COMSTOCK RESOURCES INC
Form 10-K
February 22, 2011

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTIONS 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 SECTIONS 13 OR 15(d)**
OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission File No. 001-03262
COMSTOCK RESOURCES, INC.
(Exact name of registrant as specified in its charter)

NEVADA	**94-1667468**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification Number)*

5300 Town and Country Blvd., Suite 500, Frisco, Texas 75034
(Address of principal executive offices including zip code)

(972) 668-8800
(Registrant s telephone number and area code)

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

Common Stock, $.50 Par Value	**New York Stock Exchange**
(Title of class)	*(Name of exchange on which registered)*

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

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

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

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 þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T

(§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ 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. þ

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

Large accelerated filer þ Accelerated filer o Non-accelerated filer o Smaller reporting company o

(Do not check if smaller reporting company)

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

As of February 22, 2011, there were 47,706,101 shares of common stock outstanding.

The aggregate market value of the common stock held by non-affiliates of the registrant, based on the closing price of common stock on the New York Stock Exchange on June 30, 2010 (the last business day of the registrant s most recently completed second fiscal quarter), was $1.2 billion.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Definitive Proxy Statement for the 2011 Annual Meeting of Stockholders are incorporated by reference into Part III of this report.

COMSTOCK RESOURCES, INC.

ANNUAL REPORT ON FORM 10-K

For the Fiscal Year Ended December 31, 2010

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

The information contained in this report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These forward-looking statements are identified by their use of terms such as expect, estimate, anticipate, project, plan, intend, believe and si All statements, other than statements of historical facts, included in this report, are forward-looking statements, including statements mentioned under Risk Factors and Management s Discussion and Analysis of Financial Condition and Results of Operations, regarding:

amount and timing of future production of oil and natural gas;
the availability of exploration and development opportunities;
amount, nature and timing of capital expenditures;
the number of anticipated wells to be drilled after the date hereof;
our financial or operating results;
our cash flow and anticipated liquidity;
operating costs including lease operating expenses, administrative costs and other expenses;
finding and development costs;
our business strategy; and
other plans and objectives for future operations.

Any or all of our forward-looking statements in this report may turn out to be incorrect. They can be affected by a number of factors, including, among others:

the risks described in Risk Factors and elsewhere in this report;
the volatility of prices and supply of, and demand for, oil and natural gas;
the timing and success of our drilling activities;
the numerous uncertainties inherent in estimating quantities of oil and natural gas reserves and actual future production rates and associated costs;
our ability to successfully identify, execute or effectively integrate future acquisitions;
the usual hazards associated with the oil and natural gas industry, including fires, well blowouts, pipe failure, spills, explosions and other unforeseen hazards;
our ability to effectively market our oil and natural gas;
the availability of rigs, equipment, supplies and personnel;
our ability to discover or acquire additional reserves;
our ability to satisfy future capital requirements;
changes in regulatory requirements;
general economic conditions, status of the financial markets and competitive conditions;
our ability to retain key members of our senior management and key employees; and
hostilities in the Middle East and other sustained military campaigns and acts of terrorism or sabotage that impact the supply of crude oil and natural gas.

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DEFINITIONS

The following are abbreviations and definitions of terms commonly used in the oil and gas industry and this report. Natural gas equivalents and crude oil equivalents are determined using the ratio of six Mcf to one barrel. All references to us, our, we or Comstock mean the registrant, Comstock Resources, Inc. and where applicable, its consolidated subsidiaries.

Bbl means a barrel of U.S. 42 gallons of oil.

Bcf means one billion cubic feet of natural gas.

Bcfe means one billion cubic feet of natural gas equivalent.

Btu means British thermal unit, which is the quantity of heat required to raise the temperature of one pound of water from 58.5 to 59.5 degrees Fahrenheit.

Completion means the installation of permanent equipment for the production of oil or gas.

Condensate means a hydrocarbon mixture that becomes liquid and separates from natural gas when the gas is produced and is similar to crude oil.

Development well means a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole means a well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Exploratory well means a well drilled to find and produce oil or natural gas reserves not classified as proved, to find a new productive reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

GAAP means generally accepted accounting principles in the United States of America.

Gross when used with respect to acres or wells, production or reserves refers to the total acres or wells in which we or another specified person has a working interest.

MBbls means one thousand barrels of oil.

MBbls/d means one thousand barrels of oil per day.

Mcf means one thousand cubic feet of natural gas.

Mcfe means one thousand cubic feet of natural gas equivalent.

MMBbls means one million barrels of oil.

MMBtu means one million British thermal units.

MMcf means one million cubic feet of natural gas.

MMcf/d means one million cubic feet of natural gas per day.

MMcfe/d means one million cubic feet of natural gas equivalent per day.

MMcfe means one million cubic feet of natural gas equivalent.

Net when used with respect to acres or wells, refers to gross acres of wells multiplied, in each case, by the percentage working interest owned by us.

Net production means production we own less royalties and production due others.

Oil means crude oil or condensate.

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Operator means the individual or company responsible for the exploration, development, and production of an oil or gas well or lease.

PV 10 Value means the present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with the Securities and Exchange Commission guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service, future income tax expense and depreciation, depletion and amortization, and discounted using an annual discount rate of 10%. This amount is the same as the standardized measure of discounted future net cash flows related to proved oil and natural gas reserves except that it is determined without deducting future income taxes. Although PV 10 Value is not a financial measure calculated in accordance with GAAP, management believes that the presentation of PV 10 Value is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account corporate future income taxes and our current tax structure. We use this measure when assessing the potential return on investment related to our oil and gas properties. Because many factors that are unique to any given company affect the amount of estimated future income taxes, the use of a pre-tax measure is helpful to investors when comparing companies in our industry.

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

Proved developed non-producing means reserves (i) expected to be recovered from zones capable of producing but which are shut-in because no market outlet exists at the present time or whose date of connection to a pipeline is uncertain or (ii) currently behind the pipe in existing wells, which are considered proved by virtue of successful testing or production of offsetting wells.

Proved developed producing means reserves expected to be recovered from currently producing zones under continuation of present operating methods. This category may also include recently completed shut-in gas wells scheduled for connection to a pipeline in the near future.

Proved reserves means the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

Proved undeveloped reserves means reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances are estimates for proved undeveloped reserves attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

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Recompletion means the completion for production of an existing well bore in another formation from which the well has been previously completed.

Reserve life means the calculation derived by dividing year-end reserves by total production in that year.

Reserve replacement means the calculation derived by dividing additions to reserves from acquisitions, extensions, discoveries and revisions of previous estimates in a year by total production in that year.

Royalty means an interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner s royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

3-D seismic means an advanced technology method of detecting accumulations of hydrocarbons identified by the collection and measurement of the intensity and timing of sound waves transmitted into the earth as they reflect back to the surface.

Working interest means an interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations. The share of production to which a working interest owner is entitled will always be smaller than the share of costs that the working interest owner is required to bear, with the balance of the production accruing to the owners of royalties. For example, the owner of a 100% working interest in a lease burdened only by a landowner s royalty of 12.5% would be required to pay 100% of the costs of a well but would be entitled to retain 87.5% of the production.

Workover means operations on a producing well to restore or increase production.

PART I

ITEMS 1. and 2. *BUSINESS AND PROPERTIES*

We are a Nevada corporation engaged in the acquisition, development, production and exploration of oil and natural gas. Our common stock is listed and traded on the New York Stock Exchange.

Our oil and gas operations are concentrated in East Texas/North Louisiana and South Texas. Our oil and natural gas properties are estimated to have proved reserves of 1,051.0 Bcfe with an estimated PV 10 Value of $797.6 million as of December 31, 2010 and a standardized measure of discounted future net cash flows of $606.1 million. Our consolidated proved oil and natural gas reserve base is 98% natural gas and 50% proved developed on a Bcfe basis as of December 31, 2010.

Our proved reserves at December 31, 2010 and our 2010 average daily production are summarized below:

	Reserves at December 31, 2010				2010 Average Daily Production			
	Oil (MMBbls)	Natural Gas (Bcf)	Total (Bcfe)	% of Total	Oil (MBbls/d)	Natural Gas (MMcf/d)	Total (MMcfe/d)	% of Total
East Texas / North Louisiana	1.2	862.9	870.4	82.8%	0.4	142.6	145.0	72.2%
South Texas	2.9	141.1	158.3	15.1%	0.4	39.5	42.1	21.0%
Other Regions	0.1	21.7	22.3	2.1%	1.1	6.9	13.6	6.8%
Total	4.2	1,025.7	1,051.0	100%	1.9	189.0	200.7	100%

Strengths

High Quality Properties. Our operations are focused in two primary operating areas, the East Texas/North Louisiana and South Texas regions. Our properties have an average reserve life of approximately 14.3 years and have extensive development and exploration potential. We have a substantial acreage position in our East Texas/North Louisiana region in the Haynesville or Bossier shale resource play where we have identified 91,011 gross (79,457 net to us) acres prospective for Haynesville or Bossier shale development. During 2010 we also acquired 20,859 acres (18,320 net to us) in South Texas which are prospective for development of the Eagle Ford shale formation.

Successful Exploration and Development Program. In 2010 we spent $536.7 million on exploration and development activities. We drilled 78 wells in 2010, 49.3 net to us, at a cost of $390.6 million. We spent $134.7 million to acquire additional leases, $3.2 million on other leasehold costs and $2.6 million to acquire seismic data. We also spent $5.6 million for recompletions, workovers, abandonment and production facilities. Our drilling activities in 2010 added 431 Bcfe to our proved reserves and increased our production by 12% in 2010. Due to unavailability of completion services in 2010 we only completed 37 (21.6 net to us) of the 72 (45.0 net to us) Haynesville or Bossier shale wells that we drilled. We expect to complete all of the remaining wells drilled in 2010 during 2011.

