ISRAMCO INC
Form 10-K
March 23, 2012

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

FORM 10-K

Mark one:

x	ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE FISCAL YEAR ENDED DECEMBER 31, 2011
r	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.)

2425 West Loop South, Suite 810, 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 r No x

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 r No x

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 x No r

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No r

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.r

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

Large accelerated filer r	Accelerated filer x	Non-accelerated filer r	Smaller Reporting Company r

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

As of March 22, 2012, there were 2,717,691 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 23, 2012, based on the last sale price of such equity reported on the Nasdaq market, was approximately $227 million.

DOCUMENTS INCORPORATED BY REFERENCE

Information required by Part III, Items 10, 11, 12, 13 and 14, is incorporated by reference to portions of the registrant’s definitive proxy statement for its 2012 annual meeting of stockholders, which will be filed on or before April 30, 2012.

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ISRAMCO, INC.
2011 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," "ach "anticipate," "will," "continue," "potential," "should," "could" and similar terms and phrases. Although we believe tha 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 volatility in commodity prices for oil and natural gas, including continued declines in prices;
- 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;
- environmental risks;
- drilling and operating risks;
- 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;
- our ability to retain key members of senior management and key technical employees;
- our ability to repay our credit facility when due;
- 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;
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general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business, may be less favorable than expected, including the possibility that the current economic recession in the United States will be severe and prolonged, which could adversely affect the demand for oil and natural gas and make it difficult, if not impossible, to access financial markets;

- other economic, competitive, governmental, legislative, regulatory, geopolitical and technological factors that may negatively impact our business, operations or pricing.

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., a Delaware corporation incorporated in 1982 (hereinafter, “we”, the “Company” or “Isramco”), 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 off shore Israel and operate a well service company that provides well maintenance and workover services, well completion and recompletion services.

At December 31, 2011, 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 34,990 thousand barrels of oil equivalent (“MBOE”), consisting of 3,234 thousand barrels (MBbls) of oil, and 179,155 million cubic feet (MMcf) of natural gas and 1,896 thousand barrels (MBbls) of natural gas liquids. Approximately 27% of our proved reserves were classified as proved developed (See Note 16 Supplemental Oil and Gas Information to Consolidated Financial Statements to our consolidated financial statements). Full year 2011 production averaged 2.16 MBOE/d compared to 2.3 MBOE/d in 2010.

Our business strategy is to maximize the rate of return on investment of capital by controlling operating and capital costs, acquiring strategic oil and gas properties and improving of existing oil and gas properties. An additional important goal for implementing our business strategy is to maintain the lowest possible operating cost structure, among other things, by serving as operator of a substantial portion of our oil and natural gas properties.

Exploration, Development and Production

United States

We, through our wholly-owned subsidiaries, are involved in oil and gas exploration, developing, production and operation of wells in the United States and the operation of a well service company. 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 589 wells located mainly in Texas and New Mexico.

In August, 2011 we created a new subsidiary and in October began operation of a well service company. We began the operations by acquiring five well services rigs and related equipment.

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 known as the “Michal", "Matan" and "Shimson" Licenses.

In 2009, two natural gas discoveries, known as "Tamar" and "Dalit", were made within the area covered by Michal and Matan Licenses, respectively. In December 2009, the Israeli Petroleum Commissioner granted Noble Energy, Inc. (“Noble”) and its partners, Isramco Negev 2-LP, Delek Drilling, Avner Oil & Gas, and Dor Gas (the “Tamar Consortium”), two leases (the “Tamar Lease” and the "Dalit Lease"). The Leases are scheduled to expire on December 2038 and cover the Tamar and Dalit gas fields (collectively the “Tamar Field”). The Tamar Field is approximately 95 kilometers of the coast of the Israel in the Israel exclusive economic zone of the Eastern Mediterranean with a water depth of approximately 1700 meters.

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During January – March 2012, the Tamar Consortium has executed gas supply contracts for sales of natural gas to five separate industrial customers located in Israel and to the Israel Electricity Company. It is anticipated that gas deliveries under such contracts would begin in mid 2013. The contracts are also subject to certain material conditions precedent. Therefore there can be no assurances that there will be any actual gas deliveries under any of such supply contracts.

We own an overriding royalty interest of 1.5375% in the Tamar Field, which will increase to 2.7375% after payout (collectively the "Tamar Royalty"). An overriding royalty interest is an ownership in a percentage of production or production revenues, free of cost of production or development from the underlying leases. As with most overriding royalty interests, we have no control over the operations, drilling, expenses, or timing of production or sales or any other aspect of development or production of the underlying natural gas.

We have a third party reserve report from independent petroleum engineers, Netherland, Sewell & Associates dated March 21, 2012 and estimating reserves allocable to the Tamar Royalty as of December 31, 2011 (the "Tamar Reserve Report"). This reserve report estimates that by reason of its ownership of the Tamar Royalty, we have proven undeveloped reserves estimated at 154.1 billion cubic feet of natural gas. The Tamar Reserve Report indicates that the undiscounted estimated future net revenue (after deduction of estimated production and ad valorem taxes but before estimated income tax) for such reserves (paid out over time) at $634,462,200. The Tamar Reserve Report estimates the net present worth of such reserves, discounted at 10% annual discount rate factor, at $241,737,300 (See Note 16 Supplemental Oil and Gas Information to Consolidated Financial Statements to our consolidated financial statements). The gas price used to value the reserves in the Tamar Reserve Report is the 12-month unweighted arithmetic average of the first-of-the-month Henry Hub spot price for each month in the period January through December 2011. That price of $4.118 per MMBTU is a hypothetical sales price held constant throughout the estimated life of the reserves allocable to the Tamar Royalty for purposes of the estimate and does not represent any actual sales price or contractual sales price for the gas. The report indicates that there are no commercial oil deposits or condensate that is included as reserves.

The amount of proceeds, if any, we receive from the production of the natural gas will be determined not only by the timing of production and price received but, as our interest increases at payout, the expenses and costs incurred by the operations. Payout is the point when all the cost of leasing, drilling, producing and operating the leases have been recovered from proceeds from production from the leases as defined in the royalty agreement.

As we do not control any of those factors affecting our payments (time of production, price received, costs incurred) for our interest and based on that and the other risk factors as set out herein it is difficult to determine the amounts or timing of any amounts we receive with precision or when payout is likely to occur, if ever. Based on reserves and anticipated production and using the income from these interests may be very significant to the Company, if they can be commercially produced.

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

- There has not been any large scale production of natural gas offshore Israel. Therefore there may be geological, geophysical or other unforeseen problems that may be unique to the offshore Israel site that could limit such production. In addition, even if commercial production of the reserves can be achieved, it is uncertain what the likely life of such commercial production is likely to be.

- Even if our reserves can be produced, there are no natural gas pipelines or other suitable transportation modalities that presently exist to transport the natural gas. Therefore, commercial exploitation of the reserves will require construction of pipelines or other transportation modalities to enable the natural gas to market. The development plan presently contemplates transportation of gas production through a 152 kilometer pipeline through the Tamar Field to Ashdod. There can be no assurance that the pipeline will be completed or completed on a timely basis.

- There has been significant political upheaval and unrest in the Mideast, particularly in Syria, Egypt and other countries near Israel. In addition, there is considerable hostility between Iran and Israel and other countries. There is significant risk that war, acts of terrorism or other force majeure may delay, prevent or destroy commercial production of natural gas from the Tamar Field, thereby diminishing or preventing production of natural gas from the Tamar Field.

- The Tamar Consortium will be required to obtain significant financing to develop and produce the field and build transportation to market. There can be no assurances as to whether such financing will be procured, the timing of the financing or whether the financing will be procured on favorable terms and conditions.

- 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 is unknown

The Company also has an interest in a separate area of the Eastern Mediterranean. Based on a gas find, a 30 year lease covering 53 square kilometers (approximately 13,100 acres) offshore Israel was granted in June 2000 (the "Med Yavne Lease"). The original operator of the Med Yavne Lease was BG International Limited, a member of the British Gas Group ("BG"). BG resigned as the operator of the Lease and relinquished all of its working interests in the Med Yavne Lease. The remaining participants in the lease appointed I.O.C - Israel Oil Company Ltd ("IOC") as the successor operator.

Our participation interest of the Med Yavne Lease is 0.7052 %. We also hold an overriding royalty interest in the Med Yavne Lease of 0.1% before payout and 1.3% after payout. We have no reserves attributed to this interest and this lease may not be capable of being economically produced

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Derivative Instruments and Hedging Activities

We 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 generally hedge a substantial, but varying, portion of our anticipated oil and natural gas production for the next 48 and 15 months, respectively. 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. Our results of operations would potentially have been significantly different had we elected and qualified for hedge accounting on our derivative contracts.

As of December 31, 2011 we had swap contracts for a volume of 282,873 barrels of crude oil during 36 months, commencing January 2012, and swap contracts for a volume of 174,222 MMBTU of natural gas during 3 months commencing January 2012.

Hereunder are the open swap contracts positions as of December 31, 2011:

	Swap Contracts			
	Natural Gas		Crude Oil	
	Volume (MMBTU) (*)	Weighted Average Price ($/MMBTU)	Volume (Bbl)	Weighted Average Price ($/Bbl)
2012	174,222	8.65	127,473	99.67
2013	-	-	89,400	103.51
2014	-	-	66,000	103.51

(*) Mcf = MMBTU

During the second quarter of 2009, we made the decision to mitigate a portion of our interest rate risk with interest rate swaps. These swap instruments reduce our exposure to market rate fluctuations by converting variable interest rates to fixed interest rates.

Under these swaps, we make payments to, or receive payments from, the counterparties based upon the differential between a specified fixed price and a price related to the three-month LIBOR. These interest rate swaps convert a portion of our variable rate interest on our Scotia debt (as defined in Note 6, “Long-term Debt and Interest Expense”) to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. We have elected to designate these positions for hedge accounting and therefore the unrealized gains and losses are recorded in accumulated other comprehensive loss. The Company measures hedge effectiveness by assessing the changes in the fair value or expected future cash flows of the hedged item.

As of December 31, 2011 we did not have open interest rate swap positions.

On March 9, 2010, pursuant to an agreement with Wells Fargo & Company, the derivative contracts between Isramco and Wells Fargo were terminated and the Company signed new swap contracts with Macquarie Bank, N.A. for an aggregate volume of 336,780 barrels of crude oil during the 46 month period commencing March 2011.

Competitive Conditions in the Business

The oil and natural gas industry is highly competitive and we compete with a substantial number of 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 a great many well service 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, attracting customers to a new well service business 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.

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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. 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. 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.

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.

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 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 and results of operations. For further discussion on risks, see Item 1A. Risk Factors.

Regulations

We do not have any offshore operations in the US. 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 is to potentially limit the amount of oil and natural gas that we can produce from our wells and to 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.

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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.

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.

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 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.

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.

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The Clean Water Act, wastewater and storm water discharges

The oil and gas industry, and our operations, 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 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.

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 not heretofore engaged in extensive hydraulic fracturing or other well stimulation services on the wells for which we are the operator and when we do we engage third parties to conduct these operations on our behalf.

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 are 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.

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Climate change legislation and greenhouse gas regulation

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.

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.

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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

There have been several regulatory and governmental initiatives to restrict the hydraulic-fracturing process, which could have an adverse impact on our completion or production activities. The U.S. Environmental Protection Agency (EPA) has asserted federal regulatory authority pursuant to the Safe Drinking Water Act over certain hydraulic-fracturing practices notwithstanding the existence of current oil and gas regulations adopted at the state level. Moreover, the EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with final results expected to be available by 2014. The EPA has also announced plans to propose effluent limitations for the treatment and discharge of wastewater resulting from hydraulic-fracturing activities by 2014. Certain other governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic-fracturing practices, including evaluations by the U.S. Department of Energy and the DOI, and coordination of an administration-wide review of these practices by the White House Council on Environmental Quality. Congress is currently considering, and has from time to time in the past considered, bills that would regulate hydraulic fracturing and/or require public disclosure of chemicals used in the hydraulic-fracturing process. A number of states, including states in which we operate, have adopted or are considering legal requirements that could impose more stringent permitting, public disclosure, and well-construction requirements on hydraulic-fracturing activities.

These laws and their implementing regulations, as well as state counterparts, generally restrict the level of pollutants emitted to ambient air, discharges to surface water, and disposals or other releases to surface and below-ground soils and ground water. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil, and criminal penalties; the imposition of investigatory, remedial, and corrective action obligations or the incurrence of capital expenditures; the occurrence of delays in the development of projects; and the issuance of injunctions restricting or prohibiting some or all of the Company’s activities in a particular area. Compliance with these laws and regulations also, in most cases, requires new or amended permits that may contain new or more stringent technological standards or limits on emissions, discharges, disposals, or other releases in association with new or modified operations. Application for these permits can require an applicant to collect substantial information in connection with the application process, which can be expensive and time-consuming. In addition, there can be delays associated with public notice and comment periods required prior to the issuance or amendment of a permit as well as the agency’s processing of an application. Many of the delays associated with the permitting process are beyond the control of the Company.

Many states where the Company operates also have, or are developing, similar environmental laws, regulations, or analogous controls governing many of these same types of activities. While the legal requirements may be similar in form, in some cases the actual implementation of these requirements may impose additional, or more stringent, conditions or controls that can significantly alter or delay the development of a project or substantially increase the cost of doing business.

The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor determinable as new standards, such as air emission standards and water quality standards, continue to evolve. However, environmental laws and regulations, including those that may arise to address concerns about global climate change and the threat of adverse impacts to groundwater arising from hydraulic-fracturing activities, are expected to continue to have an increasing impact on the Company's operations.

Employees

As of December 31, 2011, we had 62 full-time employees. We hire independent contractors on an as needed basis. We have no collective bargaining agreements with our employees. We believe that our employee relationships are satisfactory.

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. 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. For example, in recent years market prices for natural gas in the United States have declined substantially from the highs achieved in 2008 and the rapid development of shale plays throughout North America has contributed significantly to this trend. 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;
- worldwide and domestic supplies of crude oil, natural gas and NGLs;
- actions taken by foreign oil and gas producing nations;
- the level of global crude oil and natural gas inventories;
- the price and level of foreign imports of oil, natural gas and NGLs;
- the effect of worldwide energy conservation efforts;
- the price and availability of alternative and competing fuels;
- 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;
- labor unrest in oil and natural gas producing regions;
- regional pricing differentials;
- weather conditions;
- electricity dispatch;
- domestic and foreign governmental regulations and taxes; and
- the overall economic environment.

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;
- causing us to delay or postpone some of our capital projects;

- reducing our revenues, operating income and cash flows;
- 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.

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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 Congress has considered climate-change legislation that would seek to reduce emissions of green-house gases (GHGs) through establishment of a “cap-and-trade” plan. It is not possible at this time to predict whether or when Congress may re-introduce or act on climate-change legislation. 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, including one that requires a reduction in emissions of GHGs from motor vehicles and another that requires certain construction and operating permit reviews for GHG emissions from certain large stationary sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHGs from certain sources, including, among others, onshore and offshore oil and natural-gas production facilities, which includes certain of our operations, on an annual basis. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations.

