

ABRAXAS PETROLEUM CORP  
Form 10-K  
March 15, 2012

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

FORM 10-K

(Mark One)

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

For the Fiscal Year Ended December 31, 2011

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

Commission File Number 001-16071

ABRAXAS PETROLEUM CORPORATION  
(Exact name of Registrant as specified in its charter)

Nevada  
(State or Other Jurisdiction of  
Incorporation or Organization)

74-2584033  
(I.R.S. Employer Identification Number)

18803 Meisner Drive  
San Antonio, TX 78258  
(Address of principal executive offices)

(210) 490-4788  
Registrant's telephone number, including area code

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of each class:	Name of each exchange on which registered:
Common Stock, par value \$.01 per share	The NASDAQ Stock Market, LLC
Preferred Stock Purchase Rights	The NASDAQ Stock Market, LLC

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:

None

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

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

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Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes xNo

Indicate by check mark if 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). YesxNo

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, 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. Yes xNo

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

Large accelerated filer Accelerated filer x  
Non-accelerated filer (Do not check if Smaller reporting company  
smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).Yes  
Nox

As of June 30, 2011, the last day of the registrant's most recently completed second fiscal quarter, the aggregate market value of the common stock held by non-affiliates of the registrant was \$328,674,470 based on the closing sale price as reported on The NASDAQ Stock Market.

As of March 12, 2012, there were 92,261,057 shares of common stock outstanding.

Documents Incorporated by Reference:

Document	Parts Into Which Incorporated
Portions of the registrant's Proxy Statement relating to the 2012 Annual Meeting of Stockholders to be held on May 4, 2012.	Part III

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## FORWARD-LOOKING INFORMATION

We make forward-looking statements throughout this report. Whenever you read a statement that is not simply a statement of historical fact (such as statements including words like “believe,” “expect,” “anticipate,” “intend,” “will,” “plan,” “may,” “estimate,” “could,” “potentially” or similar expressions), you must remember that these are forward-looking statements, and that our expectations may not be correct, even though we believe they are reasonable. The forward-looking information contained in this report is generally located in the material set forth under the headings “Business,” “Risk Factors,” “Properties,” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations” but may be found in other locations as well. These forward-looking statements generally relate to our plans and objectives for future operations and are based upon our management’s reasonable estimates of future results or trends. The factors that may affect our expectations regarding our operations include, among others, the following:

- our success in development, exploitation and exploration activities;
- our ability to procure services and equipment for our drilling and completion activities;
- the prices we receive for our oil and gas and the effectiveness of our hedging arrangements;
  - our ability to make planned capital expenditures;
  - declines in our production of oil and gas;
  - the availability of capital;
- political and economic conditions in oil producing countries, especially those in the Middle East;
  - price and availability of alternative fuels;
  - our restrictive debt covenants;
  - our acquisition and divestiture activities;
  - weather conditions and events;
- the proximity, capacity, cost and availability of pipelines and other transportation facilities; and
  - other factors discussed elsewhere in this report.

## GLOSSARY OF TERMS

Unless otherwise indicated in this report, gas volumes are stated at the legal pressure base of the state or area in which the reserves are located at 60 degrees Fahrenheit. Oil equivalents are determined using the ratio of six Mcf of gas to one barrel of oil, condensate or natural gas liquids.

The following definitions shall apply to the technical terms used in this report.

Terms used to describe quantities of oil and gas:

“Bbl” – barrel or barrels.

“Boe” – barrels of oil equivalent.

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“MBbl” – thousand barrels.

“MBoe” – thousand barrels of oil equivalent.

“Mcf” – thousand cubic feet of gas.

“MMBoe” – million barrels of oil equivalent.

“MMBtu” – million British Thermal Units of gas.

“MMcf” – million cubic feet of gas.

“NGL” – natural gas liquids measured in barrels.

Terms used to describe our interests in wells and acreage:

“Developed acreage” means acreage which consists of leased acres spaced or assignable to productive wells.

“Development well” is a well drilled within the proved area of an oil or gas reservoir to the depth or stratigraphic horizon (rock layer or formation) noted to be productive for the purpose of extracting reserves.

“Dry well” is an exploratory or development well found to be incapable of producing either oil or gas in sufficient quantities to justify completion.

“Exploratory well” is a well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be producing in another reservoir, or to extend a known reservoir.

“Gross acres” are the number of acres in which we own a working interest.

“Gross well” is a well in which we own an interest.

“Net acres” are the sum of fractional ownership working interests in gross acres (e.g., a 50% working interest in a lease covering 320 gross acres is equivalent to 160 net acres).

“Net well” is the sum of fractional ownership working interests in gross wells.

“Productive well” is an exploratory or a development well that is not a dry well.

“Undeveloped acreage” means those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and gas, regardless of whether or not such acreage contains proved reserves.

Terms used to assign a present value to or to classify our reserves:

“Proved reserves” are those quantities of oil and gas reserves, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable - from a given date forward, from known reservoirs, and under defined economic conditions, operating methods, and government regulations.

