CRIMSON EXPLORATION INC.
Form 10-K
March 18, 2011

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

FORM 10-K

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2010
OR
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number: 001-12108

CRIMSON EXPLORATION INC.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	20-3037840 (I.R.S. Employer Identification No.)
717 Texas Avenue, Suite 2900 Houston, Texas (Address of principal executive offices)	77002 (Zip Code)

(713) 236-7400
(Registrant's telephone number, including area code)

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

Securities registered pursuant to Section 12(g) of the Act: Common Stock, $0.001 par value per share

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

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

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. o

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

Large accelerated filer o	Accelerated filer o	Non-accelerated filer o (Do not check if smaller reporting company)	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 o No x

As of June 30, 2010, the aggregate market value of the registrant’s common stock held by non-affiliates of the registrant was $58,284,720 based on the closing sales price of $2.67 of the Registrant’s common stock. For purposes of this computation, all executive officers, directors and 10% beneficial owners of the registrant are deemed to be affiliates. Such a determination should not be deemed an admission that such executive officers, directors and 10% beneficial owners are affiliates.

On March 9, 2011, there were 45,203,278 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of our Definitive Proxy Statement for the 2011 Annual Meeting, expected to be filed within 120 days of our fiscal year end, are incorporated by reference into Part III.

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

We make forward-looking statements throughout this Annual Report within the meaning of Section 27A of the Securities Act, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act").

These forward-looking statements include, but are not limited to, statements regarding:

- estimates of proved reserve quantities and net present values of those reserves;
- reserve potential;
- business strategy;
- estimates of future commodity prices;
- amounts, timing and types of capital expenditures and operating expenses;
- expansion and growth of our business and operations;
- expansion and development trends of the oil and gas industry;
- acquisitions of natural gas and crude oil properties;
- production of crude oil and natural gas reserves;
- exploration prospects;
- wells to be drilled and drilling results;
- operating results and working capital;
- results of borrowing base redeterminations under our revolving credit facility;
- future methods and types of financing; and
- the risks described elsewhere in this Annual Report and in the documents incorporated by reference herein.

Whenever you read a statement that is not simply a statement of historical fact (such as when we describe what we "believe," "expect" or "anticipate" will occur, and other similar statements), you must remember that our expectations may not be correct, even though we believe they are reasonable. We caution that a number of factors could cause future production, revenues and expenses to differ materially from our expectations. We do not guarantee that the transactions and events described in this Annual Report will happen as described (or that they will happen at all). The forward-looking information contained in this Annual Report is generally located in the material provided under the headings "Business," "Risk Factors," and "Management's Discussion and Analysis of Financial Condition and Results of Operations" but may be found in other locations as well. These forward-looking statements generally relate to our plans and objectives for future operations and are based upon our management's reasonable estimates of future results and trends. For a discussion of risk factors affecting our business, see "Risk Factors."

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PART I

ITEM 1. Business

Company Overview

Crimson is an independent energy company engaged in the acquisition, exploitation, exploration and development of natural gas and crude oil properties. We have historically focused our operations in the onshore U.S. Gulf Coast and South Texas regions, which are generally characterized by high rates of return in known, prolific producing trends. We have recently expanded our strategic focus to include longer reserve life resource plays that we believe provide significant long-term growth potential in multiple formations.

We intend to grow reserves and production by developing our existing producing property base, developing our East Texas and South Texas resource potential, and pursuing opportunistic acquisitions in areas where we have specific operating expertise. We have developed a significant project inventory associated with our existing property base. Our technical team has a successful track record of adding reserves through the drillbit. Since January 2008 and through December 2010, we have drilled 42 gross (19.0 net) wells with an overall success rate of 93%. At December 31, 2010, we had two wells in progress.

As of December 31, 2010, our proved reserves, as estimated by our independent reserve engineering firm, Netherland, Sewell & Associates, Inc., in accordance with reserve reporting guidelines mandated by the SEC, were 166.5 Bcfe, consisting of 135.7 Bcf of natural gas and 5.1 MMBbl of crude oil, condensate and natural gas liquids, with a PV-10 of $239.7 million. As of December 31, 2010, 81% of our proved reserves were natural gas, 48% were proved developed and 89% were attributed to wells and properties operated by us. During 2010 we grew proved reserves from 97.5 Bcfe at December 31, 2009 to 166.5 Bcfe at December 31, 2010.

Our areas of primary focus include the following:

- Southeast Texas. Our Southeast Texas region includes approximately 25,900 gross (14,600 net) acres in the Felicia field area in Liberty County, and in Madison and Grimes Counties. As of December 31, 2010, we owned 72 gross (38.8 net) producing wells producing mostly from the Yegua, Georgetown and Cook Mountain formations. Our 2011 capital budget includes 5 gross (3.5 net) wells in this region, three in Liberty County, as well as initial wells targeting the Woodbine and Georgetown horizontal oil plays in Madison County.

- South Texas. Our South Texas region includes approximately 13,000 (6,150 net) acres in Karnes, Zavala and Dimmitt Counties that is held by production and which we believe to be prospective in the oil-weighted sections of the Eagle Ford Shale in those counties. Our South Texas region also includes approximately 2,800 gross (560 net) acres in Bee County, which we believe to be prospective in the Austin Chalk and gas/condensate section of the Eagle Ford Shale. We also have approximately 89,300 gross (51,300 net) acres predominantly in Brooks, Lavaca, DeWitt, Zapata, Webb and Matagorda Counties that are prospective for conventional drilling. During the third quarter of 2010, our industry partner successfully drilled two wells in Bee County confirming the existence of the Eagle Ford gas/condensate window and these wells commenced production in January 2011. As of December 31, 2010, we owned 280 gross conventional (146.3 net) producing wells in the South Texas region producing from the Wilcox, Frio and Vicksburg formations, as well as others. Our 2011 capital budget includes plans to drill three gross (1.2 net) wells in this region; one gross (0.2 net) in Bee County, one gross (0.5 net) in Zavala County and one gross (0.5 net) in Karnes County targeting the Eagle Ford oil section.

- East Texas. Our East Texas region includes approximately 18,200 gross (12,700 net) acres acquired in 2008 and 2009 in the highly prospective gas resource play in San Augustine and Sabine Counties, where we are focusing primarily on the pursuit of the Haynesville Shale, Mid-Bossier Shale and James Lime formations. In November 2009, we announced the completion and initial production of our first well on this acreage, the Kardell #1H, with the horizontal completion in the Haynesville Shale formation. In 2010, we began the operated phase of our drilling program in East Texas with our

Grizzly #1 well which we completed in the Mid-Bossier formation and which began commercial production in August 2010. We then completed our Gobi #1H well in the Mid-Bossier and it commenced production.in November 2010. All three of these wells are in our Bruin Prospect Area in San Augustine County. At the end of February 2011 we completed the Bengal #1H, which is the first well in our Tiger Prospect Area in Sabine County, Texas and it is currently being put on production. We also participated, on a non-operated basis, in the drilling of the first well in our Fairway Farms Prospect Area, the Halbert Trust GU #1, a Mid-Bossier completion that commenced production in December 2010. Our 2011 capital budget currently includes a total of 4 gross (2.2 net) wells in East Texas, three in our Bruin Prospect Area and one in our Bulldog Prospect Area. We anticipate that we will ultimately preserve between 4,000 and 6,000 net acres in East Texas by 2012 through drilling or lease extensions.

We also own interests in the following areas:

- Colorado and Other. This region includes approximately 16,900 gross (11,800 net) acres in the Denver Julesburg Basin in Colorado (mostly in Adams and Weld Counties), minor non-operating working interests in the Fenton field area of Calcasieu Parish, Louisiana and a minor crude oil property in Mississippi. There has been a recent surge in activity in the area of our Colorado properties in pursuit of the Niobrara oil formation. The vast majority of our acreage in this area is held by production, so we have the flexibility to monitor the activity, and results, of our industry peers in the Niobrara to develop our exploitation strategy. We currently plan to drill one gross (0.7 net) well in the Niobrara in 2011.

The following table sets forth certain information with respect to our proved reserves as of December 31, 2010, as estimated by Netherland, Sewell & Associates, Inc., and net production and net acreage for the twelve months ended December 31, 2010. The following table also identifies potential drilling locations as of December 31, 2010:

Region	Estimated Proved Reserves as of December 31, 2010 (MMcfe)	% Natural Gas	% Proved Developed	Average Daily Production for the Twelve Months Ended December 31, 2010 (Mcfe/d)	Net acreage at December 31, 2010	Identified Potential Gross Drilling Locations at December 31, 2010 (1) (2)
Southeast Texas	28,262	57%	86%	18,560	14,600	65
South Texas	71,024	77%	58%	12,880	51,300	359
East Texas(3)	59,336	100%	16%	2,677	12,800	245
Colorado and Other	7,876	72%	64%	1,295	12,400	191
Total	166,498	81%	48%	35,412	91,100	860

(1) Includes multiple drilling locations on acreage with multiple target formations.

(2) Includes 178 drilling locations on our resource play acreage in South Texas. Due to the nature of the acreage, these reserves and potential drilling locations may not all eventually be operated by us. See “Risk Factors— Many of our East Texas leases are not producing and must be drilled before expiration, generally within three years, in order to hold the leases by production, or they will terminate.”

(3)

All drilling locations are on resource play acreage. In the highly competitive market for Haynesville Shale acreage, failure to drill sufficient wells timely to hold this acreage will result in a substantial renewal cost, or if renewal is not feasible, loss of lease investment and prospective drilling opportunities in the Haynesville Shale, as well as in the Mid-Bossier Shale, James Lime, Pettet and Knowles Lime formations. Drilling locations in this region were identified assuming between 4,000 and 6,000 net acres are held through drilling or lease extensions and an allocated 80 acres per potential horizontal East Texas well drilled to multiple target formations.

