964)	(6,882)	(83,846)	(528,429)	(857,181)	(1,385,610)
December 31, 2016	524,827	235,760	760,587	3,767,414	30,814,191	34,581,605
Revisions of previous estimates	85,934	39,518	125,452	694,150	4,747,269	5,441,419
Extensions, discoveries, and other additions	1,094	-	1,094	10,391	-	10,391
Acquisition of minerals in place	-	-	-	-	-	-
Sales of minerals in place	-	-	-	-	-	-
Production	(67,339)	(6,991)	(74,330)	(483,132)	(897,467)	(1,380,599)
December 31, 2017	544,516	268,287	812,803	3,988,823	34,663,993	38,652,816
Revisions of previous estimates	59,219	16,658	75,877	821,922	2,143,874	2,965,796
Extensions, discoveries, and other additions	117	-	117	17,210	-	17,210
Acquisition of minerals in place	-	-	-	-	-	-
Sales of minerals in place	-	-	-	(1,126)	-	(1,126)
Production	(58,694)	(7,335)	(66,029)	(428,928)	(939,174)	(1,368,102)
December 31, 2018	545,158	277,610	822,768	4,397,901	35,868,693	40,266,594
Proved Developed Reserves						
December 31, 2018	545,158	175,610	720,768	4,397,901	22,655,026	27,052,927
December 31, 2017	544,516	226,287	770,803	3,988,823	29,268,326	33,257,149
December 31, 2016	524,827	177,760	702,587	3,767,414	23,263,024	27,030,438
Proved Undeveloped Reserves						
December 31, 2018	-	102,000	102,000	-	13,213,667	13,213,667
December 31, 2017	-	42,000	42,000	-	5,395,667	5,395,667
December 31, 2016	-	58,000	58,000	-	7,551,167	7,551,167

(1) Gas reserves are converted to BOE at the rate of six Mcf per Bbl of oil, based upon the approximate relative energy content of gas and oil. This rate is not necessarily indicative of the relationship of natural gas and oil prices. Natural gas liquids reserves are converted to BOE on a one-to-one basis with oil.

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Extensions, discoveries, and other additions —

The increase in 2018, 2017 and 2016 of the United State reserves is from development of onshore assets, primarily in the Permian Basin.

Revisions of Previous Estimates —

2016 — Proved reserves must be estimated using the assumption that prices and costs remain constant for the duration of the reservoir life. The United States downward Revisions of Previous Estimates was due to lower average first-day of the month NGLs prices calculated for the 12 months ended December 31, 2016 compared to prices as of December 31, 2015 and decreased production volumes partially offset by overall decreased production costs associated with operations in several of our leases.

2017 — Proved reserves must be estimated using the assumption that prices and costs remain constant for the duration of the reservoir life. The United States upward Revisions of Previous Estimates was due to higher average first-day of the month oil, gas, and NGL prices calculated for the 12 months ended December 31, 2017 compared to prices as of December 31, 2016 partially offset by overall decreased production. For Israel upward reveseions for 2017 relate to increased production estimates upon completion of an additional well.

2018 — Proved reserves must be estimated using the assumption that prices and costs remain constant for the duration of the reservoir life. The United States upward Revisions of Previous Estimates was due to higher average first-day of the month oil, gas, and NGL prices calculated for the 12 months ended December 31, 2018 compared to prices as of December 31, 2017 partially offset by overall decreased production.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOW

The following Standardized Measure of Discounted Future Net Cash Flow information has been developed utilizing ASC 932, Extractive Activities —Oil and Gas, (ASC 932) procedures and based on oil and natural gas reserve and production volumes estimated by our independent reserve engineering firms, Netherland, Sewell & Associates, Inc and Cawley, Gillespie & Associates, Inc. It can be used for some comparisons, but should not be the only method used to evaluate the Company or its performance. Further, the information in the following table may not represent realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flow be viewed as representative of the current value of the Company.

The Company believes that the following factors should be taken into account when reviewing the following information:

- future costs and selling prices will probably differ from those required to be used in these calculations;
- due to future market conditions and governmental regulations, actual rates of production in future years may vary significantly from the rate of production assumed in the calculations;
- a 10% discount rate may not be reasonable as a measure of the relative risk inherent in realizing future net oil and natural gas revenues; and
- future net revenues may be subject to different rates of income taxation.