“Proved developed reserves” are those quantities of oil and gas reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional reserves expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in “proved developed reserves” only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

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“Proved developed non-producing reserves” are those quantities of oil and gas reserves that are developed behind pipe in an existing well bore, from a shut-in well bore or that can be recovered through improved recovery only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells that were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to the start of production.

“Proved undeveloped reserves” are those quantities of oil and gas reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for development. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with reasonable certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proven effective by actual tests in the area and in the same reservoir.

“Probable reserves” are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves.

“Possible reserves” are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves.

“PV-10” means estimated future net revenue, discounted at a rate of 10% per annum, before income taxes and with no price or cost escalation or de-escalation, calculated in accordance with guidelines promulgated by the Securities and Exchange Commission (“SEC”).

“Standardized Measure” means estimated future net revenue, discounted at a rate of 10% per annum, after income taxes and with no price or cost escalation or de-escalation, calculated in accordance with Accounting Standards Codifications (“ASC”) 932, “Disclosures About Oil and Gas Producing Activities.”

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## Part I

Information contained in this report represents the operations of Abraxas Petroleum Corporation and Abraxas Energy Partners, L.P., which we refer to as the Partnership, which are consolidated for financial reporting purposes. On October 5, 2009, Abraxas Petroleum Corporation acquired 100% ownership of the Partnership, which we refer to as the Merger. The non-controlling interest of the former limited partners of the Partnership is presented as non-controlling interest in the accompanying Consolidated Statement of Operations through the date that their interest was acquired by Abraxas. The terms “Abraxas,” “we,” “us,” “our,” or the “Company,” refer to Abraxas Petroleum Corporation together with its consolidated subsidiaries including Abraxas Energy Partners, L.P. and Raven Drilling, LLC (“Raven Drilling”) which is a wholly owned subsidiary that owns a drilling rig. Blue Eagle Energy, LLC (“Blue Eagle”) is a joint venture between us and Rock Oil Company, LLC (“Rock Oil”) to develop the Eagle Ford shale play in South Texas. As of December 31, 2011, we owned an approximate 34.7% equity interest in Blue Eagle.

## Item 1. Business

## General

We are an independent energy company primarily engaged in the acquisition, exploitation, development and production of oil and gas in the United States and Canada. At December 31, 2011, our estimated net proved reserves were 29.0 MMBoe, (including reserves attributable to our 34.7% equity interest in the proved reserves of Blue Eagle), of which 53% were classified as proved developed, 54% were oil and NGL’s and 94% by PV-10 were operated. Our daily net production for the year ended December 31, 2011 was 3,484 Boepd, of which 45% was oil or liquids.

Our oil and gas assets are located in four operating regions in the United States, the Rocky Mountain, Mid-Continent, Permian Basin and onshore Gulf Coast, and in the province of Alberta, Canada. The following table sets forth certain information related to our properties as of and for the year ended December 31, 2011:

	Gross Producing Wells	Average Working Interest	Total Net Acres	Estimated Net Proved Reserves (MBoe)	% Oil/NGL	Net Production (MBoe)
Rocky Mountain	1,041	10.27 %	81,327	10,816.7	87.8 %	401.3
Mid-Continent	148	22.57 %	5,769	800.5	18.3 %	61.7
Permian Basin	221	73.46 %	40,979	6,720.6	42.0 %	443.5
Onshore Gulf Coast (1)	58	92.81 %	7,055	9,765.8	18.8 %	340.5
Total United States	1,468	24.28 %	135,130	28,103.6	54.4 %	1,247.0
Alberta, Canada	4	100.00 %	24,800	920.1	47.8 %	24.7
Total	1,472	24.49 %	159,930	29,023.7	54.2 %	1,271.7

(1) Includes 2,791.3 MBoe of estimated proved reserves attributable to our 34.7% equity interest in Blue Eagle.

Our properties in the Rocky Mountain region are located in the Williston Basin of North Dakota and Montana and in the Green River, Powder River and Unita Basins of Wyoming and Utah. In this region, our wells produce oil and gas from various reservoirs, including the Niobrara, Turner, Bakken and Three Forks formations. Well depths range from 7,000 feet down to 14,000 feet.

Our properties in the Mid-Continent region are primarily located in the Arkoma Basin and principally produce gas from the Hartshorne coals at 3,000 feet.

Our properties in the Permian Basin region are primarily located in two sub-basins, the Delaware Basin and the Eastern Shelf. In the Delaware Basin, our wells are located in Pecos, Reeves, and Ward Counties, Texas and produce oil and gas from multiple stacked formations from the Bell Canyon at 5,000 feet down to the Ellenburger at 16,000 feet. In the Eastern Shelf, our wells are principally located in Coke, Scurry, Midland, Mitchell and Nolan Counties, Texas and produce oil and gas from the Strawn Reef formation at 5,000 to 7,500 feet and oil from the shallower Clearfork formation at depths ranging from 2,300 to 3,300 feet.