- Taxes. The U.S. President’s Fiscal Year 2013 Budget Proposal includes provisions that would, if enacted, make significant changes to U.S. tax laws. These changes include, but are not limited to, (i) eliminating the immediate deduction for intangible drilling and development costs, (ii) eliminating the deduction from income for domestic production activities relating to oil and natural-gas exploration and development, and (iii) implementing certain international tax reforms.

- Hydraulic Fracturing is an essential and common practice used to stimulate production of natural gas and/or oil from dense subsurface rock formations such as shales that generally exist between 4,000 and 14,000 feet below ground. We apply hydraulic-fracturing techniques in some of our U.S. onshore oil and natural-gas drilling and completion programs. The process involves the injection of water, sand, and additives under pressure into a targeted subsurface formation. The water and pressure create fractures in the rock formations, which are held open by the grains of sand, enabling the oil or natural gas to flow to the wellbore. The process is typically regulated by state oil and natural-gas commissions; however, the EPA, recently asserted federal regulatory authority over certain hydraulic-fracturing activities involving diesel under the Safe Drinking Water Act and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing. In February 2012, the DOI released draft regulations governing hydraulic fracturing on federal and Indian oil and gas leases to require disclosure of information regarding the chemicals used in hydraulic fracturing, advance approval for well-stimulation activities, mechanical integrity testing of casing, and monitoring of well-stimulation operations. In addition, Congress, from time to time, has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic-fracturing process. In the event that a new, federal level of legal restrictions relating to the hydraulic-fracturing process are adopted in areas where we currently or in the future plan to operate, we may incur additional costs to comply with such federal requirements that may be significant in nature, and also could become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development, or production activities.

Certain states in which we operate, including, Louisiana, Texas, and Wyoming, have adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosure, and additional well-construction requirements on hydraulic-fracturing operations. For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas and the public of certain information regarding the components used in the hydraulic-fracturing process. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general and/or hydraulic fracturing in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, in the event state or local restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps be limited or precluded in the drilling of wells or in the amounts that we are ultimately able to produce from our reserves.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic-fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic-fracturing practices, and a committee of the U.S. House of Representatives has conducted an investigation of hydraulic-fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic-fracturing activities and plans to propose these standards by 2014. In addition, the U.S. Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods. Also, the DOI is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands. These ongoing or proposed studies, depending on any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory mechanisms.

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The recent adoption of derivatives legislation by the U.S. Congress 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 (HR 4173), signed into law in 2010, establishes, among other provisions, federal oversight and regulation of the over-the-counter derivatives market and entities, such as the Company, that participate in that market. The new legislation required the Commodities Futures Trading Commission ("CFTC") and the Securities and Exchange Commission (SEC) to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. In July 2010, the CFTC granted temporary exemptive relief from certain swap regulation provisions of the legislation until December 21, 2011, or until the agency finalized the corresponding rules. In December 2011, the CFTC extended the potential latest expiration date of the exemptive relief to July 16, 2012. In its rulemaking under the new legislation, the CFTC has 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. It is not possible at this time to predict when the CFTC will finalize other regulations, including critical rulemaking on the definition of "swap", "swap dealer" and "major swap participant." Depending on the Company's classification, the financial reform legislation may require the Company to comply with margin requirements and with certain clearing and trade-execution requirements in connection with its derivative activities. The financial reform legislation 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 new legislation and any new 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 legislation 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 legislation 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 legislation 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.

Oil and gas drilling is a speculative activity and risky.

We are engaged in the business of oil and natural gas exploration, production and operations and the development of productive oil and gas wells. Our growth will be materially dependent upon the success of future drilling. Drilling for oil and gas involves numerous risks, including the risk that no commercially productive oil or natural gas reservoirs will be encountered. The cost of drilling, completing and operating wells is substantial and uncertain, and drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors beyond our control, including unexpected drilling conditions, pressure or irregularities in formations, equipment failures or accidents, adverse weather conditions, compliance with governmental requirements and shortages or delays in the availability of drilling rigs or crews and the delivery of equipment. Although we believe that the use of 3-D seismic data and other advanced technology should increase the probability of success of our wells and should reduce average finding costs through elimination of prospects that might otherwise be drilled solely on the basis of 2-D seismic data and other traditional methods, drilling remains an inexact and speculative activity. In addition, the use of 3-D seismic data and such technologies requires greater pre-drilling expenditures than traditional drilling strategies and we could incur losses because of such expenditures. Our future drilling activities may not be successful and, if unsuccessful, such failure could have an adverse effect on our future results of operations and financial condition. Although we may discuss drilling prospects that have been identified or budgeted for, we may ultimately not lease or drill these prospects within the expected time frame, or at all. We may identify prospects through a number of methods, some of which do not include interpretation of 3-D or other seismic data. The drilling and results for these prospects may be particularly uncertain. The final determination with respect to the drilling of any scheduled or budgeted wells will be dependent on a number of factors, including (i) the results of exploration efforts and the acquisition, review and analysis of the seismic data, (ii) the availability of sufficient capital resources and the other participants for the drilling of the prospects, (iii) the approval of the prospects by other participants after additional data has been compiled, (iv) economic and industry conditions at the time of drilling, including prevailing and anticipated prices for oil and natural gas and the availability of drilling rigs and crews, (v) our financial resources and results (vi) the availability of leases and permits on reasonable terms for the prospects and (vii) the payment of royalties to lessors. There can be no assurance that these projects can be successfully developed or that the wells discussed will, if drilled, encounter reservoirs of commercially productive oil or natural gas. There are numerous uncertainties in estimating quantities of proved reserves, including many factors beyond our control.

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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.

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

Recently, concerns over inflation, energy costs, geopolitical issues, the availability and cost of credit, the United States mortgage market and a declining real estate market in the United States have contributed to increased economic uncertainty and diminished expectations for the global economy.

These factors, combined with volatile oil, natural-gas and NGLs prices, declining business and consumer confidence, and increased unemployment, have precipitated an economic slowdown and a recession. Concerns about global economic conditions have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad continues to deteriorate, or if an economic recovery is slow or prolonged, demand for petroleum products could continue to 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.

Estimates of proved oil and natural gas reserves are uncertain and any material inaccuracies in these reserve estimates will materially affect the quantities and the value of our reserves.

There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control that could cause the quantities and net present value of our reserves to be overstated or understated. The reserve information included or incorporated by reference in this report represents estimates prepared by our independent reserve engineering firms; Netherland, Sewell & Associates and Cawley, Gillespie & Associates, Inc. Estimation of reserves is not an exact science. Estimates of economically recoverable oil and natural-gas reserves and of future net cash flows depend on a number of variable factors and assumptions, any of which may cause actual results to vary considerably from these estimates, such as:

- historical production from an area compared with production from similar producing areas;
- assumed effects of regulation by governmental agencies and court rulings;
- assumptions concerning future oil and natural-gas prices, future operating costs and capital expenditures;
- estimates of future severance and excise taxes, workover, and remedial costs.

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. For the December 31, 2011, 2010, and 2009 reserves, in accordance with SEC requirements, 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, while reserves for all periods prior to December 31, 2009, are based on year-end sales prices. 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.

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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.

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 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 impact on our revenues.

Our business is highly competitive.

The oil and natural gas industry is highly competitive in many respects, including identification of attractive oil and natural gas properties for acquisition, drilling and development, securing financing for such activities and obtaining the necessary equipment and personnel to conduct such operations and activities. In seeking suitable opportunities, we compete with a number of other companies, including large oil and natural gas companies and other independent operators with greater financial resources, larger numbers of personnel and facilities, and with more expertise. There can be no assurance that we will be able to compete effectively with these entities.

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

Our commercial lenders have liens on substantially all of our oil and gas assets in the United States and could foreclose in the event that we default under our credit facilities.

Under the terms of our credit facilities with our commercial lenders, our lenders have a first priority lien on substantially all of our oil and gas assets in the United States. If we default under the credit facility, our lender would be entitled to, among other things, foreclose on our assets in order to satisfy our obligations under a credit facility.

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 have entered 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; or
- the counterparties to our hedging agreements fail to perform under the contracts.
- a sudden unexpected event materially impacts oil and natural-gas prices.

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.

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.

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The unavailability or high cost of drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies and/or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. Increasing levels of exploration and production in response to strong prices of oil and natural gas may increase the demand for oilfield services, and the costs of these services may increase, while the quality of these services may suffer.

Our oil and natural gas activities are subject to various risks that are beyond our control.

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, 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;
- unfavorable weather conditions;
- 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; and
- the availability of alternative fuels and the price at which they become available.

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We do not insure against all potential losses and could be materially and adversely affected by unexpected liabilities.

Our business is hazardous and is subject to all of the operating risks normally associated with the exploration, development, production, processing and transportation of oil, natural gas and NGLs. Such risks include potential blowouts, cratering, fires, loss of well control, mishandling of fluids and chemicals and possible underground migration of hydrocarbons and chemicals. The occurrence of any of these risks could result in environmental pollution, damage to or destruction of our property, equipment and natural resources, injury to person or loss of life. Additionally, for our non-operated properties, we generally depend on the operator for operational safety and regulatory compliance.

To mitigate financial losses resulting from these operational hazards, we maintain comprehensive general liability insurance, as well as insurance coverage against certain losses resulting from physical damages, loss of well control, business interruption and pollution events that are considered sudden and accidental. We also maintain worker's compensation and employer's liability insurance. However, our insurance coverage does not provide 100% reimbursement of potential losses resulting from these operational hazards. Additionally, insurance coverage is generally not available to us for pollution events that are considered gradual, and we have limited or no insurance coverage for certain risks such as political risk, war and terrorism. Our insurance does not cover penalties or fines assessed by governmental authorities. The occurrence of a significant event against which we are not fully insured could have a material adverse effect on our profitability, financial condition and liquidity.

Assets we acquire may prove to be worth less than we paid because of uncertainties in evaluating recoverable reserves and potential liabilities.

Our growth is primarily due to acquisitions of producing properties and underdeveloped leaseholds. We expect acquisitions may also contribute to our future growth. Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, exploration potential, future oil and natural gas prices, operating and capital costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform a review of the acquired properties which we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. 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. We are generally not entitled to contractual indemnification for preclosing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. Because of these factors, we may not be able to acquire oil and natural gas properties that contain economically recoverable reserves or be able to complete such acquisitions on acceptable terms.

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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.

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 economic 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 political and economic developments, including the following:

- war, terrorist acts and civil disturbances,
- 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.

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Members of Isramco’s management team own a significant amount of common stock, giving them influence or control in corporate transactions and other matters, and the interests of these individuals could differ from those other shareholders.

Members of our management team beneficially own approximately 60.95% of our outstanding shares of common stock as of March 23, 2012. As a result, these shareholders are 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 other significant corporate transactions.

Our stock price is volatile and 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Oil and Gas Exploration and Production - Properties and Reserves

Reserve Information. For estimates of Isramco's net proved reserves of natural gas, crude oil and natural gas liquids, see Note 16 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 16 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.

ITEM 3. LEGAL PROCEEDINGS

We previously disclosed information relating to two putative shareholder derivative petitions that were filed by individual shareholders of the Company in the District Court of Harris County, Texas. These petitions each named certain of our officers and directors as defendants. Each of these suits claims that the shareholders were damaged as a result of various breaches of fiduciary duty, self dealing and other wrongdoing in connection with the Restated Agreement between the Company and Goodrich Global, Ltd ("Goodrich") and other matters, primarily on the part of the Company's Chairman and Chief Executive Officer, Haim Tsuff, and Jackob Maimon. Jackob Maimon is a former President and a director who resigned from all positions held with us on June 29, 2011.

On or about April 6, 2011, a third complaint was filed in the 295th District Court of Harris County, Texas by Yuval Ran, who claimed to be a shareholder, against certain of our officers and directors and several corporate parties controlled by Haim Tsuff. As with the prior suits, this complaint alleged various breaches of duty, self dealing and other wrongdoing in connection with the Restated Agreement between the Company and Goodrich, primarily on the part of the Company's Chairman and Chief Executive Officer, Haim Tsuff, and Jackob Maimon In addition, this suit alleged claims relating to other transactions between the Company and entities controlled by Haim Tsuff, including but not limited to the loan transactions between the Company and related parties, the lease and sale of a cruise ship, and the closure of the Company's Israel branch office. The third complaint was transferred to the 55th Judicial District Court of Harris County, Texas, by order signed April 20, 2011, and consolidated with the above-referenced first and second complaints by order signed May 21, 2011, into a single case, called "Lead Cause No. 2010-34535; In Re Isramco, Inc. Shareholder Derivative Litigation; In the 55th Judicial District Court of Harris County, Texas (the "Derivative Litigation").

We also disclosed information in our quarterly report for the three months ended September 30, 2011 relating to an additional putative shareholder derivative complaint that was filed by an individual shareholder, Yuval Lapiner, on July 7, 2011 in the Delaware Chancery Court in Wilmington, Delaware, naming certain of our officers and directors as defendants. The claims asserted in this case are essentially the same damage claims as asserted in the lawsuit filed in April 2011 and described above. The Company filed motions in the Chancery Court to Dismiss or Stay the lawsuit and, by order dated October 20, 2011, the case was dismissed. The plaintiff did not appeal. Yuval Lapiner then filed a motion to intervene in the Derivative Litigation and that motion was denied Mr. Lapiner then filed a motion for attorney's fees that was also denied. On December 12, 2011 the court approved the terms of the mediated settlement and entered final order and judgment in the case. The Company paid plaintiff attorney's fees in the amount of $1,000,000 and replaced its bylaws, amended various committee charters and adopted other corporate governance changes as set out in the stipulation. After the judgment was rendered Mr. Lapiner filed a motion for new trial and on February 12, 2012 filed a Notice of Appeal to the Fourteenth Court of Appeals in Houston, Texas. We do not believe the appeal will be successful nor do we believe there will be any change in the judgment.

On or about September 21, 2011, the Company's former general counsel, Dennis Holifield resigned. Mr. Holifield had been hired in March, 2011. On or about October 12, 2011, Mr. Holifield submitted a "Summary Report" to the SEC (the "Summary Report"), in which made numerous factual allegations regarding Haim Tsuff, the Company's Chief Executive Officer and Chairman; Edy Francis, the Company's Chief Financial Officer; Amir Sanker, the Company's Asset Manager; and other Company personnel. In the Summary Report, Mr. Holifield characterized the alleged conduct as illegal or criminal. On October 31, 2011 the Company received a written demand from, Mr. Holifield's attorney on the Company for $900,000.

Messrs. Tsuff, Francis, and Sanker have reviewed all of Mr. Holifield's allegations and have advised the Company that they have not engaged in any criminal conduct or other illegal activity. As of November 3, 2011, the Company's Board of Directors has constituted a committee of independent directors consisting of Max Pridgeon and Asaf Yarkoni which has been directed to investigate all of the Holifield allegations and report back to the full board and make any recommendations, if any, for corrective action.

From time to time, we are involved in disputes and other legal actions arising in the ordinary course of business. In management's opinion, none of these other disputes and legal actions is expected to have a material impact on our consolidated financial position or results of operations.

ITEM 4.

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 22, 2012, there were approximately 268 holders of record of our common stock.