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Results of operations from producing activities were as follows for the years ended December 31 (in thousands):

thousands	United States	Israel	Total
December 31, 2018			
Revenues	$15,932	$31,036	$46,968
Production costs	9,662	-	9,662
Depreciation, depletion, amortization and accretion	2,755	-	2,755
Income tax expense	808	7,138	7,946
Results of operations from producing activities	$2,707	$23,898	$26,605

thousands	United States	Israel	Total
December 31, 2017			
Revenues	$15,109	$28,781	$43,890
Production costs	9,504	-	9,504
Depreciation, depletion, amortization and accretion	3,367	-	3,367
Income tax expense	783	10,073	10,856
Results of operations from producing activities	$1,455	$18,708	$20,163

thousands	United States	Israel	Total
December 31, 2016			
Revenues	$12,947	$27,462	$40,409
Production costs	8,922	-	8,922
Depreciation, depletion, amortization and accretion	3,995	-	3,995
Income tax expense	10	9,612	9,622
Results of operations from producing activities	$20	$17,850	$17,870

Estimates of future net cash flows from proved reserves of natural gas, oil, condensate, and NGLs for 2017, 2016, and 2015 are computed using the average first-day-of-the-month price during the 12-month period for the respective year. Prices used to compute the information presented in the tables below are adjusted only for fixed and determinable amounts under provisions in existing contracts. Estimated future net cash flows for all periods presented are reduced by estimated future development and production based on existing costs, assuming continuation of existing economic conditions, and by estimated future income tax expense. These estimates also include assumptions about the timing of future production of proved reserves, and timing of future development and production costs. Income tax expense, both U.S. and foreign, is calculated by applying the existing statutory tax rates, including any known future changes, to the pretax net cash flows, giving effect to any permanent differences and reduced by the applicable tax basis. The effect of tax credits is considered in determining the income tax expense. The 10% discount factor is prescribed by U.S. Generally Accepted Accounting Principles.

In thousands

	United States	Israel	Total
December 31, 2018			
Future cash inflows	$185,185	$1,189,677	$1,374,862
Future development costs	(602)	-	(602)
Future production costs	(92,238)	(485,977)	(578,215)
Future income tax expenses	(10,935)	(161,851)	(172,786)
Future net cash flows	81,410	541,849	623,259
10% annual discount for estimated timing of cash flows	(39,486)	(293,960)	(333,446)
Standardized measure of discounted future net cash flows	$41,924	$247,889	$289,813

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	United States	Israel	Total
December 31, 2017			
Future cash inflows	$125,464	$1,116,867	$1,242,331
Future development costs	(574)	-	(574)
Future production costs	(67,245)	(432,610)	(499,855)
Future income tax expenses	(2,984)	(157,379)	(160,363)
Future net cash flows	54,661	526,878	581,539
10% annual discount for estimated timing of cash flows	(25,899)	(271,433)	(297,332)
Standardized measure of discounted future net cash flows	$28,762	$255,445	$284,207

	United States	Israel	Total
December 31, 2016			
Future cash inflows	$93,228	$976,106	$1,069,334
Future development costs	(670)	-	(670)
Future production costs	(55,554)	(354,305)	(409,859)
Future income tax expenses	-	(186,783)	(186,783)
Future net cash flows	37,004	435,018	472,022
10% annual discount for estimated timing of cash flows	(16,042)	(202,707)	(218,749)
Standardized measure of discounted future net cash flows	$20,962	$232,311	$253,273

(1) The government of Israel imposes a tax or charge upon oil and gas revenues, including revenues from oil and gas produced from the Tamar well. Currently, such oil and gas revenues would be subject to a sliding scale of taxation, beginning with the imposition of a 20% charge on oil and gas revenues at such time as total revenues received equal 1.5 times the costs expended and increasing in steps to a 46.8% charge imposed at such time as revenues received equal 1.5 times the costs expended. The current tax law provides some relief for oil and gas revenues received from reservoirs developed before January 2014 by delaying the imposition of the charges; i.e. the 20% charge would become effective at such time as total revenues received equal 2 times the costs expended and the maximum 46.8% charge would not become effective until revenues received equaled 2.8 times costs expended. Isramco’s overriding royalty would be subject to the above taxation at such time, and at the same rates, as the revenues attributable to the operating interest. The imposed Israeli tax is included in calculation of future gas revenues from Tamar Field.

CHANGES IN STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

The following is a summary of the changes in the Standardized Measure of discounted future net cash flows for the Company’s proved oil and natural gas reserves during each of the years in the three year period ended December 31, 2018:

In thousands

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

	United States	Israel	Total
2018			
Balance at January 1	$28,762	$255,445	$284,207
Sales and transfers of oil and gas produced, net of production costs	(6,551)	(30,613)	(37,164)
Net changes in prices and production costs (1)	11,827	(1,940)	9,887
Changes in estimated future development costs, net of current development costs	-	-	-
Extensions, discoveries, additions, and improved recovery, less related costs	499	-	499
Development costs incurred during the period	-	-	-
Revisions of previous quantity estimates (2)	9,419	20,009	29,428
Purchases of minerals in place	-	-	-
Sales of minerals in place	5	-	5
Accretion of discount	2,764	30,583	33,347
Net change in income taxes (3)	(5,631)	9,385	3,754
Change in production rates and other	830	(34,980)	(34,150)
Balance at December 31	$41,924	$247,889	$289,813

