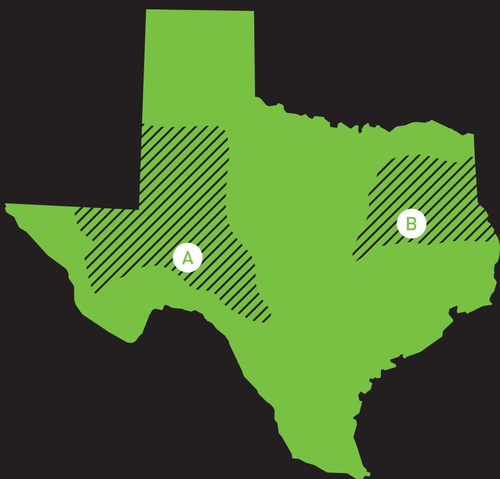
CORE STRENGTH

APPROACH RESOURCES INC.
2010 ANNUAL REPORT

CORE AREAS OF OPERATIONS



A PERMIAN BASIN

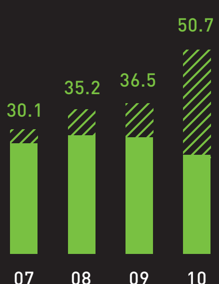
Project Pangea and Pangea West
Clearfork, Wolfcamp, Canyon Sands, Strawn, Ellenburger
48.3 MMBoe of proved reserves
153,000 gross (133,000 net) acres

B EAST TEXAS BASIN

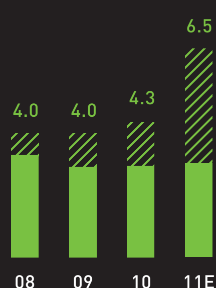
North Bald Prairie
Cotton Valley Sands and Cotton Valley Lime
2.4 MMBoe of proved reserves
7,100 gross (4,400 net) acres

PRODUCTION AND RESERVES

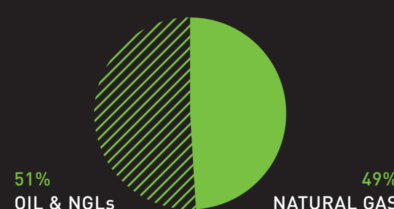
OIL & NGLs NATURAL GAS



PROVED RESERVES
(MMBoe)



DAILY PRODUCTION
(MBoe/d)



2010 RESERVE MIX

AREX HIGHLIGHTS

4.3 MBoe/d

2010 PRODUCTION

133,000

NET ACRES IN THE PERMIAN BASIN

50.7 MMBoe proved reserves
- 95% Permian Basin
- 51% Oil & NGLs
- 51% Proved developed

2,780+ Potential drilling & recompletion opportunities in the Permian Basin

Estimated proved reserves are as of December 31, 2010; acreage is as of March 1, 2011. In addition to historical information, this report contains forward-looking statements that may vary materially from actual results. Factors that could cause actual results to differ are included in our Annual Report on Form 10-K for the year ended December 31, 2010, which was filed with the Securities and Exchange Commission on March 11, 2011.

At Approach Resources Inc., our core strength is building long-term stockholder value by exploring and developing unconventional oil and gas resources in the Permian Basin, where we target stacked oil and liquids-rich formations at competitive operating and development costs. Our team of engineers and geoscientists think outside the box and apply their expertise and innovative drilling technology to unlock our resource potential.

In 2010, we remained true to our strengths by following our vision for the Wolffork oil shale, achieving growth in reserves and production and leading the way for new opportunities, all with an eye on capital discipline. It's been a successful year — and we look forward to creating stockholder value well into the future. After all, it's our core strength.

We’ve maintained a strong focus on what we do best — developing the potential of our core properties.

Dear Fellow Stockholders:

Last year, I discussed the multi-zone potential of our core operating area in the Permian Basin. At that time, we were well underway with our technical evaluation of the Wolfcamp, Dean and Clearfork, or what we call our “Wolffork” oil shale resource play.

Our technical evaluation initially relied on the log data we began collecting in 2004, when we first started drilling in Ozona Northeast. Since there is only one opportunity to cost-effectively obtain log data, we collected a full suite of logs through the entire wellbore for many of our wells. We also collected mud logs that help confirm the presence of hydrocarbons. Without a full suite of electric and mud logs across the Wolfcamp, Dean and Clearfork zones, it would have been difficult to confirm the presence of hydrocarbons and to assess the potential of the Wolffork oil shale. We also used 3-D seismic, formation micro-imaging logs and whole-core analysis to round out our geological and petrophysical study of the Wolffork.

During the second half of 2010, we tested the Wolffork with a combination of vertical wells targeting the Canyon Sands and Wolffork, and recompletions targeting the Wolfcamp and Wolffork. In an initial pilot program, we focused on the Wolfcamp formation with three Wolfcamp recompletions. During a second, five-well pilot program, we expanded our focus by drilling and completing three wells in the Canyon and Wolffork zones. We also recompleted two wells in the Wolfcamp. Combined, our evaluation and pilot programs confirmed that the Wolffork play has significant resource potential, and we believe that we may ultimately be able to complete up to six zones in a single, vertical wellbore. As with any new shale play, there is room for improvement in completion technique and cost. Our 2011 pilot program is designed to delineate the Wolffork trend across our acreage position, optimize our completion strategy and focus on cost control.

VISION


GROWTH

In 2010, we increased reserves and production and strengthened your company by creating a more balanced portfolio of assets.

During 2010, our proved reserves grew 39% to 50.7 MMBoe, and our proved oil and NGL reserves increased over 200% to 25.7 MMBbls. The increase in oil and NGL reserves drove our reserve mix to 51% oil and NGLs and 49% natural gas, from just 29% oil and NGLs and 71% natural gas in 2009. Achieving a well-balanced reserve portfolio is a priority for your company and puts us in a better position for long-term growth.

During 2010, we drilled 91 wells in the Permian Basin with a 100% success rate. Production for 2010 totaled 1.6 MMBoe, a 6% increase over 2009 production of 1.5 MMBoe. We replaced over 1000% of our production at a competitive finding and development cost of $5.70 per Boe. We noted last year that we believed development of our Permian assets could drive our oil and NGL production to approximately 50% of our total production. For 2011, we are targeting over 150% increase in oil and NGL production and over 50% increase in total production, compared to 2010. Further, production for 2011 is expected to be 55% oil and NGLs and 45% natural gas.

In 2010, we acquired approximately 34,800 net acres in the Permian Basin. Our leasing activities joined our legacy asset, Ozona Northeast, and Cinco Terry, into a large, mostly contiguous block of acreage, spanning approximately 28 miles. We now call this area Project Pangea. During the first quarter of 2011, we acquired additional acreage nine miles west of Cinco Terry, which we call Pangea West. We believe Project Pangea and Pangea West are prospective for the Wolffork and deeper zones. Currently, we are one of the largest leaseholders in the Southern Midland Basin Wolffork play, with approximately 133,000 net acres.

We also acquired a 10% working interest in Cinco Terry for $21.2 million in 2010, and we acquired the remaining 38% working interest in Cinco Terry for $76 million during the first quarter of 2011. Currently, our average working interest across Project Pangea and Pangea West is approximately 100%. More acreage and increased working interest enhance our opportunities to leverage the reserve potential of the Wolffork oil shale.

AREX PROJECTED GROWTH
CAGR 46%

AVERAGE DAILY PRODUCTION
(MBoe/d)

When it comes to developing our core strengths, our people are our best assets.

Approach has experienced incredible growth over the past three years. To support our growth, we have hired talented people and provided them with the right tools and support, encouraging ideas and solutions that further contribute to our success.

Shortly after Qingming Yang joined our team in July 2009, Dr. Yang and I began to evaluate the Wolffork zones using the log and other well data that we had accumulated since 2004. Dr. Yang, who has evaluated every major shale play in North America, helped establish rigorous criteria for evaluating the properties of the Wolffork oil shale. In October 2010, we announced our findings on the Wolffork with a detailed presentation summarizing our engineering, geological and petrophysical analyses of the Wolfcamp, Dean and Clearfork zones. We illustrated that the Wolffork has prolific potential and extends into the Southern Midland Basin. Dr. Yang also has expanded his team of geoscientists and has charged his team with optimizing exploitation of the Wolffork and evaluating strategic, complimentary acquisitions.

Our Approach team is now over 55 strong and growing. Our team is committed to advancing our understanding of the Wolffork and transitioning from a pilot program in 2010 to cost-efficient development by the end of 2011.

With great potential comes great responsibility for our management team. We understand that fluctuating commodity prices and service costs require strong resolve with respect to financial prudence. During severe commodity price declines in 2008 and 2009, we focused on lowering costs and improving our financial condition over growing reserves and production. Our historical debt-to-capital ratio has remained less than 18% and, I believe, our commitment to a strong balance sheet has helped us continue to deliver value and growth to our stockholders through an unstable economic environment. We exited 2010 with an expanded portfolio of opportunities and a continued focus on balancing our growth potential with capital discipline.

> "Together, our new portfolio of Wolffork opportunities and our inventory of repeatable, multi-year drilling locations targeting the deeper Canyon Sands, Strawn and Ellenburger will enable this company to grow, deliver strong returns to our stockholders and leverage our core strengths."

This is a very exciting time for Approach. We are well positioned to deliver successive years of production and reserve growth at competitive finding, development and operating costs. During 2010, we were fortunate to receive the support of our exceptional employees, business partners and fellow stockholders, and we thank you for your continued support and confidence in Approach.

Sincerely,

J. ROSS CRAFT, P.E.
Director, President and Chief Executive Officer


LEADERSHIP

FINANCIAL & OPERATING DATA

($ thousands, except per-unit and per-share amounts)

	2010	2009	2008
REVENUE *(IN THOUSANDS)*			
Gas	$ 28,176	$ 23,406	$ 58,819
Oil	18,640	11,323	16,413
NGLs	10,765	5,919	4,637
Total oil, NGL and gas sales	57,581	40,648	79,869
Realized gain on commodity derivatives	$ 5,784	$ 14,659	$ 2,936
Total oil, NGL and gas sales including derivative impact	$ 63,365	$ 55,307	$ 82,805
PRODUCTION			
Gas (MMcf)	6,290	6,320	7,092
Oil (MBbls)	246	206	175
NGLs (MBbls)	261	209	102
Total (MBoe)	1,556	1,468	1,459
Total (MBoe/d)	4.3	4.0	4.0
AVERAGE PRICES			
Gas (per Mcf)	$ 4.48	$ 3.70	$ 8.29
Oil (per Bbl)	75.67	54.97	93.79
NGLs (per Bbl)	41.19	28.32	45.46
Total (per Boe)	$ 37.00	$ 27.69	$ 54.74
Realized gain on commodity derivatives (per Boe)	3.72	9.99	2.01
Total including derivative impact (per Boe)	$ 40.72	$ 37.68	$ 56.75
COSTS & EXPENSES *(PER BOE)*			
Lease operating	$ 5.50	$ 5.30	$ 5.22
Severance and production taxes	1.92	1.36	2.88
Exploration	1.66	1.10	1.01
Impairment of unproved properties	1.68	2.02	4.37
General and administrative	7.34	7.23	6.09
Depletion, depreciation and amortization	14.28	16.80	16.25
FINANCIAL HIGHLIGHTS			
Net income (loss)	$ 7,462	$ (5,229)	$ 23,386
Earnings (loss) per diluted share	$ 0.34	$ (0.25)	$ 1.12
Adjusted net income*	$ 8,673	$ 3,261	$ 23,483
Adjusted net income per diluted share*	$ 0.39	$ 0.16	$ 1.13
EBITDAX*	$ 43,026	$ 36,743	$ 63,201
EBITDAX per diluted share*	$ 1.94	$ 1.75	$ 3.03
Weighted average diluted shares outstanding	22,214	20,870	20,825
Total long-term debt	$ —	$ 32,319	$ 43,537
Stockholders' equity	$ 332,946	$ 220,496	$ 223,813
Total assets	$ 413,089	$ 318,926	$ 388,241

**Adjusted net income, EBITDAX, finding and development costs and production replacement are non-GAAP financial measures. Reconciliations and other information on non-GAAP financial measures used in this report can be found following the 10-K and on the Non-GAAP Financial Information pages in the Investor Relations section of our website at www.approachresources.com.*

FORM 10-K

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

(Mark one)

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

For the fiscal year ended December 31, 2010

or

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

For the transition period from to

Commission file number: 001-33801

APPROACH RESOURCES INC.
(Exact name of registrant as specified in its charter)

Delaware	**51-0424817**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification Number)*
One Ridgmar Centre 6500 West Freeway, Suite 800 Fort Worth, Texas	**76116**
(Address of principal executive offices)	*(Zip Code)*

Registrant's telephone number, including area code

(817) 989-9000

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

Title of Each Class	Name of Each Exchange on Which Registered
Common stock, par value $0.01 per share	**NASDAQ Global Select Market**

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

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

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

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 ☑ No ☐

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a 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 ☐ Accelerated filer ☑ Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates (excluding voting shares held by officers and directors) as of June 30, 2010 was $101.5 million. This amount is based on the closing price of the registrant's common stock on the NASDAQ Global Select Market on that date.