	High	Low
2011		
First Quarter	$ 86.50	$ 56.14
Second Quarter	68.66	58.99
Third Quarter	69.00	53.40
Fourth Quarter	93.40	55.05
2010		
First Quarter	$ 80.10	$ 49.00
Second Quarter	70.50	45.05
Third Quarter	61.12	45.56
Fourth Quarter	90.36	55.96

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

Not applicable

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," "ESTIMATE," "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 and Israel. 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 2011 we created a new subsidiary that provides well maintenance and workover services, well completion and recompletion services.

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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, 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.

At December 31, 2011, 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 34,990 thousand barrels of oil equivalent (“MBOE”), consisting of 3,234 thousand barrels (MBbls) of oil, and 179,155 million cubic feet (MMcf) of natural gas and 1,896 thousand barrels (MBbls) of natural gas liquids. Approximately 27% of our proved reserves were classified as proved developed (See Note 16 Supplemental Oil and Gas Information to Consolidated Financial Statements to our consolidated financial statements). Full year 2011 production averaged 2.16 MBOE/d compared to 2.3 MBOE/d in 2010.

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.

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 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 DD&A and could result in property impairments.

Depreciation, Depletion and Amortization

Our rate of recording depreciation, depletion and amortization expense (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.

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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 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 generally hedge a substantial, but varying, portion of our anticipated oil and natural gas production for the next 36 and 3 months, respectively. 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. Our results of operations would potentially have been significantly different had we elected and qualified for hedge accounting on our derivative contracts.

Environmental Obligations 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

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.

Liquidity and Capital Resources

Our primary historical sources of capital and liquidity are internally generated cash flows from operations, availability under our senior credit agreement with our unrelated bank lenders with Bank of Nova Scotia ("Senior Credit Agreements") and loans from various related party lenders ("Related Party Loans") and asset dispositions. 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.

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Note 6 to our Consolidated Financial Statements, Long-Term Debt and Interest Expense, describes the Senior Credit Agreements and Related Party Loans. Our Senior Credit Agreements originally provided a total $300 million in credit facilities. As of December 31, 2011, the total available borrowing base was zero.

On March 3, 2011 the Company terminated its relationship with Wells Fargo and repaid its outstanding balance.

The borrowing base which relates to our oil and natural gas properties is redetermined on a semi-annual basis (with the Company and the lenders each having the right to one unscheduled redetermination per year) and adjusted based on our oil and natural gas properties, reserves, other indebtedness and other relevant factors. During the fourth quarter of 2011 the Lenders reduced the borrowing base to $0. The Company is repaying the approximately $20,000,000 outstanding balance in six installments of $3,333,000 each with the first two payments already made for January and February 2012 and the remaining installments due each month thereafter through June 2012 when the entire balance will be repaid. The Company is also in negotiations for similar credit facilities with several other commercial lenders, to obtain terms most favorable to the Company. While optimistic of a positive outcome of our consolidation efforts, the Company is uncertain as to whether it will be successful in obtaining new replacement financing or, if it is obtained, the timetable upon which such facility will be closed and other material terms and conditions. The Company believes that during the interim period that the terms of existing affiliate financing will remain flexible and additional funding will be made available if needed until a new credit facility can be entered. See Note 6 to Consolidated Financial Statements, Long-Term Debt and Interest Expense.

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 capital resources available and the success in finding and acquiring additional reserves. We expect to fund our future capital requirements through internally generated cash flows and borrowings under our Senior Credit Agreements. Long-term cash flows are subject to a number of variables, including the level of production and prices and our commodity price hedging activities as well as various economic conditions that have historically affected the oil and natural gas industry.

Debt

	As of December 31,		
	2011	2010	2009
	(In thousands except percentage)		
Senior Credit Facilities	$ -	$ 22,725	$ 32,950
Long – term debt – related party	60,211	76,354	79,354
Short – term debt – related party	6,456	-	-
Current maturities of long-term debt, short-term debt and bank overdraft	32,009	17,350	12,366
Total debt	98,676	116,429	124,670
Stockholders’ equity	18,548	18,537	13,733
Debt to capital ratio	84%	86%	90%

At year-end 2011, our total debt was $98,676,000, compared to total debt of $116,429,000 at year-end 2010 and $124,670,000 at year-end 2009. As of December 31, 2011, current debt included $20,000,000 as current maturities of the Senior Credit Facilities. During the fourth quarter of 2011 the Lenders reduced the borrowing base to $0. The Company is repaying the approximately $20,000,000 outstanding balance in six installments of $3,333,000 each with the first two payments already made for January and February 2012 and the remaining installments due each month thereafter through June 2012 when the entire balance will be repaid.

On March 3, 2011, the Company entered into a Loan Agreement with I. O. C. - Israel Oil Company, LTD., an affiliate of the Company (“IOC”) pursuant to which it borrowed the sum of $11 million. The loan bears interest at a rate of 10% per annum and is payable in quarterly payments of interest only until March 3, 2012, when all accrued interest and principal is due and payable. The loan may be prepaid at any time without penalty. The loan is unsecured. The purpose of the loan was to provide funds to Isramco for the payment of amounts due under the Wells Fargo Senior Credit Facility at maturity. On March 3, 2011 Isramco paid the outstanding principal balance due under the Wells Fargo Senior Credit Agreement. Subsequently, on March 9, 2011, pursuant to an agreement with Wells Fargo, the derivative contracts between Isramco and Wells Fargo were terminated at a cost to the Company of approximately $7,000,000. Concurrently, the Company entered into new derivative contracts for 336,780 barrels of crude oil during the 46 month period commencing March 2011 with Macquarie Bank, N.A. During September 2011 Isramco paid $5,096,000 of principal and interest pursuant to Loan agreement with IOC. The Company is actively pursuing a consolidation of all outstanding debt with Macquarie Bank and other commercial lenders.

In October 2011 the agreement with IOC, pertaining to a loan in the outstanding principal amount of $6,456,000 was renegotiated. The payoff of principal amount was extended by 6 months to September 9, 2012. Interest accrued per annum was determined on LIBOR+5.5% from initial 10%.

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Off-Balance Sheet Arrangements

At December 31, 2011, we did not have any off-balance sheet arrangements.

Cash Flow

Our primary source of cash in 2011 was cash flow from operating activities, loans from related party and proceeds from sale of investment in MediaMind Ltd shares. Our primary source of cash in 2010 and 2009 was our operating activities. In 2011 cash received from operations, from selling of investment in MediaMind Ltd shares and from related party was offset by repayments of borrowings under our Senior Credit Agreements, repayment of related party loans, purchase of equipment and payments made on settled derivatives contracts. In 2010 and 2009, cash received from operations was offset by repayments of borrowings under our Senior Credit Agreements and cash used in payments on addition to oil and gas properties, net of any divestiture activities.

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,		
	2011	2010	2009
	(In thousands)		
Cash flows provided by operating activities	$ 6,946	$ 12,063	$ 21,519
Cash flows provided by (used in) investing activities	7,643	(1,437)	(332)
Cash flows used in financing activities	(18,124)	(7,876)	(21,421)
Net increase (decrease) in cash	$ (3,535)	$ 2,750	$ (234)

Operating Activities, Net cash flows provided by operating activities were $6,946,000, $12,063,000 and $21,519,000 for the years ended December 31, 2011, 2010 and 2009, respectively. Key drivers of net operating cash flows are commodity prices, production volumes, hedging activities and operating cost.

During the year ended December 31, 2011, compared to the same period in 2010, net cash flow provided by operating activities decreased by $5,117,000 to $6,946,000. This decrease was primarily attributable to net cash paid on settled derivatives contracts of $7,007,000, less cash received on proceeds from settlements of derivative contracts, higher lease operating expenses all of which were partially offset by increased oil and natural gas liquids (“NGLs”) revenues. The increase in revenues was primarily attributable to higher average oil and NGLs prices for the year ended December 31, 2011 of $94.12/bbl and $50.24/bbl respectively, compared to $77.26/bbl and $36.97/bbl for the year ended December 31, 2010. However, we are unable to predict future production levels or future commodity prices, and, therefore, we cannot predict future levels of net cash provided by operating activities.

Net cash provided by operating activities decreased in 2010 compared to 2009 primarily due to a reduction in working capital of $4,549,000, higher lease operating expenses and expenses related to our well plugging and abandonment obligations. The reduction in net cash proceeds from our commodity price hedging activities of $8,308,000 was offset by increased oil and natural gas revenues of $8,561,000. The increase in revenues was primarily attributable to higher average oil, gas and NGLs prices for the year ended December 31, 2010 of $77.26/bbl, $4.71/mcf and $36.97/bbl, compared to $58.52/bbl, $3.48/mcf and $28.83/bbl for the year ended December 31, 2009.

Investing Activities, The primary driver of cash provided by investing activities in 2011 was proceeds from sale of marketable securities which was offset by purchase of other property and equipment of approximately $6,500,000 and an additional $2,549,000 spent on capital expenditures. Net cash flows provided (used in) in investing activities for the years ended December 31, 2011 and 2010 were $7,643,000 and $(1,437,000) respectively.

In 2010, we spent an additional $3,454,000 on capital expenditures and an additional $157,000 on other property and equipment. We participated in the drilling of 3 gross wells in 2010. In December, 2010, we completed the sale of our interests in certain properties in Wise and Parker Counties, Texas, for approximately $2.2 million.

In 2009, we spent an additional $645,000 on capital expenditures and other property and equipment.

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Financing Activities, Net cash flows used in financing activities were $18,124,000 and $7,876,000 for the years ended December 31, 2011 and 2010, respectively. Excess cash flow from proceeds of sale of marketable securities, operations and a loan from related party were primarily used to repay borrowings under our Senior Credit Agreements to the extent available. During the year ended in 2011, we repaid borrowings of $29,612,000. During the year ended in 2010, we repaid borrowings of $7,876,000.

Results of Continuing Operations

Selected Data

	Years Ended December 31,		
	2011	2010	2009
	(In thousands except per share and MBOE amounts)		
Financial Results			
Oil and Gas sales	$ 44,228	$ 39,329	$ 30,768
Other	1,420	2,871	956
Total revenues and other	45,648	42,200	31,724
Cost and expenses	41,278	41,059	42,024
Other expense (income)	(6,991)	5,784	13,369
Income tax expense (benefit)	3,975	(1,856)	(10,090)
Net income (loss) attributable to common shareholders	7,386	(2,787)	(13,579)
Net income attributable to noncontrolling interests	5	-	-
Net income (loss) attributable to Isramco	7,381	(2,787)	(13,579)
Earnings (loss) per common share – basic	$ 2.72	$ (1.03)	$ (5.00)
Earnings (loss) per common share –diluted	$ 2.72	$ (1.03)	$ (5.00)
Weighted average number of shares outstanding-basic	2,717,691	2,717,691	2,717,691
Weighted average number of shares outstanding- diluted	2,717,691	2,717,691	2,717,691
Operating Results			
Adjusted EBITDAX (1)	$ 30,606	$ 22,472	$ 26,796
Total proved reserves (MBOE)	34,990	9,031	8,565
Annual sales volumes (MBOE)	789	841	886

Average cost per MBOE:						
Production (excluding transportation and taxes)	$	20.55	$	18.32	$	12.99
General and administrative	$	5.63	$	6.09	$	4.64
Depletion	$	12.66	$	14.44	$	17.34

(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, our net income was $7,381,000, or $2.72 per share for the year ended December 31, 2011. This compares to net loss of ($2,787,000), or ($1.03) per share, for the year ended December 31, 2010.

The increase in net income was primarily due to the impact of sale of marketable securities, derivatives, higher oil and NGLs sales revenues due to higher prices and lower depreciation, depletion and amortization expenses. This was partially offset by a decrease in sales volumes of natural gas, oil and natural gas liquids ("NGLs") caused by natural decline in production, higher taxes paid due to increase in revenues, higher impairments of oil and gas assets and higher lease operating expenses.

Our net loss for 2010 totaled ($2,787,000), or ($1.03) per share, compared to a net loss for 2009 of ($13,579,000), or ($5.00) per share. The decrease in net loss was primarily due to higher natural gas, oil and NGLs sales revenues due to higher prices, the impact of derivatives, lower depreciation, depletion and amortization expenses and lower interest expense. This was partially offset by a decrease in sales volumes of natural gas, oil and NGLs caused by adverse weather conditions in Texas that restricted our ability to access, repair and maintain our wells in the first quarter of 2010, along with the natural decline in production, and higher lease operating expenses.

Revenues, Volumes and Average Prices

Sales Revenues

	Years Ended December 31,				
In thousands except percentages	2011	2010	D vs. 2011	2009	D vs. 2010
Gas sales	$ 11,135	$ 11,157	NM%	$ 9,124	22%
Oil sales	26,260	22,405	17	17,147	31
Natural gas liquid sales	6,833	5,767	18	4,497	28
Total	$ 44,228	$ 39,329	12%	$ 30,768	28%

NM—not meaningful

Our sales revenues for the year ended December 31, 2011 increased by 12% when compared to the same period of 2010, mainly due to higher oil and NGLs commodity prices. Our sales revenues for the year ended December 31, 2010 increased by 28% when compared to the same period of 2009, mainly due to higher natural gas, oil and condensate and NGLs commodity prices.

Volumes and Average Prices

	Years Ended December 31,				
	2011	2010	D vs. 2011	2009	D vs. 2010
Natural Gas					
Sales volumes Mmcf (2)	2,241	2,368	(5)%	2,623	(10)%
Price per Mcf (1)	$ 4.97	$ 4.71	6	$ 3.48	35
Total gas sales revenues (thousands)	$ 11,135	$ 11,157	NM	$ 9,124	22%
Crude Oil					
Sales volumes MBbl	279	290	(4)%	293	(1)%
Price per Bbl (1)	$ 94.12	$ 77.26	22	$ 58.52	32
	$ 26,260	$ 22,405	17%	$ 17,147	31%

Total oil sales revenues (thousands)								
Natural gas liquids								
Sales volumes MBbl (2)		136		156	(13)%		156	NM%
Price per Bbl (1)	$	50.24	$	36.97	36	$	28.83	28
Total natural gas liquids sales revenues (thousands)	$	6,833	$	5,767	18%	$	4,497	28%

(1) Amounts exclude the impact of cash paid/received on settled contracts as we did not elect to apply hedge accounting.

(2) At the end of 2010, the company sold interests in several oil and gas properties which resulted in lower natural gas, oil and natural gas liquids ("NGLs") volumes in 2011.

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The company's natural gas sales volumes decreased by 5%, crude oil sales volumes by 4% and natural gas liquids sales volumes by 13% for the year ended December 31, 2011 compared to the same period of 2010. This decrease was primarily caused by natural decline in production.

Our average natural gas price for the year ended December 31, 2011 increased by 6%, or $0.26 per Mcf, when compared to the same period of 2010. Our average crude oil price for the year ended December 31, 2011 increased by 22%, or $16.86 per Bbl, when compared to the same period of 2010. Our average natural gas liquids price for the ended December 31, 2011 increased by 36%, or $13.27 per Bbl, when compared to the same period of 2010.

In 2010 the Company's natural gas sale volumes decreased by 10%, crude oil sale volumes by 1% and natural gas liquid sale volumes by 0% compared to 2009. This decrease was primarily caused by adverse weather conditions in Texas that restricted our ability to access, repair and maintain our wells in the first quarter of 2010, along with the natural decline in production.