Efficient Operator. We operate 92% of our proved oil and natural gas reserve base as of December 31, 2010. As operator we are better able to control operating costs, the timing and plans for future development, the level of drilling and lifting costs and the marketing of production. As an operator, we receive reimbursements for overhead from other working interest owners, which reduces our general and administrative expenses.

Successful Acquisitions. We have had significant growth over the years as a result of our acquisition activity. In recent years, however, we have not made any acquisitions; in 2010 we focused exclusively on

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drill bit growth. Since 1991, we have added 984 Bcfe of proved oil and natural gas reserves from 36 acquisitions at an average cost of $1.14 per Mcfe. Our application of strict economic and reserve risk criteria have enabled us to successfully evaluate and integrate acquisitions.

Business Strategy

Pursue Exploration Opportunities. We conduct exploration activities to grow our reserve base and to replace our production each year. In late 2007 we identified the potential in our largest operating region, East Texas/North Louisiana, to explore for natural gas in the Haynesville shale formation, which was below the Cotton Valley, Hosston and Travis Peak sand formations that we have been developing. We drilled eight pilot wells to evaluate the prospectivity of the Haynesville shale in 2007 and 2008. We undertook an active leasing program in 2008 through 2010 to acquire additional acreage where we believed the Haynesville shale formation would be prospective and spent $116.9 million in 2008, $26.9 million in 2009 and $55.8 million in 2010 to increase our leasehold with Haynesville or Bossier shale potential to 91,011 gross acres (79,457 net to us). We started the commercial development of the Haynesville shale in late 2008 and have drilled 118 (77.7 net to us) successful horizontal wells through the end of 2010. In 2010, our drilling program was primarily focused on exploring and developing our Haynesville and Bossier shale acreage and we drilled 72 (45.0 net to us) Haynesville and Bossier shale horizontal wells which added 402 Bcfe to our proved reserves in 2010. We plan to continue to develop our Haynesville and Bossier shale acreage in 2011 and have budgeted to spend $348.0 million to drill 45 (27.5 net to us) Haynesville and Bossier shale horizontal wells and to complete our wells that were in progress at the end of 2010.

During 2010 we spent approximately $81.4 million to acquire 20,859 acres (18,320 net to us) in South Texas which we believe to be prospective for the production of liquid hydrocarbons in the Eagle Ford shale formation. We spent approximately $25.6 million to drill three wells (3.0 net to us) in 2010 on our Eagle Ford shale properties. Our Eagle Ford shale drilling program added 10 Bcfe to our proved reserves in 2010. We plan to continue to evaluate our Eagle Ford shale properties during 2011 and have budgeted $169.3 million to drill 22 wells (22.0 net to us) during 2011.

Exploit Existing Reserves. We seek to maximize the value of our oil and natural gas properties by increasing production and recoverable reserves through development drilling and workover, recompletion and exploitation activities. We utilize advanced industry technology, including 3-D seismic data, horizontal drilling, improved logging tools, and formation stimulation techniques. During 2010, outside of our Haynesville shale and Eagle Ford shale drilling programs, we spent $4.6 million to drill three wells (1.3 net to us). We also spent $5.6 million for recompletion and workover activity in 2010.

Maintain Flexible Capital Expenditure Budget. The timing of most of our capital expenditures is discretionary because we have not made any significant long-term capital expenditure commitments except for contracted drilling and completion services. We operate most of the drilling projects in which we participate. Consequently, we have a significant degree of flexibility to adjust the level of such expenditures according to market conditions. We have budgeted to spend approximately $522.0 million on our development and exploration projects in 2011. We intend to primarily use operating cash flow, proceeds from the sale of non-core assets and borrowings under our bank credit facility to fund our development and exploration expenditures in 2011. We may also make additional property acquisitions in 2011 that would require additional sources of funding. Such sources may include borrowings under our bank credit facility or sales of our equity or debt securities.

Acquire High Quality Properties at Attractive Costs. In prior years we have had a successful track record of increasing our oil and natural gas reserves through opportunistic acquisitions. Since 1991, we have added 984 Bcfe of proved oil and natural gas reserves from 36 acquisitions at a total cost of $1.1 billion, or

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$1.14 per Mcfe. The acquisitions were acquired at an average of 67% of their PV 10 Value in the year the acquisitions were completed. We did not complete any acquisitions of producing oil and gas properties in 2009 or 2010 due to our focus on developing our Haynesville and Bossier shale and Eagle Ford shale properties. In evaluating acquisitions, we apply strict economic and reserve risk criteria. We target properties in our core operating areas with established production and low operating costs that also have potential opportunities to increase production and reserves through exploration and exploitation activities. We also evaluate our existing properties and consider divesting of non-strategic assets when market conditions are favorable.

Primary Operating Areas

The following table summarizes the estimated proved oil and natural gas reserves for our twenty largest field areas as of December 31, 2010:

	Oil (MBbls)	Natural Gas (MMcf)	Total (MMcfe)	%	PV 10 Value(1) (000 s)	%
East Texas / North Louisiana						
Logansport	44	521,193	521,455	49.6%	$ 351,416	44.1%
Toledo Bend		134,310	134,310	12.8%	15,492	1.9%
Beckville	138	54,421	55,251	5.3%	54,188	6.8%
Mansfield		39,659	39,659	3.8%	16,991	2.1%
Waskom	417	31,758	34,259	3.3%	22,737	2.9%
Blocker	113	30,929	31,609	3.0%	27,032	3.4%
Hico-Knowles/Terryville	310	15,078	16,936	1.6%	33,962	4.3%
Darco	38	9,463	9,693	0.9%	6,175	0.8%
Douglass	3	7,171	7,191	0.7%	6,513	0.8%
Drew	34	3,387	3,588	0.3%	4,736	0.6%
Vixen		2,937	2,937	0.3%	3,098	0.4%
Other	145	12,569	13,444	1.2%	16,696	2.0%
	1,242	862,875	870,332	82.8%	559,036	70.1%
South Texas						
Fandango		53,375	53,375	5.1%	57,320	7.2%
Double A Wells	910	24,156	29,619	2.8%	51,489	6.5%
Rosita	1	27,327	27,335	2.6%	25,696	3.2%
Javelina	70	13,283	13,704	1.3%	23,150	2.9%
Eagle Ford	1,426	1,492	10,050	1.0%	9,013	1.1%
Las Hermanitas	3	9,745	9,762	0.9%	10,413	1.3%
Segno	373	1,147	3,382	0.3%	15,146	1.9%
Lopeno	46	2,640	2,916	0.3%	4,450	0.6%
Other	49	7,895	8,189	0.8%	12,466	1.5%
	2,878	141,060	158,332	15.1%	209,143	26.2%

Other						
San Juan Basin	14	4,337	4,424	0.4%	6,830	0.9%
Other	85	17,361	17,862	1.7%	22,617	2.8%
	99	21,698	22,286	2.1%	29,447	3.7%
Total	4,219	1,025,633	1,050,950	100.00%	797,626	100.00%
Discounted Future Income Taxes					(191,490)	
Standardized Measure of Discounted Future Cash Flows					$ 606,136	

(1) The PV 10 Value represents the discounted future net cash flows attributable to our proved oil and gas reserves before income tax, discounted at 10%. Although it is a non-GAAP measure, we believe that the presentation of the PV 10 Value is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account corporate future income taxes and our current tax structure. We use this measure when assessing the potential return on investment related to our oil and gas properties. The standardized measure of discounted future net cash flows represents the present value of future cash flows attributable to our proved oil and natural gas reserves after income tax, discounted at 10%.

East Texas/North Louisiana Region

Approximately 83% or 870.4 Bcfe of our proved reserves are located in East Texas and North Louisiana where we own interests in 936 producing wells (565.7 net to us) in 28 field areas. We operate 639 of these wells. The largest of our fields in this region are the Logansport, Toledo Bend, Beckville, Mansfield, Waskom, Blocker, Hico-Knowles/Terryville, Darco, Douglass, Drew and Vixen fields. Production from this region averaged 143 MMcf of natural gas per day and 403 barrels of oil per day during 2010 or 145 MMcfe per day. Most of the reserves in this area produce from the upper Jurassic aged Haynesville or Bossier shale or Cotton Valley formations and the Cretaceous aged Travis Peak/Hosston formation. In 2010, we spent $354.0 million drilling 73 wells (45.5 net to us) and $58.0 million on leasehold costs, workovers and recompletions in this region. 72 (45.0 net to us) of the 73 wells we drilled were horizontal wells that targeted the Haynesville or Bossier shale. As of December 31, 2010 we had 35 (23.4 net to us) Haynesville and Bossier shale wells that had been drilled but which were not yet completed. We plan to spend approximately $348.0 million in 2011 in this region to complete the wells that were in progress at the end of 2010 and for drilling activities which will focus primarily on the continued development of our Haynesville and Bossier shale properties.

Logansport

The Logansport field located in DeSoto Parish, Louisiana primarily produces from the Haynesville shale formation at a depth of 11,100 to 11,500 feet and from multiple sands in the Cotton Valley and Hosston formations at an average depth of 8,000 feet. Our proved reserves of 521.5 Bcfe in the Logansport field represent approximately 50% of our proved reserves. We own interests in 205 wells (129.6 net to us) and operate 143 of these wells in this field. At December 31, 2010 we had three wells (0.5 net to us) that were in the process of being completed and 19 drilled wells awaiting completion. During December 2010 net daily production attributable to our interest from this field averaged 80 MMcf of natural gas and 34 barrels of oil. In 2010 we drilled 42 (28.4 net to us) Haynesville or Bossier shale horizontal wells at Logansport. In 2011 we plan to drill 22 (15.4 net to us) horizontal Haynesville or Bossier shale wells.

