PRIMEENERGY CORP
Form 10-K
March 27, 2013

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, 2012

Or

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Transition Period From to

Commission File Number 0-7406

PrimeEnergy Corporation

(Exact name of registrant as specified in its charter)

Delaware	**84-0637348**
(state or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
9821 Katy Freeway, Houston, Texas	**77024**
(Address of principal executive offices)	**(Zip Code)**

Registrant s telephone number, including area code: (713) 735-0000

Securities registered pursuant to Section 12(b) of the Act: None

Securities registered pursuant to Section 12(g) of the Act:

Common Stock, par value $.10 per share

(Title of Class)

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

Indicate whether 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 x No ¨

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 ¨ No ¨

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. ¨

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a small reporting company.

Large Accelerated Filer	¨	Accelerated Filer	¨
Non-Accelerated Filer	¨	Smaller Reporting Company	x

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

The aggregate market value of the voting stock of the Registrant held by non-affiliates, computed by reference to the average bid and asked price of such common equity as of the last business day of the Registrant s most recently completed second fiscal quarter, was $38,298,176

The number of shares outstanding of each class of the Registrant s Common Stock as of March 26, 2013 was 2,454,219 shares, Common Stock, $0.10 par value.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant s proxy statement to be furnished to stockholders in connection with its Annual Meeting of Stockholders to be held in May 2013, are incorporated by reference in Part III hereof.

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PrimeEnergy Corporation

FORM 10-K ANNUAL REPORT

For the Fiscal Year Ended

December 31, 2012

PART I

Item 1. BUSINESS.

General

This Report may contain statements relating to the future results of the Company that are considered forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995 (the PSLRA). In addition, certain statements may be contained in the Company s future filings with the SEC, in press releases, and in oral and written statements made by or with the approval of the Company that are not statements of historical fact and constitute forward-looking statements within the meaning of the PSLRA. Such forward-looking statements, in addition to historical information, which involve risk and uncertainties, are based on the beliefs, assumptions and expectations of management of the Company. Words such as expects , believes , should , plans , anticipates , will , potential , could , intend , may , outlook , predic estimates , assumes , likely and variations of such similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve risks and uncertainties and are based on a number of assumptions that could ultimately prove inaccurate and, therefore, there can be no assurance that they will prove to be accurate. Actual results and outcomes may vary materially from what is expressed or forecast in such statements due to various risks and uncertainties. These risks and uncertainties include, among other things, the possibility of drilling cost overruns and technical difficulties, volatility of oil and gas prices, competition, risks inherent in the Company s oil and gas operations, the inexact nature of interpretation of seismic and other geological and geophysical data, imprecision of reserve estimates, and the Company s ability to replace and expand oil and gas reserves. Accordingly, stockholders and potential investors are cautioned that certain events or circumstances could cause actual results to differ materially from those projected. The forward looking statements are made as of the date of this Report and other than as required by the federal securities laws, the Company assumes no obligation to update the forward-looking statement or to update the reasons why actual results could differ from those projected in the forward-looking statements.

PrimeEnergy Corporation (the Company) was organized in March, 1973, under the laws of the State of Delaware.

We are an independent oil and natural gas company engaged in acquiring, developing and producing oil and natural gas. We presently own producing and non-producing properties located primarily in Texas, Oklahoma, West Virginia, the Gulf of Mexico, New Mexico, Colorado and Louisiana. All of our oil and gas properties and interests are located in the United States. Through our subsidiaries Prime Operating Company, Southwest Oilfield Construction Company, Eastern Oil Well Service Company and EOWS Midland Company, we act as operator and provide well servicing support operations for many of the onshore oil and gas wells in which we have an interest, as well as for third parties. We own and operate properties in the Gulf of Mexico through our subsidiary Prime Offshore L.L.C., formerly F-W Oil Exploration L.L.C. We are also active in the acquisition of producing oil and gas properties through joint ventures with industry partners. Our subsidiary, PrimeEnergy Management Corporation (PEMC), acts as the managing general partner of eighteen oil and gas limited partnerships (the Partnerships), and acts as the managing trustee of two asset and income business trusts (the Trusts).

Exploration, Development and Recent Activities

The Company s activities include development and exploratory drilling. Our strategy is to develop a balanced portfolio of drilling prospects that includes lower risk wells with a high probability of success and higher risk wells with greater economic potential.

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As of December 31, 2012, we had net capitalized costs related to proved oil and gas properties of $188 million. Total expenditures for the acquisition, exploration and development of our properties during 2012 were $86 million of which $10 thousand related to exploration costs expensed during 2012. Proved reserves as of December 31, 2012, were 25,612 thousand barrels of oil equivalent (MBoe) which consisted of 57% proved developed reserves and 43% proved undeveloped reserves.

Significant 2012 Activity

During 2012, we participated in drilling a total of 39 gross (28.91 net) wells, of which 38 (28.91 net) were successful completions. This included 29 development wells in our West Texas drilling program and the drilling of 7 wells in our Mid-Continent region.

In February 2012, we closed the acquisition of additional working interest in producing properties which we operate. These properties are located in our Gulf Coast region and were acquired at a net cost of $6.32 million.

We increased our outstanding debt by $52.2 million from $69.8 million at December 31, 2011 to $122.0 million as of December 31, 2012. As of December 31, 2012 we have $23.0 million available for future borrowings.

During 2012, we completed the plugging and abandonment of all of our offshore properties in which we had an operated working interest. In December 2011, we entered into a fixed price, turnkey contract for the plugging and abandonment of several of our offshore properties. Field work under this contract started in March 2012 and was completed in third quarter 2012.

We believe that our diversified portfolio approach to our drilling activities results in more consistent and predictable economic results than might be experienced with a less diversified or higher risk drilling program profile.

We attempt to assume the position of operator in all acquisitions of producing properties. We will continue to evaluate prospects for leasehold acquisitions and for exploration and development operations in areas in which we own interests and are actively pursuing the acquisition of producing properties. In order to diversify and broaden our asset base, we will consider acquiring the assets or stock in other entities and companies in the oil and gas business. Our main objective in making any such acquisitions will be to acquire income producing assets so as to increase our net worth and increase our oil and gas reserve base.

We presently own producing and non-producing properties located primarily in Texas, Oklahoma, West Virginia, New Mexico, Colorado and Louisiana, and we own a substantial amount of well servicing equipment. We do not own any refinery or marketing facilities, and do not currently own or lease any bulk storage facilities or pipelines other than adjacent to and used in connection with producing wells and the interests in certain gas gathering systems. All of our oil and gas properties and interests are located in the United States.

In the past, the supply of gas has exceeded demand on a cyclical basis, and we are subject to a combination of shut-in and/or reduced takes of gas production during summer months. Prolonged shut-ins could result in reduced field operating income from properties in which we act as operator.

Exploration for oil and gas requires substantial expenditures particularly in exploratory drilling in undeveloped areas, or wildcat drilling. As is customary in the oil and gas industry, substantially all of our exploration and development activities are conducted through joint drilling and operating agreements with others engaged in the oil and gas business.

Summaries of our oil and gas drilling activities, oil and gas production, and undeveloped leasehold, mineral and royalty interests are set forth under Item 2., Properties, below. Summaries of our oil and gas reserves, future net revenue and present value of future net revenue are also set forth under Item 2., Properties Reserves , below.

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Well Operations

Our operations are conducted through our principal offices in Houston, Texas, and district offices in Houston and Midland, Texas, Oklahoma City, Oklahoma, and Charleston, West Virginia. We currently operate 1,613 oil and gas wells, 359 through the Houston office, 371 through the Midland office, 385 through the Oklahoma City office and 498 through the Charleston, West Virginia office. Substantially all of the wells we operate are wells in which we have an interest.

We operate wells pursuant to operating agreements which govern the relationship between us, as operator, and the other owners of working interests in the properties, including the Partnerships, Trusts and joint venture participants. For each operated well, we receive monthly fees that are competitive in the areas of operations and also are reimbursed for expenses incurred in connection with well operations.

The Partnerships, Trusts and Joint Ventures

Since 1975, PEMC has acted as managing general partner of various partnerships, trusts and joint ventures.

PEMC, as managing general partner of the Partnerships and managing trustee of the Trusts, is responsible for all Partnership and Trust activities, the drilling of development wells and the production and sale of oil and gas from productive wells. PEMC also provides administration, accounting and tax preparation for the Partnerships and Trusts from our offices in Stamford, Connecticut. PEMC is liable for all debts and liabilities of the Partnerships and Trusts, to the extent that the assets of a given limited partnership or trust are not sufficient to satisfy its obligations. We stopped sponsoring partnerships and trusts in 1992. Today there are only 18 partnerships and two trusts remaining. The aggregate number of limited partners in the Partnerships and beneficial owners of the Trusts now administered by PEMC is approximately 2,183.

Regulation

Regulation of Oil and Natural Gas Exploration and Production:

Exploration and production operations of oil and natural gas is subject to various types of regulations under a wide range of local, state and federal statutes, rules, orders and regulations. These regulations includes requiring permits to drill wells, maintaining bonding requirements to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties on which wells are drilled, and the plugging and abandoning 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 density of wells that may be drilled in a given field and the unitization or pooling of oil and natural gas properties. Some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibiting the venting or flaring of natural gas and imposing certain requirements regarding the ratability of production. The effect of these regulations is to limit the amounts of oil and natural gas we can produce from our wells, and to limit the number of wells or the locations where we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. Because these statutes, rules and regulations undergo constant review and often are amended, expanded and reinterpreted, we are unable to predict the future cost or impact of regulatory compliance. The regulatory burden on the oil and gas industry increases its cost of doing business and, consequently, affects its profitability. We do not believe, however, we are affected differently by these regulations than others in the industry.

Our offshore operations were conducted on federal leases which are administered by the Bureau of Ocean Energy Management (the BOEM) and are required to comply with the regulations and orders promulgated by the BOEM under the Outer Continental Shelf Lands Act (OCSLA). These leases required compliance with detailed BOEM, Bureau of Safety and Environmental Enforcement (the BSEE), and other government agency

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regulations and orders that are subject to interpretation and change. The BOEM and BSEE have promulgated other regulations governing the plugging and abandonment of wells located offshore and the installation and removal of all production facilities, structures and pipelines.

The failure to comply with these rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry increases the cost of doing business and, consequently, affects profitability. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions affecting operations.

Regulation of Transportation and Sale of Natural Gas:

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 (NGA), the Natural Gas Policy Act of 1978, as amended (NGPA), and regulations promulgated thereunder by the Federal Energy Regulatory Commission (FERC) and its predecessors. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. 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 (the Decontrol Act). Effective January 1, 1993, the Decontrol Act removed all NGA and NGPA price and non-price controls affecting wellhead sales of natural gas and deregulated natural gas prices for all first sales of natural gas, which definition covers all sales of our own production. In addition, as part of the broad industry restructuring initiatives described below, the FERC has granted to all producers such as us a blanket certificate of public convenience and necessity authorizing the sale of gas for resale without further FERC approvals. As a result, all of our produced natural gas may now be sold at market prices, subject to the terms of any private contracts that may be in effect. In addition, under the provisions of the Energy Policy Act of 2005, as amended (the 2005 Act), the NGA has been amended to prohibit any forms of market manipulation in connection with the purchase or sale of natural gas. Pursuant to the 2005 Act, the FERC established new regulations that are intended to increase natural gas pricing transparency through, among other things, requiring market participants to report their gas sales transactions annually to the FERC, and new regulations that require certain non-interstate pipelines to post daily scheduled volume information and design capacity for certain points on their systems. The 2005 Act also significantly increased the penalties for violations of the NGA and the FERC s regulations. In 2010, the FERC issued Penalty Guidelines for the determination of civil penalties in an effort to add greater fairness, consistency and transparency to its enforcement program.

Our natural gas sales prices nevertheless continue to be affected by intrastate and interstate gas transportation regulation, because the prices we receive for our production are affected by the cost of transporting the gas to the consuming market. Through a series of comprehensive rulemakings, beginning with Order No. 436 in 1985 and continuing through Order No. 636 in 1992 and Order No. 637 in 2000, the FERC has adopted regulatory changes that have significantly altered the transportation and marketing of natural gas. These changes were intended by the FERC to foster competition by, among other things, transforming the role of interstate pipeline companies from wholesale marketers of gas to the primary role of gas transporters, and by increasing the transparency of pricing for pipeline services. The FERC has also established regulations governing the relationship of pipelines with their marketing affiliates, which essentially require that designated employees function independently of each other, and that certain information not be shared. The FERC has also implemented standards relating to the use of electronic data exchange by the pipelines to make transportation information available on a timely basis and to enable transactions to occur on a purely electronic basis.

In light of these statutory and regulatory changes, most pipelines have divested their gas sales functions to marketing affiliates, which operate separately from the transporter and in direct competition with all other merchants, and most pipelines have also implemented the large-scale divestiture of their gas gathering facilities to affiliated or non-affiliated companies. Interstate pipelines thus now generally provide unbundled, open and nondiscriminatory transportation and transportation-related services to producers, gas marketing companies, local

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distribution companies, industrial end users and other customers seeking such services. Sellers and buyers of gas have gained direct access to the particular pipeline services they need, and are better able to conduct business with a larger number of counterparties. We believe these changes generally have improved our access to markets while, at the same time, substantially increasing competition in the natural gas marketplace.

The OCSLA, which is administered by the BOEM and the FERC, requires that all pipelines operating on or across the OCS provide open access, non-discriminatory transportation service. One of FERC s principal goals in carrying out OCSLA s mandate is to increase transparency in the market to provide producers and shippers on the OCS with greater assurance of open access service on pipelines located on the OCS and non-discriminatory rates and conditions of service on such pipelines. On June 18, 2008, the BOEM issued a final rule, effective August 18, 2008, that implements a hotline, alternative dispute resolution procedures, and complaint procedures for resolving claims of having been denied open and nondiscriminatory access to pipelines on the OCS.

In December 2007, the FERC issued rules (Order No. 704) requiring that any market participant that engages in wholesale sales or purchases of natural gas that equal or exceed 2.2 million British thermal units (MMBtu) during a calendar year must annually report, starting May 1, 2009, such sales and purchases to the FERC. These rules are intended to increase transparency of the wholesale natural gas markets and assist the FERC in monitoring such markets and in detecting market manipulation.

Additional proposals and proceedings that might affect the natural gas industry are pending before FERC and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently 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.

Intrastate natural gas transportation is subject to regulation by state regulatory agencies. The basis for intrastate regulation of 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 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 our operations in any way that is materially different from the effect of such regulation on competitors.

Regulation of Transportation of Oil:

Our sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. The price received from the sale of these products is affected by the cost of transporting the products to market. Much of that transportation is through interstate common carrier pipelines, which are regulated by FERC under the Interstate Commerce Act (ICA). FERC requires that pipelines regulated under the ICA file tariffs setting forth the rates and terms and conditions of service, and that such service not be unduly discriminatory or preferential.

Effective January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. These regulations may tend to increase the cost of transporting oil and natural gas liquids by interstate pipeline, although the annual adjustments may result in decreased rates in a given year. Every five years, the FERC must examine the relationship between the annual change in the applicable index and the actual cost changes experienced in the oil pipeline industry. In December 2010, to implement this required five-year re-determination, the FERC established an upward adjustment in the index to track oil pipeline cost changes and determined that the Producer Price Index for Finished Goods plus 2.65 percent should be the oil pricing index for the five-year period beginning July 1, 2011. The result of indexing is a ceiling rate for each rate, which is the maximum at which

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the pipeline may set its interstate transportation rates. A pipeline may also file cost-of-service based rates if rate indexing will be insufficient to allow the pipeline to recover its costs. Rates are subject to challenge by protest when they are filed or changed. For indexed rates, complaints alleging that the rates are unjust and unreasonable may only be pursued if the complainant can show that a substantial change has occurred since the enactment of the Energy Policy Act of 1992 in either the economic circumstances of the pipeline or in the nature of the services provided, that were a basis for the rate. There is no such limitation on complaints alleging that the pipeline s rates or term and conditions of service are unduly discriminatory or preferential.

Another FERC matter that may impact our transportation costs relates to a policy that allows a pipeline structured as a master limited partnership or similar non-corporate entity to include in its rates a tax allowance with respect to income for which there is an actual or potential income tax liability, to be determined on a case by case basis. Generally speaking, where the holder of a partnership unit interest is required to file a tax return that includes partnership income or loss, such unit-holder is presumed to have an actual or potential income tax liability sufficient to support a tax allowance on that partnership income. We currently do not transport any of our oil or natural gas liquids on a pipeline structured as a master limited partnership.