We have significantly increased our proved reserves and production through acquisitions since our recapitalization in early 2005. In 2007, we tripled our reserve size through the acquisition from EXCO Resources, Inc. ("EXCO") of producing properties in the South Texas, Southeast Texas and Southwest Louisiana regions, adding an aggregate of approximately 95 Bcfe to our net proved reserves at a cost of $2.50 per Mcfe of proved reserves as of the effective date. We also added 21 Bcfe to our South Texas proved reserves through the Smith Production Inc. ("Smith") acquisition in 2008 at an average cost of $2.82 per Mcfe of proved reserves as of the closing date. Our acquisitions are typically focused on areas in which we can leverage our geographic and geological expertise to exploit those drilling opportunities identified at the time of the acquisition and develop an inventory of additional drilling prospects that we believe will enable us to grow production and add reserves. We intend to continue to pursue the acquisition of assets in our core areas, to continue to selectively expand our presence and exploit our positions in our East Texas and South Texas resource plays and to continue to develop exploratory opportunities through our internal prospect generation team.

During 2008 and 2009, we acquired approximately 12,700 net acres in San Augustine and Sabine Counties in East Texas, which we have proved to be prospective in the Haynesville Shale, Mid-Bossier, and James Lime formations. Recent activity in the area indicates that the Pettet and Knowles Lime formations also appear prospective. We have separated our acreage into several joint development areas ("JDAs") of varying sizes and are working with other industry players holding acreage positions in those areas to jointly develop our positions. We believe that we will ultimately be able to preserve between 4,000 and 6,000 net acres in this play through drilling, re-leasing or obtaining lease extensions. We have successfully drilled five (100% success rate) wells on our East Texas acreage and currently have two awaiting completion and one being placed on production.

Offices

We currently lease and sublease, through January 31, 2014, 54,939 square feet of executive and corporate office space located at 717 Texas Avenue in downtown Houston, Texas. Rent, including parking and net of sublease rent, related to this office space for the twelve months ended December 31, 2010 was approximately $1.1 million. Effective January 1, 2010, we subleased to a subtenant 27,144 square feet of this space for a total rental of approximately $86,000 per month through September 30, 2011.

Strategy

The key elements of our business strategy are:

- Enhance our portfolio by shifting capital to our oil and liquids rich opportunities. During 2011 we will pursue a balanced drilling program that is designed to validate our multiple oil and liquids rich opportunities in proven, active areas, while continuing to preserve only the highest-potential, concentrated portions of our acreage position in the East Texas Haynesville/Mid-Bossier/James Lime play. We made the decision to allocate a much larger portion of our 2011 capital budget to the oil-weighted opportunities due to superior current economics, the weakness of the natural gas market and the difficulty in consolidating drilling units in the East Texas gas play prior to lease expirations due to the shift in focus of the other operators in the area to oil weighted projects.

- Exploit our existing producing conventional property base to generate cash flows. We believe our multi-year drilling inventory of high return exploitation opportunities on our existing producing properties provides us with a solid platform to continue growing our reserves and production for the next several years. We believe these projects, if successful, will allow us to fund a substantial portion of our resource play activity from cash flows from operations. We are currently focusing much of our exploitation drilling on our Liberty County acreage, located in Southeast Texas. We will be targeting the Yegua and Cook Mountain formations in which we and other industry players have experienced consistent success in the area. We own 3D seismic data that covers substantially all of our Liberty County acreage, giving us a higher degree of confidence in the potential in this area. During 2010, our Liberty County program produced three successful wells and one successful recompletion. Our 2011 capital program includes three wells in Liberty County.

- Develop our East Texas resource play. We continue to attempt to preserve as much of our 12,700 net acre position in East Texas as logistically and economically feasible, i.e., through a combination of drilling, re-leasing or extending expiring leases. Our efforts are currently focused primarily on our Bruin, Tiger and Fairway Farms Prospect Areas in San Augustine and Sabine Counties through 2011, with full development in multiple formations to be pursued in the following years depending upon market economics, capital availability and success rate. During 2011, we expect to drill 4.0 gross (2.2 net) wells that target the Haynesville and Mid-Bossier Shales, while retaining future development opportunities in shallower formations. We believe we will be able to preserve between 4,000 and 6,000 net acres of our 12,700 position through drilling, re-leasing or extending expiring leases. After we complete the drilling planned for 2011 and early 2012, to preserve this acreage, we will allocate additional drilling capital to this area when drilling economies improve.

- Develop our South Texas resource play. Pursuant to its participation agreement with us, our industry partner successfully drilled two horizontal wells on our position in Bee County during 2010 proving the prospectivety of the Eagle Ford Shale on our acreage. During 2011, we expect to drill initial wells in our held-by-production areas in both of our Karnes and Zavala County areas, targeting the Eagle Ford oil window, and a third well in Bee County. We plan to allocate substantial capital over the next several years to develop the oil and natural gas liquids resource we believe exists on our South Texas acreage.

- Pursue the developing Woodbine/Georgetown horizontal oil play in our Madisonville Field in Madison County, Texas. We have approximately 5,000 net acres in Madison and Grimes counties from which we have historically focused primarily on maximizing production from producing conventional wells. Recent horizontal drilling for oil in the Woodbine and Georgetown formations, adjacent to our acreage, has been very successful. Based on those results, we believe that portions of our asset base in the area are prospective for the Woodbine and Georgetown. We currently plan to drill two wells on our acreage during 2011 to validate this belief.

- Colorado Niobrara Shale. Our activities here have historically been limited to the production of small amounts of oil and gas from the D & J Sands in Weld and Adams Counties. Recent industry activity in the area has proven that the application of horizontal drilling technology for oil in the shallower Niobrara Shale provides tremendous return possibilities. We believe that the Niobrara is prospective in parts of our acreage and will likely drill one well on our acreage in 2011 to validate that belief.

- Explore in defined producing trends. Our exploration activities consist primarily of step-out drilling in known, producing formations in our legacy areas of South and Southeast Texas and Colorado. In 2007, we began acquiring seismic data to use in identifying new exploration prospects. Currently, we have a library of over 4,200 square miles of 3D seismic data and over 2,500 linear miles of 2D seismic data.

- Make opportunistic acquisitions that meet our strategic and financial objectives. We intend to continue evaluating opportunistic acquisitions of natural gas and crude oil properties, including both undeveloped and developed reserves in areas where we currently have a presence and specific operating expertise.

- Reduce commodity price exposure through hedging. We employ the use of swaps and costless collar derivative instruments to limit our exposure to commodity prices. We currently have 12.5 Bcfe of equivalent production hedged for 2011 and 2012, consisting of 6.0 Bcf of natural gas hedges, 225.8 MBbl of crude oil hedges and 2.1 million gallons of natural gas liquids hedges in place for 2011, at average floor prices of $6.31/MMBtu, $77.83/Bbl and $7.32/gallon, respectively and 3.8 Bcf of natural gas hedges and 175.2 MBbl of crude oil hedges in place for 2012 at average floor prices of $5.00/MMBTU and $84.99/Bbl, respectively.

Our Employees

On March 9, 2011, we had 63 full time employees, of which 19 were field personnel. We have been able to attract a talented team of industry professionals from our industry peers that have been successful in achieving significant growth and success in the past. As such, we are well-positioned to adequately manage and develop our existing assets and also to increase our proved reserves and production through exploitation and exploration drilling. None of our employees are covered by collective bargaining agreements. We believe our relationship with our employees is good.

Government Regulation and Industry Matters

Federal and State Regulatory Requirements

We are a public company subject to the rules and regulations of the Securities and Exchange Commission ("SEC"). These rules and regulations could make it more difficult for us to obtain certain types of insurance, including director and officer liability insurance, and we may be forced to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. The impact of these rules and regulations could also make it more difficult for us to attract and retain qualified persons to serve on our board of directors, our board committees or as executive officers.

Our operations are subject to numerous laws and regulations governing the operation and maintenance of our facilities and the release of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require that we acquire permits before commencing drilling; restrict the substances that can be released into the environment in connection with drilling and production activities; limit or prohibit drilling activities on protected areas such as wetlands or wilderness areas; or require remedial measures to mitigate pollution from current or former operations. Under these laws and regulations, we could be liable for personal injury and clean-up costs and other environmental and property damages, as well as administrative, civil and criminal penalties. These laws and regulations have been changed frequently in the past. In general, these changes have imposed more stringent requirements that increase operating costs or require capital expenditures in order to remain in compliance. It is also possible that unanticipated developments could cause us to make environmental expenditures that are significantly different from those we currently expect. Existing laws and regulations could be changed or reinterpreted, and any such changes or interpretations could have an adverse effect on our business.

Industry Regulations

The availability of a ready market for natural gas, crude oil and natural gas liquids production depends upon numerous factors beyond our control. These factors include regulation of natural gas, crude oil and natural gas liquids production, federal and state regulations governing environmental quality and pollution control, state limits on allowable rates of production by well or proration unit, the amount of natural gas, crude oil and natural gas liquids available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. For example, a productive natural gas well may be “shut-in” because of an oversupply of natural gas or lack of an available natural gas pipeline in the areas in which we may conduct operations. State and federal regulations generally are intended to prevent waste of natural gas, crude oil and natural gas liquids, protect rights to produce natural gas, crude oil and natural gas liquids between owners in a common reservoir, control the amount of natural gas, crude oil and natural gas liquids produced by assigning allowable rates of production and control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies. We are also subject to changing and extensive tax laws, the effects of which cannot be predicted. The following discussion summarizes the regulation of the United States oil and gas industry. We believe that we are in substantial compliance with the various statutes, rules, regulations and governmental orders to which our operations may be subject, although there can be no assurance that this is or will remain the case. Moreover, such statutes, rules, regulations and government orders may be changed or reinterpreted from time to time in response to economic or political conditions, and there can be no assurance that such changes or reinterpretations will not materially adversely affect our results of operations and financial condition. The following discussion is not intended to constitute a complete discussion of the various statutes, rules, regulations and governmental orders to which our operations may be subject.

Regulation of Natural Gas, Crude Oil and Natural Gas Liquids Exploration and Production

Our operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes requiring permits for the drilling of wells, maintaining bonding requirements in order 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 upon which wells are drilled, the plugging and abandoning of wells and the disposal of fluids used in connection with operations. 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 and the density of wells that may be drilled in and the unitization or pooling of crude oil and natural gas properties. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of lands and leases. In areas where pooling is voluntary, it may be more difficult to form units, and therefore more difficult to develop a project, if the operator owns less than 100% of the leasehold. In addition, state conservation laws which establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these regulations may limit the amount of natural gas, crude oil and natural gas liquids we can produce from our wells and may limit the number of wells or the locations at which we can drill. The regulatory burden on the oil and gas industry increases our costs of doing business and, consequently, affects our profitability. Inasmuch as such laws and regulations are frequently expanded, amended and interpreted, we are unable to predict the future cost or impact of complying with such regulations.