The number of shares of the registrant's common stock, par value $0.01, outstanding as of March 10, 2011 was 28,434,194.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's proxy statement for its 2011 annual meeting of stockholders are incorporated by reference in Part III, Items 10-14 of this report.

Certain exhibits previously filed with the Securities and Exchange Commission are incorporated by reference into Part IV of this report.

APPROACH RESOURCES INC.

Unless the context otherwise indicates, all references in this report to "Approach," the "Company," "we," "us," "our" or "ours" are to Approach Resources Inc. and its subsidiaries. Unless otherwise noted, (i) all information in this report relating to oil and natural gas reserves and the estimated future net cash flows attributable to reserves is based on estimates and is net to our interest, and (ii) all information in this report relating to oil and natural gas production is net to our interest. Natural gas is converted throughout this report at a rate of six Mcf of gas to one barrel of oil equivalent. NGLs are converted throughout this report at a rate of one barrel of NGLs to one barrel of oil equivalent. If you are not familiar with the oil and gas terms or abbreviations used in this report, please refer to the definitions of these terms and abbreviations under the caption "Glossary" at the end of Item 15 of this report.

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Cautionary Statement Regarding Forward-Looking Statements

Various statements in this report, including those that express a belief, expectation or intention, as well as those that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). The forward-looking statements may include projections and estimates concerning the timing and success of specific projects, typical well economics and our future reserves, production, revenues, costs, income, capital spending, 3-D seismic operations, interpretation and results and obtaining permits and regulatory approvals. When used in this report, the words "will," "believe," "intend," "expect," "may," "should," "anticipate," "could," "estimate," "plan," "predict," "project," "potential" or their negatives, other similar expressions or the statements that include those words, are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

These forward-looking statements are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management's assumptions about future events may prove to be inaccurate. We caution all readers that the forward-looking statements contained in this report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to the factors listed in the "Risk Factors" section and elsewhere in this report. All forward-looking statements speak only as of the date of this report. We expressly disclaim all responsibility to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us, or persons acting on our behalf. The risks, contingencies and uncertainties relate to, among other matters, the following:

- our business strategy, including our ability to recover oil and gas in place associated with our Wolffork oil resource play in the Permian Basin;
- estimated quantities of oil, NGL and gas reserves;
- uncertainty of commodity prices in oil, gas and NGLs;
- overall United States and global economic and financial market conditions;
- domestic and foreign demand and supply for oil, gas, NGLs and the products derived from such hydrocarbons;
- disruption of credit and capital markets;
- our financial position;
- our cash flow and liquidity;
- replacing our oil and gas reserves;
- our inability to retain and attract key personnel;
- uncertainty regarding our future operating results;
- uncertainties in exploring for and producing oil and gas;
- high costs, shortages, delivery delays or unavailability of drilling and completion, equipment, materials, labor or other services;
- disruptions to, capacity constraints in or other limitations on the pipeline systems that deliver our gas and NGLs and other processing and transportation considerations;

- our inability to obtain additional financing necessary to fund our operations and capital expenditures and to meet our other obligations;
- competition in the oil and gas industry;
- marketing of oil, gas and NGLs;
- interpretation of 3-D seismic data;
- development of our current asset base or property acquisitions;
- the effects of government regulation and permitting and other legal requirements;
- plans, objectives, expectations and intentions contained in this report that are not historical; and
- other factors discussed under Item 1A. “Risk Factors” in this report.

PART I

Item 1. *Business*

General

Approach Resources Inc. is an independent energy company engaged in the exploration, development, production and acquisition of oil and gas properties. We focus on oil and natural gas reserves in oil shale and tight sands. Our management and technical team has a proven track record of finding and developing reservoirs through advanced completion, fracturing and drilling techniques. Our core properties are primarily located in the Permian Basin in West Texas (Clearfork, Wolfcamp Shale, Canyon Sands, Strawn and Ellenburger). We also own interests in the East Texas Basin (Cotton Valley Sands and Cotton Valley Lime) and in the Chama Basin in Northern New Mexico (Mancos Shale). As the operator of all of our estimated proved reserves and production, we have a high degree of control over capital expenditures and other operating matters.

At December 31, 2010, we had estimated proved oil and gas reserves of 50.7 MMBoe. Important characteristics of our proved reserves at December 31, 2010, include:

- 51% oil and NGLs and 49% natural gas;
- 51% proved developed;
- 100% operated;
- Reserve life of over 30 years based on 2010 production of 1.6 MMBoe;
- Standardized after-tax measure of discounted future net cash flows ("Standardized Measure") of $204.2 million; and
- PV-10 of $325.8 million.

PV-10 is our estimate of the present value of future net revenues from proved oil and gas reserves after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates for future income taxes. Estimated future net revenues are discounted at an annual rate of 10% to determine their present value. PV-10 is a non-GAAP, financial measure and generally differs from the Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future cash flows. PV-10 should not be considered as an alternative to the Standardized Measure as computed under GAAP. See Item 2. "Properties — Proved Oil and Gas Reserves" for a reconciliation of PV-10 to the Standardized Measure.

Over 95% of our proved reserves and production at December 31, 2010, were located in the Permian Basin in Crockett and Schleicher Counties, Texas, where we owned working interests in 548 producing oil and gas wells. At December 31, 2010, we leased approximately 102,000 net acres in the Permian Basin. No proved reserves had been recorded for our Wolffork oil shale resource play in the Permian Basin as of December 31, 2010. In addition to our producing wells, we had an estimated 2,300 potential drilling locations in the Permian Basin at December 31, 2010, of which 311 were proved. We also had an estimated 480 potential Wolffork recompletion opportunities in the Permian Basin, none of which were proved. We owned working interests in nine producing gas wells in the East Texas Basin, and have identified 23 proved drilling locations in the East Texas Basin at December 31, 2010.

During 2010, we drilled a total of 91 gross (56.2 net) wells in the Permian Basin with a 100% success rate. In 2010, our production totaled 1,556 MBoe, or 4.3 MBoe/d, and was 67% natural gas and 33% oil and NGLs.

We were incorporated in 2002. Our common stock began trading on the NASDAQ Global Market in the United States under the symbol "AREX" on November 8, 2007, and is now listed on the NASDAQ Global Select Market ("NASDAQ"). Our principal executive offices are located at One Ridgmar Centre, 6500 West Freeway, Suite 800, Fort Worth, Texas 76116. Our telephone number is (817) 989-9000.

Business Strategy

Our goal is to build long-term stockholder value by growing reserves and production in a cost-efficient manner. To accomplish our goal, we plan to carry out a balanced program of (1) developing our core Permian Basin drilling inventory, (2) evaluating and developing our Wolffork oil shale resource play, (3) operating as a low-cost producer, (4) completing strategic, complementary acquisitions and (5) maintaining financial flexibility. The following are key elements of our strategy:

- *Continue to develop our low risk, multi-year drilling inventory.* Since 2004, we have been operating in the Permian Basin, where we have drilled approximately 525 wells and, as of March 1, 2011, lease approximately 133,000 net acres. Focusing on our Permian Basin properties allows us to develop operating, technical and regional expertise important to interpreting geological and operating trends, enhancing production rates, maximizing well recovery and building a low-risk, multi-year drilling inventory. We believe we have a large inventory of low-risk drilling locations that provide us the ability to continue to increase production and reserves at a competitive cost. During 2010, we drilled a total of 91 gross (56.2 net) wells in the Permian Basin with a 100% success rate.

- *Evaluate and develop our Wolffork oil shale resource play.* Our core properties, located in the Permian Basin of West Texas, are characterized by stacked-pay, development opportunities. In October 2010, we announced the results of a detailed geological, petrophysical and engineering study of the Wolfcamp Shale and Clearfork formations, which we refer to together as the "Wolffork," located across our acreage position in the Permian Basin. We refer to our Wolffork drilling program in the Permian Basin as "Project Pangea." We identified the Wolffork through extensive regional mapping and whole-core data, 3-D seismic data from over 135,000 acres and well data from over 400 wellbores that we drilled and completed while targeting deeper zones. We plan to dedicate substantially all of our 2011 exploration and development drilling budget to the Wolffork oil shale resource play as well as our traditional Canyon Sands drilling.

- *Operate our properties as a low-cost producer.* We strive to minimize our operating costs by concentrating our assets within geographic areas where we can consolidate operating control and thus create operating efficiencies. We operate 100% of our reserve base and plan to continue to operate a substantial portion of our producing properties in the future. Operating control allows us to better manage timing and risk as well as the cost of exploration and development, drilling and ongoing operations.

- *Acquire strategic, complementary assets.* We continually review opportunities to acquire producing properties, undeveloped acreage and drilling prospects in our existing core area in the Permian Basin. We focus particularly on opportunities where we believe our operational efficiency, reservoir management and geological expertise in unconventional oil and gas properties will enhance value and performance. We remain focused on unconventional resource opportunities, but will also look at conventional opportunities based on individual project economics.

- *Maintain financial flexibility.* Our financial results depend on many factors, particularly the price of oil, gas and NGLs. We believe in maintaining financial flexibility given the volatility of these prices, fluctuation in drilling and oilfield service costs and the risks involved in drilling. During times of severe price declines, we may from time to time reduce capital expenditures and curtail drilling in order to preserve our financial flexibility and the net asset value of our existing proved reserves. We believe that a strong balance sheet and liquidity provide us with significant financial flexibility to pursue our strategic and financial objectives. Also, we may from time to time enter into commodity price swaps and collars to partially mitigate the risk of commodity price volatility.

2010 Activity

During 2010, we drilled a total of 91 gross (56.2 net) wells in the Permian Basin with a 100% success rate. Production for 2010 totaled 1,556 MBoe (4.3 MBoe/d), compared to 1,468 MBoe (4 MBoe/d) in 2009, a 6% increase. Our costs incurred in 2010 totaled $90 million, and included $59.8 million for exploration and development drilling, $21.2 million, net of purchase price adjustments, for the purchase of an additional working interest in Cinco Terry and $9 million for acreage acquisitions in the Permian Basin. Additional highlights for 2010 include:

Wolffork Oil Shale Resource Play

We were founded in 2002 to explore and develop unconventional oil and gas reservoirs at a competitive cost structure. In 2004, we began to assemble underdeveloped acreage in the Permian Basin and began a drilling program targeting the Canyon Sands, Strawn and Ellenburger formations in 27,000 net acres. Since 2004, we have drilled approximately 525 wells in the Permian Basin and, as of March 1, 2011, we lease approximately 133,000 net acres in the Permian Basin. For a majority of our wells, we collected more log data, including mud logs that help identify hydrocarbon-bearing formations, than, based on our operating experience in the area, we believe is typical for the area where we operate. The log data indicated that hydrocarbons were present in the Clearfork and Wolfcamp Shale formations above the Canyon Sands, Strawn and Ellenburger zones.