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 the regulation of oil transportation rates will not affect our operations in any way that is materially different from the effect of such regulation on 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 access to oil pipeline transportation services generally will be available to us to the same extent as to competitors.

Environmental Regulations:

General. Our operations are subject to extensive federal, state and local laws and regulations relating to the generation, storage, handling, emission, transportation and discharge of materials into the environment. Various federal, state and local laws and regulations governing the protection of the environment, such as the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), the Federal Oil Pollution Act of 1990, as amended (OPA), the Federal Water Pollution Control Act of 1972, as amended (the Clean Water Act), the Safe Drinking Water Act of 1974, as amended (the Safe Drinking Water Act), and the Federal Clean Air Act, as amended (the Clean Air Act) affect our operations and costs. In particular, exploration, development and production operations, activities in connection with storage and transportation of oil and other hydrocarbons and use of facilities for treating, processing or otherwise handling hydrocarbons and related wastes may be subject to regulation under these and similar state legislation. These laws and regulations:

- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- impose substantial liabilities for pollution resulting from operations.

Permits are required for the operation of our various facilities. These permits can be revoked, modified or renewed by issuing authorities. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties or the imposition of injunctive relief. Changes in

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environmental laws and regulations occur regularly, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as those in the oil and natural gas industry in general. Although we believe that compliance with environmental regulations will not have a material adverse effect on us, risks of substantial costs and liabilities related to environmental compliance issues are part of oil and gas production operations. No assurance can be given that significant costs and liabilities will not be incurred. Also, it is possible that other developments, such as stricter environmental laws and regulations, and claims for damages to property or persons resulting from oil and gas production could result in substantial costs and liabilities to us.

The transition zone and shallow-water areas of the U.S. Gulf Coast are ecologically sensitive. Environmental issues have led to higher drilling costs and a more difficult and lengthy well permitting process. U.S. laws and regulations applicable to our operations include those controlling the discharge of materials into the environment, requiring removal and cleanup of materials that may harm the environment, requiring consistency with applicable coastal zone management plans, or otherwise relating to the protection of the environment.

As with the industry generally, compliance with existing regulations increases the overall cost of business. The areas affected include:

- unit production expenses primarily related to the control and limitation of air emissions and the disposal of produced water;
- capital costs to drill exploration and development wells primarily related to the management and disposal of drilling fluids and other oil and natural gas exploration wastes; and
- capital costs to construct, maintain and upgrade equipment and facilities.

Superfund. The CERCLA, also known as the Superfund law, and comparable state laws and regulations imposes liability, without regard to fault or the legality of the original conduct, on certain persons with respect to the release of hazardous substances into the environment. These persons include the current and past owners and operators of a site where the release occurred and any party that treated or disposed of or arranged for the treatment or disposal of hazardous substances found at a site. Under CERCLA, such persons may be subject to joint and several strict liability 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 also authorizes the Environmental Protection Agency (EPA), and in some cases, private parties, to undertake actions to clean up such hazardous substances, or to recover the costs of such actions from the responsible parties. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substance released into the environment. In the course of ordinary operations, we have used materials and generated wastes and will continue to use materials and generate wastes that may fall within CERCLA s definition of hazardous substances. We may also be an owner or operator of sites on which hazardous substances have been released. As a result, we may be responsible under CERCLA for all or part of the costs to clean up sites where such substances have been released.

We currently own or lease properties that for many years have been used for the exploration and production of oil and natural gas. Although we and our predecessors have used operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed or released on, under or from the properties currently owned or leased by us or on, under or from other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose actions with respect to the treatment and disposal or release of hydrocarbons or other wastes were not under our control. State and federal laws applicable to oil and gas wastes and properties have become stricter over time. Under these increasingly stringent requirements, these properties and wastes disposed on these properties may be subject to CERCLA 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;

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to clean up contaminated property, including contaminated groundwater; or

to perform remedial operations to prevent future contamination.

At this time, we do not believe that we are associated with any Superfund site and have not been notified of any claim, liability or damages under CERCLA.

Oil Pollution Act of 1990. The OPA and regulations thereunder impose liability on responsible parties for damages resulting from oil spills into or upon navigable waters, and adjoining shorelines or in the exclusive economic zone of the United States. Liability under OPA is strict, and under certain circumstances joint and several, and potentially unlimited. A responsible party includes the owner or operator of an onshore facility and the lessee or permittee of the area in which an offshore facility is located. The OPA also requires the lessee or permittee of the offshore area in which a covered offshore facility is located to establish and maintain evidence of financial responsibility in the amount of $35.0 million ($10.0 million if the offshore facility is located landward of the seaward boundary of a state) to cover liabilities related to an oil spill for which such person is statutorily responsible. The amount of required financial responsibility may be increased above the minimum amounts to an amount not exceeding $150.0 million depending on the risk represented by the quantity or quality of oil that is handled by the facility. We carry insurance coverage to meet these obligations, which we believe is customary for comparable companies in the oil and gas industry. 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 believe that compliance with OPA s financial responsibility and other operating requirements will not have a material adverse effect on our operations.

U.S. Environmental Protection Agency. The U.S. Environmental Protection Agency regulations address the disposal of oil and natural gas operational wastes under three federal acts more fully discussed in the paragraphs that follow. The Resource Conservation and Recovery Act of 1976, as amended (RCRA), provides a framework for the safe disposal of discarded materials and the management of solid and hazardous wastes. The direct disposal of operational wastes into offshore waters is also limited under the authority of the Clean Water Act. When injected underground, oil and natural gas wastes are regulated by the Underground Injection Control program under the Safe Drinking Water Act. If wastes are classified as hazardous, they must be properly transported, using a uniform hazardous waste manifest, documented, and disposed at an approved hazardous waste facility. We have coverage under the Region VI National Production Discharge Elimination System Permit for discharges associated with exploration and development activities. We take the necessary steps to ensure all offshore discharges associated with a proposed operation, including produced waters, will be conducted in accordance with the permit.

Resource Conservation and Recovery Act. The RCRA is the principal federal statute governing the treatment, storage and disposal of hazardous 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 natural gas exploration and production waste to be classified as nonhazardous waste. A similar exemption is contained in many of the state counterparts to RCRA. As a result, we are not required to comply with a substantial portion of RCRA s requirements because the operations generate minimal quantities of hazardous wastes. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes oil and natural gas exploration and production wastes from regulation as hazardous waste. 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 of and would cause us to incur increased operating expenses.

Clean Water Act. The Clean Water Act and resulting regulations imposes restrictions and controls on the discharge of produced waters and other wastes into navigable waters. Permits must be obtained to discharge

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pollutants into state and federal waters and to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into certain coastal and offshore waters. Further, the EPA has adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges.

Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The Clean Water Act 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 our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

Safe Drinking Water Act. Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from oil and natural gas production. The Safe Drinking Water Act establishes a regulatory framework for underground injection, with the main goal being 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 Louisiana and Texas, 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 the permits could subject us to civil and/or criminal enforcement. We believe we are in compliance in all material respects with the requirements of applicable state underground injection control programs and permits.

Hydraulic Fracturing. Many of our exploration and production 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 several chemical additives, as well as sand 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. Most of our 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 have recently been introduced in Congress that would subject hydraulic fracturing to federal regulation under the Safe Drinking Water Act. If adopted, these bills could result in additional permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. These permitting requirements and restrictions could result in delays in operations at well sites as well as increased costs to make wells productive. Moreover, the bills introduced in Congress would require the public disclosure of certain information regarding the chemical makeup of hydraulic fracturing fluids, many of which are proprietary to the service companies that perform the hydraulic fracturing operations. Such disclosure 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. In addition to these federal legislative proposals, some states and local governments have adopted, and others are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances, 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. If these types of conditions are adopted, we could be subject to increased costs and possibly limits on the productivity of certain wells.

Greenhouse Gas. In response to recent studies suggesting that emissions of carbon dioxide and certain other gases may be contributing to warming of the Earth s atmosphere, the U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases from sources within the United States between 2012 and

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2050. For example, the 110th session of Congress considered various bills that proposed a cap and trade scheme of regulation of greenhouse gas emissions that generally would ban emissions above a defined reducing annual cap. Covered parties would be authorized to emit greenhouse emissions through the acquisition and subsequent surrender of emission allowances that may be traded or acquired on the open market. In addition, at least 17 states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs require either major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries or gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year until the overall greenhouse gas emission reduction goal is achieved.

Depending on the particular program, we could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations or from combustion of oil or natural gas we produce. Although we would not be impacted to a greater degree than other similarly situated producers of oil and gas, a stringent greenhouse gas control program could have an adverse effect on our cost of doing business and could reduce demand for the oil and gas we produce.

Also, in the wake of the U.S. Supreme Court s decision in April 2007 in *Massachusetts v. Environmental Protection Agency*, the EPA has begun to regulate carbon dioxide and other greenhouse gas emissions, even though Congress has yet to adopt new legislation specifically addressing emissions of greenhouse gases. In late 2009, the EPA issued a Mandatory Reporting of Greenhouse Gases final rule, which was amended in December 2010, establishing a new comprehensive regulation and reporting scheme for operators of stationary sources emitting certain levels of greenhouse gases, and a Final Rule finding that certain current and projected levels of greenhouse gases in the atmosphere threaten public health and welfare of current and future generations. Most recently, in late 2010, the EPA finalized new greenhouse gas reporting requirements for upstream petroleum and natural gas systems, which will be added to EPA s greenhouse gas reporting rule.

Marine Protected Areas. Executive Order 13158, issued on May 26, 2000, directs federal agencies to safeguard existing Marine Protected Areas (MPAs) in the United States and establish new MPAs. The order requires federal agencies to avoid harm to MPAs to the extent permitted by law and to the maximum extent practicable. It also directs the EPA to propose new regulations under the Clean Water Act to ensure appropriate levels of protection for the marine environment. This order has the potential to adversely affect our operations by restricting areas in which we may carry out future development and exploration projects and/or causing us to incur increased operating expenses.

Marine Mammal and Endangered Species. Federal Lease Stipulations include regulations regarding the taking of protected marine species (sea turtles, marine mammals, Gulf sturgeon and other listed marine species). The Bureau of Safety and Environmental Enforcement (BSEE) also issue numerous regulations under the nomenclature Notice to Lessees and Operators (NTL) that provide formal guidelines on implementation of OCS regulations and standards. We believe we are in compliance in all material respects with the requirements regarding protection of marine species.

Consideration of Environmental Issues in Connection with Governmental Approvals. Our operations frequently require licenses, permits and/or other governmental approvals. Several federal statutes, including OCSLA, the National Environmental Policy Act (NEPA), and the Coastal Zone Management Act (CZMA) require federal agencies to evaluate environmental issues in connection with granting such approvals and/or taking other major agency actions. OCSLA, for instance, requires the U.S. Department of Interior (DOI) to evaluate whether certain proposed activities would cause serious harm or damage to the marine, coastal or human environment. Similarly, NEPA requires DOI and other federal agencies to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency would have to prepare an environmental assessment and, potentially, an environmental impact statement. CZMA, on the other hand, aids states in developing a coastal management program to protect the coastal environment from growing

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demands associated with various uses, including offshore oil and natural gas development. In obtaining various approvals from the DOI, we must certify that we will conduct our activities in a manner consistent with an applicable program.

Lead-Based Paints. Various pieces of equipment and structures we own may have been coated with lead-based paints as was customary in the industry at the time these pieces of equipment were fabricated and constructed. These paints may contain lead at a concentration high enough to be considered a regulated hazardous waste when removed. If we need to remove such paints in connection with maintenance or other activities and they qualify as a regulated hazardous waste, this would increase the cost of disposal. High lead levels in the paint might also require us to institute certain administrative and/or engineering controls required by the Occupational Safety and Health Act and BSEE to ensure worker safety during paint removal.

Air Pollution Control. The Clean Air Act and state air pollution laws adopted to fulfill its mandates provide a framework for national, state and local efforts to protect air quality. Operations utilize equipment that emits air pollutants 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. Air emissions associated with offshore activities are projected using a matrix and formula supplied by BSEE, which has primacy from the EPA for regulating such emissions.

Naturally Occurring Radioactive Materials. Naturally Occurring Radioactive Materials (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 natural 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 our operations are in material compliance with all applicable NORM standards established by the states, as applicable.

Taxation

Our oil and gas operations are affected by federal income tax laws applicable to the petroleum industry. For U.S income tax reporting purposes, intangible drilling and development costs incurred or borne during the year are permitted to be deducted currently, rather than capitalized. As an independent producer, we are also entitled to a deduction for percentage depletion with respect to the first 1,000 barrels per day of domestic crude oil (and/or equivalent units of domestic natural gas) produced, if such percentage depletion exceeds cost depletion. Generally, this deduction is computed based upon the lesser of 100% of the net income, or 15% of the gross income from a property, without reference to the basis in the property. The amount of the percentage depletion deduction so computed which may be deducted in any given year is limited to 65% of taxable income. Any percentage depletion deduction disallowed due to the 65% of taxable income test may be carried forward indefinitely.

See Notes 1 and 9 to the consolidated financial statements included in this Report for a discussion of accounting for income taxes.

Competition and Markets

The business of acquiring producing properties and non-producing leases suitable for exploration and development is highly competitive. Our competition, in our efforts to acquire both producing and non-producing properties, include oil and gas companies, independent concerns, income programs and individual producers and operators, many of which have financial resources, staffs and facilities substantially greater than those available to us. Furthermore, domestic producers of oil and gas must not only compete with each other in marketing their

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output, but must also compete with producers of imported oil and gas and alternative energy sources such as coal, nuclear power and hydroelectric power. Competition among petroleum companies for favorable oil and gas properties and leases can be expected to increase.

The availability of a ready market for any oil and gas produced by us at acceptable prices per unit of production will depend upon numerous factors beyond our control, including the extent of domestic production and importation of oil and gas, the proximity of our producing properties to gas pipelines and the availability and capacity of such pipelines, the marketing of other competitive fuels, fluctuation in demand, governmental regulation of production, refining, transportation and sales, general national and worldwide economic conditions, and use and allocation of oil and gas and their substitute fuels. There is no assurance that we will be able to market all of the oil or gas produced by us or that favorable prices can be obtained for the oil and gas production.

Major Customers

Listed below are the percent of our total oil and gas sales made to each of our customers whose purchases represented more than 10% of our oil and gas sales in 2012.

Oil Purchasers:	
Plains All American Inc.	57%
Sunoco, Inc.	26%
Gas Purchasers:	
Atlas Pipeline Mid-Continent	45%
Unimark LLC	14%

Although there are no long-term purchasing agreements with these purchasers, we believe that they will continue to purchase our oil and gas products and, if not, could be readily replaced by other purchasers.

Employees

At March 1, 2013, we had 226 full-time and 7 part-time employees, 42 of whom were employed at our principal offices in Houston, Texas, at the offices of Prime Operating Company, Eastern Oil Well Service Company, EOWS Midland Company and Prime Offshore L.L.C., 14 employees in Stamford, Connecticut, and 177 employees who were primarily involved in our district operations in Houston and Midland, Texas, Oklahoma City, Oklahoma and Charleston, West Virginia.

Item 1A. RISK FACTORS.

Natural gas and oil prices fluctuate widely, and low prices for an extended period of time are likely to have a material adverse impact on our business.

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for natural gas and, to a lesser extent, oil. Lower commodity prices may reduce the amount of natural gas and oil that we can produce economically. Historically, natural gas and oil prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile. Natural gas prices decreased from an average price of $4.00 per MMbtu in 2011 to an average price of $2.75 per MMbtu in 2012. Oil prices decreased from an average price of $94.88 per barrel in 2011 to an average price of $94.05 per barrel in 2012. Depressed prices in the future would have a negative impact on our future financial results.

Prices for natural gas and oil are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- the level of consumer product demand;

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- weather conditions;
- political conditions in natural gas and oil producing regions, including the Middle East;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the price of foreign imports;
- actions of governmental authorities;
- pipeline capacity constraints;
- inventory storage levels;
- domestic and foreign governmental regulations;
- the price, availability and acceptance of alternative fuels; and
- overall economic conditions.

These factors and the volatile nature of the energy markets make it impossible to predict with any certainty the future prices of natural gas and oil. If natural gas prices decline significantly for a sustained period of time, the lower prices may adversely affect our ability to make planned expenditures, raise additional capital or meet our financial obligations.