Regulation of Sales and Transportation of Natural Gas

Federal legislation and regulatory controls have historically affected the price of natural gas produced by us, and the manner in which such production is transported and marketed. Under the Natural Gas Act of 1938, or NGA, the Federal Energy Regulatory Commission, or the FERC, regulates the interstate transportation and the sale in interstate commerce for resale of natural gas. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act, or the Decontrol Act, deregulated natural gas prices for all “first sales” of natural gas, including all sales by us of our own production. As a result, all of our domestically produced natural gas may now be sold at market prices, subject to the terms of any private contracts that may be in effect. However, the Decontrol Act did not affect the FERC’s jurisdiction over natural gas transportation.

Under the provisions of the Energy Policy Act of 2005, or the 2005 Act, the NGA has been amended to prohibit market manipulation by any person, including marketers, in connection with the purchase or sale of natural gas, and the FERC has issued regulations to implement this prohibition. The Commodity Futures Trading Commission, or CFTC, also holds authority to monitor certain segments of the physical and futures energy commodities market including oil and natural gas. With regard to physical purchases and sales of natural gas and other energy commodities, and any related hedging activities that we undertake, we are thus required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the CFTC. These agencies hold substantial enforcement authority, including the ability to assess civil penalties of up to $1 million per day per violation.

Under the 2005 Act, the FERC has also established regulations that are intended to increase natural gas pricing transparency through, among other things, new reporting requirements and expanded dissemination of information about the availability and prices of gas sold. To the extent that we enter into transportation contracts with interstate pipelines that are subject to FERC regulation, we are subject to FERC requirements related to use of such interstate capacity. Any failure on our part to comply with the FERC’s regulations or an interstate pipeline’s tariff could result in the imposition of civil and criminal penalties.

Our natural gas sales are affected by intrastate and interstate gas transportation regulation. Following the Congressional passage of the Natural Gas Policy Act of 1978, or the NGPA, the FERC adopted a series of regulatory changes that have significantly altered the transportation and marketing of natural gas. Beginning with the adoption of Order No. 436, issued in October 1985, the FERC has implemented a series of major restructuring orders that have required pipelines, among other things, to perform “open access” transportation of gas for others, “unbundle” their sales and transportation functions, and allow shippers to release their unneeded capacity temporarily and permanently to other shippers. As a result of these changes, 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. It remains to be seen, however, what effect the FERC’s other activities will have on access to markets, the fostering of competition and the cost of doing business. We cannot predict what new or different regulations the FERC and other regulatory agencies may adopt, or what effect subsequent regulations may have on our activities. We do not believe that we will be affected by any such new or different regulations materially differently than any other seller of natural gas with which we compete.

In the past, Congress has been very active in the area of gas regulation. However, as discussed above, the more recent trend has been in favor of deregulation, or “lighter handed” regulation, and the promotion of competition in the gas industry. There regularly are other legislative proposals pending in the federal and state legislatures that, if enacted, would significantly affect the petroleum industry. At the present time, it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on us. Similarly, and despite the trend toward federal deregulation of the natural gas industry, we cannot predict whether or to what extent that trend will continue, or what the ultimate effect will be on our sales of gas. Again, we do not believe that we will be affected by any such new legislative proposals materially differently than any other seller of natural gas with which we compete.

Oil Price Controls and Transportation Rates

Sales prices of crude oil, condensate and gas liquids by us are not currently regulated and are made at market prices. Our sales of these commodities are, however, subject to laws and to regulations issued by the Federal Trade Commission, or the FTC, prohibiting manipulative or fraudulent conduct in the wholesale petroleum market. The FTC holds substantial enforcement authority under these regulations, including the ability to assess civil penalties of up to $1 million per day per violation. Our sales of these commodities, and any related hedging activities, are also subject to CFTC oversight as discussed above.

The price we receive from the sale of these products may be affected by the cost of transporting the products to market. Much of the transportation is through interstate common carrier pipelines. Effective as of 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. The FERC's regulation of crude oil transportation rates may tend to increase the cost of transporting crude oil and natural gas liquids by interstate pipelines, 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 March 2006, to implement the second of the required five-yearly re-determinations, the FERC established an upward adjustment in the index to track oil pipeline cost changes. The FERC determined that the Producer Price Index for Finished Goods plus 1.3 percent (PPI plus 1.3 percent) should be the oil pricing index for the five-year period beginning July 1, 2006. We are not able at this time to predict the effects of these regulations or FERC proceedings, if any, on the transportation costs associated with crude oil production from our crude oil producing operations.

Environmental Regulations

Various federal, state and local authorities regulate our operations with regard to air and water quality, release of substances and other environmental matters. These laws and regulations may require the acquisition of a permit before drilling commences, 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 within wilderness, wetlands and other protected areas, require remedial measures to mitigate pollution from current or former operations, such as pit closure and plugging abandoned wells, and impose substantial liabilities for pollution resulting from production and drilling operations. In addition, various laws and regulations require that inactive well, pipeline, and facility sites be abandoned and reclaimed. Public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that further restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business and prospects could be adversely affected.

The Comprehensive Environmental Response, Compensation and Liability Act, also known as "CERCLA" or the "Superfund" law, and similar state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of potentially responsible persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These potentially responsible persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several 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, and 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 substances released into the environment. We generate materials in the course of our operations that may be regulated as hazardous substances.

We generate wastes that may be subject to the federal Resource Conservation and Recovery Act or the RCRA, and comparable state statutes. The U.S. Environmental Protection Agency, or the EPA, and various state agencies have limited the approved methods of disposal for certain hazardous and nonhazardous wastes. Furthermore, certain wastes generated by our crude oil and natural gas operations that are currently exempt from regulation as "hazardous wastes" may in the future be designated as "hazardous wastes," and therefore be subject to more rigorous and costly operating and disposal requirements.

We currently own or lease numerous properties that for many years have been used for the exploration and production of crude oil and natural gas. Although we believe that we have used good operating and waste disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us or on or under locations where such wastes have been taken for recycling or disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons or wastes was not under our control. These properties and the wastes disposed thereon may be subject to the CERCLA, RCRA and analogous state laws as well as state laws governing the management of crude oil and natural gas wastes. Under such laws, which may impose strict, joint and several liability, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination) or to perform remedial plugging operations to prevent future contamination.

Our operations may be subject to the Clean Air Act, or the CAA, and comparable state and local requirements. Amendments to the CAA adopted in 1990 contain provisions that have resulted in the gradual imposition of pollution control requirements with respect to air emissions from our operations. The EPA and states have developed, and continue to develop, regulations to implement these requirements. While we may be required to incur capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing air emission-related issues, we do not believe that our operations will be materially adversely affected by any such requirements.

In response to certain scientific studies suggesting that emissions of certain gases, commonly referred to as greenhouse gases, or "GHGs," and including carbon dioxide and methane, are contributing to the warming of the Earth's atmosphere and other climatic conditions. The EPA made findings in December 2009 that emissions of GHGs present an endangerment to public health and the environment. Based on these findings, the EPA has adopted and implemented two sets of regulations under the CAA that would restrict emissions of GHGs under existing provisions of the CAA. The first regulation limits emissions of GHGs from motor vehicles and the second one that regulates emissions of GHGs from certain large stationary sources under the Prevention of Significant Deterioration, or "PSD," and Title V permitting programs, effective January 2, 2011. This stationary source rule "tailors" these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Facilities required to obtain PSD permits for their GHG emissions also will be required to reduce those emissions according to "best available control technology" standards for GHG will be established by the states or, in some instances, by the EPA on a case-by-case basis. The EPA's rules relating to emissions of GHGs from large stationary sources of emissions are currently subject to a number of legal challenges but the federal courts have thus far declined to issue any injunctions to prevent EPA from implementing or requiring state environmental agencies to implement the rules. In addition, in November 2010, the EPA expanded its existing GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage, and distribution facilities, beginning in 2012 for emissions occurring in 2011.

In addition, from time to time Congress has considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. These allowances would be expected to escalate significantly in cost over time. Although it is not possible at this time to predict when Congress may pass climate change legislation, any future federal laws that may be adopted to address GHG emissions could require us to incur increased operating costs and could adversely affect demand for the oil and natural gas we produce.

Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have in adverse effect on our assets and operations.

The Federal Water Pollution Control Act, also known as the "Clean Water Act," and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters. Pursuant to the Clean Water Act and analogous state laws, permits must be obtained to discharge pollutants into state waters or waters of the United States. Any such discharge of pollutants into regulated waters must be performed in accordance with the terms of the permit issued by the EPA or the analogous state agency. Spill prevention, control and countermeasure, or "SPCC" plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. It is customary to recover natural gas from deep shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into rock formations to stimulate gas production. The process is typically regulated by state oil and gas commissions. However, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the federal Safe Drinking Water Act's Underground Injection Program. While the EPA has yet to take any action to enforce or implement this newly asserted regulatory authority, industry groups have filed suit challenging the EPA's recent decision. At the same time, the EPA has commenced a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health with results of the study expected to be available in late 2012, and a committee of the U.S. House of Representatives is conducting an investigation of hydraulic fracturing practices. In addition, legislation was proposed in the recently completed session of Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process, and such legislation could be introduced and adopted in the current session of Congress. Also, some states and local governments are considering increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions and temporary or permanent bans on hydraulic fracturing in certain environmentally-sensitive areas such as watersheds. The adoption of any federal or state legislation or implementing regulations imposing limitations on the hydraulic fracturing process could lead to operational delays or increased operating costs.

The Oil Pollution Act of 1990, or the "OPA," contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil to surface waters. Noncompliance with OPA may result in varying civil and criminal penalties and liabilities.

We are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, or the "OSHA," and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Title to Properties

We believe we have satisfactory title to all of our producing properties in accordance with standards generally accepted in the oil and gas industry. Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, which we believe do not materially interfere with the use of or affect the value of such properties. As is customary in the industry in the case of undeveloped properties, little investigation of record title is made at the time of acquisition (other than a preliminary review of local records). Detailed investigations, including a title opinion rendered by a licensed attorney, are typically made before commencement of drilling operations.