In October 2010, we announced our Wolffork oil shale resource play. We performed a detailed geological and petrophysical evaluation using extensive regional mapping, 3-D seismic data from over 135,000 acres, whole-core data and well data from over 400 wellbores that we have drilled and completed while targeting the Canyon Sands, Strawn and Ellenburger zones at depths of 7,250 to 8,900 feet. The Wolffork is composed of three stacked pay zones, the Clearfork, Dean and Wolfcamp Shale formations, totaling more than 2,500 feet of potential gross pay. We believe that the Wolffork oil shale resource play will significantly enhance our opportunities in the Permian Basin, and we plan to continue our pilot program targeting the Wolffork in 2011 with a combination of vertical, horizontal and recompletion projects.

Acquisition of Acreage

We acquired approximately 41,500 gross (34,800 net) acres in the Permian Basin in Crockett and Schleicher Counties, Texas, during 2010. The acreage acquisitions joined our legacy asset in the southeast part of Project Pangea, Ozona Northeast, to Cinco Terry, in the northwest part of Project Pangea.

2010 Acquisition of Working Interest

In October 2010, we acquired a 10% working interest in Cinco Terry from a non-operating partner for $21.2 million, net of purchase price adjustments, which was funded with borrowings under our revolving credit facility. We believe the acquisition of additional interests in Cinco Terry increases our opportunities in this area and enhances our leverage to the reserve potential of the Wolffork oil shale resource play.

Proved Reserve and Production Growth

In 2010, our estimated proved reserves increased 39%, or 14.2 MMBoe, to 50.7 MMBoe from 36.5 MMBoe, and our production increased 6% to 4.3 MBoe/d. Planned processing upgrades contributed to the increase in proved reserves at year end 2010. On April 1, 2011, we will begin realizing NGL revenues from the liquids-rich gas stream in Ozona Northeast under a gas purchase and processing contract with DCP Midstream, LP. See Item 1. "Business — Markets and Customers." Development drilling and planned processing upgrades in Cinco Terry, the acquisition of an additional working interest in Cinco Terry and improved pricing also contributed to the increase in proved reserves at December 31, 2010. The increase in production is attributable to our drilling program in the Permian Basin during 2010. On average, we operated three rigs in 2010, and drilled a total of 91 gross (56.2 net) wells, with a 100% success rate.

Balanced Reserve Profile

Our proved reserve profile at year end 2010 was 51% oil and NGLs and 49% natural gas, compared to 23% oil and NGLs and 77% natural gas at year end 2009. During 2010, our proved oil and NGL reserves increased over 200%, or 17.2 MMBbls, to 25.6 MMBbls from 8.4 MMBbls in 2009. Our increase in proved oil and NGL reserves is primarily due to planned processing upgrades in Ozona Northeast. On April 1, 2011, we will begin realizing NGL revenues from the liquids-rich gas stream in Ozona Northeast.

2010 Equity Offering

In November 2010, we completed an equity offering and issued an aggregate of 6.6 million shares of our common stock at $16.25 per share in an underwritten public offering (the "2010 Offering"). After deducting underwriting discounts and transaction costs of approximately $5.7 million, we received net proceeds of approximately $101.8 million, which we intend to use to fund our capital expenditures for the Wolffork oil shale resource play, working interest and leasehold acquisitions in the Permian Basin and general working capital needs. Pending these uses, we used a portion of the proceeds of the 2010 Offering to repay all outstanding borrowings under our revolving credit facility.

Additional Working Interest Acquisition — 2011

In February 2011, we acquired a 38% working interest in Cinco Terry from two non-operating partners for $76 million, subject to usual and customary post-closing adjustments (the "Working Interest Acquisition"). The Working Interest Acquisition was funded with cash on hand and borrowings under our revolving credit facility. As a result of the Working Interest Acquisition, our working and net revenue interests in Cinco Terry are now approximately 100% and 76%, respectively. Our 2010 results of operations do not include production, revenues or costs from the Working Interest Acquisition. Further, our year-end 2010 estimated proved reserves, PV-10 and Standardized Measure do not include estimated proved reserves associated with the Working Interest Acquisition.

Plans for 2011

In November 2010, we announced a 2011 capital budget of approximately $100 million. In January 2011, we acquired approximately 10,900 contiguous, net acres approximately nine miles west of our existing acreage in northeast Crockett County, Texas. In addition, in March 2011, we announced the Working Interest Acquisition for $76 million. Given our recent activity, in March 2011 we increased our capital budget to $220 million, of which approximately $130 million will be allocated to drilling and recompletion projects in the Permian Basin and approximately $90 million will be allocated to the Working Interest Acquisition and lease extensions, renewals and lease acquisitions in the Permian Basin.

The 2011 drilling program includes operating one rig to drill 11 gross (11 net) horizontal wells targeting the Wolfcamp Shale, one rig to drill 19 gross (19 net) vertical wells targeting the Wolffork and Canyon Sands, one rig to drill 26 gross (26 net) vertical wells targeting the Canyon Sands (which we expect to recomplete in the Wolffork in 2012) and one workover rig to recomplete 10 gross (10 net) wells in the Wolffork. Our objectives for the 2011 drilling program include delineating the Clearfork and Wolfcamp Shale zones across Project Pangea, improving initial production rates by refining our stimulation strategy, advancing our understanding of optimal well spacing and hydrocarbon recovery and improving our cost structure.

Our 2011 capital budget is subject to change depending upon a number of factors, including additional data on our Wolffork oil shale resource play, results of Wolfcamp Shale and Wolffork drilling and recompletions, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil, gas and NGLs, the availability of sufficient capital resources for drilling prospects, our financial results and the availability of lease extensions and renewals on reasonable terms.

Markets and Customers

The revenues generated by our operations are highly dependent upon the prices of, and supply and demand for, oil and gas. The price we receive for our oil and gas production depends on numerous factors beyond our control, including seasonality, the condition of the domestic and global economies, particularly in the manufacturing sectors, political conditions in other oil and gas producing countries, the extent of domestic production and imports of oil and gas, the proximity and capacity of gas pipelines and other transportation facilities, supply and demand for oil and gas, the marketing of competitive fuels and the effects of federal, state and local regulation. The oil and gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers.

During the year ended December 31, 2010, Ozona Pipeline Energy Company ("Ozona Pipeline"), Shell Trading U.S. Company ("Shell") and WTG Benedum/Belvan Partners, LP ("WTG") were our most significant purchasers, accounting for approximately 34.3%, 32.4% and 31.8%, respectively, of our total oil, NGL and gas sales for 2010, excluding realized commodity derivative settlements. In addition, in January 2011, we entered into an agreement with DCP Midstream, LP to purchase natural gas and process NGLs from Ozona Northeast after our agreement with Ozona Pipeline expires on March 31, 2011.

Commodity Derivative Activity

We enter into financial swaps and options to mitigate portions of the risk of market price fluctuations related to future oil and gas production.

All derivative instruments are recorded on the balance sheet at fair value. Changes in the derivative's fair value are currently recognized in the statement of operations unless specific commodity derivative accounting criteria are met and contracts have been designated as cash flow hedge instruments. For qualifying cash-flow commodity derivatives, the gain or loss on the derivative is deferred in accumulated other comprehensive income to the extent the commodity derivative is effective. The ineffective portion of the commodity derivative is recognized immediately in the statement of operations. Gains and losses on commodity derivative instruments included in accumulated other comprehensive income are reclassified to oil and gas sales revenue in the period that the related production is delivered. Derivative contracts that do not qualify for commodity derivative accounting treatment are recorded as derivative assets and liabilities at fair value in the balance sheet, and the associated unrealized gains and losses are recorded as current income or expense in the statement of operations.

Historically, we have not designated our derivative instruments as cash-flow commodity derivatives. We record our open derivative instruments at fair value on our consolidated balance sheets as either unrealized gains or losses on commodity derivatives. We record changes in such fair value in earnings on our consolidated statements of operations under the caption entitled "unrealized gain (loss) on commodity derivatives."

Title to Properties

Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. We do not believe that any of these burdens materially interfere with our use of the properties in the operation of our business.

We believe that we have generally satisfactory title to or rights in all of our producing properties. As is customary in the oil and gas industry, we make a general investigation of title at the time we acquire undeveloped properties. We receive title opinions of counsel before we commence drilling operations. We believe that we have satisfactory title to all of our other assets. Although title to our properties is subject to encumbrances in certain cases, we believe that none of these burdens will materially detract from the value of our properties or from our interest therein or will materially interfere with our use of the properties in the operation of our business.

Competition

The oil and gas industry is highly competitive, and we compete for prospective properties, producing properties, personnel and services with a substantial number of other companies that have greater resources. Many of these companies explore for, produce and market oil and gas, carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and gas properties, attracting highly-skilled personnel and obtaining purchasers and transporters of the oil and gas we produce. We also face competition from alternative fuel sources, including coal, heating oil, imported LNG, nuclear and other nonrenewable fuel sources, and renewable fuel sources such as wind, solar, geothermal, hydropower and biomass. Competitive conditions may also be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the United States government. However, it is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such laws and regulations may, however, substantially increase the costs of exploring for, developing or producing oil and gas and may prevent or delay the commencement or continuation of a given operation. The effect of these risks cannot be accurately predicted.

Regulation

The oil and gas industry in the United States is subject to extensive regulation by federal, state and local authorities. At the federal level, various federal rules, regulations and procedures apply, including those issued by the United States Department of Interior and the United States Department of Transportation (Office of Pipeline Safety). At the state and local level, various agencies and commissions regulate drilling, production and midstream activities. These federal, state and local authorities have various permitting, licensing and bonding requirements. Various remedies are available for enforcement of these federal, state and local rules, regulations and procedures, including fines, penalties, revocation of permits and licenses, actions affecting the value of leases, wells or other assets, and suspension of production. As a result, there can be no assurance that we will not incur liability for fines and penalties or otherwise subject us to the various remedies as are available to these federal, state and local authorities. However, we believe that we are currently in material compliance with these federal, state and local rules, regulations and procedures.

Transportation and Sale of Natural Gas

The Federal Energy Regulatory Commission (“FERC”) regulates interstate gas pipeline transportation rates and service conditions. Although FERC does not regulate oil and gas producers such as us, FERC’s actions are intended to foster increased competition within all phases of the oil and gas industry and its regulation of third-party pipelines and facilities could indirectly affect our ability to transport or market our production. To date, FERC’s policies have not materially affected our business or operations. It is unclear what impact, if any, future rules or increased competition within the oil and gas industry will have on our sales efforts.

FERC or other federal or state regulatory agencies may consider additional proposals or proceedings that might affect the oil and gas industry. In addition, new legislation may affect the industries and markets in which we operate. We cannot predict when or if these proposals will become effective or any effect they may have on our operations. We do not believe, however, that any of these proposals will affect us any differently than other oil and gas producers with which we compete.

Regulation of Production

Oil and gas production is regulated under a wide range of federal and state statutes, rules, orders and regulations. State and federal statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. The states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum rates of production from oil and gas wells, the regulation of spacing, and requirements for plugging and abandonment of wells. Also, each state generally imposes an ad valorem, production or severance tax with respect to production and sales of oil, NGLs and gas within its jurisdiction.

Environmental Regulations

In the United States, the exploration for and development of oil and gas and the drilling and operation of wells, fields and gathering systems are subject to extensive federal, state and local laws and regulations governing environmental protection as well as discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling begins;
- require the installation of expensive pollution controls or emissions monitoring equipment;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and gas drilling, completion, production, transportation and processing activities;
- suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands and other protected areas; and
- require remedial measures to mitigate and remediate pollution from historical and ongoing operations, such as the closure of waste pits and plugging of abandoned wells.

These laws, rules and regulations may also restrict the rate of oil and gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability.

Governmental authorities have the power to enforce compliance with environmental laws, regulations and permits, and violations are subject to injunction, as well as administrative, civil and criminal penalties. The effects of existing and future laws and regulations could have a material adverse impact on our business, financial condition and results of operations. While we believe that we are in substantial compliance with existing environmental laws and regulations and that continued compliance with current requirements would not have a material adverse effect on us, there is no assurance that this will continue in the future.