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Our properties in the onshore Gulf Coast region are located along the Edwards trend in DeWitt and Lavaca Counties, Texas and in the Portilla field in San Patricio County, Texas. In the Edwards trend, our wells produce gas from the Edwards formation at a depth of 14,000 feet and in the Portilla field, our wells produce oil and gas from the Frio sands and the deeper Vicksburg from depths of approximately 7,000 to 9,000 feet. In addition, we also own a 34.7% equity interest in a joint venture targeting the Eagle Ford in South Texas.

Our properties in the province of Alberta, Canada are located in the Pekisko fairway and the Nordegg/Tomahawk area of Central Alberta in addition to an emerging shale play in central Alberta.

### Strategy

Our business strategy is to provide long term growth in net asset value per share by increasing daily production and proved reserves over time as well as adding to our inventory of development projects, while maintaining a conservative leverage position to enhance financial flexibility. Key elements of our business strategy include:

**Developing our drilling inventory.** Through our existing acreage position, we have a multi-year drilling inventory in excess of 300 net potential drilling locations (based on standard industry spacing parameters and management estimates) in our existing properties. We plan to focus our development efforts in 2012 on the oil and liquids-rich Bakken, Three Forks, Eagle Ford, Pekisko and Niobrara formations, as well as our Texas oil plays. We will continue to pursue acreage acquisitions, on a conservative basis, in an effort to increase and enhance our core acreage positions.

**Maintaining a mix of operated and non-operated leasehold positions in our resource plays.** While developing our resource plays, we plan on maintaining a mix of operated and non-operated interests. As operator, we retain more control over the timing, selection and process of drilling prospects and completion design, which enhances our ability to maximize return on invested capital and gives us greater control over the timing, allocation, and amounts of our capital expenditures. As a non-operated working interest partner, we believe we can leverage our partners' knowledge and experience and potentially reduce our costs and enhance our returns.

**Increasing the oil component of our production and proved reserves.** By focusing our 2012 drilling activity in the oil and liquids-rich resource plays, we expect to continue to increase the oil/liquids component of both our production and proved reserves. For the year ended December 31, 2011, our mix of oil/liquids and gas production was 45% and 55%, respectively, as compared to our 36% and 64% mix of oil/liquids and gas production for the year ended December 31, 2010. Our proved reserves at December 31, 2011 were 54% oil/liquids and 46% gas.

**Maintaining financial flexibility.** Our primary sources of capital are availability under our credit facility and cash flow from operations. We plan on deploying our available capital in a cost-effective manner, utilizing pad development drilling, with our own drilling rig in the Williston Basin.

### 2012 Budget and Drilling Activities

Our capital expenditure budget for 2012 is \$70 million, an increase of approximately 17% over 2011. Approximately 75% of the 2012 budget will be spent on unconventional horizontal oil wells in the Bakken/Three Forks and Niobrara plays in the Rocky Mountain region with the remainder targeting conventional oil plays in the Permian Basin region and in the province of Alberta, Canada. The 2012 capital expenditure budget is subject to change depending upon a number of factors, including the availability of sufficient capital resources, the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the results of our exploitation efforts, and our ability to obtain permits for drilling locations.

We have a substantial inventory of acreage in several basins, or plays, exposing us to significant resource potential which will be the focus of our development plans in 2012. Our acreage in the unconventional plays includes the Williston Basin focused on the Bakken and Three Forks formations, the onshore Gulf Coast Basin focused on the Eagle Ford Shale, the Powder River Basin focused on the

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Niobrara Shale and Turner formation and the Southern Alberta Basin focused on the Bakken formation. Our acreage in the conventional plays includes the Western Alberta Basin focused on the Pekisko formation and several oil plays in Texas focused on the Strawn, Frio and Yates formations. Our net acreage position for each basin or play is detailed in the following table:

Basin/Play	Targeted Formation(s)	Net Acres
Williston	Bakken / Three Forks	20,835
Onshore Gulf Coast	Eagle Ford	12,177 (1)
Powder River	Niobrara	17,800
Western Alberta	Pekisko	6,880
Southern Alberta	Bakken	10,000
Texas Oil Plays	Strawn / Frio / Yates	8,700
Other	Various	83,538
	Total	159,930

(1) All of the acreage in the Eagle Ford Shale play is owned by Blue Eagle.

In 2012, we intend to concentrate our activities in the following plays:

**Williston Basin - Bakken/Three Forks.** We currently lease approximately 20,835 net acres, primarily in counties located on the Nesson Anticline and in areas west including Rough Rider and Lewis & Clark in North Dakota and in Sheridan County, Montana, which are prospective for the Bakken and Three Forks formations. In 2010 and 2011, we drilled two operated wells and participated in an additional 19 gross (1.0 net) non-operated wells.

In July 2011, Abraxas purchased a used Oilwell 2000 hp diesel electric drilling rig in order to help us control the timing and cost of drilling our operated wells. The rig has been refurbished and will be mobilized to the Williston Basin to drill Bakken / Three Forks wells using a multi-well pad drilling system in the near future. Abraxas anticipates that the rig will be ready to spud its first well in late March to early April, 2012 in the North Fork area of McKenzie County, North Dakota where the Company has 60 gross (18 net) identified drilling locations. In 2012, we plan to drill up to ten operated horizontal long lateral wells, utilizing our own drilling rig, and participate in additional non-operated wells targeting the Bakken or Three Forks formations.