Toledo Bend

The Toledo Bend field in Desoto and Sabine Parishes, Louisiana was discovered in 2008 with our first horizontal Haynesville shale well. In 2010, we drilled nine (4.7 net to us) Haynesville shale horizontal wells and ten (7.5 net to us) Bossier shale horizontal wells at Toledo Bend. Production from the Haynesville shale in the Toledo Bend ranges from 11,400 to 11,800 feet and from 10,880 to 11,300 feet in the Bossier shale. Our proved reserves of 134 Bcfe in the Toledo Bend field represent approximately 13% of our reserves. We own interests in 28 producing wells (17.8 net to us) and operate twenty of these wells. At December 31, 2010 we had four wells (2.1 net to us) that were in the process of being drilled, one well in the process of being completed and six drilled wells awaiting completion. During December 2010, net daily production attributable to our interest from this field averaged 29 MMcf of natural gas. In 2011, we plan to drill 18 (10.9 net to us) horizontal Haynesville or Bossier shale wells in this field.

Beckville

The Beckville field, located in Panola and Rusk Counties, Texas, has estimated proved reserves of 55 Bcfe which represents approximately 5% of our proved reserves. We operate 193 wells in this field and own interests in 83 additional wells for a total of 276 wells (161.5 net to us). During December 2010, production attributable to our interest from this field averaged 13 MMcf of natural gas per day and 52 barrels of oil per day. The Beckville field produces primarily from the Cotton Valley formation at depths ranging from 9,000 to 10,000 feet. The field is also prospective for future Haynesville shale development.

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Mansfield

The Mansfield field is located in DeSoto Parish Louisiana and produces from the Haynesville shale between 12,250 and 12,350 feet. During 2010 we drilled nine (2.3 net to us) Haynesville shale horizontal wells in this field. At December 31, 2010 in Mansfield we had two wells in the process of being drilled, three wells in the process of being completed and three drilled wells awaiting completion. Our proved reserves in this field of 40 Bcfe represent approximately 4% of our reserves. During December 2010, net daily production attributable to our interest for this field averaged 3 MMcf of natural gas.

Waskom

The Waskom field, located in Harrison and Panola Counties in Texas, represents approximately 3% (34 Bcfe) of our proved reserves as of December 31, 2010. We own interests in 67 wells in this field (43.5 net to us) and operate 51 wells in this field. During December 2010, net daily production attributable to our interest averaged 6 MMcf of natural gas and 30 barrels of oil from this field. The Waskom field produces from the Cotton Valley formation at depths ranging from 9,000 to 10,000 feet and from the Haynesville shale formation at depths of 10,800 to 10,900 feet. We drilled one Haynesville shale well in the Waskom field in 2010 and will drill one (1.0 net to us) horizontal Haynesville shale well in 2011.

Blocker

Our proved reserves of 32 Bcfe in the Blocker field located in Harrison County, Texas represent approximately 3% of our proved reserves. We own interests in 76 wells (70 net to us) and operate 70 of these wells. During December 2010, net daily production attributable to our interest from this field averaged 6 MMcf of natural gas and 35 barrels of oil. Most of this production is from the Cotton Valley formation between 8,600 and 10,150 feet and the Haynesville shale formation between 11,100 and 11,450 feet. During 2010 we drilled one successful Cotton Valley well at Blocker.

Hico-Knowles/Terryville

We have 17 Bcfe of proved reserves in the Hico-Knowles/Terryville field area located in Lincoln County, Louisiana which represent approximately 2% of our reserves. We own interests in 68 wells (25.3 net to us) and operate 22 of these wells. This field produces primarily from the Hosston/Cotton Valley formations between 7,200 and 11,000 feet. During December 2010, net daily production attributable to our interest from this field averaged 5 MMcf of natural gas and 95 barrels of oil.

Darco

The Darco field is located in Harrison County, Texas and produces from the Cotton Valley formation at depths from approximately 9,800 to 10,200 feet. Our proved reserves of 10 Bcfe in the Darco field represent approximately 1% of our reserves. We own interests in 24 wells (18.8 net to us) and operate all of these wells. During December 2010, net daily production attributable to our interest from this field averaged 1 MMcf of natural gas and 10 barrels of oil.

Douglass

The Douglass field is located in Nacogdoches County, Texas and is productive from stratigraphically trapped reservoirs in the Pettet Lime and Travis Peak formations. These reservoirs are found at depths from 9,200 to 10,300 feet. Our proved reserves of 7 Bcfe in the Douglass field represent approximately 1% of our

reserves. We own interests in 40 wells (25.8 net to us) and operate 33 of these wells. During December 2010, net daily production attributable to our interest from this field averaged 1 MMcf of natural gas and 5 barrels of oil.

Drew

The Drew Field located in Ouachita Parish, Louisiana has an estimated proved reserves of 4 Bcfe which represents less than 1% of our total company proved reserves. Production is from the Cotton Valley formation between 9,000 feet and 9,600 feet. We own interest in eight wells (5.3 net to us) and operate six of these wells. During December 2010, net daily production attributable to our interest from this field averaged 1 MMcf of natural gas and 5 barrels of oil per day.

Vixen

The Vixen Field located in Caldwell Parish, Louisiana has an estimated proved reserves of 3 Bcfe which represents less than 1% of our total company proved reserves. Production is from various Hosston sands between 8,300 feet to 10,500 feet. We own interest in seven wells (6.0 net) and operate all of these wells. During December 2010, net daily production attributable to our interest from this field averaged 1 MMcf of natural gas.

South Texas Region

Approximately 15%, or 158 Bcfe, of our proved reserves are located in South Texas, where we own interests in 228 producing wells (124.7 net to us). We own interests in 15 field areas in the region, the largest of which are the Fandango, Double A Wells, Rosita, Javelina, Eagle Ford, Las Hermanitas, Segno and Lopeno fields. Net daily production rates from this region averaged 40 MMcf of natural gas and 429 barrels of oil during 2010 or 42 MMcfe per day. We spent $82.0 million in this region in 2010 to acquire acreage which is prospective for development of the Eagle Ford shale. We also spent $25.6 million to drill three Eagle Ford shale wells (3.0 net to us) and $12.0 million to drill one vertical well (0.5 net to us) and for other development activity. We plan to spend approximately $174.0 million in 2011 for development and exploration activity targeting the Eagle Ford shale formation in this region.

Fandango

We own interests in 21 wells (21 net to us) in the Fandango field, located in Zapata County, Texas. We operate all of these wells which produce from the Wilcox formation at depths from approximately 13,000 to 18,000 feet. Our proved reserves of 53 Bcfe in this field represent approximately 5% of our total reserves. Production from this field averaged 12 MMcf of natural gas per day during December 2010. We drilled one successful exploration well and two successful development wells since we acquired this field in 2007.

Double A Wells

Our properties in the Double A Wells field have proved reserves of 30 Bcfe, which represent 3% of our reserves. We own interests in and operate 57 producing wells (27.9 net to us) in this field in Polk County, Texas. Net daily production from the Double A Wells area averaged 5 MMcf of natural gas and 175 barrels of oil during December 2010. These wells produce from the Woodbine formation at an average depth of 14,300 feet.

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Rosita

We own interests in 31 wells (16.8 net to us) in the Rosita field, located in Duval County, Texas. We operate four of these wells which produce from the Wilcox formation at depths from approximately 9,300 to 17,000 feet. Our proved reserves of 27 Bcfe in this field represent approximately 3% of our total reserves. Production from this field averaged 4 MMcf of natural gas and two barrels of oil per day during December 2010.

Javelina

We own interests in and operate 18 wells, (18 net to us), in the Javelina field in Hidalgo County in South Texas. These wells produce primarily from the Vicksburg formation at a depth of approximately 10,900 to 12,500 feet. Proved reserves attributable to our interests in the Javelina field are 14 Bcfe, which represents 1% of our total proved reserves. During December 2010, production attributable to our interest from this field averaged 4 MMcf of natural gas per day and 38 barrels of oil per day.

Eagle Ford

We have 20,859 acres distributed across Atascosa, McMullen and Karnes Counties which is prospective for Eagle Ford shale development in South Texas. The Eagle Ford Shale is found between 7,500 feet and 11,500 feet across our acreage position. In 2010 we had two producing wells which we operate with a 100% working interest. In December 2010 both of these wells were producing a total of 525 barrels of oil per day and 352 Mcf per day of natural gas net to our interest. Our Eagle Ford proved reserves from this initial exploration activity during 2010 is estimated to be 10 Bcfe (85% oil) and represents 1% of our reserves.

Las Hermanitas

We own interests in and operate 15 natural gas wells (12.2 net to us) in the Las Hermanitas field, located in Duval County, Texas. These wells produce from the Wilcox formation at depths from approximately 11,400 to 11,800 feet. Our proved reserves of 10 Bcfe in this field represent approximately 1% of our proved reserves. During December 2010, net daily production attributable to our interest from this field averaged 3 MMcf of natural gas. We acquired interests in this field in 2006 and have subsequently drilled eleven successful wells in this field since the acquisition.

Segno

The Segno Field located in Polk County, Texas has an estimated proved reserves of 3 Bcfe which represents less than 1% of our total company proved reserves. Production is from shallow Yegua sands from 5,000 feet to 5,600 feet and deep Wilcox sands between 11,300 feet to 13,350 feet. We own interests in 10.5 net wells and do not operate any of the wells. During December 2010, net daily production attributable to our interest from this field averaged 1 MMcf of natural gas and 98 barrels of oil per day.