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, 2011 compared to 2010 and 2009.

In thousands	Natural Gas	Oil	Natural gas liquids
2009 sales revenues	$ 9,124	$ 17,147	$ 4,497
Changes associated with sales volumes	(887)	(176)	-
Changes in prices	2,920	5,434	1,270
2010 sales revenues	11,157	22,405	5,767
Changes associated with sales volumes	(598)	(850)	(739)
Changes in prices	576	4,705	1,805
2011 sales revenues	$ 11,135	$ 26,260	$ 6,833

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	2011	2010	2009
Income from operations before income taxes	$ 11,361	$ (4,643)	$ (23,669)
Depreciation, depletion, amortization and impairment expense	14,016	13,893	21,119
Interest expense	7,760	7,646	9,219
Unrealized gain on derivative contract	(3,384)	4,727	19,298
Accretion Expenses	853	849	829
Consolidated Adjusted EBITDAX	$ 30,606	$ 22,472	$ 26,796

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Operating Expenses

In thousands except percentages	2011	2010	D vs. 2011	2009	D vs. 2010
	Years Ended December 31,				
Lease operating expense, transportation and taxes	$ 20,981	$ 19,894	5%	$ 15,651	27%
Depreciation, depletion and amortization	9,982	12,142	(18)	15,368	(21)
Impairments of oil and gas assets	4,034	1,751	130	5,751	(70)
Accretion expense	853	849	NM	829	2
Production Services	675	-		-	
Loss from plug and abandonment	315	1,300	(76)	312	317
General and administrative	4,438	5,123	(13)	4,113	25
	$ 41,278	$ 41,059	1%	$ 42,024	(2)%

During 2011, our operating expenses increased by 1% when compared to 2010 due to the following factors:

- Lease operating expense, transportation cost and taxes increased by 5%, or $1,087,000 in 2011 when compared to 2010. This increase was the result of the costs associated with a plan we initiated last year to workover a number of our wells, along with the incremental costs involved in operating older, more mature fields that require additional repair and maintenance. In addition due to changes in regulatory requirements in Texas we incurred additional expenses regarding previously inactive wells in order to renew production in the future. Finally, the higher oil and NGL sales increased the taxes paid during 2011. On a per unit basis, lease operating expenses (excluding transportation and taxes) increased by $2.23 per MBOE to $20.55 per MBOE in 2011 from $18.32 per MBOE in 2010.

- 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 18%, or $2,160,000, in 2011 when compared to 2010, primarily due to higher prices (per MBOE) that impacted our estimated total reserves, which are the basis for the depletion calculation, lower oil and gas production. On a per unit basis, depletion expense decreased by $1.78 per MBOE to $12.66 per MBOE in 2011 from $14.44 per MBOE in 2010.

- Impairments of oil and gas assets of $4,034,000 in 2011 were primarily a result of lower natural gas prices in general and the low volume of gas produced in a few of our fields.

- The expenses for production services pertain to our well service activities performed by our new subsidiary.

- General and administrative expenses decreased by 13%, or $685,000 in 2011 when compared to 2010, primarily due to attorney's fees and expenses related to certain derivative litigation pending in Harris County, Texas incurred in 2010 which was finalized in 2011. The decrease was partially offset by legal expenses associated with legal claim submitted by former employee.

During 2010, our operating expenses decreased by 2% when compared to 2009 due to the following factors:

- Lease operating expense, transportation cost and taxes increased by 27%, or $4,243,000, in 2010 when compared to 2009. This increase was the result of the costs associated with a plan we initiated in January 2010 to workover a number of our wells, along with the incremental costs involved in operating older, more mature fields that require additional repair and maintenance as well as the increasing costs of environmental remediation expenditures. Finally, the higher oil and gas sale prices we received had the effect of increasing the taxes paid during 2010. On a per unit basis, lease operating expenses (excluding transportation and taxes) increased by $5.33 per MBOE to $18.32 per MBOE in 2010, from $12.99 per MBOE in 2009.

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- 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 to these factors may cause our composite DD&A rate and expense to fluctuate from period to period. Our DD&A decreased by 21%, or $3,226,000, in 2010 when compared to 2009 primarily due to higher prices (per MBOE) that impacted our estimated total reserves, which are the basis for the depletion calculation and the impact of a 2009 impairment of $5,751,000 on the depletable base used to calculate DD&A. On a per unit basis, depletion expense decreased by $2.90 per MBOE to $14.44 per MBOE in 2010 from $17.34 per MBOE in 2009.

- Impairments of oil and gas assets of $1,751,000 in 2010 were primarily a result of lower natural gas prices in general and the low volume of gas produced in a few of our Central Texas fields.

- General and administrative expenses increased by 25%, or $1,010,000, in 2010 when compared to 2009, primarily due to attorney's fees and expenses related to certain derivative litigation pending in Harris County, Texas.

Other expenses (income)

	Years Ended December 31,				
In thousands except percentages	2011	2010	D vs. 2011	2009	D vs. 2010
Interest expense net	$ 7,760	$ 7,646	1%	$ 9,219	(17)%
Realized gain on sale of investment and other	(15,910)	-		(250)	(100)
Net loss (gain) on derivative contracts	922	(1,862)	(150)	4,400	(142)
Currency exchange rate differences	237	-	-	-	-
	$ (6,991)	$ 5,784	(221)%	$ 13,369	(57)%

Interest expense. Isramco's interest expense increased by 1%, or $114 thousand, for the year ended December 31, 2011 compared to the same period of 2010. This increase is primarily due to a new loan obtained by the company that was used, along with other proceeds and capital, to make required payments on debt to Macquarie Bank, N.A in connection with assignment and transfer of Wells Fargo Senior Credit Facility which were partially offset by the lower average outstanding balance of the loans.

In 2010 Isramco's interest expense decreased by 17%, or $1,573,000, for the year ended December 31, 2010 compared to the same period of 2009. This decrease is primarily due to the lower average outstanding balance of the loans which we obtained to fund the Five States acquisition in 2007 and the GFB acquisition in 2008, and to decreases in average LIBOR rates during 2010. The decrease was partially offset by the payments on interest rate swaps.

Net loss (gain) on derivative contracts. We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil and natural gas production. Consistent with the prior year, we have elected not to designate any positions as cash flow hedges for accounting purposes. Accordingly, we recorded the net change in the mark-to-market value of these derivative contracts in the consolidated statement of operations.

At December 31, 2011, the Company had a $2.4 million derivative asset, of which $1 million was classified as current. For the year ended December 31, 2011, the Company recorded a net derivative loss of $0.9 million (a $3.4 million unrealized gain offset by a $4.3 million loss from net cash paid on settled contracts).

At December 31, 2010, the Company had a $2.5 million derivative asset, of which $2.2 million was classified as current and a $3.5 million derivative liability, of which $1.1 million was classified as current. For the year ended December 31, 2010, the Company recorded a net derivative gain of $1.86 million (a $4.7 million unrealized loss partially offset by a $6.6 million gain from net cash received on settled contracts).

At December 31, 2009, the Company had a $5.6 million derivative asset, of which $3.4 million was classified as current and a $1.8 million derivative liability, of which $0.1 million was classified as current. For the year ended December 31, 2009, the Company recorded a net derivative loss of $4.4 million (a $19.3 million unrealized loss partially offset by a $14.9 million gain from net cash received on settled contracts).

Income Tax

Income tax expense for the year ended December 31, 2011 was primarily driven by sale of investment in MediaMind shares. The net income resulted in $15.91 million.

Income tax benefit for the year ended December 31, 2010 decreased by $8.2 million from the prior year. The decrease in our income tax benefit from the prior year was primarily due to our pre-tax loss of $4.6 million for the year ended December 31, 2010 compared to our pre-tax loss of $23.7 million in 2009. The effective tax rates for the years ended December 31, 2011, 2010 and 2009 were 35%, 40% and 42.6%, respectively.

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Recently Issued Accounting Pronouncements

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Derivative Instruments and Hedging Activity

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.

We are 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. Each of the counterparties to our derivative contracts is a lender in our Senior Credit Agreement. We did not post collateral under any of these contracts as they are secured under the Senior Credit Agreement. Please refer to Item 8. Consolidated Financial Statements and Supplementary Data—Note 5, "Derivatives and Hedging Activities" for additional information.

We are also exposed to interest rate risk on our variable interest rate debt. 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. As of December 31, 2011 we did not have open interest rate swap positions. 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.

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. See Item 8. Consolidated Financial Statements and Supplementary Data—Note 5, "Derivatives and Hedging Activities" for more details.

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 Supplementary Data—Note 7, "Fair Value of Financial Instruments" for additional information.

Interest Sensitivity

We are also 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, that may result in reductions of earnings or cash flows due to increases in the interest rates we pay on our obligations.

At December 31, 2011, total debt was $98,876,000.This debt bears interest at floating or market interest rates. The interest rate applicable to approximately 99% of this debt is based upon LIBOR. Fluctuations in market interest rates will cause our annual interest costs to fluctuate.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY 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.

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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, 2011 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.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Isramco's management is responsible for establishing and maintaining adequate internal control over financial reporting for Isramco, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Under the supervision and with the participation of Isramco's management, including our principal executive and principal financial officers, Isramco conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Framework"). Based on this evaluation under the COSO Framework, which was completed on March 12, 2012, management concluded that its internal control over financial reporting was effective as of December 31, 2011.

The effectiveness of Isramco's internal control over financial reporting as of December 31, 2011 has been audited by MaloneBailey, LLP, an independent registered public accounting firm who audited Isramco's consolidated financial statements as of and for the year ended December 31, 2011, as stated in their report, which is included under "Item 8. Financial Statements and Supplementary Data" in this report.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There was no change in Isramco's internal control over financial reporting during the fourth quarter of 2011 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

The information called for by items 10, 11, 12 13 and 14 will be contained in the Company's definitive proxy statement which the Company intends to file within 120 days after the end of the Company's fiscal year ended December 31, 2011 and such information is incorporated herein by reference.

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 defined point at which one party has recovered its prior costs.

"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.

4.1 First Amended and Restated Promissory Note dated as of February 27, 2007, issued to NAPHTHA ISRAEL PETROLEUM CORP., LTD. in the principal amount of $18,500,000 filed as an Exhibit to the 10-K for the year ended December 31, 2010 and incorporated herein by reference.

4.2 First Amended and Restated Promissory Note dated as of February 27, 2007, issued to NAPHTHA ISRAEL PETROLEUM CORP., LTD. in the principal amount of $11,500,000 filed as an Exhibit to the 10-K for the year ended December 31, 2010 and incorporated herein by reference.

4.3 First Amended and Restated Promissory Note dated as of February 27, 2007, issued to and I.O.C. ISRAEL OIL COMPANY, LTD. in the principal amount of $12,000,000 filed as an Exhibit to the 10-K for the year ended December 31, 2010 and incorporated herein by reference.

4.4 Promissory Note dated as of February 27, 2007, issued to and J.O.E.L JERUSALEM OIL EXPLORATION, LTD. in the principal amount of $7,000,000, filed as an Exhibit to the 10-Q for the quarter ended March 31, 2007 and incorporated herein by reference.

4.5 Promissory Note dated as of May 25, 2009, issued to and J.O.E.L JERUSALEM OIL EXPLORATION, LTD. in the principal amount of $48,900,000 filed as an Exhibit to the 10-K for the year ended December 31, 2010 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.

10.2 LOAN AGREEMENT, dated as of February 27, 2007, between ISRAMCO, INC., and NAPHTHA ISRAEL PETROLEUM CORP., LTD., filed as an Exhibit to the 10-Q for the quarter ended March 31, 2007 and incorporated herein by reference.

10.3 LOAN AGREEMENT, dated as of February 27, 2007, between ISRAMCO, INC., and NAPHTHA ISRAEL PETROLEUM CORP., LTD., filed as an Exhibit to the 10-Q for the quarter ended March 31, 2007 and incorporated herein by reference.

10.4 LOAN AGREEMENT, dated as of February 27, 2007, Between ISRAMCO, INC., and I.O.C. ISRAEL OIL COMPANY, LTD., filed as an Exhibit to the 10-Q for the quarter ended March 31, 2007 and incorporated herein by reference.

10.5 LOAN AGREEMENT, dated as of February 26, 2007, between ISRAMCO, INC., and J.O.E.L JERUSALEM OIL EXPLORATION, LTD., filed as an Exhibit to the 10-Q for the quarter ended March 31, 2007 and incorporated herein by reference.

10.6 CREDIT AGREEMENT dated as of March 2, 2007 among ISRAMCO ENERGY, L.L.C., each of the lenders that is a signatory hereto or which becomes a signatory hereto; and WELLS FARGO BANK, N. A., a national banking association, as agent for the Lenders., filed as an Exhibit to the 10-Q for the quarter ended March 31, 2007 and incorporated herein by reference.

10.7 GUARANTY AGREEMENT, dated as of March 2, 2007 by ISRAMCO, Inc. in favor of Wells Fargo Bank, N.A., as administrative agent (the "ADMINISTRATIVE AGENT") for the lenders that are or become parties to the Credit Agreement referred to in Item 10.6., filed as an Exhibit to the 10-Q for the quarter ended March 31, 2007 and incorporated herein by reference.

10.8 PLEDGE AGREEMENT, dated as of March 2, 2007 by Isramco, Inc. in favor of Wells Fargo Bank, N.A., as administrative agent for itself and the lenders (the "LENDERS") which are parties to the Credit Agreement referred to in Item 10.6, filed as an Exhibit to the 10-Q for the quarter ended March 31, 2007 and incorporated herein by reference.

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10.9 Employment Agreement dated as of September 1, 2007 between Isramco Inc. and Edy Francis, filed as an Exhibit to the 10-Q for the quarter ended September 30, 2007 and incorporated herein by reference.+

10.10 Agreement dated as of December 31, 2007 between Isramco Inc. and I.O.C. Israel Oil Company Ltd and addendum dated January 1, 2008, filed as an Exhibit to the 10-Q for the quarter ended March 31, 2008 and incorporated herein by reference.

10.11 Amended and restated credit agreement dated on April 28, 2008 between Isramco Resources, LLC and The Bank of Nova Scotia and Capital One, N.A., filed as an Exhibit to the 10-Q for the quarter ended March 31, 2008 and incorporated herein by reference.

10.12 Amended and Restated Loan Agreement dated as of May 25, 2008 between Isramco Inc. and J.O.E.L. Jerusalem Oil Explorations Ltd. filed as an Exhibit to the 10-K for the year ended December 31, 2009 and incorporated herein by reference.

10.13 Amended and Restated Agreement dated as of November 17, 2008 between Isramco Inc. and Goodrich Global Ltd. filed as an Exhibit to the 10-K for the year ended December 31, 2009 and incorporated herein by reference.

10.14 First Amendment to Loan Agreement dated as of February 1, 2009, between Isramco, Inc. and I.O.C. Israel Oil Company, Ltd.($18.5 million) filed as an Exhibit to the 10-K for the year ended December 31, 2009 and incorporated herein by reference.

10.15 First Amendment to Loan Agreement dated as of February 1, 2009, between Isramco, Inc, and Naphtha Israel Petroleum Corp., Ltd.($11.5 million) filed as an Exhibit to the 10-K for the year ended December 31, 2009 and incorporated herein by reference.