We have granted mortgage liens on substantially all of our natural gas and crude oil properties to secure our revolving credit agreement and second lien credit agreement. These mortgages and the credit agreements contain substantial restrictions and operating covenants that are customarily found in credit agreements of this type. See Note 9 — “Debt" for further information.

Marketing

We sell a significant portion of our natural gas production to purchasers pursuant to sales agreements which contain a primary term of up to two years and crude oil production to purchasers under sales agreements with primary terms of up to one year. The sales prices for natural gas are tied to industry standard published index prices, subject to negotiated price adjustments, while the sale prices for crude oil are tied to industry standard posted prices subject to negotiated price adjustments.

Our purchasers are engaged in the natural gas and crude oil business throughout the world. Historically, we have been dependent upon a few purchasers for a significant portion of our revenue. For the years ended December 31, 2010, 2009 and 2008, our top ten purchasers collectively represented approximately 80%, 72% and 71% of total revenues, respectively. Our three largest purchasers in 2010 accounted for 32%, 15% and 10% of total revenues, respectively. This concentration of purchasers may increase our overall exposure to credit risk, and our purchasers will likely be similarly affected by changes in economic and industry conditions. Our financial condition and results of operations could be materially adversely affected if one or more of our significant purchasers fails to pay us or ceases to acquire our production on terms that are favorable to us or at all. However, we believe our current purchasers could be replaced by other purchasers under contracts with similar terms and conditions.

Competition

The oil and gas industry is highly competitive and we compete with a substantial number of other companies that have greater resources. Many of these companies explore for, produce and market natural gas and crude oil, carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and gas properties, and obtaining purchasers and transporters for the natural gas and crude oil we produce. There is also competition between producers of natural gas and crude oil and other industries producing alternative energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the government of the United States; however, it is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such laws and regulations may, however, substantially increase the costs of exploring for, developing or producing natural gas and crude oil and may prevent or delay the commencement or continuation of a given operation. The effect of these risks cannot be accurately predicted.

Insurance Matters

As is common in the oil and gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because premium costs are considered prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position, results of operations or cash flows.

Executive Officers

See Item 9. “Directors and Executive Officers of the Registrant,” which information is incorporated herein by reference.

ITEM 1A. Risk Factors

Risks Related to Our Business

Natural gas, crude oil and natural gas liquids prices are volatile, and a decline in prices can significantly affect our financial results and impede our growth.

Our revenue, cash flow from operations and future growth depend upon the prices and demand for natural gas, crude oil and natural gas liquids. The markets for these commodities are very volatile. Even relatively modest drops in prices can significantly affect our financial results and impede our growth. Changes in natural gas, crude oil and natural gas liquids prices have a significant impact on the value of our reserves and on our cash flow. In addition, periods of sustained lower prices may compel us to reduce our capital expenditures and budget for drilling. Prices for natural gas, crude oil and natural gas liquids may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas, crude oil and natural gas liquids and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of natural gas, crude oil and natural gas liquids;
- the price of foreign imports;
- worldwide economic conditions;
- political and economic conditions in oil producing countries, including the Middle East and South America;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the level of consumer product demand;
- weather conditions;
- technological advances affecting energy consumption;
- availability of pipeline infrastructure, treating, transportation and refining capacity;
- domestic and foreign governmental regulations and taxes; and
- the price and availability of alternative fuels.

Lower natural gas, crude oil and natural gas liquids prices may not only decrease our revenues on a per share basis, but also may reduce the amount of natural gas, crude oil and natural gas liquids that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves.

Many of our East Texas leases are not producing and must be drilled before expiration, generally within three years, in order to hold the leases by production, or they will terminate. In the highly competitive market for Haynesville Shale acreage, failure to drill sufficient wells timely to hold this acreage will result in a substantial renewal cost, or if renewal is not feasible, loss of lease investment and prospective drilling opportunities in the Haynesville Shale, as well as in the Mid-Bossier Shale, James Lime, Pettet and Knowles Lime formations.

Our East Texas leases have three year terms which require that an initial producing well be drilled prior to expiration date or the lease will terminate. Most of our leases in this area were signed in late 2008. Generally, once an initial well is drilled and completed as a producer, the lease is extended for the duration of production subject to payment of royalties and additional wells may be drilled on that lease.

The leases in this area are extremely fragmented and much of the leased acreage is not contiguous. In many cases, contiguous leases owned by us are not large enough to accommodate horizontal drilling to the Haynesville or Mid-Bossier Shales, which usually involves a horizontal lateral of between 4,000 to 5,000 feet within lease lines. In other cases, leases may be from fractional interest land owners and may not comprise a sufficient aggregate percentage working interest to make such a well economical. As a result, in order to realize the drilling opportunities in the Haynesville Shale, Mid-Bossier Shale, James Lime, Pettet and Knowles Lime formations, we and other similarly situated major lease owners and operators in East Texas will need to cooperate and negotiate joint drilling operations to drill initial wells prior to lease expirations. These negotiations may include the right to act as operator for jointly owned wells. If we do not reach agreements with other major lease owners and operators to drill wells prior to lease expirations, or if we are unable to drill timely sufficient wells to hold our acreage, we will lose the drilling opportunities and investment in the expiring leases unless we can successfully negotiate to renew the leases. While we currently estimate that we will be able to hold, by production, up to 4,000 net acres, and may be able to re-lease, or extend least terms, on up to another 2,000 to 4,000 net acres; ,we may not be able to renew the expired leases, or if renewed, the cost of releasing could be substantial, particularly if development in this area proves successful.

Part of our strategy involves drilling in new or emerging plays; therefore, our drilling results in these areas are not certain.

The results of our drilling in new or emerging plays, such as in our East Texas resource play, are more uncertain than drilling results in areas that are more developed and have established production. Since new or emerging plays and new formations have limited or no production history, we are less able to use past drilling results in those areas to help predict our future drilling results. Accordingly, our drilling results are subject to greater risks in these areas and could be unsuccessful. We may be unable to execute our expected drilling program in these areas because of disappointing drilling results, capital constraints, lease expirations, access to adequate gathering systems or pipeline take-away capacity, availability of drilling rigs and other services or otherwise, and/or natural gas, crude oil and natural gas liquids price declines. To the extent we are unable to execute our expected drilling program in these areas, our return on investment may not be as attractive as we anticipate and our common stock price may decrease. We could incur material write-downs of unevaluated properties, and the value of our undeveloped acreage could decline in the future if our drilling results are unsuccessful.

The results of our planned drilling in our East Texas and South Texas resource plays, which are emerging plays with limited drilling and production history in certain areas, are subject to more uncertainties than our drilling program in our more established areas of operation in the onshore South Texas and U.S. Gulf Coast regions and may not meet our expectations for reserves or production.

In October 2009, we completed drilling our first well in the Haynesville Shale in East Texas, for which we are not the operator and since successfully completed three operator and one non-operator wells in the Mid-Bossier formation. We also have two operated wells awaiting completion. In late January 2011, we completed our first two horizontal wells in Bee County, Texas in the Eagle Ford Shale. The presence of the Haynesville Shale in the East Texas area where we own leases was determined after the activity in the north Louisiana portion of the Haynesville Shale play and, therefore is not yet as defined. Part of our drilling strategy to maximize recoveries from the Haynesville Shale involves the drilling of horizontal wells using completion techniques that have proven to be successful in other shale formations. Our direct experience with horizontal drilling of these shale plays is limited. Similarly, drilling activity in the Eagle Ford formation is also much less extensive and defined as more mature basins or other shale plays. The ultimate success of these drilling and completion strategies and techniques in these formations will be better evaluated over time as more wells are drilled and production profiles are better established. Accordingly, the results of our future drilling in the emerging shale plays are more uncertain than drilling results in our more established areas of operation with established reserves and production history.

Initial production rates in shale plays, and particularly in the Haynesville Shale, tend to decline steeply in the first twelve months of production and are not necessarily indicative of sustained production rates.

Initial production rates in shale plays, and particularly in the Haynesville Shale, tend to decline steeply in the first twelve months of production and are not necessarily indicative of sustained production rates.

Our development and exploration operations, including on our East Texas resource play acreage, require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our natural gas, crude oil and natural gas liquids reserves.

The oil and gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of natural gas, crude oil and natural gas liquids reserves. We intend to finance our future capital expenditures primarily with cash flow from operations and borrowings under our revolving credit agreement. Our cash flow from operations and access to capital is subject to a number of variables, including:

- our proved reserves;
- the level of natural gas, crude oil and natural gas liquids we are able to produce from existing wells;
- the prices at which natural gas, crude oil and natural gas liquids are sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues decrease as a result of lower natural gas, crude oil and natural gas liquids prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels, to further develop and exploit our current properties, or to conduct exploratory activity. In order to fund our capital expenditures, we may need to seek additional financing. Our credit agreements contain covenants restricting our ability to incur additional indebtedness without the consent of the lenders. Our lenders may withhold this consent in their sole discretion. In addition, if our borrowing base is redetermined resulting in a lower borrowing base under our revolving credit agreement, we may be unable to obtain financing otherwise available under our revolving credit agreement. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Capital resources.”

Furthermore, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. In particular, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity on terms that are similar to existing debt, and reduced, or in some cases ceased, to provide funding to borrowers. The failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our natural gas, crude oil and natural gas liquids reserves.

The impairment of financial institutions could adversely affect us.

We have exposure to different counterparties, and we have entered into transactions with counterparties in the financial services industry specifically, with members of our bank group. These transactions could expose us to credit risk in the event of default of our counterparty. We have exposure to these financial institutions in the form of derivative transactions in connection with our hedges. We also maintain insurance policies with insurance companies to protect us against certain risks inherent in our business. In addition, if any lender under our credit agreement is unable to fund its commitment, our liquidity could be reduced by an amount up to the aggregate amount of such lender’s commitment under our credit agreement.

We have a substantial amount of indebtedness, which may adversely affect our cash flow and our ability to operate our business.