The following is a summary of some of the existing laws, rules and regulations to which our business operations are subject.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA") also known as the Superfund law, and comparable state statutes impose strict liability, and under certain circumstances, joint and several liability, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to strict, joint and several liabilities for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. While we generate materials in the course of our operations that may be regulated as hazardous substances, we have not received notification that we may be potentially responsible for cleanup costs under CERCLA.

Waste Handling

The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the federal Environmental Protection Agency ("EPA") the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of oil or gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our operating expenses, which could have a material adverse effect on our business, financial condition and results of operations.

We currently own or lease, and have in the past owned or leased, properties that for many years have been used for oil and gas exploration, production and development activities. Although we used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on, under or from the properties owned or leased by us or on, under or from other locations where such wastes have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons and wastes was not under our control. These properties and the materials disposed or released on, at, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes or contamination, or to perform remedial activities to prevent future contamination.

Air Emissions

The federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of hazardous and toxic air pollutants at specified sources. These regulatory programs may require us to obtain permits before beginning construction on a new source of air emissions and may require us to reduce emissions at existing facilities. As a result, we may be required to incur increased capital and operating costs. Additionally, federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and analogous state laws and regulations.

In February 2005, the Kyoto Protocol to the United Nations Framework Convention on Climate Change (the "Protocol") became effective. Pursuant to the Protocol, adopting countries are required to implement national programs to reduce emissions of greenhouse gasses ("GHGs"), which are suspected of contributing to global warming. The United States is not currently a participant in the Protocol. However, Congress has considered legislation directed at reducing GHG emissions and the EPA may be required to regulate GHG emissions, and many states have already adopted legislation or undertaken regulatory initiatives addressing GHG emissions from various sources. The oil and gas industry is a direct source of certain GHG emissions, namely carbon dioxide and methane, and future restrictions on such emissions would likely adversely impact our future business, financial condition and results of operations.

In December 2010, the EPA enacted final rules on mandatory reporting of GHGs. Under the final rules, owners or operators of facilities that contain petroleum and natural gas systems and emit 25,000 metric tons or more of GHGs per year (expressed as carbon dioxide equivalent or CO_2E) will be required to report emissions. Owners or operators are required to collect emission data, calculate GHG emissions and follow specified procedures for quality assurance, missing data, recordkeeping and reporting. Our operations in the Permian Basin are subject to the EPA's mandatory reporting rules. As a result, we will be required to incur increased capital and operating costs, although as of the date of this report we do not expect these costs to be material.

At this time, although it is not possible to accurately estimate how potential future laws or regulations addressing GHG emissions would impact our business, passage of such laws or regulation affecting areas in which we conduct business could have a material adverse effect on our future business, financial condition and results of operations.

Water Discharges

The Federal Water Pollution Control Act, also known as the Clean Water Act, and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances into regulated waters, including wetlands. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

The Safe Drinking Water Act, Groundwater Protection and the Underground Injection Control Program

The Federal Safe Drinking Water Act ("SWDA") and the Underground Injection Control program (the "UIC program") promulgated under the SWDA and state programs regulate the drilling and operation of salt water disposal wells. The EPA has delegated administration of the UIC program in Texas to the Texas Railroad Commission. Permits must be obtained before drilling salt water disposal permits, and casing integrity monitoring must be conducted periodically to ensure the casing is not leaking saltwater to groundwater. Contamination of groundwater by oil and natural gas drilling, production and related operations may result in fines, penalties and remediation costs, among other sanctions and liabilities under the SWDA and state laws. In addition, third party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages and bodily injury. We engage third parties to provide hydraulic fracturing or other well stimulation services to us for many of the wells that we drill and operate.

Threatened and Endangered Species, Migratory Birds and Natural Resources

Various state and federal statues prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds, wetlands and natural resources. These statutes include the Endangered Species Act, the Migratory Bird Treaty Act, the Clean Water Act and CERCLA. The United States Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or development. Where takings of or harm to species or damages to wetlands, habitat or natural resources occur or may occur, government entities or at times private parties may act to prevent oil and gas exploration activities or seek damages for harm to species, habitat or natural resources resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and may seek natural resources damages and, in some cases, criminal penalties.

OSHA and Other Laws and Regulations

We are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements and with other OSHA and comparable requirements.

We believe that we are in substantial compliance with all existing environmental laws and regulations that apply to our current operations and that our ongoing compliance with existing requirements will not have a material adverse effect on our business, financial condition or results of operations. We did not incur any material capital expenditures for remediation or pollution control activities for the year ended December 31, 2010. In addition, as of the date of this report, we are not aware of any environmental issues or claims that will require material capital or operating expenditures during 2011. However, the passage of additional or more stringent laws or regulations in the future could have a negative effect on our business, financial condition and results of operations, including our ability to develop our undeveloped acreage. For example, see our discussion of regulatory proceedings in New Mexico below.

State and Local Regulations — New Mexico

In April 2008, the Board of County Commissioners of Rio Arriba County, New Mexico (the "County") imposed a moratorium on all oil and gas drilling on private lands the County, pending the adoption of an ordinance that would regulate oil and gas operations. The moratorium covered all of our El Vado East prospect in the County. In May 2009, the Board of County Commissioners lifted the moratorium and adopted a final oil and gas drilling ordinance. The ordinance requires special use permits for oil and gas operations in the eastern part of the County where our El Vado East prospect is located.

Our mineral lease for El Vado East currently requires us to drill a minimum of eight wells before the end of the primary term of the lease, which originally was set to expire on April 2, 2009. However, the drilling moratorium, regulatory proceedings and an inability to obtain permits delayed our drilling plans in El Vado East and, accordingly, we have invoked our right to assert "force majeure" under our mineral lease and extended the primary term of the lease during the period of force majeure, up to a maximum of four years past the original primary term, or April 2, 2013.

In 2010, we received conditional permits for eight drilling locations from the County. After the County denied a ninth location, we filed a lawsuit in New Mexico state court challenging the denial and have since reached a settlement with the County to reverse its prior decision and grant a conditional permit for a ninth location. The conditional permits require that additional conditions be met and additional County approval received before drilling can begin. In addition, we have received notice from the State of New Mexico that public hearings on requested proration units will be required for at least two potential drilling locations in the County.

Assuming no further, unexpected delays in the permitting process, we believe we will be able to satisfy our initial drilling commitment before the end of the primary term as extended by force majeure. However, our inability to timely meet this drilling commitment or negotiate appropriate extensions under the lease could result in the termination of the lease and an impairment of our investment in El Vado East, the current carrying value of which is $3.2 million.

Employees

At February 28, 2011, we had 55 full-time employees, 22 of whom are field personnel. We regularly use independent contractors and consultants to perform various field and other services. None of our employees are represented by a labor union or covered by any collective bargaining agreement. We believe that our relations with our employees are excellent.

Insurance Matters

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

Available Information

We maintain an internet website under the name *www.approachresources.com*. The information on our website is not a part of this report. We make available, free of charge, on our website, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports, as soon as reasonably practicable after providing such reports to the Securities and Exchange Commission (the "SEC"). Also, the charters of our Audit Committee and Compensation and Nominating Committee, and our Code of Conduct, are available on our website and in print to any stockholder who provides a written request to the Corporate Secretary at One Ridgmar Centre, 6500 West Freeway, Suite 800, Fort Worth, Texas 76116.

We file annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, proxy statements and other documents with the SEC under the Exchange Act. 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, NE, Washington DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers, including Approach, that file electronically with the SEC. The public can obtain any document we file with the SEC at *www.sec.gov*. Information contained on or connected to our website is not incorporated by reference into this Form 10-K and should not be considered part of this report or any other filing that we make with the SEC.

Item 1A. ***Risk Factors.***

You should carefully consider the risk factors set forth below as well as the other information contained in this report before investing in our common stock. Any of the following risks could materially and adversely affect our business, financial condition and results of operations. In such a case, you may lose all or part of your investment. The risks described below are not the only we face. Additional risks and uncertainties not currently known to us or those we currently view to be immaterial may also materially adversely affect our business, financial condition and results of operations.

Risks Related to the Oil and Natural Gas Industry and Our Business

Our future reserve and production growth is highly dependent on the success of our Wolffork oil shale resource play, which has a limited operational history and is subject to change.

We began drilling wells in the Wolffork play only recently. The wells that have been drilled or recompleted in these areas only represent a very small sample of our large acreage position, and we cannot assure you that our new vertical or horizontal wells or recompletions of existing wells will be successful. As of December 31, 2010, we had no proved reserves attributable to this play. Accordingly, we have limited information on the amount of reserves that will ultimately be recovered from our Wolffork wells. Our drilling plans in the Wolffork are flexible and depend on a number of factors, including the extent to which our initial pilot wells are successful. The determination of whether we continue to drill prospects in the Wolffork may, among other things, depend on any one or a combination of the following factors:

- our ability to determine the most effective and economic fracture stimulation for the Wolffork play;
- changes in the estimates of costs to drill or complete wells;
- the extent of our success in drilling and completing horizontal wells;
- our ability to reduce our exposure to costs and drilling risks; and
- the costs and availability of drilling and completion services and equipment, particularly fracture stimulation services and equipment.

We continue to gather data about our prospects in the Wolffork play, and it is possible that additional information may cause us to change our drilling schedule or determine that prospects in some portion of our acreage position should not be developed at all.

The use of geoscientific, petrophysical and engineering analyses and other technical or operating data to evaluate drilling prospects is uncertain and does not guarantee drilling success or recovery of economically producible reserves.

Our decisions to explore, develop and acquire prospects or properties targeting Wolffork and other zones in the Permian Basin and other areas depend on data obtained through geoscientific, petrophysical and engineering analyses, the results of which can be uncertain. Even when properly used and interpreted, data from whole cores, regional well log analyses and 3-D seismic only assist our technical team in identifying hydrocarbon indicators and subsurface structures and estimating hydrocarbons in place. They do not allow us to know conclusively the amount of hydrocarbons in place and if those hydrocarbons are producible economically. In addition, the use of advanced drilling and completion technologies for our Wolffork development, such as horizontal drilling and multi-stage fracture stimulations, requires greater expenditures than our traditional development drilling strategies. Our ability to commercially recover and produce the hydrocarbons that we believe are in place and attributable to the Wolffork and other zones will depend on the effective use of advanced drilling and completion techniques, the scope of our drilling program (which will be directly affected by the availability of capital), drilling and production costs, availability of drilling and completion services and equipment, drilling results, lease expirations, regulatory approval and geological and mechanical factors affecting recovery rates. Our estimates of unproved reserves, estimated ultimate recoveries per well, hydrocarbons in place and resource potential may change significantly as development of our oil and gas assets provides additional data.

Oil and gas prices are volatile, and a decline in oil or gas prices could significantly affect our business, financial condition and results of operations and our ability to meet our capital expenditure requirements and financial commitments.

Our revenues, profitability and cash flow depend substantially upon the prices and demand for oil and gas. The markets for these commodities are volatile, and even relatively modest drops in prices can affect significantly our financial results and impede our growth. Prices for oil and gas fluctuate widely in response to relatively minor changes in the supply and demand for oil and gas, market uncertainty and a variety of additional factors beyond our control, such as:

- domestic and foreign supply of oil and gas;
- domestic and foreign consumer demand for oil and gas;
- overall United States and global economic conditions;
- commodity processing, gathering and transportation availability and the availability of refining capacity;
- price and availability of alternative fuels;
- price and quantity of foreign imports;
- domestic and foreign governmental regulations;
- political conditions in or affecting other gas producing and oil producing countries;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- weather conditions, including unseasonably warm winter weather and tropical storms; and
- technological advances affecting oil and gas consumption.