Lopeno

The Lopeno Field located in Zapata County, Texas has an estimated proved reserves of 3 Bcfe which represents less than 1% of our total company proved reserves. Production is from shallow Queen City sands between 2,200 feet and 2,600 feet and deeper Wilcox sands between 6,400 feet and 12,500 feet. We own interests in 18 wells (3.0 net to us) and operate one of these wells. During December 2010, net daily production attributable to our interest from this field averaged 0.2 MMcf of natural gas and 3 barrels of oil per day.

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Other Regions

Approximately 2%, or 22 Bcfe, of our proved reserves are in other regions, primarily in New Mexico, Kentucky and the Mid-Continent region. We own interests in 425 producing wells (163.6 net to us) in 15 fields within these regions. The field with the largest proved reserves is our San Juan Basin properties in New Mexico. Excluding production from the Mississippi properties we sold in 2010, net daily production from our other regions during 2010 totaled 6 MMcf of natural gas and 52 barrels of oil or 6 MMcfe per day.

San Juan

Our San Juan Basin properties are located in the west-central portion of the basin in San Juan County, New Mexico. These wells produce from multiple sands of the Cretaceous Dakota formation and the Fruitland Coal seams. The Dakota is generally found at about 6,000 feet with the shallower Fruitland seams encountered at 2,500 to 3,000 feet. Our proved reserves of 4 Bcfe in the San Juan field represent less than 1% of our reserves. We own interests in 97 wells (14.6 net to us) in this field. During December 2010, net daily production attributable to our interest from this field averaged 1 MMcf of natural gas and 3 barrels of oil.

Major Property Acquisitions

As a result of our acquisitions, we have added 984 Bcfe of proved oil and natural gas reserves since 1991. Our largest acquisitions include the following:

Shell Wilcox Acquisition. In December 2007, we completed the acquisition of certain oil and natural gas properties and related assets from SWEPI LP, an affiliate of Shell Oil Company for $160.1 million. The properties acquired had estimated proved reserves of approximately 70.1 Bcfe. Major fields acquired in the acquisition include the Fandango and Rosita fields.

Javelina Acquisition. In June 2007 we acquired additional working interests in oil and gas properties in the Javelina field in South Texas from Abaco Operating LLC for $31.2 million. The properties acquired had estimated proved reserves of approximately 9.1 Bcfe.

Denali Acquisition. In September 2006 we acquired proved and unproved oil and gas properties in the Las Hermanitas field in South Texas from Denali Oil & Gas Partners LP and other working interest owners for $67.2 million. The properties acquired had estimated proved reserves of approximately 16.5 Bcfe.

Ensight Acquisition. In May 2005, we completed the acquisition of certain oil and natural gas properties and related assets from Ensight Energy Partners, L.P., Laurel Production, LLC, Fairfield Midstream Services, LLC and Ensight Energy Management, LLC (collectively, Ensight) for $190.9 million. We also purchased additional interests in those properties from other owners for $10.9 million in July 2005. The properties acquired had estimated proved reserves of approximately 121.5 billion cubic feet of natural gas equivalent and included 312 active wells, of which 119 are operated by us. Major fields acquired include the Darco, Douglass, Cadeville, and Laurel fields.

Ovation Energy Acquisition. In October 2004, we acquired producing oil and gas properties in the East Texas, Arkoma, Anadarko and San Juan basins from Ovation Energy, L.P. for $62.0 million. The properties acquired had estimated proved reserves of approximately 41.0 billion cubic feet of gas equivalent and included 165 active wells, of which 69 were operated by us.

DevX Energy Acquisition. In December 2001, we completed the acquisition of DevX Energy, Inc. (DevX) by acquiring 100% of the common stock of DevX for $92.6 million. The total purchase price

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including debt and other liabilities assumed in the acquisition was $160.8 million. As a result of the acquisition of DevX, we acquired interests in 600 producing oil and natural gas wells located onshore primarily in East and South Texas, Kentucky, Oklahoma and Kansas. DevX s properties had 1.2 MMBbls of oil reserves and 156.5 Bcf of natural gas reserves at the time of the acquisition.

Bois d Arc Acquisition. In December 1997, Comstock acquired working interests in certain producing offshore Louisiana oil and gas properties as well as interests in undeveloped offshore oil and natural gas leases for approximately $200.9 million from Bois d Arc Resources and certain of its affiliates and working interest partners. We acquired interests in 43 wells (29.6 net to us) and eight separate production complexes located in the Gulf of Mexico offshore of Plaquemines and Terrebonne Parishes, Louisiana. The acquisition included interests in the Louisiana state and federal offshore areas of Main Pass Block 21, Ship Shoal Blocks 66, 67, 68 and 69 and South Pelto Block 1. The net proved reserves acquired in this acquisition were estimated at 14.3 MMBbls of oil and 29.4 Bcf of natural gas. We divested of these offshore properties in 2008.

Black Stone Acquisition. In May 1996, we acquired 100% of the capital stock of Black Stone Oil Company and interests in producing and undeveloped oil and gas properties located in South Texas for $100.4 million. We acquired interests in 19 wells (7.7 net to us) that were located in the Double A Wells field in Polk County, Texas and we became the operator of most of the wells in the field. The net proved reserves acquired in this acquisition were estimated at 5.9 MMBbls of oil and 100.4 Bcf of natural gas.

Sonat Acquisition. In July 1995, we purchased interests in certain producing oil and gas properties located in East Texas and North Louisiana from Sonat Inc. for $48.1 million. We acquired interests in 319 producing wells (188.0 net to us). The acquisition included interests in the Logansport, Beckville, Waskom, Blocker and Hico-Knowles fields. The net proved reserves acquired in this acquisition were estimated at 0.8 MMBbls of oil and 104.7 Bcf of natural gas.

Oil and Natural Gas Reserves

The following table sets forth our estimated proved oil and natural gas reserves and the PV 10 Value as of December 31, 2010:

	Oil (MBbls)	**Natural Gas (MMcf)**	**Total (MMcfe)**	**PV 10 Value (000 s)**
Proved Developed:				
Producing	2,279	354,429	368,103	$ 608,902
Non-producing	682	152,380	156,470	150,235
Total Proved Developed	2,961	506,809	524,573	759,137
Proved Undeveloped	1,258	518,824	526,377	38,489
Total Proved	4,219	1,025,633	1,050,950	797,626
Discounted Future Income Taxes				(191,490)
Standardized Measure of Discounted Future Net Cash Flows[1]				$ 606,136

(1) The PV 10 Value represents the discounted future net cash flows attributable to our proved oil and natural gas reserves before income tax, discounted at 10%. Although it is a non-GAAP measure, we believe that the presentation of the PV 10 Value is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account corporate future income taxes and our current tax structure. We use this measure when assessing the potential return on investment related to our oil and gas properties. The standardized measure of discounted future net cash flows represents the present value of future cash flows attributable to our proved oil and natural gas reserves after income tax, discounted at 10%.

The following table sets forth our year end reserves as of December 31 for each of the last three fiscal years:

	2008		2009		2010	
	Oil (Mbbls)	Natural Gas (MMcf)	Oil (Mbbls)	Natural Gas (MMcf)	Oil (Mbbls)	Natural Gas (MMcf)
Proved Developed	5,446	354,934	4,894	367,102	2,961	506,809
Proved Undeveloped	4,222	168,709	2,320	315,287	1,258	518,824
Total Proved Reserves	9,668	523,643	7,214	682,389	4,219	1,025,633

Proved oil and natural gas reserves are the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. Crude oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserves estimates are often different from the quantities of crude oil and natural gas that are ultimately recovered.

The average prices that we realized from sales of oil and natural gas, including the effect of hedging, and lifting costs including severance and ad valorem taxes and transportation costs, for each of the last three fiscal years were as follows:

	Year Ended December 31,		
	2008	2009	2010
Oil Price $/Bbl	$87.15	$50.94	$68.35
Natural Gas Price $/Mcf	$8.83	$4.16	$4.35
Lifting costs $/Mcfe	$1.45	$1.08	$1.10

The oil and natural gas prices used for reserves estimation were as follows:

Year	Oil Price (per Bbl)	Natural Gas Price (per Mcf)
2008	$ 34.49	$ 5.33

2009	$ 49.60	$ 3.54
2010	$ 76.31	$ 4.16

Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered, and they are scheduled to be drilled within five years of their initial inclusion as proved reserves, unless specific circumstances justify a longer time. In addition, undeveloped reserves may be estimated through the use of reliable technology in addition to flow tests and production history. As of December 31, 2010, our proved reserves included 1.3 MMBbls of crude oil and 519 Bcf of natural gas, for a total of 526 Bcfe of undeveloped reserves. Approximately 83% of our proved undeveloped reserves at December 31, 2010 were associated with the future development of our Haynesville or Bossier shale properties. The remaining proved undeveloped reserves are primarily associated with developing reserves in our Cotton Valley and Hosston sand reservoirs in East Texas/North Louisiana and our Eagle Ford shale, Wilcox and Vicksburg reservoirs in South Texas. Estimated future costs relating to the development of the undeveloped reserves are projected to be approximately $1.1 billion, of which $237.3 million, $380.9 million and $299.6 million are expected to be incurred in 2011, 2012 and 2013, respectively. Costs incurred relating to the development of our undeveloped reserves were approximately $104.4 million, $20.1 million and $16.9 million in 2008, 2009 and 2010, respectively. Following the initial success of our Haynesville shale evaluation wells, our 2010 drilling program was focused primarily to further evaluate and develop acreage that is prospective in the Haynesville shale formation. As a result, only three of the wells we drilled in 2010 resulted in conversions of proved undeveloped reserves to proved developed producing reserves at the end of 2010. All undeveloped drilling locations which comprise our undeveloped reserves at December 31, 2010 are scheduled to be drilled within five years of the year that such reserves were first included in our reported reserves.