10.16 Loan Agreement dated as of July 14, 2009 between Isramco, Inc. and I.O.C. – Israel Oil Company, Ltd.($6.0 million) filed as an Exhibit to the 10-K for the year ended December 31, 2009 and incorporated herein by reference.

10.17 First Amendment to Loan Agreement dated as of February 1, 2009 between Isramco, Inc. and I.O.C. Israel Oil Company, Ltd.($12.0 million) filed as an Exhibit to the 10-K for the year ended December 31, 2009 and incorporated herein by reference.

10.18 Loan Agreement dated as of March 3, 2011 between Isramco, Inc. and I.O.C. – Israel Oil Company, Ltd.($11.0 million) filed as an Exhibit to the 10-K for the year ended December 31, 2010 and incorporated herein by reference.

10.19* First Amendment to Loan Agreement dated as of October 1, 2011 between Isramco, Inc. and I.O.C. Israel Oil Company, Ltd. ($11.0 million)

10.20* 2011 Stock Incentive Plan

14.1 Code of Ethics, filed as an Exhibit to Form 10-K for the year ended December 31, 2003.

23.1* Consent of Cawley, Gillespie & Associates, Inc.

23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of Sarbanes-Oxley Act.
31.2*	Certification of Chief Financial 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 Chief Financial 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,
CHIEF EXECUTIVE OFFICER
(PRINCIPAL EXECUTIVE OFFICER)

Date: March 23, 2012

/S/ EDY FRANCIS
EDY FRANCIS,
CHIEF FINANCIAL OFFICER
(PRINCIPAL FINANCIAL AND ACCOUNTING OFFICER)

Date: March 23, 2012

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 & Chief Executive Officer	March 23, 2012
/s/ Josef From Josef From	Director	March 23, 2012
/s/ Max Pridgeon Max Pridgeon	Director	March 23, 2012
/s/ Frans Sluiter Frans Sluiter	Director	March 23, 2012
/s/ Itai Ram Itai Ram	Director	March 23, 2012
/s/ Asaf Yarkoni Asaf Yarkoni	Director	March 23, 2012

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Isramco, Inc. (the "Company"), including the Company's Chief Executive Officer and Chief Financial 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. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2011.

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, 2011.

/s/ Haim Tsuff	/s/ Edy Francis
Haim Tsuff	Edy Francis
Chief Executive Officer	Chief Financial Officer

Houston, Texas
March 23, 2012

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Isramco, Inc.
Houston, Texas

We have audited the accompanying consolidated balance sheets of Isramco, Inc. and its subsidiaries (collectively the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of operations, changes in shareholders' equity, and cash flows for each of the three years ended December 31, 2011. We also have audited the Company's internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these consolidated 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 these consolidated financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. 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.

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Isramco, Inc and its subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years ended December 31, 2011, 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, 2011, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ MALONE BAILEY, LLP
www.malone-bailey.com
Houston, Texas

March 23, 2012

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ISRAMCO INC.
CONSOLIDATED BALANCE SHEETS
(In thousands, except share and per share amounts)

As of December 31	2011	2010
ASSETS		
Current Assets:		
Cash and cash equivalents	$2,122	$5,657
Accounts receivable, net	6,459	6,110
Restricted and designated cash	290	889
Inventories	86	-
Deferred tax assets	2,539	3,368
Derivative asset	961	2,156
Prepaid expenses and other	620	715
Total Current Assets	13,077	18,895
Property and Equipment, at cost – successful efforts method:		
Oil and Gas properties	225,108	222,122
Advanced payment for equipment	650	-
Other	6,860	922
Total Property and Equipment	232,618	223,044
Accumulated depreciation, depletion, amortization and impairment	(105,224)	(91,208)
Net Property and Equipment	127,394	131,836
Marketable securities, at market	4,554	16,099
Debt cost	-	70
Derivative asset	1,421	343
Deferred tax assets and other	5,461	4,635
Total assets	$151,907	$171,878
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$9,360	$9,316
Bank overdraft	823	335
Current maturities of long term debt	20,000	14,350
Derivative liability	-	1,133
Due to related party and accrued interest	25,518	9,371
Total current liabilities	55,701	34,505
Long-term debt	-	22,725
Due to related party and accrued interest	60,408	77,132
Other Long-term Liabilities:		
Asset retirement obligations	17,250	16,577
Derivative liability – non-current	-	2,402
Total other long-term liabilities	17,250	18,979
Commitments and contingencies (Note 13)		

Shareholders' equity:		
Common stock $0.0l par value; authorized 7,500,000 shares; issued 2,746,958 shares; outstanding 2,717,691 shares	27	27
Additional paid-in capital	23,194	23,194
Accumulated deficit	(6,768)	(14,149)
Accumulated other comprehensive income	2,254	9,629
Treasury stock, 29,267 shares at cost	(164)	(164)
Total Isramco, Inc. shareholders' equity	18,543	18,537
Non controlling interest	5	-
Total equity	18,548	18,537
Total liabilities and shareholders' equity	$151,907	$171,878

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	2011	2010	2009
Revenues			
Oil and gas sales	$ 44,228	$ 39,329	$ 30,768
Production services	896	-	-
Office services	437	655	845
Other	87	2,216	111
Total revenues	45,648	42,200	31,724
Operating expenses			
Lease operating expense, transportation and taxes	20,981	19,894	15,651
Depreciation, depletion and amortization	9,982	12,142	15,368
Impairments of oil and gas assets	4,034	1,751	5,751
Accretion expense	853	849	829
Production services	675	-	-
Loss from plug and abandonment	315	1,300	312
General and administrative	4,438	5,123	4,113
Total operating expenses	41,278	41,059	42,024
Operating income (loss)	4,370	1,141	(10,300)
Other expenses (income)			
Interest expense, net	7,760	7,646	9,219
Realized gain on marketable securities	(15,910)	-	(250)
Net loss (gain) on derivative contracts	922	(1,862)	4,400
Currency exchange rate differences	237	-	-
Total other expenses (income)	(6,991)	5,784	13,369
Income (loss) before income taxes	11,361	(4,643)	(23,669)
Income tax benefit (expense)	(3,975)	1,856	10,090
Net income (loss)	$ 7,386	$ (2,787)	$ (13,579)
Net income attributable to non-controlling interests	5	-	-
Net income (loss) attributable to Isramco	$ 7,381	$ (2,787)	$ (13,579)
Earnings (loss) per share – basic:	$ 2.72	$ (1.03)	$ (5.00)
Earnings (loss) per share – diluted:	$ 2.72	$ (1.03)	$ (5.00)
Weighted average number of shares outstanding-basic:	2,717,691	2,717,691	2,717,691
Weighted average number of shares outstanding-diluted:	2,717,691	2,717,691	2,717,691

See notes to the consolidated financial statements.

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ISRAMCO INC.
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2011, 2010 and 2009

	Common stock							
	Number of shares	Amount	Additional Paid-In Capital	Accumulated other comprehensive income (loss)	Retained Earnings (Accumulated Deficit)	Treasury stock	Non-controlling interests	Total Shareholders' Equity
	$ in thousands, except share amounts							
Balances at January 1, 2009	2,717,691	$27	$23,194	$ (240)	$ 2,217	$(164)	-	$ 25,034
Net loss					(13,579)			(13,579)
Net unrealized gain on available for sale marketable securities, net of taxes of $1,035				2,011				2,011
Net gain on derivative contracts, net of taxes $138				267				267
Total comprehensive loss								2,278
Balance of December 31, 2009	2,717,691	$27	$23,194	$ 2,038	$ (11,362)	$(164)	$ -	$ 13,733
Net loss					(2,787)			(2,787)
Net unrealized gain on available for sale marketable securities, net of taxes of $3,965				7,258				7,258
Net gain (loss) on derivative contracts, net of taxes $171				333				333
Total comprehensive loss								7,591
Balance of December 31, 2010	2,717,691	$27	$23,194	$ 9,629	$ (14,149)	$(164)	$ -	$ 18,537
Net income					7,381		5	7,386

Net unrealized loss on available for sale marketable securities, net of taxes of $3,983				(7,397)				(7,397)
Net gain (loss) on derivative contracts, net of taxes $12				22				22
Total comprehensive gain								(7,375)
Balance of December 31, 2011	2,717,691	$27	$23,194	$ 2,254	$ (6,768)	$(164)	$ 5	$ 18,548

See notes to consolidated financial statements.

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ISRAMCO INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

Year Ended December 31	2011	2010	2009
Cash Flows From Operating Activities:			
Net income (loss)	$ 7,386	$ (2,787)	$ (13,579)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization and impairment	14,016	13,893	21,119
Accretion expense	853	849	829
Realized gain on marketable securities	(15,910)	-	(250)
Changes in deferred taxes	3,975	(1,856)	(9,841)
Net unrealized loss (gain) on derivative contracts	(3,384)	4,727	19,298
Amortization of debt cost	252	252	252
Realized gain on sale of investment and capital gain	-	(2,160)	(3)
Changes in components of working capital and other assets and liabilities			
Accounts receivable	(349)	1,314	(2,008)
Prepaid expenses and other current assets	(86)	(59)	(167)
Due to related party	959	(2,360)	3,866
Inventories	(86)	-	-
Accounts payable and accrued expenses	(680)	250	2,003
Net cash provided by operating activities	6,946	12,063	21,519
Cash flows from investing activities:			
Addition to property and equipment, net	(9,060)	(3,611)	(645)
Proceeds from sale of gas properties and equipment	32	2,236	1
Restricted cash and deposit, net	598	(62)	(70)
Purchase of marketable securities	-	-	(370)
Proceeds from sale of marketable securities	16,073	-	752
Net cash provided by (used in) investing activities	7,643	(1,437)	(332)
Cash flows from financing activities:			
Repayments on loans – related parties, net	(12,537)	-	(963)
Proceeds on loans-related parties , net	11,000	-	2,000
Repayment of long-term debt	(17,075)	(7,875)	(21,250)
Borrowings (repayments) of bank overdraft, net	488	(1)	(1,208)
Net cash used in financing activities	(18,124)	(7,876)	(21,421)
Net increase (decrease) in cash and cash equivalents	(3,535)	2,750	(234)
Cash and cash equivalents at beginning of year	5,657	2,907	3,141
Cash and cash equivalents at end of year	$ 2,122	$ 5,657	$ 2,907

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 (“Isramco”, “we”, “our” or the “Company”) are primarily engaged in the acquisition, development, production and exploration of onshore oil and natural gas properties located in the United States of America (“United States”). The Company operates in one segment, oil and natural gas exploration and exploitation. 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.

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 and Cash Equivalents.

Isramco records as cash equivalents all highly liquid short-term investments with original maturities of three months or less.

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 using the specific identification method.

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.

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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 2011, 2010 and 2009, we reported an impairment charge of $4,034,000, $1,751,000 and $5,751,000, respectively, relating to our oil and gas properties.

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

Property and equipment 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. Depreciation expense for the years ended December 31, 2011, 2010 and 2009 was $246,000, $165,000 and $111,000 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. We did not identify any triggering events or record any asset impairments during 2011, 2010 and 2009.

As of December 31, 2011, the estimated useful lives of our asset classes are as follows:

Description	Years
Well service rigs and components	15
Oilfield trucks, vehicles and related equipment	7-10
Well service 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 would 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.

Marketable Securities

The Company may invest a portion of its cash in money market mutual funds which are highly liquid marketable securities. The Company accounts for marketable securities in accordance with Financial Accounting Standards Board’s (FASB) ASC 320, Investments—Debt and Equity Securities, (ASC 320) and classifies marketable securities as trading, available-for-sale, or held-to-maturity. The appropriate classification of its marketable securities is determined at the time of purchase and reevaluated at each balance sheet date.

Trading and available-for-sale securities are recorded at fair market value. Isramco holds no held-to-maturity securities. Unrealized holding gains and losses on trading securities are included in earnings. Unrealized holding gains or losses, net of the related tax effects, on available-for-sale securities are excluded from earnings and are reported net of applicable taxes as accumulated other comprehensive income, a separate component of shareholders' equity, until realized.

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 14. Asset Retirement Obligations.”

Concentrations of Credit Risk

The Company through its wholly-owned subsidiary Jay Management Company, LLC ("Jay Management") operates a substantial portion of its oil and natural gas properties. As the operator of a property, the Company makes full payments for costs associated with the property and seeks reimbursement from the other working interest owners in the property for their share of those costs. The Company’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 also 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. The Company has not experienced any significant losses from uncollectible accounts. 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.

In 2011, one individual purchaser of the Company's production accounted for 30% of the Company’s total sales and an additional three individual purchasers of the Company's production accounted for approximately 26% of its total sales (two purchasers approximately 9% each and another approximately 8%), collectively representing 56% of the Company's total sales. In 2010, one individual purchaser of the Company's production accounted for 23% of the Company’s total sales and an additional three individual purchasers of the Company's production accounted for approximately 27% of its total sales (approximately 9% each), collectively representing 50% of the Company's total sales. In 2009, two individual purchasers of the Company's production each accounted for in excess of 10% of the Company’s total sales and an additional three individual purchasers of the Company's production accounted for approximately 25.5% of its total sales (approximately 8.5% each), collectively representing 50% of the Company's total sales.

Revenue Recognition

Revenues from the sale of oil and natural gas are recognized when the products are sold to a purchaser at a fixed or determinable price, delivery has occurred and title has transferred, and collectability of the revenue is reasonably assured. The Company follows the entitlement method of accounting for recording oil and gas revenues. Under this method, any revenues received in excess of the Company’s interest in production are treated as a liability. If revenues received are less than Company's interest in production, the deficiency is recorded as an asset. The Company's imbalance position was not significant in terms of volumes or values at December 31, 2011 and 2010.

Revenues from our well service activities are recognized when all of the following criteria have been met: (i) evidence of an arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the price to the customer is fixed and determinable and (iv) collectability is reasonably assured.

- Evidence of an arrangement exists when a final understanding between us and our customer has occurred, and can be evidenced by a completed customer purchase order, field ticket, supplier contract, or master service agreement.

- Delivery has occurred or services have been rendered when we have completed requirements pursuant to the terms of the arrangement as evidenced by a field ticket.

- The price to the customer is fixed and determinable when the amount that is required to be paid is agreed upon. Evidence of the price being fixed and determinable is evidenced by contractual terms, our price book, a completed customer purchase order, or a field ticket.

- Collectability is reasonably assured when we screen our customers and provide goods and services to customers according to determined credit terms that have been granted based on credit evaluation and assessment.

We present our revenues net of any sales taxes collected by us from our customers that are required to be remitted to local or state governmental taxing authorities.

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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 have consisted of transactions in which the Company hedges the variability of cash flow related to a forecasted transaction. The Company has 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.

In 2011, 2010 and 2009, we recorded gain (loss) of ($0.9) million, $1.9 million and ($4.4) million, respectively, related to our derivative instruments. Fair values are derived principally from market quoted and other independent third-party quotes.