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2017			
Balance at January 1	$20,962	$232,311	$253,273
Sales and transfers of oil and gas produced, net of production costs	(5,630)	(28,781)	(34,411)
Net changes in prices and production costs (1)	8,193	(6,683)	1,510
Changes in estimated future development costs, net of current development costs	-	-	-
Extensions, discoveries, additions, and improved recovery, less related costs	266	-	266
Development costs incurred during the period	-	-	-
Revisions of previous quantity estimates (2)	5,764	47,645	53,409
Purchases of minerals in place	-	-	-
Sales of minerals in place	-	-	-
Accretion of discount	1,920	30,088	32,008
Net change in income taxes (3)	(1,570)	(3,828)	(5,398)
Change in production rates and other	(1,143)	(15,307)	(16,450)
Balance at December 31	$28,762	$255,445	$284,207

2016			
Balance at January 1	$28,797	$248,886	$277,683
Sales and transfers of oil and gas produced, net of production costs	(4,022)	(27,462)	(31,484)
Net changes in prices and production costs (1)	(2,585)	(26,275)	(28,860)
Changes in estimated future development costs, net of current development costs	-	-	-
Extensions, discoveries, additions, and improved recovery, less related costs	379	-	379
Development costs incurred during the period	-	-	-
Revisions of previous quantity estimates	(1,339)	612	(727)
Purchases of minerals in place	-	-	-
Sales of minerals in place	-	-	-
Accretion of discount	2,613	33,347	35,960
Net change in income taxes	-	716	716
Change in production rates and other	(2,881)	2,487	(394)
Balance at December 31	$20,962	$232,311	$253,273

(1) The increase in United States in 2018 and 2017, the increase in Israel in 2018, and the decrease in Israel in 2017 and decrease in both in 2016 were driven primarily by higher and lower, respectively, 12-month average commodity prices. For Israel the commodity prices for the last 12 months are based on actual sales from contractual agreements rather than a market index.

(2) Revisions of previous quantity estimates in the United States in 2018 and 2017 related to increased economics of the properties with better pricing. For Israel this change in 2018 is related to better pricing and in 2017 relates to increased production estimates upon completion of an additional well.

(3) The decrease in United States and Israel future tax 2018 and 2017 is related to the decrease in applicable tax rate from 35% to 21% due to the changes in the United States Tax Law effective January 1, 2018 partially offset by projected inability to utilize net operating losses.

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Unaudited Quarterly Financial Information

(In Thousands, Except Per Share Data)

Quarter Ended	March 31	June 30	September 30	December 31
2018				
Total revenues and other	$17,493	$19,992	$22,846	$21,008
Net income before taxes	6,312	6,169	7,834	3,299
Net income (loss)	4,654	4,383	5,893	1,546
Net loss attributable to noncontrolling interests	(381)	(325)	(285)	(467)
Net income (loss) attributable to Isramco	5,035	4,708	6,178	2,013
Earnings (loss) per share:				
Attributable to common stockholders - basic	$1.85	$1.73	$2.27	$0.74
Attributable to common stockholders - diluted	$1.85	$1.73	$2.27	$0.74
Average number common shares outstanding - basic	2,717,648	2,717,648	2,717,648	2,717,648
Average number common shares outstanding - diluted	2,717,648	2,717,648	2,717,648	2,717,648
2017				
Total revenues and other	$14,800	$18,379	$16,574	$16,194
Net income before taxes	4,427	6,748	5,052	3,584
Net income (loss)	2,721	4,252	3,180	(35,979)
Net loss attributable to noncontrolling interests	(447)	(384)	(296)	(389)
Net income (loss) attributable to Isramco	3,168	4,636	3,476	(35,590)
Earnings (loss) per share:				
Attributable to common stockholders - basic	$1.17	$1.71	$1.28	$(13.11)
Attributable to common stockholders - diluted	$1.17	$1.71	$1.28	$(13.11)
Average number common shares outstanding - basic	2,717,648	2,717,648	2,717,648	2,717,648
Average number common shares outstanding - diluted	2,717,648	2,717,648	2,717,648	2,717,648
2016				
Total revenues and other	$12,693	$13,870	$14,422	$13,957
Net income before taxes	345	3,259	4,809	110
Net income (loss)	69	1,947	2,994	(121)
Net loss attributable to noncontrolling interests	(442)	(485)	(379)	(550)
Net income attributable to Isramco	511	2,432	3,373	429
Earnings per share:				
Attributable to common stockholders - basic	$0.19	$0.89	$1.24	$0.16
Attributable to common stockholders - diluted	$0.19	$0.89	$1.24	$0.16
Average number common shares outstanding - basic	2,717,648	2,717,648	2,717,648	2,717,648
Average number common shares outstanding - diluted	2,717,648	2,717,648	2,717,648	2,717,648