Drilling natural gas and oil wells is a high-risk activity.

Our growth is materially dependent upon the success of our drilling program. Drilling for natural gas and oil involves numerous risks, including the risk that no commercially productive natural gas or oil 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.

Our future drilling activities may not be successful and, if unsuccessful, such failure will have an adverse effect on our future results of operations and financial condition. Our overall drilling success rate or our drilling success rate for activity within a particular geographic area may decline. We may ultimately not be able to lease or drill identified or budgeted prospects within our expected time frame, or at all. We may not be able to lease or drill a particular prospect because, in some cases, we identify a prospect or drilling location before seeking an option or lease rights in the prospect or location. Similarly, our drilling schedule may vary from our capital budget. The final determination with respect to the drilling of any scheduled or budgeted wells will be dependent on a number of factors, including:

- the results of exploration efforts and the acquisition, review and analysis of the seismic data;
- the availability of sufficient capital resources to us and the other participants for the drilling of the prospects;
- the approval of the prospects by other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for natural gas and oil and the availability of drilling rigs and crews;
- our financial resources and results; and
- the availability of leases and permits on reasonable terms for the prospects.

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These projects may not be successfully developed and the wells, if drilled, may not encounter reservoirs of commercially productive natural gas or oil.

Reserve estimates depend on many assumptions that may prove to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated.

Reserve engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The process of estimating quantities of proved reserves is complex and inherently uncertain, and the reserve data included in this document are only estimates. The process relies on interpretations of available geologic, geophysical, engineering and production data. As a result, estimates of different engineers may vary. In addition, the extent, quality and reliability of this technical data can vary. The differences in the reserve estimation process are substantially due to the geological conditions in which the wells are drilled. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as natural gas and oil prices. Additional assumptions include drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgment of the persons preparing the estimate.

Results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, initial reserve estimates often vary from the quantities of natural gas and oil that are ultimately recovered, and such variances may be material. Any significant variance could reduce the estimated quantities and present value of our reserves.

You should not assume that the present value of future net cash flows from our proved reserves is the current market value of our estimated natural gas and oil reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on the twelve-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month, and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance with the Financial Accounting Standards Board (FASB) in Accounting Standards Codification Section 932 may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

Our future performance depends on our ability to find or acquire additional natural gas and oil reserves that are economically recoverable.

In general, the production rate of natural gas and oil properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Unless we successfully replace the reserves that we produce, our reserves will decline, eventually resulting in a decrease in natural gas and oil production and lower revenues and cash flow from operations. Our future natural gas and oil production is, therefore, highly dependent on our level of success in finding or acquiring additional reserves. We may not be able to replace reserves through our exploration, development and exploitation activities or by acquiring properties at acceptable costs. Low natural gas and oil prices may further limit the kinds of reserves that we can develop economically. Lower prices also decrease our cash flow and may cause us to decrease capital expenditures.

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Exploration, development and exploitation activities involve numerous risks that may result in dry holes, the failure to produce natural gas and oil in commercial quantities and the inability to fully produce discovered reserves.

We are continually identifying and evaluating opportunities to acquire natural gas and oil properties. We may not be able to successfully consummate any acquisition, to acquire producing natural gas and oil properties that contain economically recoverable reserves, or to integrate the properties into our operations profitably.

We face a variety of hazards and risks that could cause substantial financial losses.

Our business involves a variety of operating risks, including:

- blowouts, cratering and explosions;
- mechanical problems;
- uncontrolled flows of natural gas, oil or well fluids;
- formations with abnormal pressures;
- pollution and other environmental risks; and
- natural disasters.

In addition, we conduct operations in shallow offshore areas, which are subject to additional hazards of marine operations, such as capsizing, collision and damage from severe weather. Any of these events could result in injury or loss of human life, loss of hydrocarbons, significant damage to or destruction of property, environmental pollution, regulatory investigations and penalties, impairment of our operations and substantial losses to us.

Our operation of natural gas gathering and pipeline systems also involves various risks, including the risk of explosions and environmental hazards caused by pipeline leaks and ruptures.

We may not be insured against all of the operating risks to which we are exposed.

We maintain insurance coverage against certain, but not all, hazards that could arise from our operations both onshore and offshore. Such insurance is believed to be reasonable for the hazards and risks faced by us. We do not carry business interruption insurance. In addition pollution and environmental risks are not fully insurable. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

As of December 31, 2012, we maintain for onshore operations total excess liability insurance with limits of $20 million per occurrence and in the aggregate covering certain general liability and certain sudden and accidental environmental risks with a deductible of $10,000 per occurrence, subject to all terms, restrictions and sub-limits of the policies. Thru July 30, 2012, when plugging and abandonment of our operated offshore properties were substantially complete, we also maintained for offshore operations total excess liability insurance with limits of $35 million per occurrence and in the aggregate covering certain general liability and certain sudden and accidental environmental risks with a deductible of $10,000 per occurrence, subject to all terms, restrictions and sub-limits of the policies. We also maintain general liability insurance limits of $1 million per occurrence and $2 million in the aggregate for both our onshore as well as our offshore operations.

We have several policies that cover environmental risks. We have environmental coverage under the per occurrence and aggregate limits of our general and umbrella liability policies (for a twelve-month term). These policies provide third-party surface cleanup, bodily injury and property damage coverage, and defense costs when a pollution event is sudden and accidental and is discovered within thirty days of commencement and reported to the insurance company within ninety days of discovery. This is standard coverage in oil and gas insurance policies.

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We seek to protect ourselves from some but not all operating hazards through insurance coverage. However, some risks are either not insurable or insurance is available only at rates that we consider uneconomical. Those risks include pollution liability in excess of limits sufficient to meet the legal financial responsibility requirement of the BSEE as prescribed under the OPA and individual state legal financial responsibility requirements.

Depending on competitive conditions and other factors, we attempt to obtain contractual protection against uninsured operating risks from our customers and contractors. However, customers and contractors who provide contractual indemnification protection may not in all cases maintain adequate insurance to support their indemnification obligations. Our insurance or indemnification arrangements may not adequately protect us against liability or loss from all the hazards of our operations. The occurrence of a significant event that we have not fully insured or indemnified against or the failure of a customer to meet its indemnification obligations to us could materially and adversely affect our results of operations and financial condition. Furthermore, we may not be able to maintain adequate insurance in the future at rates we consider reasonable.

With regard to our offshore operations, generally, indemnities and insurance limits for each contract are negotiated with each of our contractors. Our contracts generally follow the industry standard of providing mutual hold harmless and indemnity agreements, which results in each party being liable or responsible for all claims related to its employees and its contractors, as well as any damage to its and its contractor s property. Currently, substantially all of our contracts contain mutual hold harmless and indemnity provisions.

From time to time, a small number of our contractors have requested contractual provisions that require us to respond to third-party claims. In some of these instances we have accepted the risk with the understanding that it would be covered under our current coverage. We evaluate these risk-transferring negotiations cautiously, and we feel that we have adequately mitigated this risk through existing coverage or acquiring supplemental coverage when appropriate.

Federal and state legislation and regulatory initiatives related to hydraulic fracturing could result in increased costs and operating restrictions or delays.

Bills have recently been introduced in Congress that would subject hydraulic fracturing to federal regulation under the Safe Drinking Water Act. If adopted, these bills could result in additional permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. These permitting requirements and restrictions could result in delays in operations at well sites as well as increased costs to make wells productive. Moreover, the bills introduced in Congress would require the public disclosure of certain information regarding the chemical makeup of hydraulic fracturing fluids, many of which are proprietary to the service companies that perform the hydraulic fracturing operations. Such disclosure 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. In addition to these federal legislative proposals, some states and local governments have adopted, and others are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances, including 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. If these types of conditions are adopted, we could be subject to increased costs and possibly limits on the productivity of certain wells.

We have limited control over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund with respect to them. The failure of an operator of our wells to adequately perform operations, an operator s breach of the applicable agreements or an operator s failure to act in ways that are in our best interest could reduce our production and revenues. Our dependence on the operator

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and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities and lead to unexpected future costs.

Terrorist activities and the potential for military and other actions could adversely affect our business.

The threat of terrorism and the impact of military and other action have caused instability in world financial markets and could lead to increased volatility in prices for natural gas and oil, all of which could adversely affect the markets for our operations. Future acts of terrorism could be directed against companies operating in the United States. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of terrorist organizations. These developments have subjected our operations to increased risk and, depending on their ultimate magnitude, could have a material adverse effect on our business.

Our ability to sell our natural gas and oil production could be materially harmed if we fail to obtain adequate services such as transportation and processing.

The sale of our natural gas and oil production depends on a number of factors beyond our control, including the availability and capacity of transportation and processing facilities. Our failure to obtain these services on acceptable terms could materially harm our business.

Competition in our industry is intense, and many of our competitors have substantially greater financial and technological resources than we do, which could adversely affect our competitive position.

Competition in the natural gas and oil industry is intense. Major and independent natural gas and oil companies actively bid for desirable natural gas and oil properties, as well as for the equipment and labor required to operate and develop these properties. Our competitive position is affected by price, contract terms and quality of service, including pipeline connection times, distribution efficiencies and reliable delivery record. Many of our competitors have financial and technological resources and exploration and development budgets that are substantially greater than ours. These companies may be able to pay more for exploratory projects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may be able to expend greater resources on the existing and changing technologies that we believe are and will be increasingly important to attaining success in the industry.

We may have hedging arrangements that expose us to risk of financial loss and limit the benefit to us of increases in prices for natural gas and oil.

From time to time, when we believe that market conditions are favorable, we use certain derivative financial instruments to manage price risks associated with our production in all of our regions. These hedging arrangements limit the benefit to us of increases in prices. We will continue to evaluate the benefit of employing derivatives in the future.

The loss of key personnel could adversely affect our ability to operate.

Our operations are dependent upon a relatively small group of key management and technical personnel, and one or more of these individuals could leave our employment. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on us. In addition, our drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers and other professionals. Competition for experienced geologists, engineers and some other professionals is intense. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed.

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We are subject to complex laws and regulations, including environmental regulations, which can adversely affect the cost, manner or feasibility of doing business.

Our operations are subject to extensive federal, state and local laws and regulations, including tax laws and regulations and those relating to the generation, storage, handling, emission, transportation and discharge of materials into the environment. These laws and regulations can adversely affect the cost, manner or feasibility of doing business. Many laws and regulations require permits for the operation of various facilities, and these permits are subject to revocation, modification and renewal. Governmental authorities have the power to enforce compliance with their regulations, and violations could subject us to fines, injunctions or both. These laws and regulations have increased the costs of planning, designing, drilling, installing and operating natural gas and oil facilities. In addition, we may be liable for environmental damages caused by previous owners of property we purchase or lease. Risks of substantial costs and liabilities related to environmental compliance issues are inherent in natural gas and oil operations. It is possible that other developments, such as stricter environmental laws and regulations, and claims for damages to property or persons resulting from natural gas and oil production, would result in substantial costs and liabilities.

Item 1B. UNRESOLVED STAFF COMMENTS.

We are a smaller reporting company and therefore no response is required pursuant to this Item.

Item 2. PROPERTIES.

Our executive offices as well as offices of Prime Operating Company, Eastern Oil Well Service Company, EOWS Midland Company and Prime Offshore L.L.C., are located in leased premises in Houston, Texas, and the offices of Southwest Oilfield Construction Company are in Oklahoma City, Oklahoma. We also maintain leased office space at One Landmark Square, Stamford, Connecticut for the administration, accounting and tax preparation for the Partnerships and Trusts.

We maintain district offices in Houston and Midland, Texas, Oklahoma City, Oklahoma and Charleston, West Virginia, and have field offices in Carrizo Springs and Midland, Texas, Kingfisher and Garvin, Oklahoma and Orma, West Virginia.

Substantially all of our oil and gas properties are subject to a mortgage given to collateralize indebtedness or are subject to being mortgaged upon request by our lenders for additional collateral.

The information set forth below concerning our properties, activities, and oil and gas reserves include our interests in affiliated entities.

The following table sets forth the exploratory and development drilling experience with respect to wells in which we participated during the three years ended December 31, 2012.

	2012		2011		2010	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploratory:						
Oil	1	0.42				
Gas	1	0.50				
Dry	1	0.03				
Development:						
Oil	36	27.96	35	21.98	47	19.96
Gas						
Dry			1	0.34		
Total:						
Oil	37	28.38	35	21.98	47	19.96
Gas	1	0.50				
Dry	1	0.03	1	0.34		
	39	28.91	36	22.32	47	19.96

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Oil and Gas Production

As of December 31, 2012, we had ownership interests in the following numbers of gross and net producing oil and gas wells and gross and net producing acres [1].

	Gross	Net
Producing wells[1]:		
Oil Wells	793	401
Gas Wells	956	502
Producing Acres	320,441	110,070

[1] A gross well or gross acre is a well or an acre in which a working interest is owned. A net well or net acre is the sum of the fractional revenue interests owned in gross wells or gross acres. Wells are classified by their primary product. Some wells produce both oil and gas.

The following table shows our net production of oil and natural gas for each of the three years ended December 31, 2012. Net production is net after royalty interests of others are deducted and is determined by multiplying the gross production volume of properties in which we have an interest by percentage of the leasehold, mineral or royalty interest owned by us.

	2012	2011	2010
Oil (barrels)	745,000	628,000	627,000
Gas (Mcf)	4,715,000	5,000,000	5,939,000

The following table sets forth our average sales price per barrel of oil and average sales prices per one thousand cubic feet (Mcf) of gas, together with our average production costs per unit of production for the three years ended December 31, 2012.

	2012	2011	2010
Average sales price per barrel	$ 90.34	$ 92.13	$ 75.14
Average sales price per Mcf	4.45	7.64	6.43
Average production costs per net equivalent barrel [1]	23.14	22.05	19.27

[1] Net equivalent barrels are computed at a rate of 6 Mcf per barrel and costs exclude production taxes.

Average oil and gas prices received excluding the impact of derivatives were:

	2012	2011	2010
Oil Price per barrel	$ 89.67	$ 90.04	$ 75.84
Gas Price per Mcf	4.45	6.38	5.75

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Undeveloped Acreage

The following table sets forth the approximate gross and net undeveloped acreage in which we have leasehold, mineral and royalty interests as of December 31, 2012.   Undeveloped acreage   is that acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas, regardless of whether or not such acreage contains proved reserves.

	Leasehold Interests		Mineral Interests		Royalty Interests	
State	**Gross Acres**	**Net Acres**	**Gross Acres**	**Net Acres**	**Gross Acres**	**Net Acres**
Colorado			799	23		
Montana			14,304	60		
Nebraska			2,554	331		
North Dakota			640	1		
Oklahoma	880	741	320		2,880	24
Texas	5,240	3,719	640	2		
Wyoming					140	35
TOTAL	6,120	4,460	19,257	417	3,020	59

Reserves

Our interests, including the interests held by the Partnerships, in proved developed and undeveloped oil and gas properties have been evaluated by Ryder Scott Company, L.P. for each of the three years ended December 31, 2012. The professional qualifications of the technical persons primarily responsible for overseeing the preparation of the reserves estimates can be found in Exhibit 99.1, the Ryder Scott Company, L.P. Report on Registrant s Reserves Estimates. In matters related to the preparation of our reserve estimates, our district managers report to the Houston Central manager, who maintains oversight and compliance responsibility for the internal reserve estimate process and provides oversight for the annual preparation of reserve estimates of 100% of our year-end reserves by our independent third party engineers, Ryder Scott Company, L.P. The members of our district and central groups consist of degreed engineers, geologists and geophysicists and technicians with between approximately ten and thirty-five years of industry experience, and between three and twenty years managing our reserves. Our Houston Central manager, the technical person primarily responsible for overseeing the preparation of reserves estimates, has over twenty-five years of experience, holds a Bachelor of Science degree in Natural Gas Engineering and is a member of the Society of Petroleum Engineers and American Association of Petroleum Geologists. See Part II, Item 8.,   Financial Statements and Supplementary Data , for additional discussions regarding proved reserves and their related cash flows.