During the second quarter of 2008, we made the decision to mitigate a portion of our interest rate risk with interest rate swaps. These swap instruments reduce our exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. These interest rate swaps convert a portion of our variable rate interest of our Scotia debt (as defined in Note 6, "Long-term Debt and Interest Expense") to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. We have elected to designate these positions for hedge accounting and therefore the unrealized gains and losses are recorded in accumulated other comprehensive loss. The Company measures hedge effectiveness by assessing the changes in the fair value or expected future cash flows of the hedged item.

As of the date of this report there are no open interest rate swap positions.

Income Taxes

We account for deferred income taxes using the asset and liability method and provide income 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.

See “Note 8. 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 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 year ended December 31, 2011, Isramco's stock options were anti-dilutive.

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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.

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

ASU 2010-13. In April 2010, the FASB issued ASU No. 2010-13, Compensation — Stock Compensation (Topic 718): Effect of Denominating the Exercise Price of a Share-Based Payment Award in the Currency of the Market in Which the Underlying Equity Security Trades. This ASU codifies the consensus reached in EITF Issue No. 09-J, "Effect of Denominating the Exercise Price of a Share-Based Payment Award in the Currency of the Market in Which the Underlying Equity Security Trades." The amendments to the Codification clarify that an employee share-based payment award with an exercise price denominated in the currency of a market in which a substantial portion of the entity's equity shares trades should not be considered to contain a condition that is not a market, performance, or service condition. Therefore, an entity would not classify such an award as a liability if it otherwise qualifies as equity. ASU 2010-13 is effective for fiscal years beginning on or after December 15, 2010. The amendments in this update should be applied by recording a cumulative-effect adjustment to the opening balance of retained earnings. The cumulative-effect adjustment should be calculated for all awards outstanding as of the beginning of the fiscal year in which the amendments are initially applied, as if the amendments had been applied consistently since the inception of the award. The cumulative-effect adjustment should be presented separately. We adopted the provisions of ASU 2010-13 on January 1, 2011, and the adoption of this standard did not have a material impact on our financial position, results of operations, or cash flows.

ASU 2011-05. In June 2011, the FASB issued ASU 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income. The amendments in this ASU allow an entity the option to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In both choices, an entity is required to present each component of net income along with total net income, each component of other comprehensive income along with a total for other comprehensive income, and a total amount for comprehensive income. This ASU eliminates the option to present the components of other comprehensive income as part of the statement of changes in stockholders' equity. ASU 2011-05 should be applied retrospectively for interim and annual reporting periods beginning after December 15, 2011 with early adoption permitted. Adoption of this ASU will have no impact on the Company's consolidated financial statements.

ASU 2011-12. In December 2011, the FASB issued ASU 2011-12, Deferral of the Effective Date for Amendment to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income (Topic 220): Presentation of Comprehensive Income. This ASU defers the guidance on whether to require entities to present reclassification adjustments out of accumulated other comprehensive income by component in both the statement where net income is presented and the statement where other comprehensive income is presented for both interim and annual financial statements. ASU 2011-12 reinstated the requirements for the presentation of reclassifications that were in place prior to the issuance of ASU 2011-05 and did not change the effective date of ASU 2011-05. ASU

2011-12 should be applied consistently with ASU 2011-05; accordingly, this ASU is to be applied retrospectively for interim and annual reporting periods beginning after December 15, 2011, with early adoption permitted. Adoption of this ASU will have no impact on the Company's consolidated financial statements.

ASU 2011-04. In May 2011, the FASB issued ASU 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS. This ASU represents the converged guidance of the FASB and the IASB on measuring fair value and for disclosing information about fair value measurements. The amendments in this ASU clarify the Board's intent about the application of existing fair value measurement and disclosure requirements and changes particular principles or requirements for measuring fair value and for disclosing information about fair value measurements. ASU 2011-04 is effective prospectively for interim and annual reporting periods beginning after December 15, 2011. Adoption of this ASU will have no impact on the Company's consolidated financial statements.

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2. New Subsidiaries

In August 2011 the Company created three new subsidiaries. Only one of them has started activity and has acquired equipment and been providing a full range of well services to major oil companies and independent oil and natural gas production companies. The services include rig-based and workover services, well completion and recompletion services, plugging and abandonment of wells at the end of their useful lives and other ancillary oilfield services. The Company operates in major oil and natural gas producing regions in Texas and New Mexico.

3. Transactions with Affiliates and Related Parties

On November 17, 2008, the Company and Goodrich Global, Ltd. (“Goodrich”) entered into an Amended and Restated Agreement, as subsequently amended on November 24, 2008 (“Restated Agreement”). The Restated Agreement replaced the consulting agreement originally entered into in May 1996. Under the the Restated Agreement, the Company pays to Goodrich, which is owned and controlled by Haim Tsuff, the Chairman of the Board of Directors and Chief Executive Officer of Isramco, $360,000 per annum in installments of $30,000 per month, in addition to reimbursing Goodrich for all reasonable expenses incurred in connection with services rendered on behalf of the Company. Goodrich is entitled to receive, with respect to each completed fiscal year beginning with the fiscal year ended on December 31, 2008, an amount in cash equal to five percent (5%) of the Company’s pre-tax recorded profit calculated without reference to gain or loss in derivative transactions (the “Supplemental Payment”). The Supplemental payment is to be made within ten (10) business days after the filing with the Securities and Exchange Commission of the Company’s Annual Report on Form 10-K for such fiscal year. For purposes of the Supplemental Payment in the Restated Agreement, “profit” means the pre – tax recorded profit as specified in the Company’s annual report on Form 10-K, but excluding unrealized gain or loss on derivative transactions. The Restated Agreement has an initial term through May 31, 2011; provided that the term of the Restated Agreement will be deemed to have been automatically extended for an additional three year period unless the Company furnishes Goodrich, by March 3, 2011, with written notice of its election to not extend the term of such agreement. The Company did not furnish notice of termination, and the Restated Agreement was accordingly extended. The Restated Agreement contains certain customary confidentiality and non-compete provisions. If the Restated Agreement is terminated by the Company other than for cause, then Goodrich is entitled to receive the equivalent of payments due through the then remaining term of the agreement. For the year ended December 31, 2011, 2010 and 2009 we paid Goodrich the total amount of $360,000, $360,000 and $360,000, respectively. The conditions precedent for Supplemental Payments were not met and no Supplemental Payments have been made. In addition, in connection settlement of the Derivative Litigation, the parties to the Restated Agreement amend the Restated Agreement to eliminate the provisions providing for Supplemental Payment.

4. Marketable Securities

In August 2011 the Company sold all of its investment in a company called MediaMind Ltd. The realized gain from this transaction amounted to $15,910,000.

Sales of marketable securities resulted in realized gains of $15,910,000, $0 and $250,000 for the years ended December 31, 2011, 2010 and 2009, respectively.

Available-for-sale securities, which are primarily traded on the Tel-Aviv Stock Exchange and on the National Association of Securities Dealers Automated Quotation (“NASDAQ”), consist of the following (in thousands):

As of December 31	2011		2010	
	Cost	Market Value	Cost	Market Value

$	1,087	$	4,554	$	1,200	$	16,099

In January and February 2012, the Company sold its investment of 278,408 shares of stock in an affiliated company Jerusalem Oil Exploration Ltd. The total consideration received from the sale was approximately $4,833,000.

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5. Derivative and Hedging Activities

The Company enters into derivative commodity contracts to economically hedge its exposure to price fluctuations on a portion of its anticipated oil and natural gas production. It is the Company's policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. Each of the counterparties to the Company's derivative contracts is a lender in the Company's Senior Credit Agreement. The Company did not post collateral under any of these contracts as they are secured under the Senior Credit Agreement.

As of December 31, 2011, the Company has swaps agreements. A swap requires the Company to make a payment to, or receive receipts from, the counterparty based upon the differential between a specified fixed price and a price related to those quoted on the New York Mercantile Exchange (NYMEX) for each respective period.

As of December 31, 2011 we had swap contracts for volume of 48,567 barrels of crude oil during 36 months, commencing January 2012, and swap contracts for volume of 270,613 MMBTU of natural gas during 3 months commencing January 2012. Derivative commodity contracts settle based on NYMEX West Texas Intermediate and Henry Hub prices, which may differ from the actual price received by the Company. During 2011, 2010 and 2009 the Company did not elect to designate any positions as cash flow hedges for accounting purposes, and accordingly, recorded the net change in the mark-to-market valuation of these contracts, as well as all payments and receipts on settled contracts, in current earnings as a component of other income and expenses on the consolidated statements of operations.

At December 31, 2011, the Company had a $2.4 million derivative asset, of which $1 million was classified as current. For the year ended December 31, 2011, the Company recorded a net derivative loss of $0.9 million (a $3.4 million unrealized gain offset by a $4.3 million loss from net cash paid on settled contracts).

At December 31, 2010, the Company had a $2.5 million derivative asset, of which $2.2 million was classified as current and a $3.5 million derivative liability, of which $1.1 million was classified as current. For the year ended December 31, 2010, the Company recorded a net derivative gain of $1.86 million (a $4.7 million unrealized loss partially offset by a $6.6 million gain from net cash received on settled contracts).

At December 31, 2009, the Company had a $5.6 million derivative asset, of which $3.4 million was classified as current and a $1.8 million derivative liability, of which $0.1 million was classified as current. For the year ended December 31, 2009, the Company recorded a net derivative loss of $4.4 million (a $19.3 million unrealized loss partially offset by a $14.9 million gain from net cash received on settled contracts).

Natural Gas

At December 31, 2011, the Company had the following natural gas swap positions:

Period	Volume in MMbtu's	Swaps Price / Price Range	Weighted Average Price
January 2012 – March 2012	174,222	8.65	8.65

Crude Oil

At December 31, 2011, the Company had the following crude oil swap positions:

Period	Volume in Bbls	Swaps Price / Price Range	Weighted Average Price
January 2012 – December 2012	127,473	88.20-103.51	99.67
January 2013 – December 2013	89,400	103.51	103.51
January 2014 – December 2014	66,000	103.51	103.51

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On March 9, 2011, pursuant to an agreement with Wells Fargo, the derivative contracts between Isramco and Wells Fargo were terminated and the Company signed new swap contracts with Macquarie Bank, N.A. for an aggregate volume of 336,780 barrels of crude oil during the 46 month period commencing March 2011. The payment required for the termination of these contracts was approximately $7 million.

During the second quarter of 2008, we made the decision to mitigate a portion of our interest rate risk with interest rate swaps. These swap instruments reduce our exposure to market rate fluctuations by converting variable interest rates to fixed interest rates.

Under these swaps, the Company makes payments to, or receives payments from, the counterparties based upon the differential between a specified fixed price and a price related to the one-month London Interbank Offered Rate ("LIBOR"). These interest rate swaps convert a portion of the variable rate interest of our Scotia Senior Credit Facility (as defined in Note 6, "Long-term Debt and Interest Expenses") to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. We have elected to designate these positions for hedge accounting and therefore the unrealized gains and losses are recorded in accumulated other comprehensive loss. The Company measures hedge effectiveness by assessing the changes in the fair value or expected future cash flows of the hedged item.

As of December 31, 2011 the Company did not have open interest rate swap positions.

6. Long-Term Debt and Interest Expense

Long-Term Debt as December 31 consisted of the following (in thousands):

	2011	2010
Libor + 2% Bank Revolving Credit Facility due 2011	-	9,450
Libor + 2% Bank Revolving Credit Facility due 2012	20,000	27,625
Libor + 6% Related party Debt	12,000	12,000
Libor + 5.5% Related party Debt	-	954
Libor + 6% Related party Debt	11,500	11,500
Libor + 6% Related party Debt	6,000	6,000
Libor + 6% Related party Debt	41,861	48,900
Libor + 5.5% Related party Debt	6,456	-
	97,817	116,429
Less: Current Portion of Long-Term Debt	(37,642)	(17,350)
Total	60,175	99,079

Senior Revolving Credit Facilities

The Company entered into a Senior Secured Revolving Credit Agreement, dated as of March 27, 2008 and Amended and Restated as of December 19, 2008 (the "Scotia Senior Credit Agreement"), with each of the lenders from time to time party thereto (the "Lenders"). The Bank of Nova Scotia is the administrative agent for the Lenders and Capital One, N.A. is the syndication agent for the Lenders. The Scotia Senior Credit Agreement originally provided for a $150 million facility due in 2012 with a borrowing base of $54 million that is redetermined from time to time and adjusted based on the Company's oil and gas properties, reserves, other indebtedness and other relevant factors. During the first quarter of 2011, the Lenders reduced the borrowing base to $28 million. On July 28, 2011 the borrowing base available under the other credit facility with the Bank of Nova Scotia ("Scotia") was redetermined to $20,000,000.

During the fourth quarter of 2011 the Lenders reduced the borrowing base to $0. The Company is repaying the approximately $20,000,000 outstanding balance in six installments of $3,333,000 each with the first two payments already made for January and February 2012 and the remaining installments due each month thereafter through June 2012 when the entire balance will be repaid.

The Company is also in negotiations for similar credit facilities with several other commercial lenders, to obtain terms most favorable to the Company. While optimistic of a positive outcome of our consolidation efforts, the Company is uncertain as to whether it will be successful in obtaining new replacement financing or, if is obtained, the timetable upon which such facility will be closed and other material terms and conditions.

Amounts outstanding under the Scotia Senior Credit Agreement bear interest at specified margins over the LIBOR of 1.25% to 2.00% for LIBOR loans or at specified margins over the Base Rate (as defined in the agreement) of 0.25% to 1.25% for base rate loans. Such margins fluctuate based on the utilization of the borrowing base. Borrowings under the Scotia Senior Credit Agreement are secured by first lien and security interest on the real and personal property of Isramco Resources.

The Scotia Senior Credit Agreement contains customary financial and other covenants, including minimum working capital levels of not less than 1.0 to 1.0, leverage ratio of not greater than 3.5 to 1.0 and minimum coverage of interest of not less than 2.5 to 1.0. In addition, the Company is subject to covenants limiting dividends and other restricted payments, transactions with affiliates, changes of control, asset sales, and liens on properties.

The Company entered into a Senior Secured Revolving Credit Agreement, dated as of March 2, 2007 as Amended and Restated as of June 15, 2007 (the "Wells Fargo Senior Credit Agreement"), with the lenders from time to time party thereto (the "Lenders") and Wells Fargo Bank, N.A, as administrative agent for the Lenders. The Wells Fargo Senior Credit Agreement originally provided for a $150 million facility due in March, 2011 with a borrowing base of $35.3 million that is redetermined from time to time and adjusted based on the Company's oil and gas properties, reserves, other indebtedness and other relevant factors.

On or about March 3, 2011, the Corporation paid the outstanding principal balance of the Wells Fargo Senior Credit Facility. By agreement of the parties, the derivative contracts remained in place until March 9, 2011, when these contracts were novated and replaced by new derivative contracts, for the same volumes but at current market prices, with Macquarie Bank, N.A. In connection with this transaction, the Wells Fargo Senior Credit Facility was transferred to and assumed by Macquarie Bank, N.A. This facility currently has no outstanding principal or current availability. The credit facility was assigned and transferred to Macquarie Bank, N.A. in anticipation of the finalization of a successor credit facility pursuant to which all of the Corporation's debt (including its related party debt) will be consolidated into a single facility at Macquarie Bank, N.A., or some other commercial lender. As of the date of this report the credit facility is about to be terminated and all collateral related thereto will be released. The Company is also in negotiations for similar credit facilities with several other commercial lenders, to obtain terms most favorable to the Company. While optimistic of a positive outcome of our consolidation efforts, the Company is uncertain as to whether it will be successful in obtaining new replacement financing or, if is obtained, the timetable upon which such facility will be closed and other material terms and conditions.