As of December 31, 2010, we had outstanding $179.0 million in principal amount of long-term debt. Our substantial level of indebtedness increases the possibility that we may be unable to pay, when due, the principal of, interest on, or other amounts due in respect of our indebtedness. Our substantial indebtedness, combined with our other financial obligations and contractual commitments, could have other important consequences, including the following:

- funds available for our operations and general corporate purposes or for capital expenditures will be reduced as a result of the dedication of a portion of our consolidated cash flow from operations to the payment of the principal and interest on our indebtedness;
- we may be more highly leveraged than certain of our competitors, which may place us at a competitive disadvantage;
- certain of the borrowings under our debt agreements have floating rates of interest, which causes us to be vulnerable to increases in interest rates;
- our degree of leverage could make us more vulnerable to downturns in general economic conditions;
- our ability to plan for, or react to, changes in our business and the industry in which we operate may be limited; and
- our ability to obtain additional financing on satisfactory terms to fund our working capital requirements, capital expenditures, investments, debt service requirements and other general corporate requirements may be reduced.

In addition, our revolving credit agreement and second lien credit agreement contain a number of significant covenants that place limitations on our activities and operations, including those relating to:

- creation of liens;
- hedging;
- mergers, acquisitions, asset sales or dispositions;
- payments of dividends;
- incurrence of additional indebtedness; and
- certain leases and investments outside of the ordinary course of business.

Our credit agreements require us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Our ability to comply with these ratios and financial condition tests may be affected by events beyond our control, and we cannot assure you that we will meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary or desirable corporate activities.

A breach of any of these covenants or our inability to comply with the required financial ratios or financial condition tests could also result in a default under our credit agreements. A default, if not cured or waived, could result in all of our indebtedness becoming immediately due and payable. If that should occur, we may not be able to pay all such debt or to borrow sufficient funds to refinance it. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Capital resources” for further information regarding future compliance with these covenants. Even if new financing were then available, it may not be on terms that are acceptable to us. See “—Recent market events and conditions, including disruptions in the U.S. and international credit markets and other financial systems and the deterioration of the U.S. and global economic conditions, could, among other things, impede access to capital or increase the cost of capital, which would have an adverse effect on our ability to fund our working capital and other capital requirements” and “—Our development and exploration operations, including on our East Texas resource play acreage, require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our natural gas, crude oil and natural gas liquids reserves."

Changes to current laws may affect our ability to take certain deductions.

Substantive changes to the existing federal income tax laws have been proposed that, if adopted, would affect, among other things, our ability to take certain deductions related to our operations, including depletion deductions, deductions for intangible drilling and development costs and deductions for United States production activities. These changes, if enacted into law, could negatively affect our financial condition and results of operations.

Recent changes in the financial and credit markets may impact economic growth and natural gas, crude oil and natural gas liquids prices may continue to be adversely affected by general economic conditions.

Based on a number of economic indicators, global economic activity slowed substantially in recent years. A continued slowing of global economic growth or lack of significant improvement in the global economy (and, in particular, in the United States) will likely reduce demand for natural gas, crude oil and natural gas liquids, which in turn could likely result in lower prices for natural gas, crude oil and natural gas liquids. NYMEX settlement prices for natural gas and crude oil prices dropped dramatically in 2009 from record levels, in July 2008. While prices have improved, and we hedge prices on a meaningful portion of our forecasted production from proved developed producing reserves for up to two years forward, a reduction in demand for, and the resulting lower prices of, natural gas, crude oil and natural gas liquids could adversely affect our financial condition and results of operations.

Recent market events and conditions, including disruptions in the U.S. and international credit markets and other financial systems and the deterioration of the U.S. and global economies, could, among other things, impede our access to capital or increase our cost of capital, which would have an adverse effect on our ability to fund our working capital and other capital requirements.

Recent market events and conditions, including unprecedented disruptions in the credit and financial markets and the deterioration of economic conditions in the United States and internationally have had a significant material adverse impact on a number of financial institutions and have limited access to capital and credit for many companies. These disruptions could, among other things, make it more difficult for us to obtain, or increase our cost of obtaining, capital and financing for our operations. Access to additional capital may not be available on terms acceptable to us or at all. Difficulties in obtaining capital and financing or increased costs for obtaining capital and financing for our operations would have an adverse effect on our ability to fund our working capital and other capital requirements.

We have incurred net losses in the past and there can be no assurance that we will be profitable in the future.

We have incurred net losses in three of the last five fiscal years. We cannot assure you that our current level of operating results will continue or improve. Our activities could require additional debt or equity financing. Our future operating results may fluctuate significantly depending upon a number of factors, including industry conditions, prices of natural gas, crude oil and natural gas liquids, rates of production, timing of capital expenditures and drilling success. Negative changes in these variables could have a material adverse effect on our business, financial condition, results of operations and the market value of our common stock.

We may not be able to fully realize the value of our net operating loss carryforwards for Federal income tax purposes.

As of December 31, 2010, we had net operating loss carryforwards (NOLs) of approximately $98.6 million, which are available to reduce our future federal taxable income and related income tax liability. Based upon the level of historical taxable income and our projections for future taxable income over the periods in which the deferred tax assets are deductible, we believe it is more likely than not that we will realize the benefits of these NOLs to reduce future Federal net income tax obligations. Future net losses could affect our ability to realize during the appropriate carryforward periods our available net operating loss carryforwards for Federal income tax purposes and the value of the related deferred tax asset. Our ability to use our available net operating loss carryforwards and the amount of the related deferred tax asset ultimately realizable could be reduced in the future if our estimates of future taxable income during the carryforward periods are reduced.

We currently expect we will not be able to utilize NOLs of approximately $9.1 million of due to prior occurrences of an “ownership change”, as determined under Section 382 of the Internal Revenue Code, as amended. If we were to experience a further “ownership change,” as determined under Section 382, our ability to offset taxable income arising after the ownership change with NOLs arising prior to the ownership change would be limited, possibly substantially. An ownership change would establish an annual limitation on the amount of our pre-change NOLs we could utilize to offset our taxable income in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the highest long-term tax-exempt rate during the three months prior to the date of the ownership change. The long-term tax-exempt rate is a rate published each month by the Internal Revenue Service. The application of this limitation could prevent full utilization of our pre-change NOLs arising prior to their expiration. It is possible that additional issuances of our common stock within the next few years, or the sale of our common stock by our larger shareholders, could cause us to experience another ownership change, in which case any NOLs existing at the time of the change would be limited in the manner described above.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially reduce the estimated quantities and present value of our reserves.

The process of estimating natural gas, crude oil and natural gas liquids reserves is complex. It requires interpretations of available technical data and many estimates, including estimates based upon assumptions relating to economic factors. Any significant inaccuracies in these interpretations or estimates could materially reduce the estimated quantities and present value of reserves shown in this Annual Report. See “Item 1. Business” for information about our natural gas, crude oil and natural gas liquids reserves.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as natural gas, crude oil and natural gas liquids prices, drilling and operating expenses, the amount and timing of capital expenditures, taxes and the availability of funds.

Actual future production, natural gas, crude oil and natural gas liquids prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas, crude oil and natural gas liquids reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this Annual Report. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas, crude oil and natural gas liquids prices and other factors, many of which are beyond our control.

Approximately 51.9% of our total estimated proved reserves at December 31, 2010 were proved undeveloped reserves.

Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve engineer reports assumes that substantial capital expenditures are required to develop such reserves. Although cost and reserve estimates attributable to our natural gas, crude oil and natural gas liquids reserves have been prepared in accordance with industry standards, we cannot be sure that the estimated costs are accurate, that development will occur as scheduled or that the results of such development will be as estimated.

The present value of future net cash flows from our proved reserves will not necessarily be the same as the current market value of our estimated natural gas, crude oil and natural gas liquids reserves.

You should not assume that the present value of future net revenues from our proved reserves referred to in this Annual Report is the current market value of our estimated natural gas, crude oil and natural gas liquids reserves. In accordance with the requirements of the SEC, the estimated discounted future net cash flows from our proved reserves are based on prices and costs on the date of the estimate, held flat for the life of the properties. Actual future prices and costs may differ materially from those used in the present value estimate. The present value of future net revenues from our proved reserves as of December 31, 2010 was based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period January through December 2010. For crude oil and natural gas liquids volumes, the average West Texas Intermediate posted price was $75.96 per barrel. For natural gas volumes, the average Henry Hub spot price was $4.376 per MMBtu. If crude oil prices were $1.00 per Bbl lower than the price used, our PV-10 as of

December 31, 2010 would have decreased from $239.7 million to $237.5 million. If natural gas prices were $0.10 per Mcf lower than the price used, our PV-10 as of December31, 2010, would have decreased from $239.7 million to $232.4 million. Any adjustments to the estimates of proved reserves or decreases in the price of crude oil or natural gas may decrease the value of our common stock. PV-10 is a non-GAAP financial measure. A reconciliation of our Standardized Measure of Discounted Future Net Cash Flows to PV-10 is provided under "Item 2. Properties — Proved Reserves".

Actual future net cash flows will also be affected by increases or decreases in consumption by oil and gas purchasers and changes in governmental regulations or taxation. The timing of both the production and the incurrence of expenses in connection with the development and production of oil and gas properties affects the timing of actual future net cash flows from proved reserves. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor. The effective interest rate at various times and the risks associated with our business or the oil and gas industry in general will affect the accuracy of the 10% discount factor.

Our use of 2D and 3D seismic data is subject to interpretation and may not accurately identify the presence of natural gas, crude oil and natural gas liquids. In addition, the use of such technology requires greater predrilling expenditures, which could adversely affect the results of our drilling operations.

Our decisions to purchase, explore, develop and exploit prospects or properties depend in part on data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are uncertain. For example, we have over 4,200 square miles of 3D data in the South Texas and Gulf Coast regions. However, even when used and properly interpreted, 3D seismic data and visualization techniques only assist geoscientists and geologists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know if hydrocarbons are present or producible economically. Other geologists and petroleum professionals, when studying the same seismic data, may have significantly different interpretations than our professionals.

In addition, the use of 3D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses due to such expenditures. As a result, our drilling activities may not be geologically successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area may not improve.