We had proved reserve additions of 402 Bcfe in 2010 relating to discoveries resulting from our Haynesville and Bossier shale drilling program. These reserve additions related to 177 Bcfe assigned to 68 Haynesville and Bossier shale wells (41.5 net to us) that we drilled and 225 Bcfe assigned to 89 (55.5 net to us) proved undeveloped locations offsetting these wells. During 2010 we drilled the first wells in our acreage which is prospective for the Eagle Ford shale. Based on the drilling results from our first successful wells, we added 10.1 Bcfe to our proved reserves, most of which is crude oil or condensate. We also had an additional 19 Bcfe of reserve additions from our drilling activity in our non-shale oil and gas properties.

The estimates of our oil and natural gas reserves were determined by Lee Keeling and Associates, Inc. (Lee Keeling), an independent petroleum engineering firm. Lee Keeling has been providing consulting engineering and geological services for over fifty years. Lee Keeling s professional staff is comprised of qualified petroleum engineers who are experienced in all productive areas of the United States.

Our policies regarding internal controls over the recording of reserves estimates requires that such estimates are in compliance with the SEC definitions and guidance. Inputs to our reserves estimation process, which we provide to Lee Keeling for use in their reserves evaluation, are based upon our historical results for production history, oil and natural gas prices, lifting and development costs, ownership interests and other required data. Our reservoir management group, comprised of qualified petroleum engineers, works with Lee Keeling to ensure that all data we provide is properly reflected in the final reserves estimates and consults with Lee Keeling throughout the reserves estimation process on technical questions regarding the reserve estimates.

We did not provide estimates of total proved oil and natural gas reserves during the years ended December 31, 2008, 2009 or 2010 to any federal authority or agency, other than the SEC.

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Drilling Activity Summary

During the three-year period ended December 31, 2010, we drilled development and exploratory wells as set forth in the table below:

	2008		2009		2010	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil						
Gas	127	71.5	37	27.2	65	41.1
Dry	3	1.0				
	130	72.5	37	27.2	65	41.1
Exploratory:						
Oil					3	3.0
Gas	5	2.7	17	11.4	10	5.2
Dry	1	0.5				
	6	3.2	17	11.4	13	8.2
Total	136	75.7	54	38.6	78	49.3

In 2011 to the date of this report, we have drilled nine wells (4.6 net to us) and we have five wells (4.5 net to us) that are in the process of being drilled.

Producing Well Summary

The following table sets forth the gross and net producing oil and natural gas wells in which we owned an interest at December 31, 2010:

	Oil		Natural Gas	
	Gross	Net	Gross	Net
Arkansas			15	8.0
Kansas			9	5.1
Kentucky			86	76.1
Louisiana	15	5.4	415	222.1
New Mexico	1		96	14.6
Oklahoma	10	1.2	127	17.9
Texas	36	17.9	753	483.8
Wyoming			26	1.9
Total	62	24.5	1,527	829.5

We operate 899 of the 1,589 producing wells presented in the above table. As of December 31, 2010, we owned interests in 19 wells containing multiple completions, which means that a well is producing from more than one completed zone. Wells with more than one completion are reflected as one well in the table above.

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Acreage

The following table summarizes our developed and undeveloped leasehold acreage at December 31, 2010, all of which is onshore in the continental United States. We have excluded acreage in which our interest is limited to a royalty or overriding royalty interest.

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Arkansas	1,280	684		
Kansas	6,400	4,064		
Kentucky	7,206	5,773		
Louisiana	88,816	52,534	33,511	28,107
New Mexico	10,240	1,896		
Oklahoma	38,080	5,707		
Texas	123,833	68,796	30,561	26,243
Wyoming	13,440	927		
Total	289,295	140,381	64,072	54,350

Our undeveloped acreage expires as follows:

Expires in 2011	55%
Expires in 2012	3%
Expires in 2013	42%
	100%

Title to our oil and natural gas properties is subject to royalty, overriding royalty, carried and other similar interests and contractual arrangements customary in the oil and gas industry, liens incident to operating agreements and for current taxes not yet due and other minor encumbrances. All of our oil and natural gas properties are pledged as collateral under our bank credit facility. As is customary in the oil and gas industry, we are generally able to retain our ownership interest in undeveloped acreage by production of existing wells, by drilling activity which establishes commercial reserves sufficient to maintain the lease, by payment of delay rentals or by the exercise of contractual extension rights. The Company anticipates retaining ownership of a substantial amount of the acreage with primary terms expiring in 2011 through drilling activity or by extending the leases.

Markets and Customers

The market for oil and natural gas produced by us depends on factors beyond our control, including the extent of domestic production and imports of oil and natural gas, the proximity and capacity of natural gas pipelines and other transportation facilities, demand for oil and natural gas, the marketing of competitive fuels and the effects of state and federal regulation. The oil and gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers.

Our oil production is sold under short-term contracts with a duration of six months or less. The contracts require the purchasers to purchase the amount of oil production that is available at prices tied to the spot oil markets. Our natural gas production is primarily sold under contracts with various terms and priced on first of the month index prices or on daily spot market prices. Approximately 82% of our 2010 natural gas sales were priced utilizing first of the month index prices and approximately 18% were priced utilizing daily spot prices. BP Energy Company and its subsidiaries accounted for 39% of our total 2010 sales. The loss of this customer would not have a material adverse effect on us as there is an available market for our crude oil and natural gas production from other purchasers.

With the significant increase in our natural gas production in North Louisiana due to our Haynesville shale drilling program, we have entered into longer term marketing arrangements to ensure that we have adequate transportation to get our natural gas production to the markets. As an alternative to constructing our own gathering and treating facilities, we have entered into a variety of gathering and treating agreements with midstream companies to transport our natural gas to the long-haul natural gas pipelines. We have dedicated our production in our Logansport and Toledo Bend fields under such agreements for terms that expire from 2016 to 2018. We have a commitment to transport a minimum of 7.4 Bcf over 3.2 years under one of these agreements.

We have also entered into certain agreements with a major natural gas marketing company to provide us with firm transportation for our North Louisiana natural gas production on the long-haul pipelines. Under these agreements, we have priority access at certain delivery points for 80,000 MMBtus per day. These agreements expire from 2013 to 2019. To the extent we are not able to deliver the contracted natural gas volumes, we may be responsible for the transportation costs. Our production available to deliver under these agreements in North Louisiana is expected to exceed the firm transportation arrangements we have in place. In addition, the marketing company managing the firm transportation is required to use reasonable efforts to supplement our deliveries should we have a shortfall during the term of the agreements.

Competition

The oil and gas industry is highly competitive. Competitors include major oil companies, other independent energy companies and individual producers and operators, many of which have financial resources, personnel and facilities substantially greater than we do. We face intense competition for the acquisition of oil and natural gas properties and leases for oil and gas exploration.

Regulation

General. Various aspects of our oil and natural gas operations are subject to extensive and continually changing regulation, as legislation affecting the oil and natural gas industry is under constant review for amendment or expansion. Numerous departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding upon the oil and natural gas industry and its individual members. The Federal Energy Regulatory Commission, or FERC, regulates the transportation and sale for resale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938, or NGA, and the Natural Gas Policy Act of 1978, or NGPA. In 1989, however, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and nonprice controls affecting all first sales of natural gas, effective January 1, 1993, subject to the terms of any private contracts that may be in effect. While sales by producers of natural gas and all sales of crude oil, condensate and natural gas liquids can currently be made at uncontrolled market prices, in the future Congress could reenact price controls or enact other legislation with detrimental impact on many aspects of our business. Under the provisions of the Energy Policy Act of 2005 (the 2005 Act), the NGA has been amended to prohibit any form of market manipulation with the purchase or sale of natural gas, and the FERC has issued new regulations that are intended to increase natural gas pricing transparency. The 2005 Act has also significantly increased the penalties for violations of the NGA. The FERC has issued Order No. 704 et al. which requires a market participant to make an annual filing if it has sales or purchases equal to or greater than 2.2 million MMBtu in the reporting year to facilitate price transparency.

Regulation and transportation of natural gas. Our sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation are subject to extensive regulation. The FERC requires interstate pipelines to provide open-access transportation on a not unduly discriminatory basis for similarly situated shippers. The FERC frequently reviews and modifies its

regulations regarding the transportation of natural gas, with the stated goal of fostering competition within the natural gas industry.

Intrastate natural gas transportation is subject to regulation by state regulatory agencies. The Texas Railroad Commission has been changing its regulations governing transportation and gathering services provided by intrastate pipelines and gatherers. While the changes by these state regulators affect us only indirectly, they are intended to further enhance competition in natural gas markets. We cannot predict what further action the FERC or state regulators will take on these matters; however, we do not believe that we will be affected differently in any material respect than other natural gas producers with which we compete by any action taken.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC, state commissions and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach pursued by the FERC, Congress and state regulatory authorities will continue.