Related Party Debt

In July 2009 the Company entered into a loan transaction with I.O.C. Israel Oil Company, Ltd. ("IOC"), related party, pursuant to which the Company borrowed $6 million (the "IOC Loan"). The purpose of the IOC Loan was to provide funds to Isramco Resources, LLC, which in turn paid this amount to Bank of Nova Scotia, as administrative agent, and Capital One, N.A., as a syndication agent, under the Scotia Senior Credit Agreement. This payment reduced the outstanding balance below the borrowing base and avoided the imposition of additional interest under the Scotia Senior Credit Agreement.

Amounts outstanding under the IOC Loan bear interest at LIBOR plus 6.0%. The IOC Loan matures in five years, with accrued interest payable annually on each anniversary date of the loan. The IOC Loan may be prepaid at any time without penalty.

In connection with GFB Acquisition (see Note 2), we obtained the following financing from related parties:

Pursuant to a Loan Agreement dated as of February 26, 2007 Isramco obtained a loan from JOEL Jerusalem Oil Exploration Ltd, a related party ("JOEL"), a related party, in the principal amount of $7 million, repayable at the end of 3 months (that was extended until July 11, 2007). Interest accrues at a per annum rate of 5.36%.

On July 2007, the Company and JOEL reached an agreement to revise the period of the Loan to seven years and the interest rate to LIBOR plus 6%.

In February and March, 2008 we obtained loans from JOEL in the aggregate principal amount of $48.9 million, repayable at the end of 4 months at an interest rate of LIBOR plus 1.25% per annum. Pursuant to a loan agreement signed in June 2009, the maturity date of this loan was extended for an additional period of seven years. Interest accrues at a per annum rate of LIBOR plus 6%. Principal and interest are due and payable in four equal annual installments, commencing on June 30, 2012. At any time we can make prepayments without premium or penalty.

Mr. Jackob Maimon, Isramco's president at the time and a former director of the Company is a director of JOEL. Mr. Haim Tsuff, Isramco's Chief Executive Officer and Chairman, is a controlling shareholder of JOEL.

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In connection with the Company's purchase of certain oil and gas interests mainly in New Mexico and Texas in February 2007 (See Note 2), the Company obtained loans in the total principal amount of $42 million from Naphtha Israel Petroleum Corp. Ltd., ("Naphtha") with terms and conditions as below:

Pursuant to a Loan Agreement dated as of February 27, 2007 (the "First Loan Agreement"); Isramco obtained an $18.5 million loan from Naphtha. The outstanding principal amount of the loan accrues interest at per annum rate equal to the London Inter-bank Offered Rate (LIBOR) plus 5.5%, not to exceed 11% per annum. Interest is payable at the end of each loan year. Principal plus any accrued and unpaid interest are due and payable on February 26, 2014. Interest after the maturity date accrues at the per annum rate of LIBOR plus 12% until paid in full. At any time, Isramco is entitled to prepay the outstanding amount of the loan without penalty or prepayment. To secure its obligations that may be incurred under the Loan Agreement, Jay Petroleum, LLC, a wholly – owned subsidiary of Isramco, agreed to guarantee the indebtedness. Naphtha can accelerate the loan and exercise its rights under the collateral upon the occurrence any one or more of the following events of default: (i) Isramco's failure to pay any amount that may become due in connection with the loan within five (5) days of the due date (whether by extension, renewal, acceleration, maturity or otherwise) or fail to make any payment due under any hedge agreement entered into in connection with the transaction, (ii) Isramco's material breach of any of the representations or warranties made in the loan agreement or security instruments or any writing furnished pursuant thereto, (iii) Isramco's failure to observe any undertaking contained in transaction documents if such failure continues for 30 calendar days after notice, (iv) Isramco's insolvency or liquidation or a bankruptcy event or (v) Isramco's criminal indictment or conviction under any law pursuant to which such indictment or conviction can lead to a forfeiture by Isramco of any of the properties securing the loan.

Pursuant to a Loan Agreement dated as of February 27, 2007 (the "Second Loan Agreement") Isramco obtained a loan (the "Second Loan" , in the principal amount of $11.5 million from Naphtha, repayable at the end of seven years. Interest accrues at a per annum rate of LIBOR plus 6%. Principal is due and payable in four equal installments, commencing on the fourth anniversary of the date of the loan. Interest is payable annually upon each anniversary date of this loan. At any time Isramco can make prepayments without premium or penalty. The Second Loan is not secured. The other terms of the Second Loan Agreement are identical to the terms of the First Loan Agreement.

Pursuant to a Loan Agreement dated as of February 27, 2007 (the "Third Loan Agreement ") Isramco obtained a loan in the principal amount of $12 million (the "Third Loan") from Naphtha, repayable at the end of five years. Interest accrues at a per annum rate of LIBOR plus 6%. Principal is due and payable in four equal annual installments, commencing on the second anniversary of the loan. Accrued interest is payable in equal annual installments. At any time Isramco can make prepayments without premium or penalty. The Third Loan is not secured. The other terms of the Third Loan Agreement are identical to the terms of the Loan Agreement.

Effective February 1, 2009, each of the loans from IOC and Naphtha to the Company were amended and restated to extend all payment deadlines arising on and after February, 2009, by two years.

On March 3, 2011, the Company entered into a Loan Agreement with IOC pursuant to which it borrowed the sum of $11 million. The loan bears interest at a rate of 10% per annum and is payable in quarterly payments of interest only until March 3, 2012, when all accrued interest and principal is due and payable. The loan may be prepaid at any time without penalty. The loan is unsecured. The purpose of the loan was to provide funds to Isramco for the payment of amounts due under the Wells Fargo Senior Credit Facility at maturity. On March 3, 2011 Isramco paid the outstanding principal balance due under the Wells Fargo Senior Credit Agreement. Subsequently, on March 9, 2011, pursuant to an agreement with Wells Fargo, the derivative contracts between Isramco and Wells Fargo were terminated at a cost to the Company of approximately $7,000,000. Concurrently, the Company entered into new derivative contracts for 336,780 barrels of crude oil during the 46 month period commencing March 2011 with Macquarie Bank, N.A. During September 2011 Isramco paid $5,096,000 of principal and interest pursuant to Loan agreement with IOC. The Company is actively pursuing a consolidation of all outstanding debt with Macquarie Bank and other commercial lenders.

In October 2011 the agreement with IOC, pertaining to a loan in the outstanding principal amount of $6,456,000 was renegotiated. The payoff of principal amount was extended by 6 month to September 9, 2012. Interest accrued per annum was determined on LIBOR+5.5% from initial 10%.

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

Debt Maturities

Aggregate maturities of long-term debt at December 31, 2011 are due in future years as follows (in thousands):

2012	37,642
2013	18,100
2014	24,100
2015	15,100
2016	2,875
Total	$ 97,817

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Interest Expense

The following table summarizes the amounts included in interest expense for the years ended December 31, 2011, 2010 and 2009:

	Years Ended December 31, 2011	2010	2009
	(In thousands)		
Current debt, long-term debt and other - banks	$ 1,323	$ 1,719	$ 2,658
Long-term debt – related parties	6,437	5,927	6,561
	$ 7,760	$ 7,646	$ 9,219

7. Fair Value of Financial Instruments

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.

The following tables set forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value as of December 31, 2011 and 2010. As required by ASC 820, a financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There were no transfers between fair value hierarchy levels for the years ended December 31, 2011 and 2010.

	December 31, 2011			
	Level 1	Level 2	Level 3	Total
Assets				
Marketable securities	$ 4,554	$ —	$ —	$ 4,554
Commodity derivatives	—	2,382	—	2,382
Total	$ 4,554	$ 2,382	$ —	$ 6,936

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	December 31, 2010			
	Level 1	Level 2	Level 3	Total
Assets				
Marketable securities	$ 16,099	$ —	$ —	$ 16,099
Commodity derivatives	—	2,499	—	2,499
Total	$ 16,099	$ 2,499	$ —	$ 18,598
Liabilities				
Commodity derivatives	$ —	$ 3,501	$ —	$ 3,501
Interest rate derivatives	—	34	—	34
Total	$ —	$ 3,535	$ —	$ 3,535

Marketable securities listed above are carried at fair value. The Company is able to value its marketable securities based on quoted fair values for identical instruments, which resulted in the Company reporting its marketable securities as Level 1.

Derivatives listed above include swaps that are carried at fair value. The Company records the net change in the fair value of these positions in “Net gain (loss) on derivative contracts” in the Company’s consolidated statements of operations, in case of commodity derivatives, and in “Other comprehensive income”, in case of interest rate derivatives. The Company is able to value these assets and liabilities based on observable market data for similar instruments, which resulted in the Company reporting its derivatives as Level 2. This observable data includes the forward curve for commodity prices based on quoted market prices and prospective volatility factors related to changes in the forward curves.

As of December 31, 2011 and 2010, the Company’s derivative contracts were with major financial institutions with investment grade credit ratings which are believed to have a minimal credit risk. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts discussed above; however, while no assurance to this effect can be provided, the Company does not anticipate such nonperformance. Each of the counterparties to the Company’s derivative contracts is a lender in the Company’s Senior Credit Agreement. The Company did not post collateral under any of these contracts as they are secured under the Senior Credit Agreements.

8. Income Taxes

Isramco 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 Isramco’s current ownership structure.

Isramco 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. Isramco provides for deferred taxes on temporary differences between the financial statements and tax bases of its assets using the enacted tax rates that are expected to apply to taxable income when the temporary differences are expected to reverse.

Isramco adopted Accounting Standards Codification (ASC) 740-10, effective January 1, 2007. Isramco 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, 2011. The Company's tax years subsequent to 2006 are either currently under audit or remain open and subject to examination by federal tax authorities and the tax authorities in Louisiana, New Mexico, Oklahoma and Texas, 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,		
	2011	2010	2009
		(In thousands)	
Expected tax (benefit) expense	$ 3,975	$ (1,632)	$ (8,285)
State income taxes, net	-	18	4
Foreign income taxes	-	-	-
Change in estimate of income tax basis (1)	-	-	(1,637)
Other	-	(242)	(172)
Total tax expense (benefit)	$ 3,975	$ (1,856)	$ (10,090)

(1) Changes in estimated income tax basis in connection with the preparation of 2006 and 2008 amended federal income tax returns.

Deferred tax assets at December 31, 2011 and 2010 are comprised primarily of net operating loss carry forwards and book impairment from write downs of assets. Deferred tax liabilities consist primarily of the difference between book and tax basis depreciation, depletion and amortization (DD&A) and impairment. 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. There is a net deferred tax asset and it is management's opinion that a valuation allowance is not needed, as it is more likely than not based on objective evidence that realization of the deferred tax assets is reasonably assured.

The principal components of Isramco's deferred tax assets and liabilities as of December 31 were as follows (in thousands):

	2011	2010
Deferred current tax assets:		
Unrealized hedging transactions	$ -	$ 385
Accrued interest	2,875	3,738
Deferred current tax assets	$ 2,875	$ 4,123
Deferred current tax liabilities:		
Unrealized hedging transactions	$ (336)	$ (755)
	$ (336)	$ (755)
Net current deferred tax assets	$ 2,539	$ 3,368
Deferred noncurrent tax assets:		
Unrealized hedging transactions	$ -	$ 841
Book-tax differences in property basis		
Net operating loss carry-forwards	12,020	12,154
Other		33
Deferred noncurrent tax assets	$ 12,020	$ 13,028

Deferred noncurrent tax liabilities:				
Unrealized hedging transactions	$	(497)	$	(120)
Book-tax differences in property basis		(4,538)		(1,344)
Book-tax differences in marketable securities		(1,214)		(5,265)
Other		(310)		(1,664)
Deferred noncurrent tax liabilities	$	(6,559)	$	(8,393)
Net noncurrent deferred tax assets	$	5,461	$	4,635

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

	2011	2010	2009
Current income tax:			
Federal	$ -	$ -	$ -
Foreign	-	-	-
State	-	-	-
Total current income tax	$ -	$ -	$ -
Deferred income tax			
Federal	$ 3,975	$ (1,874)	$ (10,094)
Foreign	-	-	-
State	-	18	4
Total deferred income tax	$ 3,975	$ (1,856)	$ (10,090)
Provision for income tax	$ 3,975	$ (1,856)	$ (10,090)

At December 31, 2011 the Company has U.S. tax loss carry forwards of approximately $34,343,000 which will expire in various amounts beginning in 2023 and ending in 2030. Utilization of such loss carry forwards could be limited to the extent Isramco has an ownership change that triggers the limitation under Section 382 of Internal Revenue Code of 1986, as amended.

9. 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):

	2011	2010	2009
Numerator for Basic and Diluted Earnings per Share - Net Income (loss)	$ 7,381	$ (2,787)	$ (13,579)
Denominator for Basic Earnings per Share - Weighted Average Shares	2,717,691	2,717,691	2,717,691
Potential Dilutive Common Shares -	-	-	-
Adjusted Weighted Average Shares	2,717,691	2,717,691	2,717,691
Net Income (Loss) Per Share Available to Common Stockholders – Basic	$ 2.72	$ (1.03)	$ (5.00)
Net Income (Loss) Per Share Available to Common Stockholders – Diluted	$ 2.72	$ (1.03)	$ (5.00)

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10. Stock Options

The 1993 Stock Option Plan (the 1993 Plan) was approved at the annual meeting of shareholders held in August 1993. As of December 31, 2009, 20,050 shares of common stock were reserved for issuance under the 1993 Plan. Options granted under the 1993 Plan may be either incentive stock options under the Internal Revenue Code or options that do not qualify as incentive stock options. Options granted under the 1993 Plan may be exercised for a period of up to ten years from the grant date. The exercise price for an incentive stock option may not be less than 100% of the fair market value of Isramco's common stock on the date of grant. All the options granted under the 1993 Plan to date were fully vested on the date of grant. The administrator of the 1993 Plan may set the exercise price for a nonqualified stock option at less than 100% of the fair market value of Isramco's common stock on the date of grant.

No stock options were granted during 2011, 2010 and 2009. Shares of common stock reserved for future issuance under the 1993 plan are 20,050 shares. There are no granted stock options outstanding under the 1993 Plan as of balance sheet date.

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.

11. Supplemental Cash Flow Information

Cash paid for interest and income taxes was as follows for the years ended December 31 (in thousands):

	2011	2010	2009
Interest	$ 6,723	$ 9,160	$ 6,263
Income taxes	$ -	$ -	$ -

The consolidated statements of cash flows for the year ended December 31, 2011 exclude the following non-cash transactions:

· Property and equipment of $484,000 included in accounts payable

12. Concentrations of Credit Risk

Financial instruments, which potentially expose Isramco to concentrations of credit risk, consist primarily of trade accounts receivable and oil and gas derivative assets. Isramco's customer base includes several of the major United States oil and gas operating and production companies. 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, 2011. The fair value of oil and gas derivatives contracts will be significantly impacted by the change in oil and gas future prices. Isramco continues to monitor and review credit exposure of its marketing counter-parties.