All of our reserves are located within the continental United States. The following table summarizes our oil and gas reserves at each of the respective dates:

	Reserve Category											
	Proved Developed				Proved Undeveloped				Total			
As of December 31,	**Oil (MBbls)**	**NGLs (MBbls) (a)**	**Gas (MMcf)**	**Total (MBoe) (b)**	**Oil (MBbls)**	**NGLs (MBbls) (a)**	**Gas (MMcf)**	**Total (MBoe) (b)**	**Oil (MBbls)**	**NGLs (MBbls) (a)**	**Gas (MMcf)**	**Total (MBoe) (b)**
2010	5,233		41,946	12,224	2,652		11,400	4,552	7,885		53,346	16,776
2011	6,418		43,631	13,690	2,435		9,765	4,063	8,853		53,396	17,752
2012	7,178	2,909	27,833	14,726	5,907	2,877	12,613	10,886	13,085	5,786	40,446	25,612

(a) Prior to December 31, 2012, natural gas liquids (NGLs) were included in the oil and gas reserve reports under the natural gas heading using a standard conversion factor of one barrel of NGLs to six thousand cubic feet (Mcf) of gas.

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(b) In computing total reserves on a barrels of oil equivalent (Boe), gas is converted to oil based on its relative energy content at the rate of six Mcf of gas to one barrel of oil and NGLs are converted based upon volume; one barrel of natural gas liquids equals one barrel of oil.

Our proved undeveloped reserves of 4,552 MBoe as of December 31, 2010 consisted of 75 in-fill drilling locations in our West Texas drilling program. During 2011 we drilled 24 West Texas wells at a cost of $28.4 million converting 1,209 MBoe to proved developed producing reserves and added 18 additional proved undeveloped drilling locations. Proved undeveloped reserves of 4,063 MBoe as of December 31, 2011 included 64 in-fill drilling locations in our West Texas drilling program and 5 drilling locations in our Mid-Continent region. During 2012 we drilled 29 West Texas wells and 7 Mid-Continent wells at a cost of $42.3 million converting 1,449 MBoe to proved developed producing reserves and added 85 additional proved undeveloped drilling locations. Proved undeveloped reserves of 10,886 MBoe as of December 31, 2012 included 127 drilling locations in our West Texas drilling program, 11 drilling locations in our Mid-Continent region and 2 drilling locations in our Gulf Coast region. We have no proved undeveloped reserves scheduled for development five years beyond date of first booking.

We employ technologies to establish proved reserves that have been demonstrated to provide consistent results capable of repetition. The technologies and economic data being used in the estimation of our proved reserves include, but are not limited to, electrical logs, radioactivity logs, geologic maps, production data and well test data. The estimated reserves of wells with sufficient production history are estimated using appropriate decline curves. Estimated reserves of producing wells with limited production history and for undeveloped locations are estimated using performance data from analogous wells in the area. These wells are considered analogous based on production performance from the same formation and with similar completion techniques.

The estimated future net revenue (using current prices and costs as of those dates) and the present value of future net revenue (at a 10% discount for estimated timing of cash flow) for our proved developed and proved undeveloped oil and gas reserves at the end of each of the three years ended December 31, 2012, are summarized as follows (in thousands of dollars):

	Proved Developed		Proved Undeveloped		Total			
As of December 31,	Future Net Revenue	Present Value 10 Of Future Net Revenue	Future Net Revenue	Present Value 10 Of Future Net Revenue	Future Net Revenue	Present Value 10 Of Future Net Revenue	Present Value 10 Of Future Income Taxes	Standardized Measure of Discounted Cash flow
2010	$ 282,004	$ 168,095	$ 100,934	$ 26,696	$ 382,938	$ 194,791	$ 48,307	$ 146,484
2011	394,662	217,900	121,547	35,256	516,209	253,156	68,648	184,508
2012	380,346	214,533	290,594	73,340	670,940	287,873	74,600	213,273

The PV 10 Value represents the discounted future net cash flows attributable to our proved oil and gas reserves before income tax, discounted at 10%. Although this measure is not in accordance with U.S. generally accepted accounting principles (GAAP), we believe that the presentation of the PV 10 Value is relevant and useful to investors because it presents the discounted future net cash flow attributable to proved reserves prior to taking into account corporate future income taxes and the current tax structure. We use this measure when assessing the potential return on investment related to oil and gas properties. The PV 10 of future income taxes represents the sole reconciling item between this non-GAAP PV 10 Value versus the GAAP measure presented in the standardized measure of discounted cash flow. A reconciliation of these values is presented in the last three columns of the table above. The standardized measure of discounted future net cash flows represents the present value of future cash flows attributable to proved oil and natural gas reserves after income tax, discounted at 10%.

Proved developed oil and gas reserves are reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Our reserves include amounts attributable to non-controlling interests in the Partnerships. These interests represent less than 10% of our reserves.

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In accordance with U.S. generally accepted accounting principles, product prices are determined using the twelve-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month, adjusted for oilfield or gas gathering hub and wellhead price differentials (e.g. grade, transportation, gravity, sulfur, and basic sediment and water) as appropriate. Also in accordance with SEC specifications and U.S. generally accepted accounting principles, changes in market prices subsequent to December 31 are not considered.

The range of Henry Hub daily gas prices per MMbtu during the year 2012 was a low of $1.82 and a high of $3.77 and the average was $2.75. The range during the first two months of 2013 has been from $3.08 to $3.63 with an average of $3.33. The recent futures market prices have traded in the range of $3.67 per MMbtu.

The range of NYMEX oil prices per barrel during the year 2012 was a low of $77.72 and a high of $109.39 and the average was $94.05. The range during the first two months of 2013 has been from $92.03 to $97.98, with an average of $95.02. The recent futures market prices have fluctuated around $92.00 per barrel.

While it may reasonably be anticipated that the prices received for the sale of our production may be higher or lower than the prices used in this evaluation, as described above, and the operating costs relating to such production may also increase or decrease from existing levels, such possible changes in prices and costs were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation for the SEC case. Actual volumes produced, prices received and costs incurred may vary significantly from the SEC case.

Since January 1, 2013, we have not filed any estimates of our oil and gas reserves with, nor were any such estimates included in any reports to, any federal authority or agency, other than the Securities and Exchange Commission.

District Information

The following table presents certain reserve, production and well information as of December 31, 2012.

	Appalachian	Gulf Coast	Mid-Continent	West Texas	Other	Total
Proved Reserves at Year End (MBoe)						
Developed	1,007	966	2,914	9,709	130	14,726
Undeveloped		177	331	10,378		10,886
Total	1,007	1,143	3,245	20,087	130	25,612
Average Daily Production (Boe per day)	368	523	884	2,306	102	4,183
Gross Wells	727	379	721	568	107	2,502
Net Wells	372	158	257	196	17	1,000
Gross Operated Wells	498	301	385	371	58	1,613

In several of our regions we operate field service groups to service our operated wells and locations as well as third party operators in the area. These services consist of well service support, site preparation and construction services for drilling and workover operations. Our operations are performed utilizing workover or swab rigs, water transport trucks, saltwater disposal facilities, various land excavating equipment and trucks we own and that are operated by our field employees.

Appalachian Region

Our Appalachian activities are concentrated primarily in West Virginia. This region is managed from our office in Charleston, West Virginia. Our assets in this region include a large acreage position and a high concentration of wells. At December 31, 2012, we had 727 wells (372 net), of which 498 wells are operated by

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us. There are multiple producing intervals that include the Big Lime, Injun, Blue Monday, Weir, Berea, Gordon and Devonian Shale formations at depths primarily ranging from 1,600 to 5,600 feet. Average net daily production in 2012 was 368 Boe. While natural gas production volumes from Appalachian reservoirs are relatively low on a per-well basis compared to other areas of the United States, the productive life of Appalachian reserves is relatively long. At December 31, 2012, we had 1,007 MBoe of proved reserves (substantially all natural gas) in the Appalachian region, constituting 4% of our total proved reserves. We operate a small field service group in this region utilizing one workover rig, one paraffin truck, one saltwater hauling truck and limited excavating equipment to primarily service our own operated wells and locations. As of March 1, 2013 the Appalachian region has no wells in the process of being drilled, no waterfloods in the process of being installed and no other related activities of material importance.

Gulf Coast Region

Our development, exploitation, exploration and production activities in the Gulf Coast region are primarily concentrated in Louisiana, southeast Texas and south Texas. This region is managed from our office in Houston, Texas. Principal producing intervals are in the Marg Tex, Wilcox, Pettit, Glenrose, Woodbine, San Miguel, Olmos, and Yegua formations at depths ranging from 3,000 to 12,500 feet. We had 379 wells (158 net) in the Gulf Coast region as of December 31, 2012, of which 301 wells are operated by us. Average daily production in 2012 was 523 Boe. At December 31, 2012, we had 1,143 MBoe of proved reserves (44% oil) in the Gulf Coast region, which represented 4% of our total proved reserves. We operate a field service group in this region from a field office in Carrizo Springs, Texas utilizing 3 workover rigs, 19 water transport trucks, one saltwater disposal well and several trucks and excavating equipment. Services including well service support, site preparation and construction services for drilling and workover operations are provided to third party operators as well as utilized in our own operated wells and locations. As of March 1, 2013 the Gulf Coast region has no wells in the process of being drilled, no waterfloods in the process of being installed and no other related activities of material importance.

Mid-Continent Region

Our Mid-Continent activities are concentrated in central Oklahoma. This region is managed from our office in Oklahoma City, Oklahoma. As of December 31, 2012, we had 721 wells (257 net) in the Mid-Continent area, of which 385 wells are operated by us. Principal producing intervals are in the Roberson, Avant, Skinner, Sycamore, Bromide, McLish, Hunton, Mississippian, Oswego, Red Fork, and Chester formations at depths ranging from 1,100 to 10,500 feet. Average net daily production in 2012 was 884 Boe. At December 31, 2012, we had 3,245 MBoe of proved reserves (51% oil) in the Mid-Continent area, or 13% of our total proved reserves. We operate a field service group in this region from a field office in Kingfisher, Oklahoma utilizing 3 workover rigs, one swab rig, one saltwater hauling truck and several trucks and excavating equipment. Services including well service support, site preparation and construction services for drilling and workover operations are provided to third party operators as well as utilized in our own operated wells and locations. As of March 1, 2013 the Mid-Continent region has no wells in the process of being drilled or awaiting completion, no waterfloods in the process of being installed and no other related activities of material importance.

West Texas Region

Our West Texas activities are concentrated in the Permian Basin in Texas and New Mexico. This region is managed from our office in Midland, Texas. As of December 31, 2012, we had 568 wells (196 net) in the West Texas area, of which 371 wells are operated by us. Principal producing intervals are in the Spraberry, Wolfcamp and San Andres formations at depths ranging from 5,500 to 12,500 feet. Average net daily production in 2012 was 2,306 Boe. At December 31, 2012, we had 20,087 MBoe of proved reserves (54% oil) in the West Texas area, or 78% of our total proved reserves. We operate a field service group in this region utilizing 7 workover rigs, one pump truck, two hot oiler trucks, one saltwater hauling truck and several trucks and excavating equipment. Services including well service support, site preparation and construction services for drilling and

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workover operations are provided to third party operators as well as utilized in our own operated wells and locations. As of March 1, 2013 the West Texas region has no wells in the process of being drilled or awaiting completion, no waterfloods in the process of being installed and no other related activities of material importance.

Acreage subject to expiration in the next three years;

	2013		2014		2015	
State / Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Texas	320	288			1,640	1,032
TOTAL	320	288			1,640	1,032

Item 3. LEGAL PROCEEDINGS.

None.

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PART II

Item 5. MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Our common stock is listed and principally traded on the NASDAQ Stock Market under the ticker symbol PNRG . The following table presents the high and low closing prices per share of our common stock during certain periods, as reported in the consolidated transaction reporting system.

	High	Low
2012		
First Quarter	$ 28.55	$ 19.19
Second Quarter	27.34	21.43
Third Quarter	28.00	25.01
Fourth Quarter	28.25	22.00
2011		
First Quarter	$ 30.00	$ 19.04
Second Quarter	28.51	22.30
Third Quarter	26.20	17.07
Fourth Quarter	23.83	15.26

The above quotations reflect inter-dealer prices, without retail mark-up, mark-down or commissions, and may not represent actual transactions.

As of March 20, 2013, there were 510 registered holders of the common stock.

No dividends have been declared or paid during the past two years on our common stock. Provisions of our line of credit agreement restrict our ability to pay dividends. Such dividends may be declared out of funds legally available therefore, when and as declared by our Board of Directors.

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Issuer Purchases of Equity Securities

In December 1993, we announced that the Board of Directors authorized a stock repurchase program whereby we may purchase outstanding shares of the common stock from time-to-time, in open market transactions or negotiated sales. On October 31, 2012, the Board of Directors of the Company approved an additional 500,000 shares of the Company s stock to be included in the stock repurchase program. A total of 3,500,000 shares have been authorized, to date, under this program. Through December 31, 2012, a total of 3,035,896 shares have been repurchased under this program for $44,769,588 at an average price of $14.75 per share. Additional purchases of shares may occur as market conditions warrant. We expect future purchases will be funded with internally generated cash flow or from working capital.

2012 Month	Number of Shares	Average Price Paid per share	Maximum Number of Shares that May Yet Be Purchased Under The Program at Month-End
January	8,119	$ 22.25	147,294
February	4,563	22.73	142,731
March	6,938	24.69	135,793
April	52,579	24.98	83,214
May	3,200	23.80	80,014
June	3,633	24.65	76,381
July	1,180	27.33	75,201
August	21,972	26.76	53,229
September	5,550	27.09	47,679
October	12,926	27.95	534,753
November	32,114	27.68	502,639
December	38,535	26.91	464,104
Total / Average	191,309	$ 26.10	

Item 6. SELECTED FINANCIAL DATA

We are a smaller reporting company and therefore no response is required pursuant to this Item.

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Item 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion is intended to assist you in understanding our results of operations and our present financial condition. Our Consolidated Financial Statements and the accompanying Notes to the Consolidated Financial Statements included elsewhere in this Report contains additional information that should be referred to when reviewing this material. Our subsidiaries are listed in Note 1 to the Consolidated Financial Statements.

Overview:

We are an independent oil and natural gas company engaged in acquiring, developing and producing oil and natural gas. We presently own producing and non-producing properties located primarily in Texas, Oklahoma, West Virginia, the Gulf of Mexico, New Mexico, Colorado and Louisiana. In addition, we own a substantial amount of well servicing equipment. All of our oil and gas properties and interests are located in the United States. Assets in our principal focus areas include mature properties with long-lived reserves and significant development opportunities as well as newer properties with development and exploration potential. We believe our balanced portfolio of assets and our ongoing hedging program position us well for both the current commodity price environment and future potential upside as we develop our attractive resource opportunities. Our primary sources of liquidity are cash generated from our operations and our credit facility.

We attempt to assume the position of operator in all acquisitions of producing properties and will continue to evaluate prospects for leasehold acquisitions and for exploration and development operations in areas in which we own interests. We continue to actively pursue the acquisition of producing properties. In order to diversify and broaden our asset base, we will consider acquiring the assets or stock in other entities and companies in the oil and gas business. Our main objective in making any such acquisitions will be to acquire income producing assets so as to build stockholder value through consistent growth in our oil and gas reserve base on a cost-efficient basis.

Our cash flows depend on many factors, including the price of oil and gas, the success of our acquisition and drilling activities and the operational performance of our producing properties. We use derivative instruments to manage our commodity price risk. This practice may prevent us from receiving the full advantage of any increases in oil and gas prices above the maximum fixed amount specified in the derivative agreements and subjects us to the credit risk of the counterparties to such agreements. Since all of our derivative contracts are accounted for under mark-to-market accounting, we expect continued volatility in gains and losses on mark-to-market derivative contracts in our consolidated statement of operations as changes occur in the NYMEX price indices.

Critical Accounting Estimates:

Proved Oil and Gas Reserves

Proved oil and gas reserves directly impact financial accounting estimates, including depreciation, depletion and amortization. Proved reserves represent estimated quantities of natural gas, crude oil, condensate, and natural gas liquids that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made. The process of estimating quantities of proved oil and 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. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time.

Depreciation, Depletion and Amortization for Oil and Gas Properties

The quantities of estimated proved oil and gas reserves are a significant component of our calculation of depletion expense and revisions in such estimates may alter the rate of future expense. Holding all other factors constant, if reserves were revised upward or downward, earnings would increase or decrease respectively.

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 depletion, depreciation or amortization is the sum of proved developed reserves and proved undeveloped reserves for leasehold acquisition costs and the cost to acquire proved properties. The reserve base includes only proved developed reserves for lease and well equipment costs, which include development costs and successful exploration drilling costs. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account.