**Onshore Gulf Coast Basin - Eagle Ford.** In August 2010, we formed a joint venture, Blue Eagle, with Rock Oil to develop our acreage in the Eagle Ford Shale play. At formation, we contributed 8,333 net acres, located in Atascosa, DeWitt and Lavaca Counties, Texas, and received a 50% equity interest in Blue Eagle, and Rock Oil contributed \$25 million in cash and received a 50% equity interest. Rock Oil also committed to contribute an additional \$50 million in cash, of which \$22.0 million has been contributed since formation. Upon full funding by Rock Oil, we would own a 25% equity interest and Rock Oil would own a 75% equity interest in Blue Eagle. As of December 31, 2011, we owned a 34.7% interest in Blue Eagle. During 2011, Blue Eagle drilled, completed or participated in 3 gross (2.4 net) wells and added approximately 3,800 net acres to its holdings, principally in McMullen County, Texas., Blue Eagle has announced that it will be exploring all of its strategic alternatives.

**Powder River Basin.** We currently lease a total of approximately 20,720 gross (17,800 net) acres in the southern Powder River Basin, of which 17,800 gross (15,700 net) acres are located in the Brooks Draw field of Converse and Niobrara Counties, Wyoming. Prior to 2011, we drilled a total of 12 wells, including seven horizontal wells, and acquired a 23-square mile proprietary 3-D seismic survey in the Brooks Draw field. In addition, we own approximately 2,100 net acres in southern Campbell County, Wyoming which are held by production and are near the Crossbow field operated by EOG Resources, Inc. and other recent horizontal activity. In 2012, we have budgeted the drilling of one horizontal well. We may elect to increase our activity in the area pending results of this well.

Alberta Basin - Pekisko. We currently lease 6,880 net acres in western Alberta. In 2011, we drilled or completed 6 gross (6 net) wells in the Twining area, two of which await stimulation and three of which await pipeline hookup. Our budget for 2012 currently includes the drilling of one horizontal well targeting the Pekisko formation, after which we plan to review our strategic alternatives with respect to this area, as we continue to conservatively build an acreage position in an emerging shale play in central Alberta.

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Alberta Basin – Bakken. In the emerging southern Alberta Basin Bakken play of Toole and Glacier Counties, Montana, we currently lease approximately 10,000 gross/net acres under long-term leases or direct mineral ownership. During 2010 and 2011, we acquired our leasehold position and monitored industry activity in the play, principally by Rosetta Resources Inc. and Newfield Exploration Company, and continued our own independent study of the play. During 2012, we intend to continue to conservatively acquire additional acreage in the geologically specific parts of the play.

Permian Basin – Strawn. We currently lease approximately 5,600 gross/net acres in Nolan County, Texas. In 2011, we drilled three wells in the Spires Ranch offsetting the prolific Nena Lucia field. Our budget for 2012 currently includes the drilling of three horizontal wells targeting the Strawn formation.

### Markets and Customers

The revenue generated by our operations is highly dependent upon the prices we receive for our oil and gas. Historically, the markets for oil and gas have been volatile and are likely to continue to be volatile in the future. The prices we receive for our oil and gas production are subject to wide fluctuations and depend on numerous factors beyond our control including seasonality, the condition of the United States economy (particularly the manufacturing sector), foreign imports, political conditions in other petroleum producing countries, the actions of the Organization of Petroleum Exporting Countries and domestic regulation, legislation and policies. Decreases in the prices we receive for our oil and gas have had, and could have in the future, an adverse effect on the carrying value of our proved reserves and our revenue, profitability and cash flow from operations. You should read the discussion under “Risk Factors – Risks Relating to Our Industry — Market conditions for oil and gas, and particularly volatility of prices for oil and gas, could adversely affect our revenue, cash flows, profitability and growth” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies” for more information relating to the effects of decreases in oil and gas prices on us. To help mitigate the impact of commodity price volatility, we hedge a portion of our production through the use of fixed price swaps. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations – General – Commodity Prices and Hedging Arrangements” and Note 14 of the notes to our consolidated financial statements for more information regarding our derivative activities.

Substantially all of our oil and gas is sold at current market prices under short-term arrangements, as is customary in the industry. During the year ended December 31, 2011, two purchasers accounted for approximately 26% of our oil and gas sales, and a single purchaser accounted for 14% of our oil and gas sales. We believe that there are numerous other purchasers available to buy our oil and gas and that the loss of one or both of these purchasers would not materially affect our ability to sell our oil and gas.

### Regulation of Oil and Gas Activities

The exploration, production and transportation of all types of hydrocarbons are subject to significant governmental regulations. Our properties are affected from time to time in varying degrees by political developments and federal, state, provincial and local laws and regulations. In particular, oil and gas production operations and economics are, or in the past have been, affected by industry specific price controls, taxes, conservation, safety, environmental and other laws relating to the petroleum industry, and by changes in such laws and by periodically changing administrative regulations.