Further, oil and gas prices do not necessarily fluctuate in direct relationship to each other. Because 49% of our estimated proved reserves as of December 31, 2010, were gas reserves, our financial results are also sensitive to movements in gas prices. Recent gas prices have been extremely volatile, and we expect this volatility to continue. For example, from January 1, 2010 to December 31, 2010, NYMEX natural gas prices ranged from a high of $6.01 per MMBtu to a low of $3.29 per MMBtu.

The results of higher investment in the exploration for and production of oil and gas and other factors, such as global economic and financial conditions discussed below, may cause the price of oil and gas to fall. Lower oil and gas prices may not only cause our revenues to decrease but also may reduce the amount of oil and gas that we can produce economically. Substantial decreases in oil and gas prices would render uneconomic some or all of our drilling locations. This may result in our having to make substantial downward adjustments to our estimated proved reserves and could have a material adverse effect on our business, financial condition and results of operations. Further, if oil, gas and NGL prices significantly decline for an extended period of time, we may, among other things, be unable to maintain or increase our borrowing capacity, repay current or future debt or obtain additional capital on attractive terms, all of which can affect the value of our common stock.

A substantial portion of our estimated proved reserves at December 31, 2010, are NGLs. A decline in the price of NGLs or a disruption in our ability to transport NGLs to a market could materially and adversely affect our business, financial condition and results of operations.

At December 31, 2010, 41% of our estimated proved reserves were NGL reserves. Accordingly, our financial results are sensitive to movements in NGL prices, which are impacted by, among other things, NGL supply, transportation capacity of midstream operators and demand for NGLs from downstream processing facilities. In addition, NGLs can be subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, ability of downstream processing facilities to accept NGLs, physical damage to the gathering or transportation system or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months or longer, and in many cases we are provided with limited, if any, notice as to when these circumstances will arise and their duration.

Changes in the differential between NYMEX or other benchmark prices of oil and gas and the reference or regional index price used to price our actual oil and gas sales could have a material adverse effect on our financial condition and results of operations.

The reference or regional index prices that we use to price our oil and gas sales sometimes reflect a discount to the relevant benchmark prices, such as NYMEX. The difference between the benchmark price and the price we reference in our sales contracts is called a differential. We cannot accurately predict oil and gas differentials. Changes in differentials between the benchmark price for oil and gas and the reference or regional index price we reference in our sales contracts could have a material adverse effect on our results of operations and financial condition.

Future economic conditions in the U.S. and international markets could materially and adversely affect our business, financial condition and results of operations.

The U.S. and other world economies continue to experience the effects of a global recession and credit market crisis. More volatility may occur before a sustainable growth rate is achieved either domestically or globally. Even if such growth rate is achieved, such a rate may be lower than the U.S. and international economies have experienced in the past. Global economic growth drives demand for energy from all sources, including fossil fuels. A lower, future economic growth rate will result in decreased demand for our oil, gas and NGL production and lower commodity prices, which will reduce our cash flows from operations and our profitability.

Difficult conditions in the credit and capital markets may limit our ability to obtain funding under our current revolving credit facility or other sources of debt or equity financing. The inability to obtain funding could prevent us from meeting our future capital needs to fund our development program.

Credit and capital markets have experienced unprecedented volatility and disruption. Although domestic markets continued to recover in 2010, they may remain volatile and unpredictable, particularly if weaker than expected economic growth persists. We have a significant inventory of development properties that will require substantial future investment. We will need financing to fund these and other activities. Our future access to capital could be limited if the credit or broader capital markets are constrained. This could prevent or significantly delay development of our assets.

Our lenders can limit our borrowing capabilities, which may materially impact our operations.

At December 31, 2010, we had no outstanding debt under our revolving credit facility, and our borrowing base was $150 million. At February 28, 2011, we had $67 million outstanding under our revolving credit facility, primarily as a result of financing the $76 million Working Interest Acquisition. The borrowing base under our revolving credit facility is redetermined semi-annually based upon a number of factors, including commodity prices and reserve levels. In addition to such semi-annual redeterminations, our lenders may request one additional redetermination during any 12-month period. Upon a redetermination, our borrowing base could be substantially reduced, and if the amount outstanding under our credit facility at any time exceeds the borrowing base at such time, we may be required to repay a portion of our outstanding borrowings. We use cash flow from operations and bank borrowings to fund our exploration, development and acquisition activities. A reduction in our borrowing base could limit those activities. In addition, we may significantly change our capital structure to make future acquisitions or develop our properties. Changes in capital structure may significantly increase our debt. If we incur additional debt for these or other purposes, the related risks that we now face could intensify. A higher level of debt also increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of debt depends on our future performance, which is affected by general economic conditions and financial, business and other factors, many of which are beyond our control.

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

Drilling and exploration are the main methods we use to replace our reserves. However, drilling and exploration operations may not result in any increases in reserves for various reasons. Exploration activities involve numerous risks, including the risk that no commercially productive oil or gas reservoirs will be discovered. In addition, the future cost and timing of drilling, completing and producing wells is often uncertain. Furthermore, drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- reductions in oil and gas prices;
- limitations in the market for oil and gas;
- inadequate capital resources;
- unavailability or high cost of drilling and completion equipment, materials or labor;
- compliance with governmental regulations;
- unexpected drilling conditions, pressure or irregularities in formations, equipment failures or accidents;
- lack of acceptable prospective acreage;
- adverse weather conditions;
- surface access restrictions;
- title problems; and
- mechanical difficulties.

Currently, substantially all of our producing properties are located in two counties in Texas, making us vulnerable to risks associated with having our production concentrated in a small area.

Substantially all of our producing properties and estimated proved reserves are geographically concentrated in two counties in Texas, Crockett and Schleicher. Our current production is primarily attributable to two areas in Crockett and Schleicher Counties, Ozona Northeast and the Angus field in Cinco Terry. As a result of this concentration, we are disproportionately exposed to the natural decline of production from these fields, and particularly Ozona Northeast, as well as the impact of delays or interruptions of production from these wells caused by significant governmental regulation, transportation capacity constraints, curtailments of production, natural disasters, interruption of transportation of gas produced from the wells in these areas or other events that impact these areas.

Potential identified drilling locations that we decide to drill may not yield oil or gas in commercially viable quantities and are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our drilling locations are in various stages of evaluation, ranging from locations that are ready to be drilled to locations that will require substantial additional evaluation and interpretation. There is no way to predict before drilling and testing whether any particular drilling location will yield oil or 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 before drilling whether oil or gas will be present or, if present, whether oil or gas will be present in commercial quantities. The analysis that we perform may not be useful in predicting the characteristics and potential reserves associated with our drilling locations. As a result, we may not find commercially viable quantities of oil and gas.

Our potential drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of factors, including oil and gas prices, costs and availability of drilling and completion services and equipment, the availability of capital, seasonal conditions, regulatory approvals and drilling results. Because of these uncertainties, we do not know when the drilling locations we have identified will be drilled or if they will ever be drilled or if we will be able to produce oil or gas from these or any proved drilling locations. As such, our actual drilling activities may be materially different from those presently identified, which could adversely affect our business, results of operations and financial condition.

Unless we replace our oil and gas reserves, our reserves and production will decline.

Our future oil and gas production depends on our success in finding or acquiring additional reserves. If we fail to replace reserves through drilling or acquisitions, our level of production and cash flows will be adversely affected. In general, production from oil and gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our total proved reserves will decline as reserves are produced unless we conduct other successful exploration and development activities or acquire properties containing proved reserves, or both. Our ability to make the necessary capital investment to maintain or expand our asset base of oil and gas reserves would be limited to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves.

Our actual production, revenues and expenditures related to our reserves are likely to differ from our estimates of our proved reserves. We may experience production that is less than estimated and drilling costs that are greater than estimated in our reserve reports. These differences may be material.

The proved oil, NGL and gas reserve data included in this report are estimates. Petroleum engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. Estimates of economically recoverable oil, NGL and gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, including:

- historical production from the area compared with production from other similar producing areas;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning future oil, NGL and gas prices; and
- assumptions concerning future operating costs, severance and excise taxes, development costs and workover and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating proved reserves:

- the quantities of oil, NGL and gas that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of future development expenditures; and
- future oil, NGL and gas prices.

As of December 31, 2010, approximately 49% of our proved reserves were proved undeveloped. Estimates of proved undeveloped reserves are even less reliable than estimates of proved developed reserves. Furthermore, different reserve engineers may make different estimates of reserves and future net revenues based on the same available data. Our actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material. The PV-10 included in this report should not be considered as the current market value of the estimated oil and gas reserves attributable to our properties. PV-10 is based on the average of the closing price on the first day of the month for the 12-month period prior to fiscal year end, while actual future prices and costs may be materially higher or lower. If natural gas, oil and NGL prices decline by 10% from $4.38 per MMBtu, $79.40 per Bbl of oil and $39.25 per

Bbl of NGLs to $3.94 per MMBtu, $71.46 per Bbl of oil and $35.33 per Bbl of NGLs, then our PV-10 as of December 31, 2010, would decrease from $325.8 million to $263 million. The average market price received for our production for the month of December 2010 was $4.31 per Mcf (after basis differential and Btu adjustments), $85.05 per Bbl of oil and $45.85 per Bbl of NGLs.

Actual future net revenues also will be affected by factors such as:

- the amount and timing of actual production;
- supply and demand for oil and gas;
- increases or decreases in consumption; and
- changes in governmental regulations or taxation.

The unavailability or high cost of drilling rigs, equipment, materials, 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 is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling and completion crews rise as the number of active rigs in service increases. Increasing levels of exploration and production will increase the demand for oilfield services, and the costs of these services may increase, while the quality of these services may suffer. Our primary area of operation, the Permian Basin, is currently experiencing increased demand for fracture stimulation materials, crews and services and the availability of such crews, materials and services has been severely restricted. If the availability of fracture stimulation crews, materials and services in the Permian Basin remains particularly severe, our business, results of operations and financial condition could be materially and adversely affected because our operations and properties are concentrated in the Permian Basin.

We have leases and options for undeveloped acreage that may expire in the near future.

As of December 31, 2010, we held mineral leases or options in each of our areas of operations that are still within their original lease term and are not currently held by production. Unless we establish commercial production on the properties subject to these leases, most of these leases will expire between 2011 and 2015. If these leases or options expire, we will lose our right to develop the related properties. See Item 2. "Properties — Undeveloped Acreage Expirations" for a table summarizing the expiration schedule of our undeveloped acreage over the next three years.

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

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

Our customer base is concentrated, and the loss of our key customers could, therefore, adversely affect our financial results.

In 2010, Ozona Pipeline, Shell and WTG accounted for approximately 34.3%, 32.4% and 31.8%, respectively, of our total oil, NGL and gas sales, excluding realized commodity derivative settlements. In addition, in January 2011, we entered into an agreement with DCP Midstream LP to purchase gas and process NGLs from Ozona Northeast when our agreement with Ozona Pipeline expires, which will be March 31, 2011. To the extent that any of our major purchasers reduces their purchases in gas or oil or defaults on their obligations to us, we would be adversely affected unless we were able to make comparably favorable arrangements with other customers. These purchasers' default or non-performance could be caused by factors beyond our control. A default could occur as a result of circumstances relating directly to one or more of these customers, or due to circumstances related to other market participants with which the customer has a direct or indirect relationship.

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

Our success largely depends on the skills, experience and efforts of our management team and other key personnel. The loss of the services of one or more members of our senior management team or of our other employees with critical skills needed to operate our business could have a negative effect on our business, financial condition, results of operations and future growth. In January 2011, we entered into amended and restated employment agreements with J. Ross Craft, P.E., our President and Chief Executive Officer; and Steven P. Smart, our Executive Vice President and Chief Financial Officer; and new employment agreements with J. Curtis Henderson, our Executive Vice President and General Counsel; Qingming Yang, our Executive Vice President — Business Development and Geosciences; and Ralph P. Manoushagian, our Executive Vice President — Land. If any of these officers or other key personnel resign or become unable to continue in their present roles and are not adequately replaced, our business operations could be materially adversely affected. Our ability to manage our growth, if any, will require us to continue to train, motivate and manage our employees and to attract, motivate and retain additional qualified personnel. Competition for these types of personnel is intense, and we may not be successful in attracting, assimilating and retaining the personnel required to grow and operate our business profitably.