Federal leases. Some of our operations are located on federal oil and natural gas leases that are administered by the Bureau of Land Management (BLM) of the United States Department of the Interior. These leases are issued through competitive bidding and contain relatively standardized terms. These leases require compliance with detailed Department of Interior and BLM regulations and orders that are subject to interpretation and change. These leases are also subject to certain regulations and orders promulgated by the Department of Interior s Bureau of Ocean Energy Management, Regulation & Enforcement (BOEMRE), through its Minerals Revenue Management Program, which is responsible for the management of revenues from both onshore and offshore leases. Additionally, some of our federal leases are subject to the Indian Mineral Development Act of 1982, and are therefore subject to supplemental regulations and orders of the Department of Interior s Bureau of Indian Affairs. While we cannot predict how various federal agencies may change their interpretations of existing regulations and orders or how regulations and orders issued in the future will impact our operations located on these federal leases, we do not believe we will be affected differently than other similarly situated oil and natural gas producers.

Oil and natural gas liquids transportation rates. Our sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. In other instances, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes. The price received from the sale of these products may be affected by the cost of transporting the products to market.

The FERC s regulation of pipelines that transport crude oil, condensate and natural gas liquids under the Interstate Commerce Act is generally more light-handed than the FERC s regulation of natural gas pipelines under the NGA. FERC-regulated pipelines that transport crude oil, condensate and natural gas liquids are subject to common carrier obligations that generally ensure non-discriminatory access. With respect to interstate pipeline transportation subject to regulation of the FERC under the Interstate Commerce Act, rates generally must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates are permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates governed by the Interstate Commerce Act that allowed for an increase or decrease in the transportation rates. The FERC s regulations include a methodology for such pipelines to change their rates through the use of an index system that establishes ceiling levels for such rates. The mandatory five year review in 2005 revised the methodology for this index to be based on Producer Price Index for Finished Goods (PPI-FG) plus 1.3 percent for the period July 1, 2006 through June 30, 2011. The mandatory five year review in 2010

revised the methodology for this index to be based on PPI-FG plus 2.65 percent for the period July 1, 2011 through June 30, 2016. The regulations provide that each year the Commission will publish the oil pipeline index after the PPI-FG becomes available.

With respect to intrastate crude oil, condensate and natural gas liquids pipelines subject to the jurisdiction of state agencies, such state regulation is generally less rigorous than the regulation of interstate pipelines. State agencies have generally not investigated or challenged existing or proposed rates in the absence of shipper complaints or protests. Complaints or protests have been infrequent and are usually resolved informally.

We do not believe that the regulatory decisions or activities relating to interstate or intrastate crude oil, condensate or natural gas liquids pipelines will affect us in a way that materially differs from the way it affects other crude oil, condensate and natural gas liquids producers or marketers.

Environmental regulations. We are subject to stringent federal, state and local laws. These laws, among other things, govern the issuance of permits to conduct exploration, drilling and production operations, the amounts and types of materials that may be released into the environment, the discharge and disposition of waste materials, the remediation of contaminated sites and the reclamation and abandonment of wells, sites and facilities. Numerous governmental departments issue rules and regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial civil and even criminal penalties for failure to comply. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose strict liability for environmental contamination, rendering a person liable for environmental damages and cleanup cost without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise exist or even prohibit exploration and production activities in sensitive areas. In addition, state laws often require various forms of remedial action to prevent pollution, such as closure of inactive pits and plugging of abandoned wells. The regulatory burden on the oil and natural gas industry increases our cost of doing business and consequently affects our profitability. These costs are considered a normal, recurring cost of our on-going operations. Our domestic competitors are generally subject to the same laws and regulations.

We believe that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on our operations. However, environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements or new regulatory schemes such as carbon cap and trade programs could have a material adverse effect upon our capital expenditures, earnings or competitive position, including the suspension or cessation of operations in affected areas. As such, there can be no assurance that material cost and liabilities will not be incurred in the future.

The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, imposes liability, without regard to fault, on certain classes of persons that are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current or former owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances. Under CERCLA, such persons may be subject to joint and several liability for the cost of investigating and cleaning up hazardous substances that have been released into the environment, for damages to natural resources and for the cost of certain health studies. In addition, companies that incur liability frequently also confront third party claims because it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment from a polluted site.

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The Federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, or RCRA, regulates the generation, transportation, storage, treatment and disposal of hazardous wastes and can require cleanup of hazardous waste disposal sites. RCRA currently excludes drilling fluids, produced waters and other wastes associated with the exploration, development or production of oil and natural gas from regulation as hazardous waste. Disposal of such non-hazardous oil and natural gas exploration, development and production wastes usually are regulated by state law. Other wastes handled at exploration and production sites or used in the course of providing well services may not fall within this exclusion. Moreover, stricter standards for waste handling and disposal may be imposed on the oil and natural gas industry in the future. From time to time, legislation is proposed in Congress that would revoke or alter the current exclusion of exploration, development and production wastes from RCRA s definition of hazardous wastes, thereby potentially subjecting such wastes to more stringent handling, disposal and cleanup requirements. If such legislation were enacted, it could have a significant impact on our operating cost, as well as the oil and natural gas industry in general. The impact of future revisions to environmental laws and regulations cannot be predicted.

Our operations are also subject to the Clean Air Act, or CAA, and comparable state and local requirements. Amendments to the CAA were adopted in 1990 and contain provisions that may result in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. However, we believe our operations will not be materially adversely affected by any such requirements, and the requirements are not expected to be any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities.

The Federal Water Pollution Control Act of 1972, as amended, or the Clean Water Act, imposes restrictions and controls on the discharge of produced waters and other wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into certain coastal and offshore waters, unless otherwise authorized. Further, the EPA has adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The Clean Water Act and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges for oil and other pollutants and impose liability on parties responsible for those discharges for the cost of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

Federal regulators require certain owners or operators of facilities that store or otherwise handle oil to prepare and implement spill prevention, control, countermeasure and response plans relating to the possible discharge of oil into surface waters. The Oil Pollution Act of 1990 (OPA) contains numerous requirements relating to the prevention and response to oil spills in the 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 relating to a spill. Noncompliance with OPA may result in varying civil and criminal penalties and liabilities.

Executive Order 13158, issued on May 26, 2000, directs federal agencies to safeguard existing Marine Protected Areas, or MPAs, in the United States and establish new MPAs. The order requires federal agencies to avoid harm to MPAs to the extent permitted by law and to the maximum extent practicable. It

also directs the EPA to propose new regulations under the Clean Water Act to ensure appropriate levels of protection for the marine environment. This order has the potential to adversely affect our operations by restricting areas in which we may carry out future exploration and development projects and/or causing us to incur increased operating expenses.

Certain flora and fauna that have officially been classified as threatened or endangered are protected by the Endangered Species Act. This law prohibits any activities that could take a protected plant or animal or reduce or degrade its habitat area. If endangered species are located in an area we wish to develop, the work could be prohibited or delayed and/or expensive mitigation might be required.

Other statutes that provide protection to animal and plant species and which may apply to our operations include, but are not necessarily limited to, the Oil Pollution Act, the Emergency Planning and Community Right-to-Know Act, the Marine Mammal Protection Act, the Marine Protection, Research and Sanctuaries Act, the Fish and Wildlife Coordination Act, the Fishery Conservation and Management Act, the Migratory Bird Treaty Act and the National Historic Preservation Act. These laws and regulations may require the acquisition of a permit or other authorization before construction or drilling commences and may limit or prohibit construction, drilling and other activities on certain lands lying within wilderness or wetlands and other protected areas and impose substantial liabilities for pollution resulting from our operations. The permits required for our various operations are subject to revocation, modification and renewal by issuing authorities. In addition, laws such as the National Environmental Policy Act and the Coastal Zone Management Act may make the process of obtaining certain permits more difficult or time consuming, resulting in increased costs and potential delays that could affect the viability or profitability of certain activities.

Certain statutes such as the Emergency Planning and Community Right to Know Act require the reporting of hazardous chemicals manufactured, processed, or otherwise used, which may lead to heightened scrutiny of the company s operations by regulatory agencies or the public. In 2010, EPA adopted a new reporting requirement, the Petroleum and Natural Gas Systems Greenhouse Gas Reporting Rule (40 C.F.R. Part 98, Subpart W), which requires certain onshore petroleum and natural gas facilities to begin collecting data on their emissions of greenhouse gases (GHGs) in January 2011, with the first annual reports of those emissions due on March 31, 2012. GHGs include gases such as methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning natural gas. Different GHGs have different global warming potentials with CO_2 having the lowest global warming potential, so emissions of GHGs are typically expressed in terms of CO_2 equivalents, or CO_2e. The rule applies to facilities that emit 25,000 metric tons of CO_2e or more per year, and requires onshore petroleum and natural gas operators to group all equipment under common ownership or control within a single hydrocarbon basin together when determining if the threshold is met. We have determined that these new reporting requirements apply to us and we are implementing procedures to collect the required information.

Such changes in environmental laws and regulations which result in more stringent and costly reporting, or waste handling, storage, transportation, disposal or cleanup activities, could materially affect companies operating in the energy industry. In addition, EPA is considering further regulation of climate change. Adoption of new regulations that regulate or restrict GHG emissions from oil and gas production could adversely affect our business, financial position, results of operations and prospects, as could the adoption of new laws or regulations which levy taxes or other costs on greenhouse gas emissions from other industries, which could result in changes to the consumption and demand for natural gas. We may also be assessed administrative, civil and/or criminal penalties if we fail to comply with any such new laws and regulations applicable to oil and natural gas production.

We maintain insurance against sudden and accidental occurrences, which may cover some, but not all, of the risks described above. Most significantly, the insurance we maintain will not cover the risks described above which occur over a sustained period of time. Further, there can be no assurance that such

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insurance will continue to be available to cover all such cost or that such insurance will be available at a cost that would justify its purchase. The occurrence of a significant event not fully insured or indemnified against could have a material adverse effect on our financial condition and results of operations.