Federal, state, provincial and local laws and regulations govern oil and gas activities. Operators of oil and gas properties are required to have a number of permits in order to operate such properties, including operator permits and permits to dispose of salt water. We possess all material requisite permits required by the states, provinces and other local authorities in which we operate properties. In addition, under federal and provincial law, operators of oil and gas properties are required to possess certain certificates and permits in order to operate such properties such as hazardous materials certificates, which we have obtained.

## Development and Production

The operations of our properties are subject to various types of regulation at the federal, provincial, state and local levels. These types of regulation include requiring the operator of oil and gas properties to possess permits for the drilling and development of wells, post bonds in connection with various types of activities, and file reports concerning operations. Most provinces, states, and some counties and municipalities in which we operate, regulate one or more of the following:

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- the location of wells;
- the method of drilling and casing wells;
- the method of completing and fracture stimulating wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- the notice to surface owners and other third parties.

Some provinces and states regulate the size and shape of development and spacing units or proration units for oil and gas properties. Some provinces and states allow forced pooling or unitization of tracts to facilitate exploration while other states/provinces rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, provincial and state conservation laws establish maximum allowable rates of production from oil and gas wells, generally prohibit the venting or flaring of gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and gas we can produce from our wells or limit the number of wells or the locations at which our wells can be drilled. Moreover, each province and state generally imposes a production or severance tax with respect to the production and sale of oil, gas and NGLs within its jurisdiction.

Operations on Federal, Provincial or Indian oil and gas leases must comply with numerous regulatory restrictions, including various non-discrimination statutes, and certain of such operations must be conducted pursuant to certain on-site security regulations and other permits issued by various federal agencies, including the Bureau of Land Management and the Office of Natural Resources Revenue, which we refer to as ONRR, (formerly Minerals Management Service). ONRR establishes the basis for royalty payments due under federal oil and gas leases through regulations issued under applicable statutory authority. State regulatory authorities establish similar standards for royalty payments due under state oil and gas leases. The basis for royalty payments established by ONRR and the state regulatory authorities is generally applicable to all federal and state oil and gas leases. Accordingly, we believe that the impact of royalty regulation on the operations of our properties should generally be the same as the impact on our competitors. We believe that the operations of our properties are in material compliance with all applicable regulations as they pertain to Federal or Indian oil and gas leases.

The failure to comply with these rules and regulations can result in substantial penalties, including lease suspension or termination in the case of federal or provincial leases. The regulatory burden on the oil and gas industry increases our cost of doing business and, consequently, affects our profitability. Our competitors in the oil and gas industry are subject to the same regulatory requirements and restrictions that affect us.

#### Regulation of Transportation and Sale of Natural Gas in the United States

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, as amended, which we refer to as NGA, the Natural Gas Policy Act of 1978, as amended, which we refer to as NGPA, and regulations promulgated thereunder by the Federal Energy Regulatory Commission, which we refer to as FERC, and its predecessors. In the past, the federal government has regulated the prices at which natural gas could be sold. Deregulation of wellhead natural gas sales began with the enactment of the NGPA. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, as amended, which we refer to as the Decontrol Act. The Decontrol Act removed all NGA and NGPA price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993. While sales by producers of natural gas can currently be made at unregulated market prices, Congress could reenact price controls in the future.

Since 1985, FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, FERC issued Order No. 636 and a series of related orders, which we refer to, collectively, as Order No. 636, to implement its open access policies. As a result of the Order No. 636 program, the marketing and pricing of natural gas have been significantly

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altered. The interstate pipelines' traditional role as wholesalers of natural gas has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. FERC continues to regulate the rates that interstate pipelines may charge for such transportation and storage services. Although FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, FERC issued Order No. 637 and subsequent orders, which we refer to, collectively, as Order No. 637, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting. Most major aspects of Order No. 637 have been upheld on judicial review, and most pipelines' tariff filings to implement the requirements of Order No. 637 have been accepted by the FERC and placed into effect.

The Energy Policy Act of 2005, which we refer to as EP Act 2005, gave FERC increased oversight and penalty authority regarding market manipulation and enforcement. EP Act 2005 amended the NGA to prohibit market manipulation and also amended the NGA and the NGPA to increase civil and criminal penalties for any violations of the NGA, NGPA and any rules, regulations or orders of FERC to up to \$1,000,000 per day, per violation. In addition, FERC issued a final rule effective January 26, 2006, regarding market manipulation, which makes it unlawful for any entity, in connection with the purchase or sale of natural gas or transportation service subject to FERC jurisdiction, to defraud, make an untrue statement, or omit a material fact or engage in any practice, act, or course of business that operates or would operate as a fraud. This final rule works together with FERC's enhanced penalty authority to provide increased oversight of the natural gas marketplace.

The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach currently pursued by FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers, gatherers and marketers.

Generally, intrastate natural gas transportation is subject to regulation by state regulatory agencies, although FERC does regulate the rates, terms, and conditions of service provided by intrastate pipelines that transport natural gas subject to FERC's NGA jurisdiction pursuant to Section 311 of the NGPA. The basis for state regulation of intrastate natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect the operations of our properties in any way that is materially different from the effect of such regulation on our competitors.