Liquidity And Capital Resources:

Net cash provided by operating activities for the year ended December 31, 2012 was $40 million, compared to $41 million in the prior year. Excluding the effects of significant unforeseen expenses or other income, our cash flow from operations fluctuates primarily because of variations in oil and gas production and prices or changes in working capital accounts. Our oil and gas production will vary based on actual well performance but may be curtailed due to factors beyond our control.

Our realized oil and gas prices vary due to world political events, supply and demand of products, product storage levels, and weather patterns. We sell the vast majority of our production at spot market prices. Accordingly, product price volatility will affect our cash flow from operations. To mitigate price volatility we sometimes lock in prices for some portion of our production through the use of derivatives.

If our exploratory drilling results in significant new discoveries, we will have to expend additional capital in order to finance the completion, development, and potential additional opportunities generated by our success. We believe that, because of the additional reserves resulting from the successful wells and our record of reserve growth in recent years, we will be able to access sufficient additional capital through additional bank financing.

The Company has in place both a stock repurchase program and a limited partnership interest repurchase program. Spending under these programs in 2012 was $5.1 million. The Company expects continued spending under these programs in 2013.

As of March 1, 2013, the Company maintains a credit facility totaling $250 million, with a borrowing base of $145 million. The bank reviews the borrowing base semi-annually and, at their discretion, may decrease or propose an increase to the borrowing base relative to a redetermined estimate of proved oil and gas reserves. Our oil and gas properties are pledged as collateral for the line of credit and we are subject to certain financial and operational covenants defined in the agreement. We are currently in compliance with these covenants. If we do not comply with these covenants on a continuing basis, the lenders have the right to refuse to advance additional funds under the facility and/or declare all principal and interest immediately due and payable.

It is our goal to increase our oil and gas reserves and production through the acquisition and development of oil and gas properties. We continued our drilling program in our West Texas and Mid-Continent regions. During 2013, we intend to drill a total of approximately 30 gross (20 net) wells, primarily in the West Texas area, at a net cost of $36 million. We also continue to explore and consider opportunities to further expand our oilfield servicing revenues through additional investment in field service equipment. However, the majority of our capital spending is discretionary, and the ultimate level of expenditures will be dependent on our assessment of the oil and gas business environment, the number and quality of oil and gas prospects available, the market for oilfield services, and oil and gas business opportunities in general.

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Results of Operations:

2012 and 2011 Compared

We reported net income for 2012 of $15.06 million, or $5.74 per share. During 2011, we reported net income of $4.81 million, or $1.75 per share. Net income increased in 2012 by $10.25 million or 213%, primarily due to decreased depreciation and depletion expenses and decreases in net income attributable to non-controlling interests partially offset by decreased operating revenues and an increase lease operating and income tax expenses. Depreciation and depletion decreased by $25.13 million in 2012 as compared to 2011 primarily associated with offshore properties as our offshore properties enter into the last phase of their productive lives and were plugged and abandoned during 2012. Operating revenues decreased by $6.10 million in 2012 as compared to 2011 largely due to gains on derivative instruments associated with early settlement transactions and recovery of gas transportation revenues recognized in 2011.

The significant components of net income are discussed below.

Oil and gas sales decreased $0.60 million, or 1% from $88.43 million for the year ended December 31, 2011 to $87.83 million for the year ended December 31, 2012. Crude oil and natural gas sales vary due to changes in volumes of production sold and realized commodity prices. Our realized prices at the well head decreased an average of $0.37 per barrel, or less than 1% on crude oil and $1.93 per Mcf, or 30% on natural gas during 2012 as compared to 2011.

Our crude oil production increased by 117,000 barrels, or 19% from 628,000 barrels for the year ended December 31, 2011 to 745,000 barrels for the year ended December 31, 2012. Our natural gas production decreased by 285 MMcf, or 6% from 5,000 MMcf for the year ended December 31, 2011 to 4,715 MMcf for the year ended December 31, 2012. The net increase in crude oil production volumes are a result of continued drilling success in West Texas and the Gulf Coast regions as we place new wells into production partially offset by the natural decline of existing properties. The natural gas volume decreases are primarily due to the decline of the primary natural gas producing offshore properties, slightly offset by natural gas production from wells in the West Texas region recently placed into production.

The following table summarizes the primary components of production volumes and average sales prices realized for the years ended December 31, 2012 and 2011 (excluding realized gains and losses from derivatives).

	Year Ended December 31,		Increase (Decrease)	
	2012	**2011**	**Amount**	**Percent**
Barrels of Oil Produced	745,000	628,000	117,000	19%
Average Price Received (excluding the impact of derivatives)	$ 89.67	$ 90.04	$ (0.37)	0%
Oil Revenue (In 000 s)	$ 66,830	$ 56,544	$ 10,286	18%
Mcf of Gas Produced	4,715,000	5,000,000	(285,000)	(6)%
Average Price Received (excluding the impact of derivatives)	$ 4.45	$ 6.38	$ (1.93)	(30)%
Gas Revenue (In 000 s)	$ 21,004	$ 31,885	$ (10,881)	(34)%
Total Oil & Gas Revenue (In 000 s)	$ 87,834	$ 88,429	$ (595)	(1)%

Realized net gains on derivative instruments include net gains of $0.5 million on the settlements of crude oil and natural gas derivatives for the year ended December 31, 2012. During 2012, we unwound and monetized crude oil swaps with original settlement dates from January 2012 through December 2013 for net proceeds of $1.0 million. The $1.0 million gain associated with these early settlement transactions is included in realized gain on derivative instruments for the year ended December 31, 2012. During 2011, we unwound and monetized crude oil swaps and collars with original settlement dates from September 2011 through December 2014 for net proceeds of $3.4 million and natural gas swaps with original settlement dates from October 2011 through December 2012 for net proceeds of $2.9 million. The $6.3 million gain associated with these early settlement transactions is included in realized gain on derivative instruments for the year ended December 31, 2011.

Oil and gas prices received including the impact of derivatives but excluding the early settlement transactions were:

	Year Ended December 31,		Increase (Decrease)	
	2012	2011	Amount	Percent
Oil Price	$ 88.96	$ 86.72	$ 2.24	3%
Gas Price	$ 4.45	$ 7.06	$ (2.61)	(37)%

We do not apply hedge accounting to any of our commodity based derivatives thus changes in the fair market value of commodity contracts held at the end of a reported period, referred to as mark-to-market adjustments, are recognized as unrealized gains and losses in the accompanying consolidated statements of operations. As oil and natural gas prices remain volatile, mark-to-market accounting treatment creates volatility in our revenues. During the year ended December 31, 2012, we recognized $3.5 million in unrealized gains. This unrealized gain primarily relates to held crude oil fixed swaps and collars associated with future production due to a decrease in crude oil futures market prices between January 1, 2012 and December 31, 2012.

Field service income decreased $2.78 million, or 12% from $23.20 million for the year ended December 31, 2011 to $20.42 million for the year ended December 31, 2012. This decrease in field service income is largely due to gas transportation revenues recovered in 2011. During 2011, we recognized $2.59 million in gas transportation revenues associated with approvals for the recovery of additional cost of our pipelines associated with our offshore properties.

Lease operating expense increased $2.97 million, or 8% from $36.90 million for the year ended December 31, 2011 to $39.87 million for the year ended December 31, 2012. This increase is primarily due to higher salt water disposal costs, production taxes and chemical expenses associated with new wells coming on line from the recent drilling success in West Texas, partially offset by decreased operating expenses on the offshore properties and decreased expensed workovers across all districts during 2012.

Field service expense increased $0.34 million, or 2% from $17.24 million for the year ended December 31, 2011 to $17.58 million for the year ended December 31, 2012. Field service expenses primarily consist of salaries and vehicle operating expenses which remained relatively flat with services and utilization of the equipment during the year ended December 31, 2012 as compared to the same period of 2011.

Depreciation, depletion, amortization and accretion on discounted liabilities decreased $25.13 million, or 52% from $48.40 million for the year ended December 31, 2011 to $23.27 million for the year ended December 31, 2012. This decrease is primarily due to decreased depletion rates recognized during 2012 associated with offshore properties as our offshore properties enter into the last phase of their productive lives and were plugged and abandoned during 2012.

General and administrative expense increased $0.98 million, or 7% from $14.89 million for the year ended December 31, 2011 to $15.87 million for the year ended December 31, 2012. This slight increase is largely due to increased personnel costs in 2012. The largest component of these personnel costs was salaries, however engineering consultants, rent and employee related taxes and insurance also contributed to the increase.

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Gain on sale and exchange of assets of $0.73 million for the year ended December 31, 2012 consists of sales of non-essential field service equipment whereas the gain on sale and exchange of assets of $1.60 million for the year ended December 31, 2011 consists of $1.10 million related to sales of non-producing acreage and non-core producing properties combined with $0.50 million related to undeveloped acreage sold into a joint venture.

Interest expense decreased $0.13 million, or 4% from $3.71 million for the year ended December 31, 2011 to $3.58 million for the year ended December 31, 2012. This decrease includes the reduction of interest expense of $0.79 million for the year ended December 31, 2012 associated with interest on the subordinated credit facility with a related party private lender which was paid off in June 2011. The decrease is partially offset with a net increase of $0.64 million for the year ended December 31, 2012 related to interest on outstanding bank debt. The average interest rate paid on outstanding bank borrowings subject to interest during 2012 and 2011 were 3.81% and 4.78%, respectively. As of December 31, 2012 and 2011, the total outstanding borrowings were $122.00 million and $69.80 million, respectively.

A provision for income taxes of $6.86 million, or an effective tax rate of 31% was recorded for the year ended December 31, 2012 verses a provision of $1.28 million, or an effective tax rate of 21% for the year ended December 31, 2011. Our provision for income taxes varies from the federal statutory tax rate of 34% primarily due to percentage depletion. We are entitled to percentage depletion on certain of our wells, which is calculated without reference to the basis of the property. To the extent that such depletion exceeds a property s basis it creates a permanent difference, which lowers our effective rate.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

We are a smaller reporting company and therefore no response is required pursuant to this Item.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The consolidated financial statements and supplementary information included in this Report are described in the Index to Consolidated Financial Statements at Page F-1 of this Report.

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

None.

Item 9A. CONTROLS AND PROCEDURES.

As of the end of the period covered by this Annual Report on Form 10-K, our principal executive officer and principal financial officer have evaluated the effectiveness of our disclosure controls and procedures (Disclosure Controls). Disclosure Controls, as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934, as amended (the Exchange Act), are procedures that are designed with the objective of ensuring that information required to be disclosed in our reports filed under the Exchange Act, such as this Annual Report, is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms. Disclosure Controls are also designed with the objective of ensuring that such information is accumulated and communicated to our management, including the chief executive officer and chief financial officer, as appropriate to allow timely decisions regarding required disclosure.

Our management, including the chief executive officer and chief financial officer, does not expect that our Disclosure Controls will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions.

Members of our management, including our chief executive officer and chief financial officer, have evaluated the effectiveness of our disclosure controls and procedures, as defined by paragraph (e) of Exchange Act Rules 13a-15 or 15d-15, as of December 31, 2012, the end of the period covered by this Report. Based upon that evaluation, these officers concluded that our disclosure controls and procedures were effective as of December 31, 2012.

Management s Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Our internal control over financial reporting is a process designed to provide reasonable assurance that assets are safeguarded against loss from unauthorized use or disposition, transactions are executed in accordance with appropriate management authorization and accounting records are reliable for the preparation of financial statements in accordance with U.S. generally accepted accounting principles.

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

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2012. Management based this assessment on criteria for effective internal control over financial reporting described in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management s assessment included an evaluation of the design of our internal control over financial reporting and testing of the operational effectiveness of its internal control over financial reporting. Management reviewed the results of its assessment with the Audit Committee of our Board of Directors.

Based on this assessment, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2012.

This Annual Report does not include an attestation report of the Company s registered public accounting firm regarding internal control over financial reporting. Management s report was not subject to attestation by the Company s registered public accounting firm pursuant to rules of the Securities and Exchange Commission that permit the Company to provide only management s report in this Annual Report.

There have been no changes in our internal controls over financial reporting during the fourth fiscal quarter ended December 31, 2012 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Item 9B. OTHER INFORMATION.

None.

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PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

Information relating to the Company s Directors, nominees for Directors and executive officers will be included in the Company s definitive proxy statement relating the Company s Annual Meeting of Stockholders to be held in May, 2013 which will be filed with the U.S. Securities and Exchange Commission within 120 days of December 31, 2012, and which is incorporated herein by reference.

Item 11. EXECUTIVE COMPENSATION.

Information relating to executive compensation will be included in the Company s definitive proxy statement relating to the Company s Annual Meeting of Stockholders to be held in May, 2013, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2012, and which is incorporated herein by reference.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

Information relating to security ownership of certain beneficial owners and management will be included in the Company s definitive proxy statement relating to the Company s Annual Meeting of Stockholders to be held in May, 2013, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2012, and which is incorporated herein by reference.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

Information relating to certain transactions by Directors and executive officers of the Company will be included in the Company s definitive proxy statement relating to the Company s Annual Meeting of Stockholders to be held in May, 2013, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2012, and which is incorporated herein by reference.

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES.

Information relating to principal accountant fees and services will be included in the Company s definitive proxy statement relating to the Company s Annual Meeting of Stockholders to be held in May, 2013, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2012, and which is incorporated herein by reference.

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PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.
The following documents are filed as part of this Report:

1. Financial statements (Index to Consolidated Financial Statements at page F-1 of this Report)

2. Financial Statement Schedules (Index to Consolidated Financial Statements Supplementary Information at page F-1 of this Report)

3. Exhibits:

Exhibit No.	
3.1	Restated Certificate of Incorporation of PrimeEnergy Corporation (effective July 1, 2009) (Incorporated by reference to Exhibit 3.1 to PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2009).
3.2	Bylaws of PrimeEnergy Corporation (Incorporated by reference to Exhibit 3.2 of PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2010).
10.4	Amended and Restated Agreement of Limited Partnership, FWOE Partners L.P., dated as of August 22, 2005 (Incorporated by reference to Exhibit 10.3 of PrimeEnergy Corporation Form 8-K for events of August 22, 2005).
10.4.1	Contribution Agreement between F-W Oil Exploration L.L.C. and FWOE Partners L.P. dated as of August 22, 2005 (Incorporated by reference to exhibit 10.4 of PrimeEnergy Corporation Form 8-K for events of August 22, 2005).
10.18	Composite copy of Non-Statutory Option Agreements (Incorporated by reference to Exhibit 10.18 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2004).
10.22.5.9	Second Amended and Restated Credit Agreement dated July 30, 2010, by and among PrimeEnergy Corporation, the Guarantors Party Hereto (PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, and EOWS Midland Company), Compass Bank (successor in interest to Guaranty Bank, FSB) As Administrative Agent and Letter of Credit Issuer, BBVA Compass, As Sole Lead Arranger and Sole Bookrunner and The Lenders Signatory Hereto (BNP Paribas, JPMorgan Chase Bank, N.A. and Amegy Bank National Association) (Incorporated by reference to Exhibit 10.22.5.9 of PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2010).
10.22.5.9.1	First Amendment To Second Amended and Restated Credit Agreement Among PrimeEnergy Corporation, The Guarantors Party Hereto (PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, E O W S Midland Company), Compass Bank (successor in interest to Guaranty Bank, FSB), As Administrative Agent, Letter of Credit Issuer and Collateral Agent and The Lenders Signatory Hereto (Compass Bank, BNP Paribas, JPMorgan Chase Bank, N.A., Amegy Bank National Association) effective September 30, 2010 (Incorporated by reference to Exhibit 10.22.5.9.1 to PrimeEnergy Corporation Form 10-Q for the quarter ended September 30, 2010).
10.22.5.9.2	Second Amendment To Second Amended and Restated Credit Agreement Among PrimeEnergy Corporation, The Guarantors Party Hereto (PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, E O W S Midland Company), Compass Bank (successor in interest to Guaranty Bank, FSB), As Administrative Agent, Letter of Credit Issuer and Collateral Agent and The Lenders Signatory Hereto (Compass Bank, BNP Paribas, JPMorgan Chase Bank, N.A., Amegy Bank National Association) effective June 22, 2011 (Incorporated by reference to Exhibit 10.22.5.9.2 to PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2011).