Drilling for and producing natural gas, crude oil and natural gas liquids are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our drilling and operating activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for natural gas, crude oil and natural gas liquids can be unprofitable, not only from dry holes, but from productive wells that do not produce sufficient revenues to return a profit. In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- unusual or unexpected geological formations and miscalculations;
- pressures;
- fires;
- explosions and blowouts;

- pipe or cement failures;
- environmental hazards, such as natural gas leaks, pipeline ruptures and discharges of toxic gases;
- loss of drilling fluid circulation;
- title problems;
- facility or equipment malfunctions;

- unexpected operational events;
- shortages of skilled personnel;
- shortages or delivery delays of equipment and services;
- compliance with environmental and other regulatory requirements;
- natural disasters; and
- adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life; severe damage to or destruction of property, natural resources and equipment; pollution; environmental contamination; clean-up responsibilities; loss of wells; repairs to resume operations; and regulatory fines or penalties.

Insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. We carry limited environmental insurance, thus, losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not covered in full or in part by insurance could have a material adverse impact on our business activities, financial condition and results of operations.

Our acquisition strategy may subject us to greater risks.

The successful acquisition of properties requires an assessment of recoverable reserves, future natural gas, crude oil and natural gas liquids prices, operating costs, potential environmental and other liabilities, and other factors beyond our control. Such assessments are necessarily inexact and their accuracy uncertain. In connection with such an assessment, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Such a review, however, will not reveal all existing or potential problems, costs and liabilities, nor will it permit us, as the buyer, to become sufficiently familiar with the properties to assess their capabilities or deficiencies fully. We may not inspect every well and, even when an inspection is undertaken, structural and environmental problems may not necessarily be observable.

We may be unable to successfully integrate the properties and assets we acquire with our existing operations.

Integration of the properties and assets we acquire may be a complex, time consuming and costly process. Failure to timely and successfully integrate these assets and properties with our operations may have a material adverse effect on our business, financial condition and result of operations. The difficulties of integrating these assets and properties present numerous risks, including:

- acquisitions may prove unprofitable and fail to generate anticipated cash flows;
- we may need to (i) recruit additional personnel and we cannot be certain that any of our recruiting efforts will succeed and (ii) expand corporate infrastructure to facilitate the integration of our operations with those associated with the acquired properties, and failure to do so may lead to disruptions in our ongoing businesses or distract our management; and
- our management’s attention may be diverted from other business concerns.

We are also exposed to risks that are commonly associated with acquisitions of this type, such as unanticipated liabilities and costs, some of which may be material. As a result, the anticipated benefits of acquiring assets and properties may not be fully realized, if at all.

When we acquire properties, in most cases, we are not entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities.

We generally acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties, and in these situations we cannot assure you that we will identify all areas of existing or potential exposure. In those circumstances in which we have contractual indemnification rights for pre-closing liabilities, we cannot assure you that the seller will be able to fulfill its contractual obligations. In addition, the competition to acquire producing natural gas, crude oil and natural gas liquids properties is intense and many of our larger competitors have financial and other resources substantially greater than ours. We cannot assure you that we will be able to acquire producing natural gas, crude oil and natural gas liquids properties that have economically recoverable reserves for acceptable prices.

We cannot control activities on properties that we do not operate and are unable to control their proper operation and profitability.

We do not operate a significant portion of the properties in which we own an interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, the operations of these properties. 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 interests could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depend upon a number of factors outside of our control, including:

- the nature and timing of drilling and operational activities;
- the timing and amount of capital expenditures;
- the operator's expertise and financial resources;
- the operator's ability to procure drilling and completion services;
- the approval of other participants in drilling wells; and
- the operator's selection of suitable technology.

If our access to markets is restricted, it could negatively impact our production, our income and ultimately our ability to retain our leases.

Market conditions or the unavailability of satisfactory natural gas, crude oil and natural gas liquids transportation arrangements may hinder our access to natural gas, crude oil and natural gas liquids markets or delay our production. The availability of a ready market for our natural gas, crude oil and natural gas liquids production depends on a number of factors, including the demand for and supply of natural gas, crude oil and natural gas liquids and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. Our productive properties may be located in areas with limited or no access to pipelines, thereby necessitating delivery by other means, such as trucking, or requiring compression facilities. Such restrictions on our ability to sell our natural gas, crude oil and natural gas liquids may have several adverse effects, including higher transportation costs, fewer potential purchasers (thereby potentially resulting in a lower selling price) or, in the event we were unable to market and sustain production from a particular lease for an extended time, possible loss of a lease due to lack of production.

Unless we replace our natural gas, crude oil and natural gas liquids reserves, our reserves and production will decline, which would adversely affect our cash flows, our ability to raise capital and the value of our common stock.

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing natural gas, crude oil and natural gas liquids reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future natural gas, crude oil and natural gas liquids reserves and production, and therefore our cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. The value of our common stock and our ability to raise capital will be adversely impacted if we are not able to replace our reserves that are depleted by production. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production.

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

When the prices of natural gas, crude oil and natural gas liquids increase, we typically encounter an increase in the cost of securing drilling rigs, equipment and supplies. In addition, larger producers may be more likely to secure access to such equipment by offering more lucrative terms. If we are unable to acquire access to such resources, or can obtain access only at higher prices, our ability to convert our reserves into cash flow could be delayed and the cost of producing those reserves could increase significantly, which would adversely affect our results of operations and financial condition.

Our hedging activities could result in financial losses or reduce our income.

To achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of natural gas, crude oil and natural gas liquids, as well as interest rates, we currently, and may in the future, enter into derivative arrangements for a significant portion of our natural gas, crude oil and/or natural gas liquids production and our debt that could result in both realized and unrealized hedging losses. We utilize financial commodity price hedge instruments to minimize exposure to declining prices on our crude oil, natural gas and natural gas liquids production. We typically use a combination of swaps and costless collars. We use interest rate swaps to minimize exposure to rising interest rates.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into hedging transactions for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the nominal amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of our interest rate swap agreements, we may fail to benefit when rates fall, to the extent we have agreed to pay interest at a fixed rate, or face a greater degree of exposure when rates increase, to the extent we have agreed to pay interest at a floating rate. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows.

Competition in the oil and gas industry is intense, and many of our competitors have resources that are greater than ours.

We operate in a highly competitive environment for acquiring prospects and productive properties, marketing natural gas, crude oil and natural gas liquids, and securing equipment and trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to develop and acquire more prospects and productive properties than our financial or personnel resources permit. Our ability to acquire additional prospects and discover reserves in the future will depend on our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and gas industry. Our larger competitors may be better able to withstand sustained periods of unsuccessful drilling and absorb the burden of changes in laws and regulations more easily than we can, which would adversely affect our competitive position. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital.

We depend on our senior management team and other key personnel. Accordingly, the loss of any of these individuals could adversely affect our business, financial condition and the results of operations and future growth.

Our success is largely dependent on the skills, experience and efforts of our management team and employees. The loss of the services of one or more members of our senior management team or of our other employees with critical skills needed to operate our business could have a negative effect on our business, financial conditions and results of operations and future growth. Our ability to manage our growth, if any, will require us to continue to train, motivate and manage our employees and to attract, motivate and retain additional qualified personnel.

Competition for these types of personnel is intense and we may not be successful in attracting, assimilating and retaining the personnel required to grow and operate our business profitably.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

Our operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. For instance, we may be unable to obtain all necessary permits, approvals and certificates for proposed projects. Alternatively, we may have to incur substantial expenditures to obtain, maintain or renew authorizations to conduct existing projects. If a project is unable to function as planned due to changing requirements or public opposition, we may suffer expensive delays, extended periods of non-operation or significant loss of value in a project. All such costs may have a negative effect on our business and results of operations.

Our business is subject to federal, state and local regulations as interpreted and enforced by governmental agencies and other bodies vested with much authority relating to the exploration for, and the development, production, transportation and marketing of, natural gas, crude oil and natural gas liquids. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on us.

Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas we produce.

In December 2009, the U.S. Environmental Protection Agency, or “EPA,” determined that emissions of carbon dioxide, methane, and other greenhouse gases, or “GHGs,” present an endangerment to public health and the environment because emissions of such gasses are contributing to the warming of the earth’s atmosphere and other climatic changes. Based on these findings, the EPA recently adopted regulations under existing provisions of the CAA that require a reduction in emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources, effective January 2, 2011. The EPA has published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration, or “PSD,” and Title V permitting programs, pursuant to which these permitting programs have been “tailored” to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards, which will be established by the states or, in some instances, by the EPA on a case-by-case basis. The EPA’s rules relating to emissions of GHGs from large stationary sources of emissions are currently subject to a number of legal challenges but the federal courts have thus far declined to issue any injunctions to prevent EPA from implementing or requiring state environmental agencies to implement the rules. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities. The EPA has also adopted regulations requiring the reporting of GHG emissions from specified large GHG emission sources in the United States including certain onshore and offshore oil and natural gas production facilities, which may include certain of our operations, beginning in 2012 for emissions occurring in 2011.

In addition, Congress has from time to time considered adopting legislation to reduce emissions of GHGs and almost one-half of the states have already taken legal measures to reduce emissions of GHGs primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. These allowances would be expected to escalate significantly in cost over time. The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an important and commonly used process for the completion of natural gas, and to a lesser extent, oil wells in shale formations, and involves the pressurized injection of water, sand and chemicals into rock formations to stimulate natural gas production. The process is typically regulated by state oil and gas commissions. However, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the federal Safe Drinking Water Act's Underground Injection Program. While the EPA has yet to take any action enforce or implement this newly asserted regulatory authority, industry groups have filed suit challenging the EPA's recent decision. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with results of the study anticipated to be available by late 2012, and a committee of the U.S. House of Representatives is conducting an investigation of hydraulic fracturing practices. In addition, legislation was proposed in the recently completed session of Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process, and such legislation could be introduced in the current session of Congress. Also, various state and local governments are considering increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions, and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas such as watersheds. The adoption of any federal or state legislation or implementing regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

Our operations are subject to environmental, health and safety matters.