## Natural Gas Gathering in the United States

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of the FERC. FERC has developed tests for determining which facilities constitute jurisdictional transportation facilities under the NGA and which facilities constitute gathering facilities exempt for FERC's NGA jurisdiction. From time to time, FERC reconsiders its test for defining non-jurisdictional gathering. FERC has also permitted jurisdictional pipelines to "spin down" exempt gathering facilities into affiliated entities that are not subject to FERC jurisdiction, although FERC continues to examine the circumstances in which such a "spin down" is appropriate and whether it should reassert jurisdiction over certain gathering companies and facilities that previously had been "spun down." We cannot predict the effect that FERC's activities in this regard may have on the operations of our properties, but we do not expect these activities to affect the operations in any way that is materially different from the effect thereof on our competitors.

State regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, non-discriminatory take or service requirements, but does not generally entail rate regulation. In the United States, gas gathering has received greater regulatory scrutiny at both the state and federal levels in the wake of the interstate pipeline restructuring under FERC Order 636. For example, the Texas Railroad Commission enacted a Natural Gas Transportation Standards and Code of Conduct to provide regulatory support for the state's more active review of rates, services and practices associated with the gathering and transportation of gas by an entity that provides such services to others for a fee, in order to prohibit such entities from unduly discriminating in favor of their affiliates.

#### Regulation of Transportation of Oil in the United States

Sales of oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. The transportation of oil in common carrier pipelines is subject to rate regulation. FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are

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permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil that allowed for an increase or decrease in the cost of transporting oil to the purchaser. A review of these regulations by FERC in 2000 was successfully challenged on appeal by an association of oil pipelines. On remand, FERC, in February 2003, increased the index slightly, effective July 2001. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect the operations of our properties in any way that is materially different from the effect of such regulation on our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

### Environmental Matters

Oil and gas operations are subject to numerous federal, provincial, state and local laws and regulations controlling the generation, use, storage and discharge of materials into the environment or otherwise relating to the protection of the environment. These laws and regulations may:

- require the acquisition of a permit or other authorization before construction or drilling commences;
- restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production, and natural gas processing activities;
- suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands, areas inhabited by threatened or endangered species and other protected areas;
- require remedial measures to mitigate pollution from historical and on-going operations such as the use of pits and plugging of abandoned wells;
  - restrict injection of liquids into subsurface strata that may contaminate groundwater; and
  - impose substantial penalties for pollution resulting from our operations.

Environmental permits that the operators of properties are required to possess may be subject to revocation, modification, and renewal by issuing authorities. Governmental authorities have the power to enforce compliance with their regulations and permits, and violations are subject to injunction, civil fines, and even criminal penalties. Our management believes that we are in substantial compliance with current environmental laws and regulations, and that we will not be required to make material capital expenditures to comply with existing laws. Nevertheless, changes in existing environmental laws and regulations or interpretations thereof could have a significant impact on our operations as well as the oil and gas industry in general, and thus we are unable to predict the ultimate cost and effects of future changes in environmental laws and regulations.

We are not currently involved in any administrative, judicial or legal proceedings arising under federal, state, provincial, or local environmental protection laws and regulations, or under federal, provincial or state common law, which would have a material adverse effect on our respective financial positions or results of operations. Moreover, we maintain insurance against the costs of clean-up operations, but we are not fully insured against all such risks. A serious incident of pollution may result in the suspension or cessation of operations in the affected area.

The following is a discussion of the current relevant environmental laws and regulations that relate to our operations.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, also known as Superfund, and which we refer to as CERCLA, and comparable state statutes impose strict, joint, and several liability, without regard to fault or legality of conduct, on certain classes of persons who are considered to have contributed to the release of a “hazardous substance” into the environment. These persons include the owner or operator of a disposal site or sites where a release occurred and companies that generated, disposed or

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arranged for the disposal of the hazardous substances released at the site. Under CERCLA, such persons or companies may be retroactively liable for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA authorizes the EPA, and in some cases third parties, to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. In addition, it is not uncommon for neighboring land owners and other third parties to file claims for personal injury, property damage, and recovery of response costs allegedly caused by the hazardous substances released into the environment.

In the course of our ordinary operations, certain wastes may be generated that may fall within CERCLA's definition of a "hazardous substance." We may be liable under CERCLA or comparable state statutes for all or part of the costs required to clean up sites at which these wastes have been disposed. Although CERCLA currently contains a "petroleum exclusion" from the definition of "hazardous substance," state laws affecting our operations impose cleanup liability relating to petroleum and petroleum related products, including oil cleanups.

We currently own or lease, and have in the past owned or leased, numerous properties that for many years have been used for the exploration and production of oil and gas. Although we have utilized standard industry operating and disposal practices at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties we owned or leased or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA (as defined below), and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes, including wastes disposed or released by prior owners or operators; to clean up contaminated property, including contaminated groundwater; or to perform remedial operations to prevent future contamination.