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Exhibit No.	
10.22.5.9.3	Third Amendment To Second Amended and Restated Credit Agreement Among PrimeEnergy Corporation, The Guarantors Party Hereto (PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, E O W S Midland Company), Compass Bank (successor in interest to Guaranty Bank, FSB), As Administrative Agent, Letter of Credit Issuer and Collateral Agent and The Lenders Signatory Hereto (Compass Bank, BNP Paribas, JPMorgan Chase Bank, N.A., Amegy Bank National Association) effective December 8, 2011 (Incorporated by reference to Exhibit 10.22.5.9.3 to PrimeEnergy Corporation Form 10-K for the year ended December 31, 2011).
10.22.5.9.4	Fourth Amendment To Second Amended and Restated Credit Agreement Among PrimeEnergy Corporation, The Guarantors Party Hereto (PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, E O W S Midland Company), Compass Bank (successor in interest to Guaranty Bank, FSB), As Administrative Agent, Letter of Credit Issuer and Collateral Agent and The Lenders Signatory Hereto (Compass Bank, BNP Paribas, JPMorgan Chase Bank, N.A., Amegy Bank National Association) effective June 25, 2012 (Incorporated by reference to Exhibit 10.22.5.9.4 to PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2012).
10.22.5.9.5	Fifth Amendment To Second Amended and Restated Credit Agreement Among PrimeEnergy Corporation, The Guarantors Party Hereto (PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, E O W S Midland Company, Prime Offshore L.L.C.), Compass Bank (successor in interest to Guaranty Bank, FSB), As Administrative Agent, Letter of Credit Issuer and Collateral Agent and The Lenders Signatory Hereto (Compass Bank, Wells Fargo Bank National Association, JPMorgan Chase Bank, N.A., Amegy Bank National Association, KeyBank National Association) effective November 26, 2012 (filed herewith).
10.25	Credit Agreement dated as of June 1, 2006 (but effective for all purposes as of August 22, 2005), between Prime Offshore L.L.C. as Borrower and PrimeEnergy Corporation as Lender (Incorporated by reference to Exhibit 10.25 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2006).
14	PrimeEnergy Corporation Code of Business Conduct and Ethics, as amended December 16, 2011 (Incorporated by reference to Exhibit 14 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2011).
21	Subsidiaries (filed herewith).
23	Consent of Ryder Scott & Company L.P. (filed herewith).
31.1	Certification of Chief Executive Officer pursuant to Rule 13(a)-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended (filed herewith).
31.2	Certification of Chief Financial Officer pursuant to Rule 13(a)-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended (filed herewith).
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
99.1	Summary Reserve Report dated March 20, 2013, of Ryder Scott Company, L.P. (filed herewith).
101.INS (1)	XBRL (eXtensible Business Reporting Language) Instance Document.
101.SCH (1)	XBRL Taxonomy Extension Schema Document.

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Exhibit No.	
101.CAL [1]	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF [1]	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB [1]	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE [1]	XBRL Taxonomy Extension Presentation Linkbase Document.

(1) XBRL information (the Interactive Data File) is deemed not filed for purposes of Sections 11 and 12 of the Securities Act of 1933 and Section 18 of the Securities Exchange Act of 1934.

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SIGNATURES

Pursuant to the requirements of 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, on the 27th day of March, 2013

PrimeEnergy Corporation

By: /s/ CHARLES E. DRIMAL, JR.
Charles E. Drimal, Jr.
Chairman, Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated and on the 27th day of March, 2013.

/s/ CHARLES E. DRIMAL, JR.	Chairman, Chief Executive Officer and President;
Charles E. Drimal, Jr.	The Principal Executive Officer
/s/ BEVERLY A. CUMMINGS	Director, Executive Vice President and Treasurer;
Beverly A. Cummings	The Principal Financial Officer

/s/ MATTHIAS ECKENSTEIN Matthias Eckenstein	Director	/s/ CLINT HURT Clint Hurt	Director
/s/ H. GIFFORD FONG H. Gifford Fong	Director	/s/ JAN K. SMEETS Jan K. Smeets	Director
/s/ THOMAS S.T. GIMBEL Thomas S.T. Gimbel	Director		

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INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of

PrimeEnergy Corporation and Subsidiaries:

We have audited the accompanying consolidated balance sheets of PrimeEnergy Corporation and Subsidiaries (the Company) as of December 31, 2012 and 2011, and related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the years then ended. The Company s management is responsible for these financial statements. Our responsibility is to express an opinion on these financial statements 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit includes 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, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of PrimeEnergy Corporation and Subsidiaries as of December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the years then ended, in conformity with accounting principles generally accepted in the United States of America.

/s/ Grassi & Co.

GRASSI & CO. CPAs, P.C.

New York, New York

March 26, 2013

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

(Thousands of dollars)

	As of December 31, 2012	2011
ASSETS		
Current Assets		
Cash and cash equivalents	$ 8,602	$ 8,661
Restricted cash and cash equivalents	4,672	5,142
Accounts receivable, net	13,212	16,506
Prepaid obligations	1,656	7,469
Derivative contracts	1,229	223
Other current assets	1,081	1,725
Total Current Assets	30,452	39,726
Property and Equipment		
Oil and gas properties at cost	338,204	492,393
Less: Accumulated depletion and depreciation	(150,276)	(355,643)
	187,928	136,750
Field and office equipment at cost	23,974	21,553
Less: Accumulated depreciation	(15,052)	(13,608)
	8,922	7,945
Total Property and Equipment, Net	196,850	144,695
Other Assets	784	614
Total Assets	$ 228,086	$ 185,035
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$ 19,568	$ 29,538
Accrued liabilities	7,618	8,963
Current portion of asset retirement and other long-term obligations	2,148	12,854
Derivative liability short-term	994	2,269
Due to related parties	67	67
Total Current Liabilities	30,395	53,691
Long-Term Bank Debt	122,000	69,800
Asset Retirement Obligations	6,864	6,416
Derivative Liability Long-Term	431	1,461
Deferred Income Taxes	24,194	17,914
Total Liabilities	183,884	149,282
Commitments and Contingencies		
Equity		
Common stock, $.10 par value; 2012 and 2011: Authorized: 4,000,000 shares, issued: 3,836,397 shares; outstanding 2012: 2,510,560 shares; 2011: 2,701,869 shares	383	383

Paid-in capital	6,690	6,446
Retained earnings	66,345	51,289
Accumulated other comprehensive loss, net	(35)	
Treasury stock, at cost; 2012: 1,325,837 shares; 2011: 1,134,528 shares	(36,113)	(31,120)
Total Stockholders Equity PrimeEnergy	37,270	26,998
Non-controlling interest	6,932	8,755
Total Equity	44,202	35,753
Total Liabilities and Equity	$ 228,086	$ 185,035

The accompanying Notes are an integral part of these Consolidated Financial Statements

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF OPERATIONS

(Thousands of dollars, except per share amounts)

	For the Year Ended December 31, 2012	For the Year Ended December 31, 2011
Revenues		
Oil and gas sales	$ 87,834	$ 88,429
Realized gain on derivative instruments, net	502	7,601
Field service income	20,421	23,201
Administrative overhead fees	8,585	8,688
Unrealized gain (loss) on derivative instruments	3,483	(914)
Other income	154	75
Total Revenues	120,979	127,080
Costs and Expenses		
Lease operating expense	39,868	36,897
Field service expense	17,576	17,242
Depreciation, depletion, amortization and accretion on discounted liabilities	23,269	48,400
General and administrative expense	15,870	14,890
Exploration costs	10	38
Total Costs and Expenses	96,593	117,467
Gain on Sale and Exchange of Assets	730	1,602
Income from Operations	25,116	11,215
Other Income and Expenses		
Less: Interest expense	3,577	3,711
Add: Interest income	91	446
Income Before Provision for Income Taxes	21,630	7,950
Provision for Income Taxes	6,856	1,275
Net Income	14,774	6,675
Less: Net (Loss) Income Attributable to Non-Controlling Interest	(282)	1,864
Net Income Attributable to PrimeEnergy	$ 15,056	$ 4,811
Basic Income Per Common Share	$ 5.74	$ 1.75
Diluted Income Per Common Share	$ 4.48	$ 1.38

The accompanying Notes are an integral part of these Consolidated Financial Statements

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(Thousands of dollars)

	For the Year Ended December 31, 2012	2011
Net income	$ 14,774	$ 6,675
Other Comprehensive Loss, net of taxes:		
Changes in fair value of hedge positions, net of taxes of $19 and $0, respectively	(35)	
Total other comprehensive loss	(35)	
Comprehensive income	14,739	6,675
Less: Comprehensive income (loss) attributable to non-controlling interest	(282)	1,864
Comprehensive income attributable to PrimeEnergy	$ 15,021	$ 4,811

The accompanying Notes are an integral part of these Consolidated Financial Statements

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF EQUITY

(Thousands of dollars)

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock	Total Stockholders Equity PrimeEnergy	Non-Controlling Interest	Total Equity
Balance at December 31, 2010	3,836,397	$ 383	$ 5,955	$ 46,478	$	$ (28,896)	$ 23,920	$ 9,167	$ 33,087
Purchase 100,184 shares of common stock						(2,224)	(2,224)		(2,224)
Net income				4,811			4,811	1,864	6,675
Purchase of non-controlling interest			491				491	(712)	(221)
Distributions to non-controlling interest								(1,564)	(1,564)
Balance at December 31, 2011	3,836,397	$ 383	$ 6,446	$ 51,289	$	$ (31,120)	$ 26,998	$ 8,755	$ 35,753
Purchase 191,309 shares of common stock						(4,993)	(4,993)		(4,993)
Net income				15,056			15,056	(282)	14,774
Other comprehensive loss, net of taxes					(35)		(35)		(35)
Purchase of non-controlling interest			244				244	(393)	(149)
Distributions to non-controlling interest								(1,148)	(1,148)
Balance at December 31, 2012	3,836,397	$ 383	$ 6,690	$ 66,345	$ (35)	$ (36,113)	$ 37,270	$ 6,932	$ 44,202

The accompanying Notes are an integral part of these Consolidated Financial Statements

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CASH FLOWS

(Thousands of dollars)

	For the Year Ended December 31, 2012	2011
Cash Flows from Operating Activities:		
Net income	$ 14,774	$ 6,675
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion on discounted liabilities	23,269	48,400
Gain on sale of properties	(730)	(1,602)
Unrealized (gain) loss on derivative instruments	(3,483)	914
Provision for deferred income taxes	6,970	718
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable	3,294	(3,758)
(Increase) decrease in due from related parties	(25)	123
(Increase) decrease in inventories	(2)	338
(Increase) decrease in prepaid expenses and other assets	5,761	(5,899)
Decrease in accounts payable	(9,500)	(3,849)
Decrease in accrued liabilities	(616)	(438)
Decrease in due to related parties		(283)
Net Cash Provided by Operating Activities	39,712	41,339
Cash Flows from Investing Activities:		
Capital expenditures, including exploration expense	(86,305)	(39,951)
Proceeds from sale of properties and equipment	881	1,878
Net Cash Used in Investing Activities	(85,424)	(38,073)
Cash Flows from Financing Activities:		
Purchase of stock for treasury	(4,993)	(2,224)
Purchase of non-controlling interests	(149)	(221)
Increase in long-term bank debt and other long-term obligations	111,800	81,631
Repayment of long-term bank debt and other long-term obligations	(59,857)	(85,019)
Repayment of indebtedness to related party		(20,000)
Distribution to non-controlling interest	(1,148)	(1,564)
Net Cash Provided (Used) in Financing Activities	45,653	(27,397)
Net Decrease in Cash and Cash Equivalents	(59)	(24,131)
Cash and Cash Equivalents at the Beginning of the Year	8,661	32,792
Cash and Cash Equivalents at the End of the Year	$ 8,602	$ 8,661
Supplemental Disclosures:		
Income taxes paid during the year	$ 536	$ 1,122
Net income tax refunds received during the year	$	$ 41
Interest paid during the year	$ 2,534	$ 4,033

The accompanying Notes are an integral part of these Consolidated Financial Statements

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Description of Operations and Significant Accounting Policies

Nature of Operations:

PrimeEnergy Corporation (PEC), a Delaware corporation, was organized in March 1973 and is engaged in the development, acquisition and production of oil and natural gas properties. PrimeEnergy Corporation and its subsidiaries are herein referred to as the Company. The Company owns leasehold, mineral and royalty interests in producing and non-producing oil and gas properties across the United States, including Colorado, Kansas, Louisiana, Mississippi, Montana, New Mexico, North Dakota, Oklahoma, Texas, West Virginia and Wyoming and the Gulf of Mexico. The Company operates approximately 1,600 wells and owns non-operating interests in over 800 additional wells. Additionally, the Company provides well-servicing support operations, site-preparation and construction services for oil and gas drilling and reworking operations, both in connection with the Company s activities and providing contract services for third parties. The Company is publicly traded on the NASDAQ under the symbol PNRG. PEC owns Eastern Oil Well Service Company (EOWSC), EOWS Midland Company (EMID) and Southwest Oilfield Construction Company (SOCC), all of which perform oil and gas field servicing. PEC also owns Prime Operating Company (POC), which serves as operator for most of the producing oil and gas properties owned by the Company and affiliated entities. PEC also owns Prime Offshore L.L.C. (Prime Offshore), formerly F-W Oil Exploration LLC, which owns and operates properties in the Gulf of Mexico. PrimeEnergy Management Corporation (PEMC), a wholly-owned subsidiary, acts as the managing general partner, providing administration, accounting and tax preparation services for 18 limited partnerships and 2 trusts (collectively, the Partnerships). The markets for the Company s products are highly competitive, as oil and gas are commodity products and prices depend upon numerous factors beyond the control of the Company, such as economic, political and regulatory developments and competition from alternative energy sources.

Consolidation and Presentation:

The consolidated financial statements include the accounts of PrimeEnergy Corporation, its subsidiaries and the Partnerships, using the full consolidation method for those partnerships which are controlled by the Company. The proportionate consolidation method is used to account for those undivided interests in oil and gas properties owned by the Company as well as interests held in unincorporated legal entities, such as partnerships, engaged in oil and gas production, which are not controlled by the Company. For those entities which are proportionately consolidated, the proportionate share of each entity s assets, liabilities, revenue and expenses are included in the appropriate classifications in the consolidated financial statements. Reserve estimates associated with the proportionately consolidated oil and gas interests are calculated for each property at the Partnership level, and depletion, depreciation and amortization (DD&A) rates are determined at the Partnership level. The Company s reserve estimates are based on the ownership percentage of Partnership reserve reports. DD&A expense and evaluation of impairment may differ from the Partnership as the Company s cost basis for the Partnership interests acquired may be different than the cost basis at the Partnership level for properties acquired by the Partnership. All significant intercompany balances and transactions are eliminated in preparing the consolidated financial statements.

Certain reclassifications have been made to prior year statements to conform with the current year presentation. These reclassifications have no impact on net income. Subsequent events have been evaluated through the date that the consolidated financial statements were issued.

Use of Estimates:

The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Estimates of oil and gas reserves, as determined by independent petroleum engineers, are continually subject to revision based on price, production history and other factors. Depletion expense, which is computed based on the units of production method, could be significantly impacted by changes in such estimates. Additionally, U.S. generally accepted accounting principles require that if the expected future cash flow from an asset is less than its carrying cost, that asset must be written down to its fair market value. As the fair market value of an oil and gas property will usually be significantly less than the total future net revenue expected from that property, small changes in the estimated future net revenue from an asset could lead to the necessity of recording a significant impairment of that asset.

Property and Equipment:

The Company follows the successful efforts method of accounting for its oil and gas properties. Under the successful efforts method, costs of acquiring undeveloped oil and gas leasehold acreage, including lease bonuses, brokers fees and other related costs are capitalized. Provisions for impairment of undeveloped oil and gas leases are based on periodic evaluations. Annual lease rentals and exploration expenses, including geological and geophysical expenses and exploratory dry hole costs, are charged against income as incurred. Costs of drilling and equipping productive wells, including development dry holes and related production facilities, are capitalized. All other property and equipment are carried at cost. Depreciation and depletion of oil and gas production equipment and properties are determined under the unit-of-production method based on estimated proved developed recoverable oil and gas reserves. Depreciation of all other equipment is determined under the straight-line method using various rates based on useful lives generally ranging from 5 to 10 years. The cost of assets and related accumulated depreciation is removed from the accounts when such assets are disposed of, and any related gains or losses are reflected in current earnings.

Capitalization of Interest:

Interest costs related to financing major oil and gas projects in progress are capitalized until the projects are evaluated or until the projects are substantially complete and ready for their intended use if the projects are evaluated and successful.