Regulation of oil and natural gas exploration and production. Our exploration and production operations are subject to various types of regulation at the federal, state and local levels. Such regulations include requiring permits and drilling bonds for the drilling of wells, regulating the location of wells, the method of drilling and casing wells and the surface use and restoration of properties upon which wells are drilled. Many states also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells and the regulation of spacing, plugging and abandonment of such wells. Some state statutes limit the rate at which oil and natural gas can be produced from our properties.

State regulation. Most states regulate the production and sale of oil and natural gas, including requirements for obtaining drilling permits, the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and gas resources. The rate of production may be regulated and the maximum daily production allowable from both oil and gas wells may be established on a market demand or conservation basis or both.

Office and Operations Facilities

Our executive offices are located at 5300 Town and Country Blvd., Suite 500 in Frisco, Texas 75034 and our telephone number is (972) 668-8800. We lease office space in Frisco, Texas covering 53,364 square feet at a monthly rate of $100,057. This lease expires on July 31, 2014. We also own production offices and pipe yard facilities near Marshall, Livingston, and Zapata, Texas; Logansport, Louisiana and Guston, Kentucky.

Employees

As of December 31, 2010, we had 127 employees and utilized contract employees for certain of our field operations. We consider our employee relations to be satisfactory.

Directors and Executive Officers

The following table sets forth certain information concerning our executive officers and directors.

Name	Position with Company	Age
M. Jay Allison	President, Chief Executive Officer and Chairman of the Board of Directors	55
Roland O. Burns	Senior Vice President, Chief Financial Officer, Secretary, Treasurer and Director	50
D. Dale Gillette	Vice President of Land and General Counsel	65
Mack D. Good	Chief Operating Officer	61
Stephen E. Neukom	Vice President of Marketing	61
Daniel K. Presley	Vice President of Accounting and Controller	50
Richard D. Singer	Vice President of Financial Reporting	56
David K. Lockett	Director	56
Cecil E. Martin	Director	69
David W. Sledge	Director	54

Nancy E. Underwood	Director	59

Executive Officers

A brief biography of each person who serves as a director or executive officer follows below.

M. Jay Allison has been a director since 1987, and our President and Chief Executive Officer since 1988. Mr. Allison was elected Chairman of the board of directors in 1997. From 1987 to 1988, Mr. Allison served as our Vice President and Secretary. From 1981 to 1987, he was a practicing oil and gas attorney with the firm of Lynch, Chappell & Alsup in Midland, Texas. Mr. Allison was Chairman of the Board of Directors of Bois d Arc Energy, Inc. from the time of its formation in 2004 until its merger with Stone Energy Corporation in 2008. He received B.B.A., M.S. and J.D. degrees from Baylor University in 1978, 1980 and 1981, respectively. Mr. Allison also currently serves as a Director of Tidewater, Inc.

Roland O. Burns has been our Senior Vice President since 1994, Chief Financial Officer and Treasurer since 1990, our Secretary since 1991 and a director since 1999. From 1982 to 1990, Mr. Burns was employed by the public accounting firm, Arthur Andersen. During his tenure with Arthur Andersen, Mr. Burns worked primarily in the firm s oil and gas audit practice. Mr. Burns was a director, Senior Vice President and the Chief Financial Officer of Bois d Arc Energy, Inc. from the time of its formation in 2004 until its merger with Stone Energy Corporation in 2008. Mr. Burns received B.A. and M.A. degrees from the University of Mississippi in 1982 and is a Certified Public Accountant.

D. Dale Gillette has been our Vice President of Land and General Counsel since 2006. Prior to joining us, Mr. Gillette practiced law extensively in the energy sector for 32 years, most recently as a partner with Gardere Wynne Sewell LLP, and before that with Locke Liddell & Sapp LLP. During that time he represented independent exploration and production companies and large financial institutions in numerous oil and gas transactions. Mr. Gillette has also served as corporate counsel in the legal department of Mesa Petroleum Co. and in the legal department of Enserch Corp. Mr. Gillette holds B.A. and J.D. degrees from the University of Texas and is a member of the State Bar of Texas.

Mack D. Good was appointed our Chief Operating Officer in 2004. From 1999 to 2004, he served as Vice President of Operations. From 1997 until 1999, Mr. Good served as our district engineer for the East Texas/North Louisiana region. From 1983 until 1997, Mr. Good was with Enserch Exploration, Inc. serving in various operations management and engineering positions. Mr. Good received a B.S. of Biology/Chemistry from Oklahoma State University in 1975 and a B.S. of Petroleum Engineering from the University of Tulsa in 1983. He is a Registered Professional Engineer in the State of Texas.

Stephen E. Neukom has been our Vice President of Marketing since 1997 and has served as our manager of crude oil and natural gas marketing since 1996. From 1994 to 1996, Mr. Neukom served as vice president of Comstock Natural Gas, Inc., our former wholly owned gas marketing subsidiary. Prior to joining us, Mr. Neukom was senior vice president of Victoria Gas Corporation from 1987 to 1994. Mr. Neukom received a B.B.A. degree from the University of Texas in 1972.

Daniel K. Presley has been our Vice President of Accounting since 1997 and has been with us since 1989, serving as controller since 1991. Prior to joining us, Mr. Presley had six years of experience with several independent oil and gas companies including AmBrit Energy, Inc. Prior thereto, Mr. Presley spent two and one-half years with B.D.O. Seidman, a public accounting firm. Mr. Presley received a B.B.A. from Texas A & M University in 1983.

Richard D. Singer has been our Vice President of Financial Reporting since 2005. Mr. Singer has over 30 years of experience in financial accounting and reporting. Prior to joining us, Mr. Singer most recently served as an assistant controller for Holly Corporation from 2004 to 2005 and as assistant controller for

Santa Fe International Corporation from 1988 to 2002. Mr. Singer received a B.S. degree from the Pennsylvania State University in 1976 and is a Certified Public Accountant.

Outside Directors

David K. Lockett has served as a director since 2001. Mr. Lockett is a Vice President with Dell Inc. and has held executive management positions in several divisions within Dell since 1991. Mr. Lockett has been employed by Dell Inc. for the past 19 years and has been in the technology industry for the past 34 years. Mr. Lockett was a director of Bois d Arc Energy, Inc. from 2005 until its merger with Stone Energy Corporation in 2008. Mr. Lockett received a B.B.A. degree from Texas A&M University in 1976.

Cecil E. Martin has served as a director since 1988. Mr. Martin is an independent commercial real estate investor who has primarily been managing his personal real estate investments since 1991. From 1973 to1991, he also served as chairman of a public accounting firm in Richmond, Virginia. Mr. Martin was a director and chairman of the Audit Committee of Bois d Arc Energy, Inc. from 2005 until its merger with Stone Energy Corporation in 2008. Mr. Martin also serves on the board of directors of Crosstex Energy, Inc. and Crosstex Energy, L.P. Mr. Martin holds a B.B.A. degree from Old Dominion University and is a Certified Public Accountant.

David W. Sledge has served as a director since 1996. Mr. Sledge was President and Chief Operating Officer of Sledge Drilling Company until it was acquired by Basic Energy Services, Inc. in 2007 and served as a Vice President of Basic Energy Services, Inc. from 2007 to 2009. He served as an area operations manager for Patterson-UTI Energy, Inc. from May 2004 until 2006. From 1996 until 2004, Mr. Sledge managed his personal investments in oil and gas exploration activities. Mr. Sledge was a Director of Bois d Arc Energy, Inc. from 2005 until its merger with Stone Energy Corporation in 2008. Mr. Sledge is a past director of the International Association of Drilling Contractors and is a past chairman of the Permian Basin chapter of this association. He received a B.B.A. degree from Baylor University in 1979.

Nancy E. Underwood has served as a director since 2004. Ms. Underwood is owner and President of Underwood Financial Ltd., a position she has held since 1986. Ms. Underwood holds B.S. and J.D. degrees from Emory University and practiced law at an Atlanta, Georgia based law firm before joining River Hill Development Corporation in 1981. Ms. Underwood currently serves on the Executive Board and Campaign Steering Committee of the Southern Methodist University Dedman School of Law and on the board of the Texas Health Presbyterian Foundation.

Available Information

Our executive offices are located at 5300 Town and Country Blvd., Suite 500, Frisco, Texas 75034. Our telephone number is (972) 668-8800. We file annual, quarterly and current reports, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934. The public may read and copy any materials that we file with the SEC at the SEC s Public Reference Room at 100 F Street N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains a website that contains reports, proxy and information statements, and other information that is electronically filed with the SEC. The public can obtain any documents that we file with the SEC at www.sec.gov. We also make available free of charge on our website (www.comstockresources.com) our Annual Report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after we file such material with, or furnish it to, the SEC.

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ITEM 1A. *RISK FACTORS*

You should carefully consider the following risk factors as well as the other information contained or incorporated by reference in this report, as these important factors, among others, could cause our actual results to differ from our expected or historical results. It is not possible to predict or identify all such factors. Consequently, you should not consider any such list to be a complete statement of all of our potential risks or uncertainties.

A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition, cash flow, liquidity or results of operations and our ability to meet our capital expenditure obligations and financial commitments and to implement our business strategy.

Our business is heavily dependent upon the prices of, and demand for, oil and natural gas. Historically, the prices for oil and natural gas have been volatile and are likely to remain volatile in the future. The prices we receive for our oil and natural gas production and the level of such production will be subject to wide fluctuations and depend on numerous factors beyond our control, including the following:

- the domestic and foreign supply of oil and natural gas;
- weather conditions;
- the price and quantity of imports of crude oil and natural gas;
- political conditions and events in other oil-producing and natural gas-producing countries, including embargoes, hostilities in the Middle East and other sustained military campaigns, and acts of terrorism or sabotage;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- domestic government regulation, legislation and policies;
- the level of global oil and natural gas inventories;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- overall economic conditions.