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.

A significant portion of Isramco's cash and cash equivalents is invested in marketable securities. Substantially all marketable securities owned by Isramco are held by banks in Israel and Switzerland.

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13. 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.

14. 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 sheet 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):

	2011	2010	2009
Liability for asset retirement obligation at the beginning of the year	$ 16,577	$ 16,248	$ 15,733
Liabilities Incurred	62	4	-
Liabilities settled and divested	(242)	(524)	(314)
Accretion expense	853	849	829
Liability for asset retirement obligation at the end of the year	$ 17,250	$ 16,577	$ 16,248

15. Subsequent Events

The Company has evaluated subsequent events through March 23, 2012 which is the date the consolidated financial statements were issued.

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16. Supplementary Oil and Gas Information (Unaudited)

The following supplemental information regarding the oil and gas activities of Isramco for 2011, 2010 and 2009 is presented pursuant to the disclosure requirements promulgated by the Securities and Exchange Commission and SFAS No. 69, "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	2011 United States	2010 United States
Unproved properties not being amortized	$ -	$ -
Proved property being amortized	225,108	222,122
Accumulated depreciation, depletion amortization and impairment	(104,522)	(90,752)
Net capitalized costs	120,586	131,370

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

As of December 31	2011	2010 United States	2009
Property acquisition costs—proved and unproved properties	$ 151	$ -	$ -
Exploration costs	$ -	$ -	$ -
Development costs	$ 2,398	$ 3,454	$ 423

OIL AND GAS 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.

Proved reserves represent estimated quantities of natural gas, crude oil and condensate that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions in effect when the estimates were made. Proved developed reserves are proved reserves expected to be recovered through wells and equipment in place and under operating methods used when the estimates were made.

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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.

In December 2009, Isramco adopted revised oil and gas reserve estimation and disclosure requirements that conformed the definition of proved reserves to the Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting rules, issued by the SEC in 2008. An accounting standards update revised the definition of proved oil and gas reserves to require that the average, first-day-of-the-month price during the 12-month period before the end of the year rather than the year-end price, must be used when estimating whether reserve quantities are economic to produce. This same 12-month average price is also used in calculating the aggregate amount of (and changes in) future cash inflows related to the standardized measure of discounted future net cash flows. The rules also allow for the use of reliable technologies to estimate proved oil, natural-gas, and natural-gas liquids (NGLs) reserves if those technologies have been demonstrated to result in reliable conclusions about reserve volumes.

The unaudited supplemental information on oil and gas exploration and production activities for 2011, 2010, and 2009 has been presented in accordance with the revised reserve estimation and disclosure rules, which were not applied retrospectively. The December 31, 2008 data is presented in accordance with Financial Accounting Standards Board (FASB) oil and gas disclosure requirements effective at that time.

	Oil Bbls			Gas Mcf		
	United States	Israel	Total	United States	Israel	Total
December 31, 2008	2,678,994	-	2,678,994	25,696,175	-	25,696,175
Revisions of previous estimates	616,674	-	616,674	1,378,468	-	1,378,468
Acquisition of minerals in place	-	-	-	-	-	-
Sales of minerals in place	-	-	-	-	-	-
Production	(293,601)	-	(293,601)	(2,622,389)	-	(2,622,389)
December 31, 2009	3,002,067	-	3,002,067	24,452,254	-	24,452,254
Revisions of previous estimates	606,445	-	606,445	1,616,809	-	1,616,809
Acquisition of minerals in place	-	-	-	-	-	-
Sales of minerals in place	-	-	-	-	-	-
Production	(290,589)		(290,589)	(2,368,158)	-	(2,368,158)
December 31, 2010	3,317,923	-	3,317,923	23,700,905	-	23,700,905
Revisions of previous estimates	180,104	-	180,104	3,573,698	-	3,573,698
Extensions, discoveries, and	15,033	-	15,033	21,847	154,100,000	154,121,847

other additions						
Acquisition of minerals in place	-	-	-	-	-	-
Sales of minerals in place	-		-	-		-
Production	(278,601)	-	(278,601)	(2,241,384)	-	(2,241,384)
December 31, 2011	3,234,459	-	3,234,459	25,055,066	154,100,000	179,155,066
Proved Developed Reserves						
December 31, 2011	3,234,459	-	3,234,459	25,055,066	-	25,055,066
December 31, 2010	3,317,923	-	3,317,923	23,700,905	-	23,700,905
December 31, 2009	3,002,067	-	3,002,067	24,452,254	-	24,452,254
December 31, 2008	2,678,994	-	2,678,994	25,696,175	-	25,696,175
Proved Undeveloped Reserves						
December 31, 2011	-	-	-	-	154,100,000	154,100,000
December 31, 2010	-	-	-	-	-	-
December 31, 2009	-	-	-	-	-	-
December 31, 2008	-	-	-	-	-	-
						-

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	NGL Bbls			Total MBOE		
	United States	Israel	Total	United States	Israel	Total
December 31, 2008	1,252,003	-	1,252,003	8,213,693	-	8,213,693
Revisions of previous estimates	391,115	-	391,115	1,237,534	-	1,237,534
Acquisition of minerals in place	-	-	-	-	-	-
Sales of minerals in place	-	-	-	-	-	-
Production	(155,793)	-	(155,793)	(886,459)	-	(886,459)
December 31, 2009	1,487,325	-	1,487,325	8,564,768	-	8,564,768
Revisions of previous estimates	431,465	-	431,465	1,307,378	-	1,307,378
Acquisition of minerals in place	-	-	-	-	-	-
Sales of minerals in place	-	-	-	-	-	-
Production	(155,640)	-	(155,640)	(840,922)	-	(840,922)
December 31, 2010	1,763,150	-	1,763,150	9,031,224	-	9,031,224
Revisions of previous estimates	265,863	-	265,863	1,041,583	-	1,041,583
Extensions, discoveries, and other additions	3,897	-	3,897	22,571	25,683,333	25,705,904
Acquisition of minerals in place	-	-	-	-	-	-
Sales of minerals in place	-	-	-	-	-	-
Production	(136,446)	-	(136,446)	(788,611)	-	(788,611)
December 31, 2011	1,896,464	-	1,896,464	9,306,767	25,683,333	34,990,100
Proved Developed Reserves						
December 31, 2011	1,896,464	-	1,896,464	9,306,767	-	9,306,767
December 31, 2010	1,763,150	-	1,763,150	9,031,224	-	9,031,224
December 31, 2009	1,487,325	-	1,487,325	8,564,768	-	8,564,768
	1,252,003	-	1,252,003	8,213,693	-	8,213,693

December 31, 2008						
Proved Undeveloped Reserves						
December 31, 2011	-	-	-	-	25,683,333	25,683,333
December 31, 2010	-	-	-	-	-	-
December 31, 2009	-	-	-	-	-	-
December 31, 2008	-	-	-	-	-	-

(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 —

2011 — the increase in Israel is due to the recording of reserves at the Tamar development offshore Israel.

Revisions of Previous Estimates —

2011 — Proved reserves must be estimated using the assumption that prices and costs remain constant for the duration of the reservoir life. The upward Revisions of Previous Estimates was due to significantly higher average first-day of the month oil gas and NGLs prices calculated for the 12 months ended December 31, 2011 compared to prices as of December 31, 2010.

2010 — Proved reserves must be estimated using the assumption that prices and costs remain constant for the duration of the reservoir life. The upward Revisions of Previous Estimates was due to significantly higher average first-day of the month oil, gas and NGLs prices calculated for the 12 months ended December 31, 2011 compared to prices as of December 31, 2009.

The SEC amended its definitions of oil and natural gas reserves effective December 31, 2009. Previous periods were not restated for the new rules. Key revisions include a change in pricing used to prepare reserve estimates to a 12-month unweighted average of the first-day-of-the-month prices, the inclusion of non-traditional resources in reserves, definitional changes, allowing the application of reliable technologies in determining proved reserves, and other new disclosures (Revised SEC rules).

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 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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Under the Standardized Measure for the year ended December 31, 2009, the future cash inflows were estimated by applying year-end oil and natural gas prices to the estimated future production of year-end proved reserves. Estimates of future income taxes are computed using current statutory income tax rates including consideration for estimated future statutory depletion and tax credits. The resulting net cash flows are reduced to present value amounts by applying a 10% discount factor. Use of a 10% discount rate and year-end prices were required. At December 31, 2011 and 2010, as specified by the SEC, the prices for oil and natural gas used in this calculation were the unweighted 12-month average of the first day of the month prices, except for volumes subject to fixed price contracts.

millions	United States	Israel	Total
December 31, 2011			
Future cash inflows (1)	$ 506,668,204	$ 634,462,200	$ 1,141,130,404
Future development costs	(875,854)	-	(875,854)
Future production costs	(240,176,108)	-	(240,176,108)
Future income tax expenses (2)	(45,477,986)	(341,573,223)	(387,051,209)
Future net cash flows	220,138,256	292,888,977	513,027,233
10% annual discount for estimated timing of cash flows	(107,734,348)	(168,565,572)	(276,299,920)
Standardized measure of discounted future net cash flows	$ 112,403,908	$ 124,323,405	$ 236,727,313
December 31, 2010			
Future cash inflows	$ 429,260,906	$ -	$ 429,260,906
Future development costs	(740,588)	-	(740,588)
Future production costs	(208,228,155)	-	(208,228,155)
Future income tax expenses	(33,475,234)	-	(33,475,234)
Future net cash flows	186,816,929	-	186,816,929
10% annual discount for estimated timing of cash flows	(89,183,575)	-	(89,183,575)
Standardized measure of discounted future net cash flows	$ 97,633,354	$ -	$ 97,633,354
December 31, 2009			
Future cash inflows	$ 294,721,432	$ -	$ 294,721,432
Future development costs	(556,810)	-	(556,810)
Future production costs	(147,470,220)	-	(147,470,220)
Future income tax expenses	-	-	-
Future net cash flows	146,694,402	-	146,694,402
10% annual discount for estimated timing of cash flows	(68,284,971)	-	(68,284,971)
Standardized measure of discounted future net cash flows	$ 78,409,431	$ -	$ 78,409,431

(1) The increase in Israel is due to the recording of reserves at the Tamar development offshore Israel.

(2) 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 50% 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 50% 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 income tax expenses include the taxation and income tax.

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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, 2011

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

millions	United States	International	Total
2011			
Balance at January 1	$97,633,354	$-	$97,633,354
Sales and transfers of oil and gas produced, net of production costs	(23,247,735)	-	(23,247,735)
Net changes in prices and production costs	18,142,794	-	18,142,794
Changes in estimated future development costs, net of current development costs	(1,213,256)	-	(1,213,256)
Extensions, discoveries, additions, and improved recovery, less related costs	-	124,323,405	124,323,405
Development costs incurred during the period		-	
Revisions of previous quantity estimates	14,623,353	-	14,623,353
Purchases of minerals in place	-	-	-
Sales of minerals in place	-	-	-
Accretion of discount	10,476,340	-	10,476,340
Net change in income taxes	(5,726,668)	-	(5,726,668)
Change in production rates and other	1,599,863	-	1,599,863
Balance at December 31	$112,288,045	$124,323,405	$236,611,450
2010			
Balance at January 1	$78,409,431	$-	$78,409,431
Sales and transfers of oil and gas produced, net of production costs	(19,435,256)	-	(19,435,256)
Net changes in prices and production costs	28,652,935	-	28,652,935
Changes in estimated future development costs, net of current development costs	(2,930,885)	-	(2,930,885)
Extensions, discoveries, additions, and improved recovery, less related costs	-	-	-
Development costs incurred during the period	-	-	-
Revisions of previous quantity estimates	17,549,795	-	17,549,795
Purchases of minerals in place	-	-	
Sales of minerals in place	-	-	
Accretion of discount	7,092,982	-	7,092,982
Net change in income taxes	(17,494,664)	-	(17,494,664)
Change in production rates and other	5,789,016	-	5,789,016
Balance at December 31	$97,633,354	$-	$97,633,354

2009	$	$	$
Balance at January 1	73,377,612	-	73,377,612
Sales and transfers of oil and gas produced, net of production costs	(15,116,990)	-	(15,116,990)
Net changes in prices and production costs	4,638,711	-	4,638,711
Changes in estimated future development costs, net of current development costs	211,024	-	211,024
Extensions, discoveries, additions, and improved recovery, less related costs	-	-	-
Development costs incurred during the period	-	-	-
Revisions of previous quantity estimates	11,948,600	-	11,948,600
Purchases of minerals in place	-	-	-
Sales of minerals in place	-	-	-
Accretion of discount	6,626,173	-	6,626,173
Net change in income taxes	-	-	-
Change in production rates and other	(3,275,699)	-	(3,275,699)
Balance at December 31	$78,409,431	$-	$78,409,431

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Unaudited Quarterly Financial Information
(In Thousands, Except Per Share Data)

Quarter Ended		March 31		June 30		September 30		December 31
2011								
Total Revenues	$	11,150		11,747		11,177		11,574
Net Income (loss) before taxes		(6,623)		2,001		22,607		(6,624)
Net Income (loss) attributable to common shareholders		(4,306)		1,301		14,694		(4,303)
Net income attributable to noncontrolling interests		-		-		-		5
Net income (loss) attributable to Isramco		(4,306)		1,301		14,694		(4,308)
Earnings (loss) per share:								
Net income (loss) attributable to common stockholders - basic	$	(1.58)		0.48		5.41		(1.59)
Net income (loss) attributable to common stockholders - diluted	$	(1.58)		0.48		5.41		(1.59)
Average number common shares outstanding - basic		2,717,691		2,717,691		2,717,691		2,717,691
Average number common shares outstanding - diluted		2,717,691		2,717,691		2,717,691		2,717,691
2010								
Total Revenues	$	10,165		9,527		9,928		12,580
Net Income (loss) before taxes	$	2,057		1,464		(3,802)		(4,362)
Net Income (loss)	$	1,357		966		(2,510)		(2,600)
Earnings (loss) per share:								
Net income (loss) attributable to common stockholders - basic	$	0.50	$	0.36	$	(0.92)	$	(0.96)
Net income (loss) attributable to common stockholders - diluted	$	0.50	$	0.36	$	(0.92)	$	(0.96)
Average number common shares outstanding - basic		2,717,691		2,717,691		2,717,691		2,717,691
Average number common shares outstanding - diluted		2,717,691		2,717,691		2,717,691		2,717,691
2009								
Total Revenues	$	7,007	$	7,399	$	7,810	$	9,508
Net Income (loss) before taxes	$	2,713	$	(12,223)	$	(3,236)	$	(10,923)
Net Income (loss)	$	1,790	$	(8,014)	$	(2,018)	$	(5,337)
Earnings (loss) per share:								
Net income (loss) attributable to common stockholders - basic	$	0.66	$	(2.95)	$	(0.74)	$	(1.96)
Net income (loss) attributable to common stockholders - diluted	$	0.66	$	(2.95)	$	(0.74)	$	(1.96)
Average number common shares outstanding - basic		2,717,691		2,717,691		2,717,691		2,717,691

Average number common shares outstanding - diluted	2,717,691	2,717,691	2,717,691	2,717,691

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