Our oil and natural gas exploration and production operations are subject to stringent and complex federal, state and local laws and regulations governing health and safety aspects of our operations, the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations that are applicable to our operations including the acquisition of a permit before conducting drilling or underground injection activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from operations. Numerous governmental authorities, such as the U.S. Environmental Protection Agency, or the "EPA," and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of our operations.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations due to our handling of petroleum hydrocarbons and wastes, because of air emissions and wastewater discharges related to our operations, and as a result of historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we could be subject to joint and several, strict liability for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or contamination or whether the operations were in compliance with all applicable laws at the time those actions were taken. Private parties, including the owners of properties upon which our wells are drilled and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property or natural resource damages. In addition, the risk of accidental spills or releases could expose us to significant liabilities that could have a material adverse effect on our business, financial condition or results of operations. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste control, handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our own results of operations, competitive position or financial condition. We may not be able to recover some or any of these costs from insurance. See "Item 1. Business—Environmental Regulations."

If we are unable to successfully prevent or address material weaknesses in our internal control over financial reporting, or any other control deficiencies, our ability to report our financial results on a timely and accurate basis and to comply with disclosure and other reporting requirements may be adversely affected.

While we have taken actions designed to address compliance with the internal control, disclosure control and other requirements of the Sarbanes-Oxley Act of 2002 and the rules and regulations promulgated by the SEC implementing these requirements, there are inherent limitations in our ability to control all circumstances. Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our internal controls and disclosure controls will prevent all errors 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. For example, for the quarter ended March 31, 2007, our management concluded that our historical documentation of related tax positions could have resulted in a material misstatement to our annual or interim financial statements and, accordingly, concluded that this deficiency was a material weakness. Although this material weakness was subsequently remedied, if we are unable to successfully prevent or address these and other material weaknesses in our internal control systems, our ability to report our financial results on a timely and accurate basis and to comply with disclosure and other reporting requirements may be adversely affected.

The recent adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The U.S. Congress recently adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as the Company, that participate in that market. The new legislation was signed into law by President Obama on July 21, 2010 and requires the Commodities Futures Trading Commission (the "CFTC") and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The CFTC has also proposed regulations to set position limits for certain futures and option contracts in the major energy markets, although it is not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the new legislation. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition, and our results of operations.

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Risks Related to an Investment in Our Common Stock

Two stockholders hold a significant number of our shares, which will limit your ability to influence corporate activities and may adversely affect the market price of our common stock, and those stockholders' interests may conflict with the interests of our other stockholders.

Of the approximately 44.9 million shares of our common stock outstanding at December 31, 2010, approximately 15.5 million shares are beneficially held by OCM GW Holdings, LLC ("Oaktree Holdings") and 6.0 million shares are beneficially held by America Capital Energy Corporation ("ACEC"). As a result, Oaktree Holdings owns or controls outstanding common stock representing, in the aggregate, an approximate 34.6% voting interest in us and ACEC owns or controls outstanding common stock representing, in the aggregate, an approximate 13.4% voting interest in us. As a result of this stock ownership, Oaktree Holdings and ACEC will possess significant influence over matters requiring approval by our stockholders, including the adoption of amendments to our certificate of incorporation and bylaws and significant corporate transactions. Such ownership and control may also have the effect of delaying or preventing a future change of control, impeding a merger, consolidation, takeover or other business combination or discouraging a potential acquirer from making a tender offer or otherwise attempting to obtain control of our company.

Oaktree Holdings, ACEC and their respective affiliates engage, from time to time in the ordinary course of their respective businesses, in trading securities of, and investing in, energy companies. As a result, conflicts may arise between the interests of Oaktree Holdings or ACEC, on the one hand, and the interests of our other stockholders, on the other hand. Either Oaktree Holdings or ACEC may, from time to time, compete directly or indirectly with us or prevent us from taking advantage of corporate opportunities. Either Oaktree Holdings or ACEC may also pursue acquisition opportunities that may be complementary to our business, and as a result, those acquisition opportunities may not be available to us.

The price of our common stock may fluctuate significantly, and you could lose all or part of your investment.

Volatility in the market price of our common stock may prevent you from being able to sell your common stock at or above the price you paid for your common stock. The market price for our common stock could fluctuate significantly for various reasons, including:

- our operating and financial performance and prospects;
- our quarterly or annual earnings or those of other companies in our industry;
- conditions that impact demand for natural gas, crude oil and natural gas liquids;
- future announcements concerning our business;
- changes in financial estimates and recommendations by securities analysts;
- actions of competitors;
- market and industry perception of our success, or lack thereof, in pursuing our growth strategy;
- strategic actions by us or our competitors, such as acquisitions or restructurings;
- changes in government and environmental regulation;

- general market, economic and political conditions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- sales of common stock by us or members of our management team; and
- natural disasters, terrorist attacks and acts of war.

In addition, in recent years, the stock market has experienced significant price and volume fluctuations. This volatility has had a significant impact on the market price of securities issued by many companies, including companies in our industry. The changes frequently appear to occur without regard to the operating performance of the affected companies. Hence, the price of our common stock could fluctuate based upon factors that have little or nothing to do with our company, and these fluctuations could materially reduce our share price.

We have no plans to pay regular dividends on our common stock, so you may not receive funds without selling your common stock.

Our board of directors presently intends to retain all of our earnings for the expansion of our business; therefore, we have no plans to pay regular dividends on our common stock. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends, and other considerations that our board of directors deems relevant. Also, the provisions of our revolving credit agreement and second lien credit agreement restrict the payment of dividends. Accordingly, you may have to sell some or all of your common stock in order to generate cash flow from your investment.

Future sales or the possibility of future sales of a substantial amount of our common stock may depress the price of shares of our common stock.

Future sales or the availability for sale of substantial amounts of our common stock in the public market could adversely affect the prevailing market price of our common stock and could impair our ability to raise capital through future sales of equity securities.

We may issue shares of our common stock or other securities from time to time as consideration for future acquisitions and investments. If any such acquisition or investment is significant, the number of shares of our common stock, or the number or aggregate principal amount, as the case may be, of other securities that we may issue may in turn be substantial. We may also grant registration rights covering those shares of our common stock or other securities in connection with any such acquisitions and investments.

As of December 31, 2010, we had approximately 1.7 million options to purchase shares of our common stock outstanding, of which 1.3 million were vested.

We cannot predict the size of future issuances of our common stock or the effect, if any, that future issuances and sales of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares of our common stock issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices for our common stock.

Our organizational documents may impede or discourage a takeover, which could deprive our investors of the opportunity to receive a premium for their shares.

Provisions of our certificate of incorporation and bylaws may make it more difficult for, or prevent a third party from, acquiring control of us without the approval of our board of directors. These provisions:

- permit us to issue, without any further vote or action by the stockholders, additional shares of preferred stock in one or more series and, with respect to each such series, to fix the number of shares constituting the series and the designation of the series, the voting powers (if any) of the shares of the series, and the preferences and relative, participating, optional, and other special rights, if any, and any qualification, limitations or restrictions of the shares of such series;

- require special meetings of the stockholders to be called by the Chairman of the Board, the Chief Executive Officer, the President, or by resolution of a majority of the board of directors;
- require business at special meetings to be limited to the stated purpose or purposes of that meeting;
- require that stockholder action be taken at a meeting rather than by written consent, unless approved by our board of directors;

- require that stockholders follow certain procedures, including advance notice procedures, to bring certain matters before an annual meeting or to nominate a director for election; and
- permit directors to fill vacancies in our board of directors.

The foregoing factors, as well as the significant common stock ownership by Oaktree Holdings and ACEC, could discourage potential acquisition proposals and could delay or prevent a change of control.

We are subject to the Delaware business combination law.

We are subject to the provisions of Section 203 of the Delaware General Corporation Law. In general, Section 203 prohibits a publicly held Delaware corporation from engaging in a "business combination" with an "interested stockholder" for a period of three years after the date of the transaction in which the person became an interested stockholder, unless the business combination is approved in a prescribed manner.

Section 203 defines a "business combination" as a merger, asset sale or other transaction resulting in a financial benefit to the interested stockholders. Section 203 defines an "interested stockholder" as a person who, together with affiliates and associates, owns, or, in some cases, within three years prior, did own, 15% or more of the corporation's voting stock. Under Section 203, a business combination between us and an interested stockholder is prohibited unless:

- our board of directors approved either the business combination or the transaction that resulted in the stockholders becoming an interested stockholder prior to the date the person attained the status;
- upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of our voting stock outstanding at the time the transaction commenced, excluding, for purposes of determining the number of shares outstanding, shares owned by persons who are directors and also officers and issued employee stock plans, under which employee participants do not have the right to determine confidentially whether shares held under the plan will be tendered in a tender or exchange offer; or
- the business combination is approved by our board of directors on or subsequent to the date the person became an interested stockholder and authorized at an annual or special meeting of the stockholders by the affirmative vote of the holders of at least 66 2/3% of the outstanding voting stock that is not owned by the interested stockholder.

This provision has an anti-takeover effect with respect to transactions not approved in advance by our board of directors, including discouraging takeover attempts that might result in a premium over the market price for the shares of our common stock. With approval of our stockholders, we could amend our certificate of incorporation in the future to elect not to be governed by the anti-takeover law.

We have "blank check" preferred stock.

Our certificate of incorporation authorizes the board of directors to issue preferred stock without further stockholder action in one or more series and to designate the dividend rate, voting rights and other rights preferences and restrictions. The issuance of preferred stock could have an adverse impact on holders of common stock. Preferred stock is senior to common stock. Additionally, preferred stock could be issued with dividend rights senior to the rights of holders of common stock. Finally, preferred stock could be issued as part of a "poison pill," which could have the effect of deterring offers to acquire our company.

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The holders of our common stock do not have cumulative voting rights, preemptive rights or rights to convert their common stock to other securities.

We are authorized to issue 200.0 million shares of common stock, $0.001 par value per share. As of December 31, 2010, there were approximately 44.9 million shares of common stock issued and outstanding. Since the holders of our common stock do not have cumulative voting rights, the holders of a majority of the shares of common stock present, in person or by proxy, will be able to elect all of the members of our board of directors. The holders of shares of our common stock do not have preemptive rights or rights to convert their common stock into other securities.

ITEM 2. Properties

As of December 31, 2010, we operated a majority of our producing wells and held an average 51% working interest. Gross wells are the total wells in which we own a working interest. Net wells are the sum of the fractional working interests we own in gross wells. Substantially all of our properties are located onshore in Texas. As of December 31, 2010, our properties were located in the following regions: East Texas, Southeast Texas, South Texas and Colorado and Other. We intend to allocate a substantial portion of our drilling capital budget in the next several years to the development of the significant potential that we believe exists in our resource plays depending on commodity price environment, drilling and service costs, success rates and capital availability.