If the decline in the price of natural gas that first started in 2008 continues through 2011, the lower prices will adversely affect:

- our revenues, profitability and cash flow from operations;
- the value of our proved oil and natural gas reserves;
- the economic viability of certain of our drilling prospects;
- our borrowing capacity; and
- our ability to obtain additional capital.

In the future we may enter into hedging arrangements in order to reduce our exposure to price risks. Such arrangements would limit our ability to benefit from increases in oil and natural gas prices.

The recent recession could have a material adverse impact on our financial position, results of operations and cash flows.

The oil and gas industry is cyclical and tends to reflect general economic conditions. The United States and other countries have been in a recession which could continue through 2011 and beyond, and the capital markets have experienced significant volatility. The recession has had an adverse impact on demand and pricing for crude oil and natural gas. A continuation of the recession could have a further negative impact on oil and natural gas prices. Our operating cash flows and profitability will be significantly affected by declining oil and natural gas prices. Further declines in oil and natural gas prices may also impact the value of our oil and gas reserves, which could result in future impairment charges to reduce the carrying value of our oil and gas properties and our marketable securities. Our future access to capital could be limited due to tightening credit markets and volatile capital markets. If our access to capital is limited, development of our assets may be delayed or limited, and we may not be able to execute our growth strategy.

Our future production and revenues depend on our ability to replace our reserves.

Our future production and revenues depend upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. To increase reserves and production, we must continue our acquisition and drilling activities. We cannot assure you, however, that our acquisition and drilling activities will result in significant additional reserves or that we will have continuing success drilling productive wells at low finding and development costs. Furthermore, while our revenues may increase if prevailing oil and natural gas prices increase significantly, our finding costs for additional reserves could also increase.

Prospects that we decide to drill may not yield oil or natural gas in commercially viable quantities or quantities sufficient to meet our targeted rate of return.

A prospect is a property in which we own an interest or have operating rights and that has what our geoscientists believe, based on available seismic and geological information, to be an indication of potential oil or natural gas. Our prospects are in various stages of evaluation, ranging from a prospect that is ready to be drilled to a prospect that will require substantial additional evaluation and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. The analysis that we perform using data from other wells, more fully explored prospects and/or producing fields may not be useful in predicting the characteristics and potential reserves associated with our drilling prospects. If we drill additional unsuccessful wells, our drilling success rate may decline and we may not achieve our targeted rate of return.

Federal hydraulic fracturing legislation could increase our costs and restrict our access to our oil and gas reserves.

Several proposals are before the United States Congress that, if implemented, would subject the process of hydraulic fracturing to regulation under the Safe Drinking Water Act. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. The use of hydraulic fracturing is necessary to produce commercial quantities of crude oil and natural gas from many reservoirs including the Haynesville shale, Bossier shale, Eagle Ford shale, Cotton Valley and other tight natural gas reservoirs. At the direction of Congress, EPA is currently conducting an extensive, multi-year study into the potential effects of hydraulic fracturing on underground sources of drinking water, and the results of that study have the potential to impact the likelihood or scope of future legislation or regulation.

Although it is not possible at this time to predict the final outcome of any legislation regarding hydraulic fracturing, several states, including some in which we operate such as Arkansas, have adopted or proposed rules that would limit or regulate hydraulic fracturing, and/or require disclosure of chemicals used in hydraulic fracturing. These new state rules and any new federal restrictions on hydraulic fracturing that may be imposed in areas in which we conduct business, could significantly increase our operating, capital and compliance costs as well as delay or inhibit our ability to develop our oil and natural gas reserves.

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Potential changes to US federal tax regulations, if passed, will have an adverse effect on us.

The United States Congress continues to consider imposing new taxes and repeal of many tax incentives and deductions that are currently used by independent oil and gas producers. Examples of changes being considered that would impact us are: elimination of the ability to fully deduct intangible drilling costs in the year incurred, repeal of the manufacturing tax deduction for oil and gas companies, increasing the geological and geophysical cost amortization period, and implementation of a fee on non-producing leases located on federal lands. If these proposals are enacted, our current income tax liability will increase, potentially significantly, which would have a negative impact on our cash flow from operating activities. A reduction in operating cash flow could require us to reduce our drilling activities. Since none of these proposals have yet to be included in new legislation, we do not know the ultimate impact they may have on our business.

Our debt service requirements could adversely affect our operations and limit our growth.

We had $513.4 million in debt as of December 31, 2010, and our ratio of total debt to total capitalization was approximately 32%.

Our outstanding debt will have important consequences, including, without limitation:

- a portion of our cash flow from operations will be required to make debt service payments;
- our ability to borrow additional amounts for working capital, capital expenditures (including acquisitions) or other purposes will be limited; and
- our debt could limit our ability to capitalize on significant business opportunities, our flexibility in planning for or reacting to changes in market conditions and our ability to withstand competitive pressures and economic downturns.

In addition, future acquisition or development activities may require us to alter our capitalization significantly. These changes in capitalization may significantly increase our debt. Moreover, our ability to meet our debt service obligations and to reduce our total debt will be dependent upon our future performance, which will be subject to general economic conditions and financial, business and other factors affecting our operations, many of which are beyond our control. If we are unable to generate sufficient cash flow from operations in the future to service our indebtedness and to meet other commitments, we will be required to adopt one or more alternatives, such as refinancing or restructuring our indebtedness, selling material assets or seeking to raise additional debt or equity capital. We cannot assure you that any of these actions could be effected on a timely basis or on satisfactory terms or that these actions would enable us to continue to satisfy our capital requirements.

Our bank credit facility contains a number of significant covenants. These covenants will limit our ability to, among other things:

- borrow additional money;
- merge, consolidate or dispose of assets;
- make certain types of investments;
- enter into transactions with our affiliates; and
- pay dividends.

Our failure to comply with any of these covenants could cause a default under our bank credit facility and the respective indentures governing our 67/8% senior notes due 2012 and 83/8% senior notes due 2017. A default, if not waived, could result in acceleration of our indebtedness, in which case the debt would become immediately due and payable. If this occurs, we may not be able to repay our debt or borrow sufficient funds

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to refinance it given the current status of the credit markets. Even if new financing is available, it may not be on terms that are acceptable to us. Complying with these covenants may cause us to take actions that we otherwise would not take or not take actions that we otherwise would take.

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

Our industry has experienced a shortage of drilling rigs, equipment, supplies and qualified personnel in recent years as the result of higher demand for these services. Costs and delivery times of rigs, equipment and supplies have been substantially greater than they were several years ago. In addition, demand for, and wage rates of, qualified drilling rig crews have escalated due to the higher activity levels. Shortages of drilling rigs, equipment or supplies or qualified personnel in the areas in which we operate could delay or restrict our exploration and development operations, which in turn could adversely affect our financial condition and results of operations because of our concentration in those areas.

Our business involves many uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.

Our future success will depend on the success of our exploration and development activities. Exploration activities involve numerous risks, including the risk that no commercially productive natural gas or oil reserves will be discovered. In addition, these activities may be unsuccessful for many reasons, including weather, cost overruns, equipment shortages and mechanical difficulties. Moreover, the successful drilling of a natural gas or oil well does not ensure we will realize a profit on our investment. A variety of factors, both geological and market-related, can cause a well to become uneconomical or only marginally economical. In addition to their costs, unsuccessful wells can hurt our efforts to replace production and reserves.

Our business involves a variety of operating risks, including:

- unusual or unexpected geological formations;
- fires;
- explosions;
- blow-outs and surface cratering;
- uncontrollable flows of natural gas, oil and formation water;
- natural disasters, such as hurricanes, tropical storms and other adverse weather conditions;
- pipe, cement, or pipeline failures;
- casing collapses;
- mechanical difficulties, such as lost or stuck oil field drilling and service tools;
- abnormally pressured formations; and
- environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases.

If we experience any of these problems, well bores, gathering systems and processing facilities could be affected, which could adversely affect our ability to conduct operations.

We could also incur substantial losses as a result of:

- injury or loss of life;
- severe damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;

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- clean-up responsibilities;
- regulatory investigation and penalties;
- suspension of our operations; and
- repairs to resume operations.

We pursue acquisitions as part of our growth strategy and there are risks in connection with acquisitions.

Our growth has been attributable in part to acquisitions of producing properties and companies. We expect to continue to evaluate and, where appropriate, pursue acquisition opportunities on terms we consider favorable. However, we cannot assure you that suitable acquisition candidates will be identified in the future, or that we will be able to finance such acquisitions on favorable terms. In addition, we compete against other companies for acquisitions, and we cannot assure you that we will successfully acquire any material property interests. Further, we cannot assure you that future acquisitions by us will be integrated successfully into our operations or will increase our profits.

The successful acquisition of producing properties requires an assessment of numerous factors beyond our control, including, without limitation:

- recoverable reserves;
- exploration potential;
- future oil and natural gas prices;
- operating costs; and
- potential environmental and other liabilities.

In connection with such an assessment, we perform a review of the subject properties that we believe to be generally consistent with industry practices. The resulting assessments are inexact and their accuracy uncertain, and such a review may not reveal all existing or potential problems, nor will it necessarily permit us to become sufficiently familiar with the properties to fully assess their merits and deficiencies. Inspections may not always be performed on every well, and structural and environmental problems are not necessarily observable even when an inspection is made.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may be substantially different in operating and geologic characteristics or geographic location than our existing properties. While our current operations are focused in the East Texas/North Louisiana and South Texas regions, we may pursue acquisitions or properties located in other geogra