Impairment of Long-Lived Assets:

The Company reviews long-lived assets, including oil and gas properties, for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recovered. If the carrying amounts are not expected to be recovered by undiscounted cash flows, the assets are impaired and an impairment loss is recorded. The amount of impairment is based on the estimated fair value of the assets determined by discounting anticipated future net cash flows.

Fair Value:

The Company follows the authoritative guidance that establishes a formal framework for measuring fair values of assets and liabilities in financial statements that are already required by U.S. generally accepted accounting principles to be measured at fair value. The guidance 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 transaction is based on a hypothetical transaction in the principal or most advantageous market considered from the perspective of the market participant that holds the asset or owes the liability.

The Company utilizes market data or assumptions that market participants who are independent, knowledgeable and willing and able to transact would use in pricing the asset or liability, including assumptions

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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 attempts to utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The Company is able to classify fair value balances based on the observability of those inputs. The guidance establishes a formal fair value hierarchy based on the inputs used to measure fair value. The hierarchy gives the highest priority to Level 1 measurements and the lowest priority to Level 3 measurements, and accordingly, Level 1 measurements should be used whenever possible.

Asset Retirement Obligation:

The Company follows the accounting standard for asset retirement obligations. The asset retirement obligation primarily represents the estimated present value of the amount the Company will incur to plug, abandon and remediate producing properties (including removal of offshore platforms) at the end of their productive lives, in accordance with applicable state laws. The Company determined its asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The retirement obligation is recorded as a liability at its estimated present value at its inception, with an offsetting increase to producing properties. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement.

Income Taxes:

The Company follows the asset and liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are recorded for the estimated future tax consequences attributable to the differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using the tax rate in effect for the year in which those temporary differences are expected to turn around. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the year of the enacted rate change. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

The Company is required to make judgments, including estimating reserves for potential adverse outcomes regarding tax positions that the Company has taken. The Company accounts for uncertainty in income taxes using a recognition and measurement threshold for tax positions taken or expected to be taken in a tax return. The effective tax rate and the tax basis of assets and liabilities reflect management s estimates of the ultimate outcome of various tax uncertainties.

General and Administrative Expenses:

General and administrative expenses represent cost and expenses associated with the operation of the Company.

Earnings Per Common Share:

Basic earnings per share are computed by dividing earnings available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share reflect per share amounts that would have resulted if dilutive potential common stock had been converted to common stock in gain periods.

Statements of Cash Flows:

For purposes of the consolidated statements of cash flows, the Company considers short-term, highly liquid investments with original maturities of less than ninety days to be cash equivalents.

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Concentration of Credit Risk:

The Company maintains significant banking relationships with financial institutions in the State of Texas. The Company limits its risk by periodically evaluating the relative credit standing of these financial institutions. The Company s oil and gas production purchasers consist primarily of independent marketers and major gas pipeline companies.

Hedging:

The Company periodically enters into oil and gas financial instruments to manage its exposure to oil and gas price volatility. The oil and gas reference prices upon which the price hedging instruments are based reflect various market indices that have a high degree of historical correlation with actual prices received by the Company.

The financial instruments are accounted for in accordance with applicable accounting standards for derivative instruments and hedging activities. Such standards require that applicable derivative instruments be measured at fair market value and recognized as assets or liabilities in the balance sheet. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation is generally established at the inception of a derivative. For derivatives designated as cash flow hedges and meeting applicable effectiveness guidelines, changes in fair value, to the extent effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value of a derivative resulting from ineffectiveness or an excluded component of the gain/loss is recognized immediately in the statement of operations.

Recently Adopted Accounting Standards:

In December 2011, the FASB issued ASU No. 2011-11, Disclosures about Offsetting Assets and Liabilities (ASU 2011-11), which requires that an entity disclose both gross and net information about instruments and transactions that are either eligible for offset in the balance sheet or subject to an agreement similar to a master netting agreement, including derivative instruments. ASU 2011-11 was issued in order to facilitate comparison between U.S. GAAP and IFRS financial statements by requiring enhanced disclosures, but does not change existing U.S. GAAP that permits balance sheet offsetting. This authoritative guidance is effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. The adoption of ASU 2011-11 will not have an impact on the Company s consolidated financial position, results of operations or cash flows as it only requires enhanced disclosures.

2. Acquisitions and Dispositions

Historically, the Company has repurchased the noncontrolling interests of the partners and trust unit holders in certain of the Partnerships, which consist primarily of oil and gas interests. The Company purchased such noncontrolling interests in an amount totaling $149,000 in 2012 and $221,000 in 2011.

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3. Additional Balance Sheet Information

Accounts receivable at December 31, 2012 and 2011 consisted of the following:

	December 31,	
(Thousands of dollars)	**2012**	**2011**
Joint interest billings	$ 2,189	$ 2,347
Trade receivables	1,580	1,558
Oil and gas sales	9,362	9,876
Other	436	3,146
	13,567	16,927
Less: Allowance for doubtful accounts	(355)	(421)
Total	$ 13,212	$ 16,506

Accounts payable at December 31, 2012 and 2011 consisted of the following:

	December 31,	
(Thousands of dollars)	**2012**	**2011**
Trade	$ 3,968	$ 5,853
Royalty and other owners	9,652	13,645
Prepaid drilling deposits	306	779
Other	5,642	9,261
Total	$ 19,568	$ 29,538

Accrued liabilities at December 31, 2012 and 2011 consisted of the following:

	December 31,	
(Thousands of dollars)	**2012**	**2011**
Compensation and related expenses	$ 2,517	$ 2,137
Property costs	4,549	5,117
Income tax		362
Other	552	1,347
Total	$ 7,618	$ 8,963

4. Property and Equipment

Capitalized interest is included as part of the cost of oil and gas properties. The capitalized rates are based upon the Company s weighted-average cost of borrowings used to finance the expenditures. There was no interest capitalized during 2012 or 2011.

5. Long-Term Debt

Bank Debt:

Effective July 30, 2010, the Company entered into a Second Amended and Restated Credit Agreement between Compass Bank as agent and a syndicated group of lenders (Credit Agreement). The Credit Agreement has a revolving line of credit and letter of credit facility of up to $250 million with a final maturity date of July 30, 2014. The credit facility is subject to a borrowing base determined by the lenders taking into consideration the estimated value of PEC s oil and gas properties in accordance with the lenders customary practices for oil and gas loans. This process involves reviewing PEC s estimated proved reserves and their valuation. The borrowing base is redetermined semi-annually, and the available borrowing amount could be increased or decreased as a result of such redetermination. In addition, PEC and the lenders each have at their discretion the right to request the borrowing base be re-determined with a maximum of one such request each year. A revision to PEC s reserves may prompt such a request on the part of the lenders, which could possibly result in a reduction in the borrowing base and availability under the credit facility. At any time if the sum of the outstanding borrowings and letter of credit exposures exceed the applicable portion of the borrowing base, PEC would be required to repay the excess amount within a prescribed period.

The Credit Agreement has been amended from time to time to further define the limitations on loans or advances and investments made in the Company s limited partnerships; modify the Company s borrowing base and monthly reduction amounts; remove the floor rate component of LIBO rate loans; modify financial reporting requirements to the agent; increase hedging allowances; allow for a one-time advance to be made to the Company s offshore subsidiary; and amend restrictions on the payments for dividends, distributions or repurchase of PEC s stock.

The Credit Agreement includes terms and covenants that require the Company to maintain a minimum current ratio, total indebtedness to EBITDAX (earnings before depreciation, depletion, amortization, taxes, interest expense and exploration costs) ratio and interest coverage ratio, as defined, and restrictions are placed on the payment of dividends, the amount of treasury stock the Company may purchase, commodity hedge agreements, and loans and investments in its consolidated subsidiaries and limited partnerships. The credit facility is collateralized by the mortgaged properties and any other property, including interests of the Company s limited partnerships, that was considered in determining the borrowing base in effect. The Company is required to mortgage, and grant a security interest in, consolidated proved oil and gas properties.

Effective June 22, 2011 and subject to facility borrowing base availability amounts, the banks approved a one-time advance of up to $16.0 million to be made from PEC to its offshore subsidiary specifically to be used to pay in full the offshore subsidiary s indebtedness to a related party. The banks required this advance to be made within 30 days after the effective date and the Company completed the advance to its offshore subsidiary on June 24, 2011. Under the Credit Agreement, the maximum percentage of production available to enter into commodity hedge agreements is 90% of proved developed producing reserves for each of the next succeeding four calendar years for crude oil and natural gas computed separately. In addition, the Company s restrictions on the payment of dividends, distributions or purchase of treasury stock is limited to an aggregate of $2.5 million in each calendar year.

At December 31, 2012, the credit facility borrowing base was $145.0 million with no monthly reduction amount. The borrowings made within the credit facility may be placed in a base rate loan or LIBO rate loan. The Company s borrowing rates in the credit facility provide for base rate loans at the prime rate (3.25% at December 31, 2012) plus applicable margin utilization rates that range from 1.75% to 2.0%, and LIBO rate loans at LIBO published rates plus applicable utilization rates (2.75% to 3.00% at December 31, 2012). At December 31, 2012, the Company had in place one base rate loan and one LIBO rate loan with effective rates of 5.00% and 2.97%, respectively.

At December 31, 2012, the Company had $122.0 million of borrowings outstanding under its revolving credit facility at a weighted-average interest rate of 3.17%, and $23.0 million available for future borrowings. The combined weighted average interest rates paid on outstanding bank borrowings subject to base rate and LIBO interest were 3.81% for the year ended December 31, 2012, as compared to 4.78% for the year ended December 31, 2011.

The Company entered into interest rate hedge agreements to help manage interest rate exposure. These contracts include interest rate swaps. Interest rate swap transactions generally involve the exchange of fixed and floating rate interest payment obligations without the exchange of the underlying principal amounts. In July

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2012, the Company entered into interest swap agreements for a period of two years, which commence in January 2014, related to $75 million of the Company s bank debt resulting in a fixed rate of 0.563% plus the Company s current applicable margin.

Indebtedness to Related Parties Non-Current:

In 2008, the Company s offshore subsidiary entered into a subordinated credit facility with a private lender that is controlled by a Director of PEC with an availability of $50 million. Borrowings under this facility bore interest, payable monthly, at a rate of 10% per annum. On January 18, 2011, the Company s offshore subsidiary made a $4.0 million payment on this loan. Further, on June 27, 2011, this loan, along with all accrued interest, was paid in full from the Company s offshore subsidiary, and the note was cancelled.

6. Commitments

Operating Leases:

The Company has several non-cancelable operating leases, primarily for rental of office space, that have a term of more than one year. The future minimum lease payments for the operating leases at December 31, 2012 are as follows.

(Thousands of dollars)	**Operating Leases**
2013	$ 662
2014	261
2015	122
Total minimum payments	$ 1,045

Rent expense for office space for the years ended December 31, 2012 and 2011 was $755,000 and $800,000, respectively.

Asset Retirement Obligation:

A reconciliation of the liability for plugging and abandonment costs for the years ended December 31, 2012 and 2011 is as follows:

	Year Ended December 31,	
(Thousands of dollars)	**2012**	**2011**
Asset retirement obligation at beginning of period	$ 19,013	$ 17,147
Liabilities incurred	733	398
Liabilities settled	(15,361)	(421)
Accretion expense	1,053	1,015
Revisions in estimated liabilities	3,574	874
Asset retirement obligation at end of period	$ 9,012	$ 19,013

The Company s liability is determined using significant assumptions, including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive life of wells and a risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Revisions to the asset retirement obligation are recorded with an offsetting change to producing properties, resulting in prospective changes to depreciation, depletion and amortization expense and accretion of discount. Because of the subjectivity of assumptions and the relatively long life of most of the Company s wells, the costs to ultimately retire the wells may vary significantly from previous estimates.

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In December 2011, the Company entered into a fixed price contract for the plugging and abandonment of a substantial portion of its offshore properties. In connection with this contract, the Company deposited $6.0 million with the contractor which is reflected in prepaid obligations at December 31, 2011. All work under this contract was completed in 2012.

7. Contingent Liabilities

The Company, as managing general partner of the affiliated Partnerships, is responsible for all Partnership activities, including the drilling of development wells and the production and sale of oil and gas from productive wells. The Company also provides the administration, accounting and tax preparation work for the Partnerships, and is liable for all debts and liabilities of the affiliated Partnerships, to the extent that the assets of a given limited Partnership are not sufficient to satisfy its obligations. At December 31, 2012, the affiliated Partnerships have established cash reserves in excess of their debts and liabilities, and the Company believes these reserves will be sufficient to satisfy Partnership obligations.

The Company is subject to environmental laws and regulations. Management believes that future expenses, before recoveries from third parties, if any, will not have a material effect on the Company s financial condition. This opinion is based on expenses incurred to date for remediation and compliance with laws and regulations, which have not been material to the Company s results of operations.

From time to time, the Company is party to certain legal actions arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on the financial position or results of operations of the Company.

8. Stock Options and Other Compensation

In May 1989, non-statutory stock options were granted by the Company to four key executive officers for the purchase of shares of common stock. At December 31, 2012 and 2011, options on 767,500 shares were outstanding and exercisable at prices ranging from $1.00 to $1.25. According to their terms, the options have no expiration date.

9. Income Taxes

The components of the provision (benefit) for income taxes for the years ended December 31, 2012 and 2011 are as follows:

	Year Ended December 31,	
(Thousands of dollars)	**2012**	**2011**
Current:		
Federal	$ 16	$ 503
State	(130)	54
Total current	(114)	557
Deferred:		
Federal	7,009	522
State	(39)	196
Total deferred	6,970	718
Total income tax provision	$ 6,856	$ 1,275

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The components of net deferred tax assets and liabilities are as follows:

(Thousands of dollars)	At December 31, 2012	2011
Current Assets:		
Accrued liabilities	$ 613	$ 474
Allowance for doubtful accounts	124	148
Derivative contracts	(83)	723
Total current deferred income tax assets	$ 654	$ 1,345
Non-Current Assets:		
Alternative minimum tax credits	$ 5,890	$ 5,873
Net operating loss carry-forwards	114	161
Percentage depletion carry-forwards	4,287	2,946
Derivative contracts	91	520
Total non-current assets	10,382	9,500
Non-Current Liabilities:		
Basis differences relating to managed partnerships	1,492	1,989
Depletion and depreciation	33,084	25,425
Total non-current liabilities	34,576	27,414
Net non-current deferred income tax liabilities	$ 24,194	$ 17,914

The total provision for income taxes for the years ended December 31, 2012 and 2011 varies from the federal statutory tax rate as a result of the following:

(Thousands of dollars)	Year Ended December 31, 2012	2011
Expected tax expense	$ 7,450	$ 2,069
State income tax, net of federal benefit	(112)	167
Percentage depletion	(902)	(1,242)
Other, net	420	281
Total income tax provision	$ 6,856	$ 1,275

Deferred income taxes reflect the impact of temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and such amounts recognized for tax purposes. Differences relating to oil and gas properties owned through Prime Offshore are reflected under Depletion and depreciation, while basis differences relating to the managed partnerships are reflected under Basis differences relating to managed partnerships.

The Company is entitled to percentage depletion on certain of its wells, which is calculated without reference to the basis of the property. To the extent that such depletion exceeds a property s basis, it creates a permanent difference, which lowers the Company s effective rate. The Company s effective tax rates in 2012 and 2011 are lower than the statutory federal rate primarily due to percentage depletion deductions in excess of the Company s basis in the property.

The Company has not recorded any provision for uncertain tax positions. The Company files income tax returns in the U.S. federal jurisdiction and various state and local jurisdictions. The 2004, 2005, 2006, and 2009 federal income tax returns have been audited by the Internal Revenue Service, while the 2010 and 2011 returns remain open for examination. Returns for unexamined earlier years may be examined and adjustments made to

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the amount of percentage depletion carryforwards flowing from those years into an open tax year, although in general no assessment of income tax may be made for those years on which the statute has closed. State returns for the years 2009, 2010 and 2011 remain open for examination by the relevant taxing authorities.

10. Segment Information and Major Customers

The Company operates in one industry oil and gas exploration, development, operation and servicing. The Company s oil and gas activities are entirely in the United States.

The Company sells its oil and gas production to a number of purchasers. Listed below are the percent of the Company s total oil and gas sales made to each of the customers whose purchases represented more than 10% of the Company s oil and gas sales in the year 2012.

Oil Purchasers:		Gas Purchasers:	
Plains All American Inc.	57%	Atlas Pipeline Mid-Continent	45%
Sunoco, Inc.	26%	Unimark LLC	14%

Although there are no long-term oil and gas purchasing agreements with these purchasers, the Company believes that they will continue to purchase its oil and gas products and, if not, could be replaced by other purchasers.