We have three affiliated stockholders who, together with our board and management, have a 24.4% interest in our company, whose interests may differ from your interests and who will be able to control or substantially influence the outcome of matters voted upon by our stockholders.

At December 31, 2010, Yorktown Energy Partners V, L.P., Yorktown Energy Partners VI, L.P. and Yorktown Energy Partners VII, L.P. (collectively "Yorktown"), which are under common management, beneficially owned approximately 14.6% of our outstanding common stock in the aggregate, together with a Yorktown representative who serves on our board of directors. In addition, our non-Yorktown directors and management team beneficially own or control approximately 9.8% of our common stock outstanding. As a result of this ownership and control, Yorktown, together with our board and management, has the ability to control or substantially influence the vote in any election of directors. Yorktown, together with our board and management, also has control or substantial influence over our decisions to enter into significant corporate transactions and, in their capacity as our majority stockholders, these stockholders may have the ability to effectively block any transactions that they do not believe are in Yorktown's or management's best interest. As a result, Yorktown, together with our board and management, is able to control, directly or indirectly and subject to applicable law, or substantially influence all matters affecting us, including the following:

- any determination with respect to our business direction and policies, including the appointment and removal of officers;
- any determinations with respect to mergers, business combinations or dispositions of assets;
- our capital structure;

- compensation, equity programs and other human resources policy decisions;
- changes to other agreements that may adversely affect us; and
- the payment, or nonpayment, of dividends on our common stock.

Yorktown, together with our board and management, also may have an interest in pursuing transactions that, in their judgment, enhance the value of their respective equity investments in our company, even though those transactions may involve risks to you as a minority stockholder. In addition, circumstances could arise under which their interests could be in conflict with the interests of our other stockholders or you, a minority stockholder. Also, Yorktown and their affiliates have and may in the future make significant investments in other companies, some of which may be competitors. Yorktown and its affiliates are not obligated to advise us of any investment or business opportunities of which they are aware, and they are not restricted or prohibited from competing with us.

We have renounced any interest in specified business opportunities, and certain members of our board of directors and certain of our stockholders generally have no obligation to offer us those opportunities.

In accordance with Delaware law, we have renounced any interest or expectancy in any business opportunity, transaction or other matter in which our outside directors and certain of our stockholders, each referred to as a Designated Party, participates or desires to participate in that involves any aspect of the exploration and production business in the oil and industry. If any such business opportunity is presented to a Designated Party who also serves as a member of our board of directors, the Designated Party has no obligation to communicate or offer that opportunity to us, and the Designated Party may pursue the opportunity as he sees fit, unless:

- it was presented to the Designated Party solely in that person's capacity as a director of our company and with respect to which, at the time of such presentment, no other Designated Party has independently received notice of or otherwise identified the business opportunity; or
- the opportunity was identified by the Designated Party solely through the disclosure of information by or on behalf of us.

As a result of this renunciation, our outside directors should not be deemed to have breached any fiduciary duty to us if they or their affiliates or associates pursue opportunities as described above and our future competitive position and growth potential could be adversely affected.

We are subject to complex governmental laws and regulations that may adversely affect the cost, manner or feasibility of doing business.

Our operations and facilities are subject to extensive federal, state and local laws and regulations relating to the exploration for, and the development, production and transportation of, oil and gas, operating safety and protection of the environment, including those relating to air emissions, wastewater discharges, land use, storage and disposal of wastes and remediation of contaminated soil and groundwater. Future laws or regulations, any adverse changes in the interpretation of existing laws and regulations or our failure to comply with existing legal requirements may harm our business, results of operations and financial condition. We may encounter reductions in reserves or be required to make large and unanticipated capital expenditures to comply with governmental laws and regulations, such as:

- price control;
- taxation;
- lease permit restrictions;
- drilling bonds and other financial responsibility requirements, such as plug and abandonment bonds;
- spacing of wells;
- unitization and pooling of properties;

- safety precautions; and
- permitting requirements.

Under these laws and regulations, we could be liable for:

- personal injuries;
- property and natural resource damages;
- well reclamation costs, soil and groundwater remediation costs; and
- governmental sanctions, such as fines and penalties.

Our operations could be significantly delayed or curtailed, and our cost of operations could significantly increase as a result of environmental safety and other regulatory requirements or restrictions. We are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. We may be unable to obtain all necessary licenses, permits, approvals and certificates for proposed projects. Intricate and changing environmental and other regulatory requirements may require substantial expenditures to obtain and maintain permits. If a project is unable to function as planned, for example, due to costly or changing requirements or local opposition, it may create expensive delays, extended periods of non-operation or significant loss of value in a project. See Item 1. “Business — Regulation.”

Environmental laws and regulations may expose us to significant costs and liabilities.

There is inherent risk of incurring significant environmental costs and liabilities in our oil and gas operations due to the handling of petroleum hydrocarbons and generated wastes, the occurrence of air emissions and water discharges from work-related activities and the legacy of pollution from historical industry operations and waste disposal practices. We may incur joint and several or strict liability under these environmental laws and regulations in connection with spills, leaks or releases of petroleum hydrocarbons and wastes on, under or from our properties and facilities, many of which have been used for exploration, production or development activities for many years, oftentimes by third parties not under our control. Private parties, including the owners of properties upon which we conduct drilling and production activities as well as facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. In addition, changes in environmental laws and regulations occur frequently, and any such changes that result in more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our business, financial condition and results of operations. We may not be able to recover some or any of these costs from insurance. See Item 1., “Business — Regulation.”

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

Both houses of Congress have actively considered legislation to reduce emissions of GHGs, and many states have already taken measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs require either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. These allowances are expected to escalate significantly in cost over time. Any law that may be adopted to restrict or reduce emissions of GHGs could have an adverse effect on demand for the oil and gas that we produce.

In December 2009, the EPA published its findings that GHGs present an endangerment to public health and the environment because emissions of such gasses are, according to the EPA, contributing to the warming of the earth’s atmosphere and other climate changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA has adopted two sets of regulations under the Clean Air Act pertaining to GHGs. The first limits emissions of GHGs from motor vehicles beginning with the 2012 model year. The EPA has asserted that these final motor vehicle GHG emission standards trigger Clean Air Act construction and operating permit requirements for stationary sources, commencing when the motor vehicle standards took effect in January 2011. In June 2010, the EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration ("PSD") and Title V permitting programs. This rule "tailors" these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. It is widely expected that facilities required to obtain PSD permits for their GHG emissions also will be required to reduce those emissions according to "best available control technology" standards for GHGs that have yet to be developed. The EPA's rules and regulations regarding GHGs could have an adverse effect on demand for the oil and gas that we produce.

In December 2010, the EPA enacted final rules on mandatory reporting of GHGs. Under the final rules, owners or operators of facilities that contain petroleum and natural gas systems and emit 25,000 metric tons or more of GHGs per year (expressed as carbon dioxide equivalent or CO_2E) from processing operations, stationary combustion, miscellaneous use of carbonates and other source categories will report GHG emissions from all source categories located at the facility for which emission calculation methods are defined in the rule. Beginning in 2011, operators are required to collect emission data, calculate GHG emissions and follow specified procedures for quality assurance, missing data, recordkeeping and reporting. Our operations in the Permian Basin are subject to the EPA's mandatory reporting rules. As a result, we will be required to incur increased capital and operating costs to monitor and report GHG emissions.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays in our production of oil and gas and lower returns on our capital investments.

Bills were introduced in the previous U.S. Congress to regulate hydraulic fracturing operations and related injection of fracturing fluids and propping agents used in fracturing fluids by the oil and natural gas industry under the federal Safe Drinking Water Act ("SDWA") and to require the disclosure of chemicals used in the hydraulic fracturing process under the SDWA, Emergency Planning and Community Right-to-Know Act ("EPCRA") or other authority. Hydraulic fracturing is an important and commonly used process in the completion of unconventional oil and natural gas wells in shale and tight sand formations. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate oil and natural gas production. We engage third parties to provide hydraulic fracturing or other well stimulation services to us for many of the wells that we drill and operate. Sponsors of such bills have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies, surface waters, and other natural resources, and threaten health and safety. In addition, in March 2010, the EPA announced its intention to conduct a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health and, in February 2011, the EPA issued a draft study plan on hydraulic fracturing. Certain states have also considered or imposed reporting obligations relating to the use of hydraulic fracturing techniques.

Additional legislation or regulation could make it easier for parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. There has also been increasing public controversy regarding hydraulic fracturing with regard to use of fracturing fluids, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated in Texas and other states implicating hydraulic fracturing practices.

Legislation, regulation, litigation and enforcement actions at the federal, state or local level that restrict the provision of hydraulic fracturing services could limit the availability and raise the cost of such services, delay completion of new wells and production of our oil and gas, lower our return on capital expenditures and have a material adverse impact on our business, financial condition, results of operations and cash flows and quantities of oil and gas reserves that may be economically produced.

Changes in tax laws may adversely affect our results of operations and cash flows.

President Obama's Proposed Fiscal Year 2011 and 2012 Budgets include proposed legislation that would, if enacted into law, make significant changes to U.S. tax laws, including the elimination of certain key United States federal income tax incentives currently available to oil and gas exploration and production companies. These changes include, but are not limited to:

- repeal of the percentage depletion allowance for oil and gas properties;
- elimination of current deductions for intangible drilling costs;
- elimination of the domestic manufacturing deduction for oil and gas companies; and
- extension of the amortization period for certain geological and geophysical expenditures.

It is unclear whether any such changes will be enacted or how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or otherwise limit certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively impact our financial condition and results of operations.

The adoption and implementation of new statutory and regulatory requirements for derivative transactions could have an adverse impact on our ability to hedge risks associated with our business.

The U.S. Congress has passed, and the President has signed into law, the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Act"). The Dodd-Frank Act provides for new statutory and regulatory requirements for derivative transactions, including oil and gas hedging transactions. Certain transactions will be required to be cleared on exchanges, and cash collateral will be required for these transactions. The Dodd-Frank Act provides for a potential exception from these clearing and cash collateral requirements for commercial end-users, and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and to the parties to those transactions. The Dodd-Frank Act requires the SEC and the Commodities Futures and Trading Commission ("CFTC") to promulgate rules to define these terms in detail, and in December 2010, the SEC and CFTC proposed such rules.

We enter into financial swaps and options from time to time in order to hedge against commodity price uncertainty and enhance the predictability of cash flows from oil and gas sales. Depending on the rules and definitions ultimately adopted by the SEC and CFTC, we might in the future be required to provide cash collateral for our commodities hedging transactions. Posting of cash collateral could cause significant liquidity issues for us by reducing our ability to use our cash for capital expenditures or other corporate purposes. A requirement to post cash collateral could therefore significantly reduce our ability to execute strategic hedges to reduce commodity price uncertainty and thus protect cash flows.

We are at risk until the SEC and CFTC adopt final rules and definitions that confirm that companies such as ourselves are not required to post cash collateral for our derivative hedging contracts. In addition, even if we are not required to post cash collateral for our derivative contracts, the banks and other derivatives dealers who are our contractual counterparties will be required to comply with the Dodd-Frank Act's new requirements, and the costs of their compliance will likely be passed on to customers such as ourselves, thus decreasing the benefits to us of hedging transactions and reducing our profitability.

Operating hazards, natural disasters or other interruptions of our operations could result in potential liabilities, which may not be fully covered by our insurance.

The oil and gas business involves certain operating hazards such as:

- well blowouts;
- cratering;

- explosions;
- uncontrollable flows of gas, oil or well fluids;
- fires;
- pollution; and
- releases of toxic gas.

The occurrence of one of the above may result in injury, loss of life, suspension of operations, environmental damage and remediation and/or governmental investigations and penalties.