Oil Pollution Act of 1990. Federal regulations also require certain owners and operators of facilities that store or otherwise handle oil to prepare and implement spill response plans relating to the potential discharge of oil into surface waters. The Federal Oil Pollution Act, which we refer to as OPA, contains numerous requirements relating to prevention of, reporting of, and response to oil spills into waters of the United States. State laws mandate oil cleanup programs with respect to contaminated soil. A failure to comply with OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions. We are not aware of any action or event that would subject us to liability under OPA, and we believe that compliance with OPA's financial responsibility and other operating requirements will not have a material adverse effect on our financial position or results of operations.

Resource Conservation Recovery Act. The Resource Conservation and Recovery Act, which we refer to as RCRA, is the principal federal statute governing the treatment, storage and disposal of hazardous and non-hazardous solid wastes. RCRA imposes stringent operating requirements and liability for failure to meet such requirements, on a person who is either a "generator" or "transporter" of hazardous waste or an "owner" or "operator" of a hazardous waste treatment, storage or disposal facility. At present, RCRA includes a statutory exemption that allows most oil and gas exploration and production wastes to be classified and regulated as non-hazardous wastes. A similar exemption is contained in many of the state counterparts to RCRA. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes oil and gas exploration and production wastes from regulation as hazardous wastes. Repeal or modification of the exemption by administrative, legislative or judicial process, or modification of similar exemptions in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose and would cause us to incur increased operating expenses. Also, in the ordinary course of our operations, we generate small amounts of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes.

Naturally Occurring Radioactive Materials, which we refer to as NORM, are materials not covered by the Atomic Energy Act, whose radioactivity is enhanced by technological processing such as mineral extraction or processing through exploration and production conducted by the oil and gas industry. NORM wastes are regulated under the RCRA framework, but primary responsibility for NORM regulation has been a state function. Standards have been developed for worker protection; treatment, storage and disposal of NORM waste; management of waste piles, containers and tanks; and limitations upon the release of NORM contaminated land for unrestricted use. We believe that the operations of our properties are in material compliance with all applicable NORM standards established by the various states in which we operate wells.

**Clean Water Act.** The Clean Water Act, which we refer to as the CWA, and analogous state laws, impose restrictions and controls on the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or an analogous state agency.

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The CWA regulates storm water run-off from oil and natural gas facilities and requires a storm water discharge permit for certain activities. Such a permit requires the regulated facility to monitor and sample storm water run-off from its operations. The CWA and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure requirements of the CWA require appropriate containment berms and similar structures to help prevent the contamination of waters of the United States in the event of a petroleum hydrocarbon tank spill, rupture or leak. The CWA and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges for oil and other pollutants and impose liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. We believe that the operations of our properties comply in all material respects with the requirements of the CWA and state statutes enacted to control water pollution.

**Safe Drinking Water Act.** Our operations also produce wastewaters that are disposed via underground injection wells. These activities are regulated by the Safe Drinking Water Act, which we refer to as the SDWA, and analogous state and local laws. Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from oil and gas production. The main goal of the SDWA is the protection of usable aquifers. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. Hazardous-waste injection well operations are strictly controlled, and certain wastes, absent an exemption, cannot be injected into underground injection control wells. In most states, no underground injection may take place except as authorized by permit or rule. We currently own and operate various underground injection wells. Failure to abide by our permits could subject us to civil and/or criminal enforcement. We believe that we are in compliance in all material respects with the requirements of applicable state underground injection control programs and our permits.

**Clean Air Act.** The Clean Air Act, which we refer to as the CAA, and state air pollution laws and regulations provide a framework for national, state and local efforts to protect air quality. The operations of our properties utilize equipment that emits air pollutants which may be subject to federal and state air pollution control laws. These laws require utilization of air emissions abatement equipment to achieve prescribed emissions limitations and ambient air quality standards, as well as operating permits for existing equipment and construction permits for new and modified equipment. On August 23, 2011 EPA proposed new more restrictive regulations governing air emissions from oil and gas operations, including regulations which, if adopted, would impose new restrictions on volatile organic compounds, sulfur dioxide and hazardous air pollutants. The proposed regulations also seek to restrict air emissions arising from hydraulic fracturing operations.

Permits and related compliance obligations under the CAA, as well as changes to state implementation plans for controlling air emissions in regional non-attainment areas may require oil and natural gas exploration and production operators to incur future capital expenditures in connection with the addition or modification of existing air emission control equipment and strategies. In addition, some oil and natural gas facilities may be included within the categories of hazardous air pollutant sources, which are subject to increasing regulation under the CAA. Failure to comply with these requirements could subject a regulated entity to monetary penalties, injunctions, conditions or restrictions on operations and enforcement actions. Oil and natural gas exploration and production facilities may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe that we are in compliance in all material respects with the requirements of applicable federal and state air pollution control laws.