11. Financial Instruments

Fair Value Measurements:

Authoritative guidance on fair value measurements defines fair value, establishes a framework for measuring fair value and stipulates the related disclosure requirements. The Company follows a three-level hierarchy, prioritizing and defining the types of inputs used to measure fair value. The fair values of the Company s interest rate swaps, natural gas and crude oil price collars and swaps are designated as Level 3. The following fair value hierarchy table presents information about the Company s assets and liabilities measured at fair value on a recurring basis at December 31, 2012 and 2011:

December 31, 2012 *(Thousands of dollars)*	Quoted Prices in Active Markets For Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2012
Assets				
Commodity derivative contracts	$	$	$ 1,347	$ 1,347
Total assets	$	$	$ 1,347	$ 1,347
Liabilities				
Commodity derivative contracts	$	$	$ (1,371)	$ (1,371)
Interest rate derivative contracts			(54)	(54)
Total liability	$	$	$ (1,425)	$ (1,425)

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December 31, 2011 *(Thousands of dollars)*	**Quoted Prices in Active Markets For Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Balance at December 31, 2011**
Assets				
Commodity derivative contracts	$	$	$ 223	$ 223
Total assets	$	$	$ 223	$ 223
Liabilities				
Commodity derivative contracts	$	$	$ (3,730)	$ (3,730)
Total liability	$	$	$ (3,730)	$ (3,730)

The derivative contracts were measured based on quotes from the Company s counterparties. Such quotes have been derived using valuation models that consider various inputs including current market and contractual prices for the underlying instruments, quoted forward prices for natural gas and crude oil, volatility factors and interest rates, such as a LIBOR curve for a similar length of time as the derivative contract term as applicable. These estimates are verified using comparable NYMEX futures contracts or are compared to multiple quotes obtained from counterparties for reasonableness.

The significant unobservable inputs for Level 3 derivative contracts include basis differentials and volatility factors. An increase (decrease) in these unobservable inputs would result in an increase (decrease) in fair value, respectively. The Company does not have access to the specific assumptions used in its counterparties valuation models. Consequently, additional disclosures regarding significant Level 3 unobservable inputs were not provided.

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the years ended December 31, 2012 and 2011.

(Thousands of dollars)	**Year Ended December 31, 2012**	**2011**
Net liabilities at beginning of period	$ (3,507)	$ (2,593)
Total realized and unrealized (gains) losses:		
Included in earnings (a)	3,985	6,687
Included in other comprehensive loss	(54)	
Purchases, sales, issuances and settlements	(502)	(7,601)
Net liabilities at end of period	$ (78)	$ (3,507)

(a) Derivative instruments are reported in revenues as realized gain/loss and on a separately reported line item captioned unrealized gain/loss on derivative instruments, and interest rate swap instruments are reported as a reduction to interest expense.

Derivative Instruments:

The Company is exposed to commodity price and interest rate risk, and management considers periodically the Company s exposure to cash flow variability resulting from the commodity price changes and interest rate fluctuations. Futures, swaps and options are used to manage the Company s exposure to commodity price risk inherent in the Company s oil and gas production operations. The Company does not apply hedge accounting to any of its commodity based derivatives. Both realized and unrealized gains and losses associated with commodity derivative instruments are recognized in earnings.

Interest rate swap derivatives continue to be treated as cash-flow hedges and are used to fix or float interest rates on existing debt. The value of these interest rate swaps at December 31, 2012 is located in accumulated

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other comprehensive loss, net of tax. Settlement of the swaps, currently scheduled to begin in January 2014, will be recorded within interest expense.

The following table sets forth the effect of derivative instruments on the consolidated balance sheets at December 31, 2012 and 2011:

(Thousands of dollars)	**Balance Sheet Location**	**Fair Value at December 31, 2012**	**2011**
Asset Derivatives:			
Derivatives not designated as cash-flow hedging instruments:			
Crude oil commodity contracts	Derivative contracts	$ 189	$ 223
Natural gas commodity contracts	Derivative contracts	1,040	
Crude oil commodity contracts	Other assets	118	
Total		$ 1,347	$ 223
Liability Derivatives:			
Derivatives designated as cash-flow hedging instruments:			
Interest rate swap contracts	Derivative liability long-term	$ (54)	$
Derivatives not designated as cash-flow hedging instruments:			
Crude oil commodity contracts	Derivative liability short-term	(994)	(2,269)
Crude oil commodity contracts	Derivative liability long-term	(377)	(1,461)
Total		$ (1,425)	$ (3,730)
Total derivative instruments		$ (78)	$ (3,507)

The following table sets forth the effect of derivative instruments on the consolidated statements of operations for the years ended December 31, 2012 and 2011:

(Thousands of dollars)	**Location of gain/loss recognized in income**	**Amount of gain/loss recognized in income 2012**	**2011**
Derivatives not designated as cash-flow hedge instruments:			
Natural gas commodity contracts	Unrealized gain (loss) on derivative instruments, net	$ 1,040	$ (3,037)
Crude oil commodity contracts	Unrealized gain on derivative instruments, net	2,443	2,123
Natural gas commodity contracts (a)	Realized gain on derivative instruments, net		6,289
Crude oil commodity contracts (a)	Realized gain on derivative instruments, net	502	1,312
		$ 3,985	$ 6,687

(a) In August 2011 and October 2011, the Company unwound and monetized natural gas and crude oil swaps and collars with original settlement dates from September 2011 through December 2014 for aggregated net proceeds of $6.29 million. The $6.29 million gain associated with these early settlement transactions is included in realized gain on derivative instruments for the year ended December 31, 2011. In January 2012, March 2012 and May 2012, the Company unwound and monetized crude oil swaps with original

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settlement dates from January 2012 through December 2013 for aggregated net proceeds of $1.03 million. The $1.03 million gain associated with these early settlement transactions is included in realized gain on derivative instruments for the year ended December 31, 2012.

12. Related Party Transactions

The Company, as managing general partner or managing trustee, makes an annual offer to repurchase the interests of the partners and trust unit holders in certain of the Partnerships or Trusts. The Company purchased such interests in an amount totaling $149,000 during 2012 and $221,000 during 2011.

Treasury stock purchases in any reported period may include shares from a related party. In April 2012, the Company purchased 45,179 shares of common stock as treasury shares from a Director for $1.13 million. There were no other related party treasury stock purchases during the years ended December 31, 2012 and 2011.

Receivables from related parties consist of reimbursable general and administrative costs, lease operating expenses and reimbursement for property development and related costs. These receivables are due from joint venture partners, which may include members of the Company s Board of Directors.

Payables owed to related parties primarily represent receipts collected by the Company as agent for the joint venture partners, which may include members of the Company s Board of Directors, for oil and gas sales net of expenses. Also included in interest expense in 2011 is $787,000 of interest expense paid to a private lender that is controlled by a director of the Company, with whom the Company s offshore subsidiary entered into a credit agreement. The agreement provided for a loan of $20 million at a rate of 10% per annum and is secured by a second lien position of all the assets of the offshore subsidiary. On June 27, 2011, this loan along with all accrued interest was paid in full from the Company s offshore subsidiary, and the note was cancelled.

13. Restricted Cash and Cash Equivalents

Restricted cash and cash equivalents include $4.44 million and $4.39 million at December 31, 2012 and 2011, respectively, of cash primarily pertaining to oil and gas revenue payments. There were corresponding accounts payable recorded at December 31, 2012 and 2011 for these liabilities. Both the restricted cash and the accounts payable are classified as current on the accompanying consolidated balance sheets.

14. Salary Deferral Plan

The Company maintains a salary deferral plan (the Plan) in accordance with Internal Revenue Code Section 401(k), as amended. The Plan provides for matching contributions of which $463,000 and $447,000 were made in 2012 and 2011, respectively.

15. Earnings per Share

Basic earnings per share are computed by dividing earnings available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share reflect per

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share amounts that would have resulted if dilutive potential common stock had been converted to common stock in gain periods. The following reconciles amounts reported in the financial statements:

	Year Ended December 31, 2012			2011		
	Net Income (In 000 s)	Weighted Average Number of Shares Outstanding	Per Share Amount	Net Income (In 000 s)	Weighted Average Number of Shares Outstanding	Per Share Amount
Basic	$ 15,056	2,624,335	$ 5.74	$ 4,811	2,747,732	$ 1.75
Effect of dilutive securities:						
Options		735,244			731,702	
Diluted	$ 15,056	3,359,579	$ 4.48	$ 4,811	3,479,434	$ 1.38

16. Shareholder s Equity

The Company has in place a stock repurchase program whereby it may purchase outstanding shares of its common stock from time-to-time, in open market transactions or negotiated sales. The Company uses the cost method to account for its treasury share purchases.

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SUPPLEMENTARY INFORMATION

PRIMEENERGY CORPORATION AND SUBSIDIARIES

SUPPLEMENTARY INFORMATION

CAPITALIZED COSTS RELATING TO

OIL AND GAS PRODUCING ACTIVITIES

Years Ended December 31, 2012 and 2011

(Unaudited)

	As of December 31,	
(Thousands of dollars)	**2012**	**2011**
Proved Developed oil and gas properties	$ 336,135	$ 491,938
Proved Undeveloped oil and gas properties	2,069	455
Unproved oil and gas properties		
Total Capitalized Costs	338,204	492,393
Accumulated depreciation, depletion and valuation allowance	150,276	355,643
Net Capitalized Costs	$ 187,928	$ 136,750

COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION,

EXPLORATION AND DEVELOPMENT ACTIVITIES

Years Ended December 31, 2012 and 2011

(Unaudited)

	Year Ended December 31,	
(Thousands of dollars)	**2012**	**2011**
Acquisition of Properties, Developed	$ 6,482	$ 273
Acquisition of Properties, Undeveloped	2,030	146
Exploration Costs	10	38

Development Costs	66,671	38,820

See accompanying Notes to Supplementary Information

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

SUPPLEMENTARY INFORMATION

STANDARDIZED MEASURE OF DISCOUNTED FUTURE

NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES

Years Ended December 31, 2012 and 2011

(Unaudited)

	As of December 31,	
(Thousands of dollars)	**2012**	**2011**
Future cash inflows	$ 1,524,137	$ 1,113,603
Future production costs	(673,629)	(530,237)
Future development costs	(179,568)	(67,158)
Future income tax expenses	(186,072)	(148,283)
Future Net Cash Flows	484,868	367,925
10% annual discount for estimated timing of cash flows	(271,595)	(183,417)
Standardized Measure of Discounted Future Net Cash Flows	$ 213,273	$ 184,508

STANDARDIZED MEASURE OF DISCOUNTED FUTURE

NET CASH FLOWS AND CHANGES THEREIN

RELATING TO PROVED OIL AND GAS RESERVES

Years Ended December 31, 2012 and 2011

(Unaudited)

The following are the principal sources of change in the standardized measure of discounted future net cash flows during 2012 and 2011:

	Year Ended December 31,	
(Thousands of dollars)	**2012**	**2011**
Sales of oil and gas produced, net of production costs	$ (48,673)	$ (59,133)
Net changes in prices and production costs	504	77,637
Extensions, discoveries and improved recovery	164,557	49,108

Revisions of previous quantity estimates	40,964	8,579
Net change in development costs	(145,382)	(30,834)
Reserves sold		
Reserves purchased	6,563	
Accretion of discount	18,451	14,648
Net change in income taxes	(5,952)	(20,342)
Changes in production rates (timing) and other	(2,267)	(1,639)
Net change	28,765	38,024
Standardized measure of discounted future net cash flow:		
Beginning of year	184,508	146,484
End of year	$ 213,273	$ 184,508

See accompanying Notes to Supplementary Information

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

SUPPLEMENTARY INFORMATION

RESERVE QUANTITY INFORMATION

Years Ended December 31, 2012 and 2011

(Unaudited)

	As of December 31, 2012			2011	
	Oil (MBbls)	NGLs (MBbls) (a)	Gas (MMcf)	Oil (MBbls)	Gas (MMcf)
Proved Developed Reserves:					
Beginning of year	6,418		43,631	5,233	41,946
Extensions, discoveries and improved recovery	224	49	1,000	836	3,536
Revisions of previous estimates	252	2,860	(15,821)	273	121
Converted from undeveloped reserves	861		3,527	704	3,028
Reserves sold					
Reserves purchased	168		211		
Production	(745)		(4,715)	(628)	(5,000)
End of year	7,178	2,909	27,833	6,418	43,631
Proved Undeveloped Reserves:					
Beginning of year	2,435		9,765	2,652	11,400
Extensions, discoveries and improved recovery	3,446	1,401	6,158	460	1,955
Revisions of previous estimates	887	1,476	217	27	(562)
Converted to developed reserves	(861)		(3,527)	(704)	(3,028)
Reserves sold					
Reserves purchased					
End of year	5,907	2,877	12,613	2,435	9,765
Total Proved Reserves at the End of the Year	13,085	5,786	40,446	8,853	53,396

(a) Prior to December 31, 2012, natural gas liquids (NGLs) were included in the oil and gas reserve reports under the natural gas heading using a standard conversion factor of one barrel of NGLs to six thousand cubic feet (Mcf) of gas.

See accompanying Notes to Supplementary Information

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

SUPPLEMENTARY INFORMATION

RESULTS OF OPERATIONS FROM OIL AND GAS PRODUCING ACTIVITIES

Years Ended December 31, 2012 and 2011

(Unaudited)

	Year Ended December 31,	
(Thousands of dollars)	**2012**	**2011**
Revenue:		
Oil and gas sales	$ 88,336	$ 96,030
Costs and Expenses:		
Lease operating expenses	39,868	36,897
Exploration costs	10	38
Depreciation and depletion	19,883	42,282
Income tax expense	8,941	3,200
Total Costs and Expenses	68,702	82,417
Results of Operations From Producing Activities (excluding corporate overhead and interest costs)	$ 19,634	$ 13,613

See accompanying Notes to Supplementary Information

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

NOTES TO SUPPLEMENTARY INFORMATION

(Unaudited)

1. Presentation of Reserve Disclosure Information

Reserve disclosure information is presented in accordance with U.S. generally accepted accounting principles. The Company s reserves include amounts attributable to non-controlling interests in the Partnerships. These interests represent less than 10% of the Company s reserves.

2. Determination of Proved Reserves

The estimates of the Company s proved reserves were determined by an independent petroleum engineer in accordance with U.S. generally accepted accounting principles. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development and other factors. Estimated future net revenues were computed by reserves, less estimated future development and production costs based on current costs.

3. Results of Operations from Oil and Gas Producing Activities

The results of operations from oil and gas producing activities were prepared in accordance with U.S. generally accepted accounting principles. General and administrative expenses, interest costs and other unrelated costs are not deducted in computing results of operations from oil and gas activities.

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

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves and the changes of standardized measure of discounted future net cash flows relating to proved oil and gas reserves were prepared in accordance with U.S. generally accepted accounting principles.

Future cash inflows are computed as described in Note 2 by applying current prices to year-end quantities of proved reserves.

Future production and development costs are computed estimating the expenditures to be incurred in developing and producing the oil and gas reserves at year-end, based on year-end costs and assuming continuation of existing economic conditions.

Future income tax expenses are calculated by applying the year-end U.S. tax rate to future pre-tax cash inflows relating to proved oil and gas reserves, less the tax basis of properties involved. Future income tax expenses give effect to permanent differences and tax credits and allowances relating to the proved oil and gas reserves.

Future net cash flows are discounted at a rate of 10% annually (pursuant to applicable guidance) to derive the standardized measure of discounted future net cash flows. This calculation does not necessarily represent an estimate of fair market value or the present value of such cash flows since future prices and costs can vary substantially from year-end and the use of a 10% discount figure is arbitrary.

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5. Changes in Reserves

The 2012 and 2011 extensions and discoveries reflect the successful drilling activity in the Company s West Texas and Mid-Continent areas. The Company is employing technologies to establish proved reserves that have been demonstrated to provide consistent results capable of repetition. The technologies and economic data being used in the estimation of its proved reserves include, but are not limited to, electrical logs, radioactivity logs, geologic maps, production data and well test data. The estimated reserves of wells with sufficient production history are estimated using appropriate decline curves. Estimated reserves of producing wells with limited production history and for undeveloped locations are estimated using performance data from analogous wells in the area. These wells are considered analogous based on production performance from the same formation and with similar completion techniques.