In addition, our operations in Texas are especially susceptible to damage from natural disasters such as tornados and involve increased risks of personal injury, property damage and marketing interruptions. Any of these operating hazards could cause serious injuries, fatalities or property damage, which could expose us to liabilities. The payment of any of these liabilities could reduce, or even eliminate, the funds available for exploration, development and acquisition, or could result in a loss of our properties. Consistent with insurance coverage generally available to the industry, our insurance policies provide limited coverage for losses or liabilities relating to pollution, with broader coverage for sudden and accidental occurrences. Our insurance might be inadequate to cover our liabilities. The insurance market in general and the energy insurance market in particular have been difficult markets over the past several years. Insurance costs are expected to continue to increase over the next few years and we may decrease coverage and retain more risk to mitigate future cost increases. If we incur substantial liability and the damages are not covered by insurance or are in excess of policy limits, or if we incur liability at a time when we are not able to obtain liability insurance, then our business, results of operations and financial condition could be materially adversely affected.

Our results are subject to quarterly and seasonal fluctuations.

Our quarterly operating results have fluctuated in the past and could be negatively impacted in the future as a result of a number of factors, including:

- seasonal variations in oil, NGL and gas prices;
- variations in levels of production; and
- the completion of exploration and production projects.

Market conditions or transportation impediments may hinder our access to oil, NGL and gas markets or delay our production.

Market conditions and the unavailability of satisfactory oil and gas processing and transportation may hinder our access to oil and gas markets or delay our production. Although currently we control the gathering system operations for some of our production in the Permian Basin, we do not have such control over the regional or downstream pipelines in the Permian Basin or in other areas where we operate or expect to conduct operations. The availability of a ready market for our oil, NGL and gas production depends on a number of factors, including the demand for and supply of oil, NGLs and gas and the proximity of reserves to pipelines or trucking and terminal facilities. In addition, the amount of oil, NGLs and gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, ability of downstream processing facilities to accept unprocessed gas, physical damage to the gathering or transportation system or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months, and in many cases we are provided with limited, if any, notice as to when these circumstances will arise and their duration. As a result, we may not be able to sell, or may have to transport by more expensive means, the oil, NGL and gas production from wells or we may be required to shut in oil or gas wells or delay initial production until the necessary gathering and transportation systems are available. Any significant curtailment in gathering system or pipeline capacity, or significant delay in construction of necessary gathering and transportation facilities, could adversely affect our business, financial condition and results of operations.

Our growth strategy could fail or present unanticipated problems for our business in the future, which could adversely affect our ability to make acquisitions or realize anticipated benefits of those acquisitions.

Our growth strategy includes acquiring oil and gas businesses and properties. We may not be able to identify suitable acquisition opportunities or finance and complete any particular acquisition successfully. Furthermore, acquisitions involve a number of risks and challenges, including:

- diversion of management's attention;
- the need to integrate acquired operations;
- potential loss of key employees of the acquired companies;
- potential lack of operating experience in a geographic market of the acquired business; and
- an increase in our expenses and working capital requirements.

Any of these factors could adversely affect our ability to achieve anticipated levels of cash flows from the acquired businesses or realize other anticipated benefits of those acquisitions.

Joint drilling ventures and similar arrangements could expose us to risks.

As the operator in a joint drilling venture, we could be exposed to a risk of loss if a non-operating participant fails to meet its obligations to fund its portion of the drilling and operating costs as agreed under a joint operating or other applicable agreement. In addition, as a non-operator in a joint drilling venture, we could have limited or no ability to influence or control the future development of non-operated properties or the amount of capital expenditures that we are required to fund. The failure of an operator to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interest could reduce our production and revenues and increase our capital expenditures and operating costs. If we are a non-operator, our dependence on an operator and our limited ability to influence or control operations and future development could have a material adverse effect on our business, financial condition and results of operations.

Severe weather could have a material adverse impact on our business.

Our business could be materially and adversely affected by severe weather. Repercussions of severe weather conditions may include:

- curtailment of services;
- weather-related damage to drilling rigs, resulting in suspension of operations;
- weather-related damage to our producing wells or facilities;
- inability to deliver materials to jobsites in accordance with contract schedules; and
- loss of production.

A terrorist attack or armed conflict could harm our business.

Terrorist activities, anti-terrorist efforts and other armed conflict involving the United States may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occurs or escalates, the resulting political instability and societal disruption could reduce overall demand for oil and gas, potentially putting downward pressure on demand for our services and causing a reduction in our revenue. Oil and gas related facilities could be direct targets for terrorist attacks, and our operations could be adversely impacted if significant infrastructure or facilities we use for the production, transportation or marketing of our oil and gas production are destroyed or damaged.

Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become difficult to obtain, if available at all.

Risks Related to Our Financial Condition

We will require additional capital to fund our future activities. If we fail to obtain additional capital, we may not be able to fully implement our business plan, which could lead to a decline in reserves.

We depend on our ability to obtain financing beyond our cash flow from operations. Historically, we have financed our business plan and operations primarily with internally generated cash flows, borrowings under our revolving credit facility and issuances of common stock. We also require capital to fund our exploration and development budget. As of December 31, 2010, approximately 49% of our total estimated proved reserves were proved undeveloped. Recovery of such reserves will require significant capital expenditures and successful drilling operations. According to our year-end 2010 reserve report, the estimated capital required to develop our current proved developed and proved undeveloped oil and gas reserves is $259 million. We will be required to meet our needs from our internally-generated cash flows, debt financings and equity financings.

If our revenues decrease as a result of lower commodity prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. We may, from time to time, need to seek additional financing. Our revolving credit facility contains covenants restricting our ability to incur additional indebtedness without lender consent. There can be no assurance that our bank lenders will provide this consent or as to the availability or terms of any additional financing. If we incur additional debt, the related risks that we now face could intensify.

Even if additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations and available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our projects, which in turn could lead to a possible loss of properties and a decline in our oil and gas reserves.

Our bank lenders can limit our borrowing capabilities, which may materially impact our operations.

At December 31, 2010, we had no outstanding borrowings under our revolving credit facility, and our borrowing base was $150 million. At February 28, 2011, we had $67 million in outstanding borrowings under our revolving credit facility, primarily as a result of financing the $76 million Working Interest Acquisition. The borrowing base under our revolving credit facility is redetermined semi-annually. Redeterminations are based upon information contained in an annual reserves report prepared by an independent petroleum engineering firm and a mid-year report prepared by our own engineers. In addition, as is typical in the oil and gas industry, our bank lenders have substantial flexibility to reduce our borrowing base on the basis of subjective factors. Upon a redetermination, we could be required to repay a portion of our outstanding borrowings, including the amount of all unpaid reimbursement obligations, to the extent such amounts exceed the redetermined borrowing base. We may not have sufficient funds to make such required repayment, which could result in a default under the terms of the revolving credit facility and an acceleration of the loan. We intend to finance our development, exploration and acquisition activities with cash flow from operations, borrowings under our revolving credit facility and other financing activities. In addition, we may significantly alter our capital structure to make future acquisitions or develop our properties. Changes in our capital structure may significantly increase our level of debt. If we incur additional debt for these or other purposes, the related risks that we now face could intensify. A higher debt level also increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of debt depends on our future performance which will be affected by general economic conditions and financial, business and other factors. Many of these factors are beyond our control. Our level of debt affects our operations in several important ways, including the following:

- a portion of our cash flow from operations is used to pay interest on borrowings;

- the covenants contained in the agreements governing our debt limit our ability to borrow additional funds, pay dividends, dispose of assets or issue shares of preferred stock and otherwise may affect our flexibility in planning for, and reacting to, changes in business conditions;
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions or general corporate purposes;
- a leveraged financial position would make us more vulnerable to economic downturns and could limit our ability to withstand competitive pressures; and
- any debt that we incur under our revolving credit facility will be at variable rates which makes us vulnerable to increases in interest rates.

We engage in commodity derivative transactions which involve risks that can harm our business.

To manage our exposure to price risks in the marketing of our gas production, we enter into gas price and basis differential commodity derivative agreements. While intended to reduce the effects of volatile gas prices and basis differentials, such transactions may limit our potential gains and increase our potential losses if gas prices were to rise substantially over the price established by the commodity derivative, or if the basis spread changes substantially from the basis differential established by the commodity derivative. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which our production is less than expected, there is a widening of price differentials between delivery points for our production and the delivery point assumed in the commodity derivative arrangement or the counterparties to the commodity derivative agreements fail to perform under the contracts. In addition, as discussed above in this Item 1A. "Risk Factors," proposed legislation relating to derivatives transactions may restrict our ability to execute transactions to protect against risks of fluctuating commodity prices.

Risks Related to Our Common Stock

The price of our common stock may fluctuate significantly, which could negatively affect us and holders of our common stock.

The trading price of our common stock may fluctuate significantly in response to a number of factors, many of which are beyond our control. For instance, if our financial or operating results, particularly related to the development of our Wolffork play, are below the expectations of securities analysts and investors, the market price of our common stock could decrease significantly. Other factors that may affect the market price of our common stock include:

- announcements relating to significant corporate transactions;
- fluctuations in our quarterly and annual financial or operating results;
- operating and stock price performance of companies that investors deem comparable to us; and
- changes in government regulation or proposals relating to us.

In addition, the U.S. securities markets have recently experienced significant price and volume fluctuations. These fluctuations often have been unrelated to the operating performance of companies in these markets. Market fluctuations and broad market, economic and industry factors may negatively affect the price of our common stock, regardless of our operating performance. Any volatility of or a significant decrease in the market price of our common stock could also negatively affect our ability to make acquisitions using common stock. Further, if we were to be the object of securities class action litigation as a result of volatility in our common stock price or for other reasons, it could result in substantial costs and diversion of our management's attention and resources, which could adversely affect our business financial results and results of operations.

Common stockholders will be diluted if additional shares are issued.

In our initial public offering in November 2007, we sold 8.8 million shares of common stock to repay borrowings outstanding on our revolving credit facility, repurchase 2 million shares of common stock from a selling stockholder and acquire the 30% working interest in Ozona Northeast that we did not already own. In November 2010, we sold 6.6 million shares of common stock. We intend to use proceeds from the 2010 Offering to fund our capital expenditures for the Wolffork oil shale resources play, working interest and leasehold acquisitions in the Permian Basin and general working capital needs. Pending these uses, we used a portion of the proceeds to repay all outstanding borrowings under our revolving credit facility. We may issue additional shares of common stock, preferred stock, depositary shares, warrants, rights, units and debt securities for general corporate purposes, including repayment or refinancing of borrowings, working capital, capital expenditures, investments and acquisitions. We continue to actively seek to expand our business through complementary or strategic acquisitions of assets, and we may issue shares of common stock in connection with those acquisitions. We also issue restricted stock to our executive officers, employees and independent directors as part of their compensation. If we issue additional shares of our common stock in the future, it may have a dilutive effect on our current outstanding stockholders.

Because we have no plans to pay dividends on our common stock, investors must look solely to stock appreciation for a return on their investment in us.

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain all future earnings to fund the development and growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant. Covenants contained in our revolving credit facility restrict the payment of dividends. Investors must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment. Investors seeking cash dividends should not purchase our common stock.

The equity trading markets may be volatile, which could result in losses for our stockholders.