Proved Reserves

Estimates of proved reserves at December 31, 2010, 2009, and 2008 were prepared by Netherland, Sewell & Associates, Inc. ("Netherland, Sewell"), our independent consulting petroleum engineers in accordance with the definitions and guidelines of the SEC. The scope and results of their procedures are summarized in a letter which is included as an exhibit to this Annual Report on Form 10-K. The technical persons responsible for preparing the reserve estimates are independent petroleum engineers and geoscientists that meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

The estimated proved reserves were reviewed by our corporate reservoir engineering group and by certain members of our senior management team. We maintain an internal staff of reservoir engineers and geoscience professionals who work closely with our independent petroleum consultant to ensure the integrity, accuracy and timeliness of the data, methods and assumptions used in the preparation of the reserves estimates.

The following tables reflect our estimated proved reserves at December 31 for each of the preceding three years. The 2009 information reflects the disposition of substantially all of our Southwest Louisiana properties, resulting in the disposition of 7,631 MMcfe in 2009. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Recent Developments—Southwest Louisiana Disposition."

	2010	2009	2008
Natural Gas (MMcf)			
Developed	60,325	49,075	66,712
Undeveloped	75,350	20,785	29,457
Total	135,675	69,860	96,169
Crude Oil (MBbl)			
Developed	1,403	1,274	1,616
Undeveloped	761	690	948
Total	2,164	1,964	2,564
Natural Gas Liquids (MBbl)			
Developed	1,898	1,977	2,423
Undeveloped	1,075	664	976
Total	2,973	2,641	3,399
Total MMcfe			
Developed	80,130	68,581	90,946
Undeveloped	86,368	28,908	41,001
Total	166,498	97,489	131,947
Proved developed reserves percentage	48 %	70 %	69 %
PV-10 (in millions)	$239.7	$176.4	$291.0
Estimated reserve life (in years)	12.9	7.1	6.9
Prices utilized in estimates:			
Natural gas ($/MMBtu)	$4.38	$3.87	$5.71
Crude oil ($/Bbl)	$75.96	$57.65	$41.00
Natural gas liquids ($/Bbl)	$40.38	$30.77	$26.71

Under SEC rules, prices used in determining our proved reserves as of December 31, 2010 are based upon an unweighted 12-month first day of the month average price per MMBtu (Henry Hub spot) of natural gas and per barrel of oil (West Texas Intermediate posted). Prior to 2009, natural gas prices were based on the Henry Hub spot price at year end and crude oil prices were based upon the West Texas Intermediate posted price at year end. All prices, under both sets of rules, are adjusted for quality, energy content, transportation fees and regional price differentials in determining proved reserves. Prices for natural gas liquids in the table represent average prices for natural gas liquids used in the proved reserve estimates, calculated in accordance with applicable SEC rules.

PV-10

PV-10 at year-end is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved natural gas and crude oil reserves, less future development and productions costs, discounted at 10% per annum to reflect timing of future cash flows and using pricing assumptions in effect at the end of the period. PV-10 differs from Standardized Measure of Discounted Future Net Cash Flows because it does not include the effects of income taxes or non-property related expenses such as general and administrative expenses and debt service or depreciation, depletion and amortization on future net revenues. Neither PV-10 nor Standardized Measure represents an estimate of fair market value of our natural gas and crude oil properties. PV-10 is used by the industry and by our management as an arbitrary reserve asset value measure to compare against past reserve bases and the reserve bases of other business entities that are not dependent on the taxpaying status of the entity.

The following table provides a reconciliation of our Standardized Measure of Discounted Future Net Cash Flows to PV-10:

	December 31, 2010	2009 (in millions)	2008
Standardized measure of discounted future net cash flows	$ 226.5	$ 176.4	$ 260.9
Present value of future income taxes discounted at 10%	13.2	—	30.1
PV-10	$ 239.7	$ 176.4	$ 291.0

The following table reflects our estimated proved reserves by category as of December 31, 2010.

	Natural Gas (MMcf)	Crude Oil (MBbl)	Natural Gas Liquids (MBbl)	Total (MMcfe)	% of Total Proved	PV-10 (In millions)
Proved developed producing	48,096	1,217	1,424	63,942	38.4%	$ 171.0
Proved developed non-producing	12,229	186	474	16,189	9.7%	24.1
Proved undeveloped	75,350	761	1,075	86,367	51.9%	44.6
Total	135,675	2,164	2,973	166,498	100.0%	$ 239.7

Our estimated net proved reserves as of December 31, 2010, were approximately 81% natural gas, 11% natural gas liquids and 8% crude oil and condensate.

Our average proved reserves-to-production ratio, or average reserve life, is approximately 12.9 years based on our proved reserves as of December 31, 2010 and production for the twelve months ended December 31, 2010. During 2010, 11 gross (4.5 net) operated and non-operated wells were drilled, 8 of which were successful. In 2011, we currently expect to drill 13 gross (7.9 net) wells, two of which are already in progress. Also, as of December 31, 2010, we had identified 82 proved undeveloped drilling locations and 778 other unproved drilling locations.

Proved Developed Reserves

Total proved developed reserves increased from 68.6 Bcfe at December 31, 2009 to 80.1 Bcfe at December 31, 2010. The change in proved developed reserves was attributable to 18.4 Bcfe of new reserves added from drilling and 6.0 Bcfe from positive performance revisions, offset in part by 12.9 Bcfe from 2010 production.

Proved Undeveloped Reserves

From December 31, 2009 to December 31, 2010, total proved undeveloped reserves increased from 28.9 Bcfe to 86.4 Bcfe. The increase in proved undeveloped reserves was attributable to 51.3 Bcfe from 2010 drilling and 6.1 Bcfe from positive performance revisions.

All of our undeveloped locations have been added within the last five years, almost half of which were added in May 2007 with our acquisition of Gulf Coast assets from EXCO. We believe our financial resources allow us the flexibility to drill all of the remaining undeveloped locations within a five year period from the time the locations were acquired.

Standardized Measure of Discounted Future Net Cash Flows

The following table sets forth as of December 31 for each of the preceding three years, the estimated future net cash flow from and standardized measure of discounted future net cash flows of our proved reserves, which were prepared in accordance with the rules and regulations of the SEC and the Financial Accounting Standards Board. Future net cash flow represents future gross cash flow from the production and sale of proved reserves, net of crude oil, natural gas and natural gas liquids production costs (including production taxes, ad valorem taxes and operating expenses) and future development costs. The calculations used to produce the figures in this table are based on current cost and price factors at December 31 for each year. Future income taxes were estimated using future cash inflows, future tax depletion expense on existing producing properties and available net operating loss carryforwards that existed at year end for all years reported. At December 31, 2009, the future pretax net cash flows from our proved oil and gas reserves are estimated to be less than the sum of the tax basis of the applicable producing properties and our available net operating loss ("NOLs") carryforward; therefore, there was zero future tax benefit or expense at December 31, 2009. We believe it is more likely than not that all of our total available NOLs will be realized within the appropriate carryforward period. Our operations and all NOLs are attributable to our oil and gas assets. We cannot assure you that the proved reserves will all be developed within the periods used in the calculations or that those prices and costs will remain constant. A standardized measure of discounted future net cash flows is not required to be presented for interim financial presentation dates.

	2010	2009	2008
Future cash inflows	$860,655,250	$475,007,800	$749,121,400
Future production and development costs			
Production	(218,221,203)	(156,581,500)	(214,969,100)
Development	(195,819,078)	(55,021,500)	(86,068,300)
Future cash flows before income taxes	446,614,969	263,404,800	448,084,000
Future income taxes	(37,624,289)	—	(46,695,950)
Future net cash flows after income taxes	408,990,680	263,404,800	401,388,050
10% annual discount for estimated timing of cash flows	(182,476,004)	(86,982,100)	(140,485,818)
Standardized measure of discounted future net cash flows	$226,514,676	$176,422,700	$260,902,233

Significant Properties

Summary proved reserve information for our properties, by region, with proved reserves is provided below as of December 31, 2010.

	Proved Reserves				PV-10 (1)
Regions	Crude Oil (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (MMcfe)	Amount ($000)
Southeast Texas	1,148	16,174	867	28,262	$108,945
South Texas	651	54,481	2,106	71,024	100,706
East Texas	—	59,336	—	59,336	13,734
Colorado & Other	365	5,684	—	7,876	16,336
Total	2,164	135,675	2,973	166,498	$239,721

(1) Under new SEC rules, prices used in determining our proved reserves as of December 31, 2010 and 2009 are based upon an unweighted 12-month first day of the month average price per MMBtu (Henry Hub spot) of natural gas and per barrel of oil (West Texas Intermediate posted). All prices are adjusted for quality, energy content, transportation fees and regional price differentials in determining proved reserves.

Production, Price and Cost History

See "Part I, Item 7.-Management's Discussion and Analysis of Financial Condition and Results of Operations."

Productive Wells

The following table shows the number of producing wells we owned by location at December 31, 2010:

	Crude Oil		Natural Gas	
	Gross Wells	Net Wells	Gross Wells	Net Wells
Southeast Texas	16	7.2	56	31.6
South Texas	15	4.2	265	142.1
East Texas	—	—	4	2.1
Colorado & Other	28	17.1	26	6.2
Total	59	28.5	351	182.0

In addition, as of December 31, 2010, we had 159 inactive wells and 16 salt water disposal wells.

Developed and Undeveloped Acreage

Developed acreage is acreage spaced or assigned to productive wells. Undeveloped acreage is acreage on which wells have not been drilled or completed to a point that would form the basis to determine whether the property is capable of production of commercial quantities of natural gas, crude oil and natural gas liquids. Gross acres are the total acres in which we own a working interest. Net acres are the sum of the fractional working interests we own in gross acres. The following table shows the approximate developed and undeveloped acreage that we have an interest in, by location, at December 31, 2010.

	Developed		Undeveloped	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Southeast Texas	20,979	11,260	4,919	3,331
South Texas	77,630	42,831	11,662	8,474
East Texas	2,587	1,686	15,626	11,073
Colorado & Other	10,550	5,716	9,560	6,692