**Hydraulic Fracturing.** Most of our current operations depend on the use of hydraulic fracturing to enhance production from oil and gas wells. This technology involves the injection of fluids—usually consisting mostly of water but typically including small amounts of chemical additives—as well as sand, or other proppants, into a well under high pressure in order to create fractures in the rock that allow oil or gas to flow more freely to the wellbore. Many of our newer wells would not be economical without the use of hydraulic fracturing to stimulate production from the

well. Hydraulic fracturing operations have historically been overseen by state regulators as part of their oil and gas regulatory programs. However, bills such as Fracturing Responsibility and Awareness of Chemicals (FRAC) Act have been introduced in Congress to subject hydraulic fracturing to federal regulation under laws such as the Safe Drinking Water Act. If adopted, these bills could result in additional chemical disclosure and permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. These requirements and restrictions could result in delays in operations at existing and new well sites as

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well as increased costs to make our wells productive. Moreover, these bills would require the public disclosure of information regarding the chemical makeup of hydraulic fracturing fluids, many of which are proprietary to the service companies that perform the hydraulic fracturing operations. If enacted, these laws could make it easier for third parties to initiate litigation against us in the event of perceived problems with drinking water wells in the vicinity of an oil or gas well or other alleged environmental problems. EPA has finalized its Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources, which is expected to result in a final report on the subject with recommendations in 2014. Also, the U.S. Department of the Interior has announced that it intends to propose regulations governing hydraulic fracturing which occurs on federal lands, including requiring chemical disclosure. In addition to these federal legislative and regulatory proposals, some states and local governments have considered imposing, or have adopted and some have adopted various conditions and restrictions on hydraulic fracturing operations, including but not limited to requirements regarding chemical disclosure, casing and cementing of wells, withdrawal of water for use in high-volume hydraulic fracturing of horizontal wells, baseline testing of nearby water wells, and restrictions on the type of additives that may be used in hydraulic fracturing operations. These types of conditions are widely adopted, we could be subject to increase costs and possibly limits on the productivity of certain wells. Some states in which we operate have implemented disclosure requirements of chemicals used in hydraulic fracturing.

Climate change legislation and greenhouse gas regulation. Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response to these studies, many nations have agreed to limit emissions of "greenhouse gases" or "GHGs" 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. As a result of the Supreme Court decision in *Massachusetts, et al. v. EPA*, on December 7, 2009, the EPA issued a finding that serves as the foundation under the Clean Air Act to issue other rules that would result in federal greenhouse gas regulations and emissions limits under the Clean Air Act, even without Congressional action. As part of this array of new regulations, the EPA has issued a GHG monitoring and reporting rule that requires certain parties, including participants in the oil and natural gas industry, to monitor and report their GHG emissions, including methane and carbon dioxide, to the EPA. These regulations may apply to our operations. The EPA has adopted other rules that would regulate GHGs, one of which would regulate GHGs from stationary sources, and may affect sources in the oil and natural gas exploration and production industry and the pipeline industry. The EPA's finding, the greenhouse gas reporting rule, and the proposed rules to regulate the emissions of greenhouse gases may affect the cost of our operations and also affect the outcome of other climate change lawsuits pending in United States federal courts in a manner unfavorable to our industry.

Although various climate change legislative measures have been under consideration by the U.S. Congress, it is not possible at this time to predict whether, or if, Congress will act on climate change legislation, although initiatives such as cap-and-trade legislation, appears to be unlikely to become law in their current form. Finally, some states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of GHGs, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs. Depending on the particular jurisdiction of our operations, we could be required to purchase and surrender allowances for GHG emissions resulting from our operations. 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.

National Environmental Policy Act. Oil and gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, which we refer to as NEPA. NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having 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. If we were to conduct any exploration and production activities on federal lands in the future, those activities would need to obtain governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and gas projects.

**Endangered Species Act.** The Endangered Species Act, which we refer to as the ESA, restricts activities that may affect endangered or threatened species or their habitats. While some of our properties may be located in areas that may be designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. We are aware of new efforts to seek to

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cause the U.S. Fish and Wildlife Service to list additional species as endangered or threatened, and those actions or the discovery of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

**Abandonment Costs.** All of our oil and gas wells will require proper plugging and abandonment at some time in the future. We have posted bonds with most regulatory agencies to ensure compliance with our plugging responsibility. Plugging and abandonment operations and associated reclamation of the surface site are important components of our environmental management system. We plan accordingly for the ultimate disposition of properties that are no longer producing.

**Title to Properties**

As is customary in the oil and gas industry, we make only a cursory review of title to undeveloped oil and gas leases at the time we acquire them. However, before drilling commences, we make a thorough title search, and any material defects in title are remedied prior to the time actual drilling of a well begins. To the extent title opinions or other investigations reflect title defects, we, rather than the seller/lessor of the undeveloped property, are typically obligated to cure any title defect at our expense. If we were unable to remedy or cure any title defect of a nature such that it would not be prudent to commence drilling operations on the property, we could suffer a loss of our entire investment in the property. We believe that we have good title to our properties, some of which are subject to immaterial encumbrances, easements and restrictions. The oil and gas properties we own are also typically subject to royalty and other similar non-cost bearing interests customary in the industry. We do not believe that any of these encumbrances or burdens will materially affect our ownership or use of our properties.