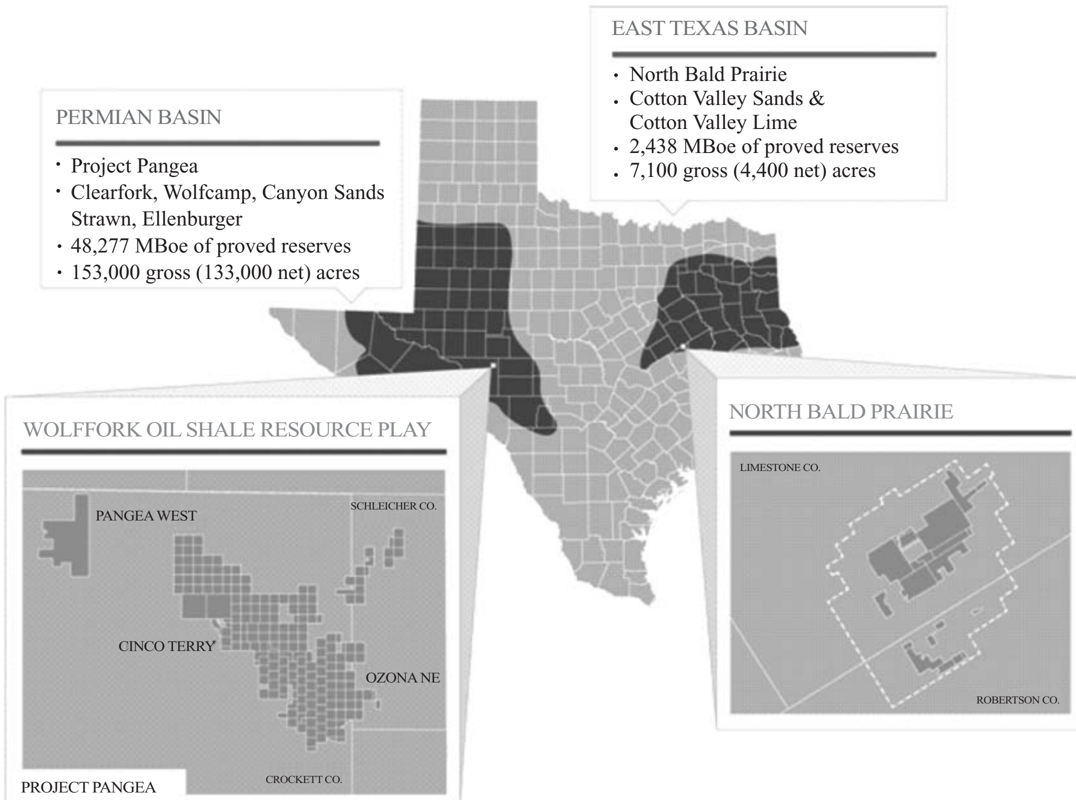
The equity trading markets may experience periods of volatility, which could result in highly variable and unpredictable pricing of equity securities. The market price of our common stock could change in ways that may or may not be related to our business, our industry or our operating performance and financial condition.

Item 1B. *Unresolved Staff Comments.*

As of the date of this filing, we have no unresolved comments from the staff of the SEC.

Item 2. *Properties*

The following map is an overview of our operating areas and the geologic basins where we operated in Texas at March 1, 2011.



The following table is a summary of data for our operating areas for the year ended December 31, 2010.

Operating Area	Average Daily Production (Boe/d)	Total Production (MBoe)	Percentage of Production	Proved Reserves (MBoe)	Percentage of Proved Reserves
Permian Basin	4.2	1,520	98%	48,277	95%
East Texas Basin	0.1	36	2%	2,438	5%
Total	4.3	1,556	100%	50,715	100%

Permian Basin — Project Pangea and Pangea West

Clearfork, Wolfcamp, Canyon Sands, Strawn and Ellenburger

Our properties in the Permian Basin are located in Crockett and Schleicher Counties, Texas. We began operations in the Permian Basin through a farm-in agreement for 27,000 net acres in 2004, and have since increased our total acreage position to approximately 153,000 gross (133,000 net) acres as of March 1, 2011. At December 31, 2010, we owned interests in approximately 548 gross (482.2 net) wells, all of which we operate. As of December 31, 2010, we had working and net revenue interests of approximately 100% and 79%, respectively, in our southeast Permian operations, or Ozona Northeast, and 62% and 47%, respectively, in our northwest Permian operations, or Cinco Terry. At December 31, 2010, our average working and net revenue interests across our Permian operations were approximately 88% and 68%, respectively.

Since we began drilling our Permian Basin properties in 2004, we have primarily produced our reserves from the Canyon Sands, Strawn and Ellenburger formations at depths ranging from 7,250 feet to 8,900 feet. The Canyon Sands were deposited in submarine fan and are tight sandstone reservoirs characterized by low permeability. We use a specialized foamed fracture stimulation treatment to increase permeability, which enhances production rates and well recovery. The Strawn formation is a fractured carbonate reservoir between the Canyon Sands and Ellenburger zones. The Ellenburger formation is a fractured carbonate and dolomite reservoir that does not require a specialized fracture stimulation treatment.

As of December 31, 2010, we had estimated proved reserves of 48.3 MMBoe in the Permian Basin, composed of 53% oil and NGLs and 47% natural gas. Our Permian proved reserves increased 42%, and oil and NGL proved reserves increased 204%, over year-end 2009. Planned processing contributed to the increase in proved reserves at year end 2010. On April 1, 2011, we will begin realizing NGL revenues from the gas stream in Ozona Northeast. Development drilling and planned processing upgrades in Cinco Terry, acquisition of an additional working interest in Cinco Terry and improved pricing also contributed to the increase in proved reserves at December 31, 2010.

During 2010 in the Permian Basin, we incurred $59.8 million to drill 91 gross (56.2 net) wells, of which five gross (3.5 net) wells were waiting on completion at December 31, 2010. At December 31, 2010, we estimate that we had approximately 2,300 drilling locations in inventory, including 311 proved locations in the Permian Basin targeting the Wolffork, Canyon Sands and deeper zones. We also estimate that we had an additional 480 recompletion opportunities in the Permian Basin, targeting the Wolffork zones, none of which were proved.

Wolffork Oil Shale Resource Play

As mentioned above, since we began drilling our Permian Basin properties in 2004, we have primarily produced our reserves from the Canyon Sands, Strawn and Ellenburger formations at depths ranging from 7,250 feet to 8,900 feet. While we targeted these deeper zones, we collected log data, including mud logs that indicate the presence of hydrocarbons in the Clearfork and Wolfcamp Shale formations, or “Wolffork,” above the Canyon Sands, Strawn and Ellenburger zones.

We performed a detailed geological and petrophysical evaluation of the Wolffork formations using logs, 3-D seismic, whole core data and regional mapping. The Wolffork is composed of three stacked pay zones, the Clearfork, Dean and Wolfcamp Shale formations with combined gross pay thickness of approximately 2,500 feet. We believe Wolfcamp Shale is a source rock with significant potential for hydrocarbons, located in the oil-to-wet gas window across our Permian acreage position, and is naturally fractured due to its proximity to the Ouachita-Marathon thrust belt and mineralogy, specifically the carbonate and quartz minerals. The Wolfcamp Shale has gross pay thickness of approximately 1,000 feet across our acreage position. The Clearfork formation across our acreage position is a siltstone, shale and carbonate reservoir approximately 1,400 feet thick. Similarly, the Dean formation, which is approximately 150 feet thick, is a siltstone, shale and carbonate reservoir. The Wolffork formations were deposited across Project Pangea by debris flow and turbidite processes.

We recompleted three wells in the Wolfcamp Shale and drilled one well and commingled production from the Canyon Sands and Wolfcamp Shale, in a four-well, initial pilot program. In addition, in March 2011, we announced results from a second pilot phase with three vertical Canyon/Wolffork wells and two vertical recompletions in the Wolfcamp Shale. We plan to continue our pilot program in 2011 with a combination of vertical, horizontal and recompletion projects.

In February 2011, we acquired an additional 38% working interest in Cinco Terry from two non-operating partners for $76 million, subject to usual and customary post-closing adjustments. The Working Interest Acquisition was funded with cash on hand and borrowings under our revolving credit facility. As a result of the Working Interest Acquisition, our working and net revenue interests in Cinco Terry are 100% and 76%, respectively, and our approximate average working and net revenue interests across our Permian Basin operations are 100% and 78%, respectively.

Our estimated proved reserves at December 31, 2010, do not include estimated proved reserves attributable to our Wolffork oil shale resource play or the Working Interest Acquisition.

East Texas Basin — North Bald Prairie

Cotton Valley Sands and Cotton Valley Lime

In July 2007, we entered into a joint drilling venture with EnCana Oil & Gas (USA) Inc. ("EnCana") in Limestone and Robertson Counties, Texas, in the East Texas Cotton Valley trend. We began drilling operations in August 2007. As of December 31, 2010, we had drilled and completed 11 gross wells, including one well completed as a saltwater disposal well. We have a 50% working interest and approximately 40% net revenue interest in the approximately 7,100 gross (4,400 net) acre project. As of December 31, 2010, we had estimated proved reserves of 14.6 Bcf in North Bald Prairie. Average daily production in 2010 was 0.6 MMcf/d, or a total of 218 MMcf.

Our primary targets in North Bald Prairie are the Cotton Valley Sands and Cotton Valley Lime, and we have identified 23 proved drilling locations as of December 31, 2010. These are all unconventional tight gas formations where we believe we can apply our geological, technical and operational expertise to improve production and recovery rates. Secondary targets include the shallower Rodessa, Pettit and Travis Peak formations.

We currently have no rigs running in North Bald Prairie. As previously reported, in December 2008, EnCana notified us that it was exercising its right to become the operator of record for joint interest wells in North Bald Prairie under the carry and earning agreement between the parties. We have continued to remain the operator of record pending payment by EnCana of joint interest billings owed to us under the joint operating agreement (the "JOA"). In July 2009, our operating subsidiary filed a lawsuit against EnCana for failure to pay joint interest billings under the JOA. This proceeding is described in more detail in Part I, Item 3, "Legal Proceedings," and Note 9 to our consolidated financial statements in this report. The JOA allows either party to propose wells in the drilling project. In addition, we have re-leased or renewed approximately 2,700 net acres in the project at working interests of 100% as such acreage has expired or come up for renewal, and EnCana has elected not to participate in such leases. We will continue to monitor natural gas prices and offset acreage development to determine when to resume drilling in North Bald Prairie.

Northern New Mexico — El Vado East

Mancos Shale

Our El Vado East prospect is an approximately 90,300 gross (79,800 net) acre Mancos Shale play located in the Chama Basin in Northern New Mexico in proximity to several productive fields, including the Puerto Chiquito West, Puerto Chiquito East and Boulder fields. Our primary objective in El Vado East is the Mancos Shale at 2,000 to 3,000 feet. The Mancos Shale is an organic-rich, Upper Cretaceous marine shale. We have a 90% working interest and a net revenue interest of approximately 72% in our El Vado East prospect. At December 31, 2010, we had no proved reserves recorded for El Vado East.

Since Rio Arriba County imposed a moratorium on permits for new oil and gas development on private lands in the County in April 2008, regulatory proceedings and an inability to timely obtain permits have delayed our drilling plans in El Vado East. In May 2009, the County lifted the drilling moratorium and enacted an oil and gas ordinance regulating oil and gas operations on private lands in the County. In addition to obtaining permits to drill from the State of New Mexico, we are now required to obtain special use permits from the County for drilling locations in El Vado East. The "force majeure" provisions of our mineral lease for El Vado East provide that if our drilling operations are delayed or prevented as a result of a governmental or regulatory order or by failure to obtain permits, then our commitments under the lease, including our initial drilling commitment of eight wells, will be extended for the period of force majeure, as long as the primary term of the lease is not extended by more than four years, or April 2013. We have invoked our right to assert force majeure under the lease. See Item 1. "Business — Regulation — New Mexico" for additional information on our New Mexico lease and the delays in drilling in New Mexico.

Southwest Kentucky — Boomerang

New Albany Shale

Our Boomerang prospect is an approximately 67,700 gross (40,400 net) acre New Albany Shale play located in Southwest Kentucky in the Illinois Basin. We have a 60% working interest and a net revenue interest of approximately 50%. Our primary objective in the Boomerang project is the New Albany Shale, at approximately 1,500 feet to 2,000 feet. The New Albany Shale is an organic-rich geologic formation of Devonian and Mississippian age.

We review our long-lived assets to be held and used, including proved and unproved oil and gas properties, accounted for under the successful efforts method of accounting. Based on the review of the recoverability of the carrying value of our unproved properties in Boomerang, we determined that we may not be able to recover costs associated with this project, and therefore have recorded an impairment expense of $2.6 million, related to all of our remaining carrying costs in this project. At December 31, 2010, we had no estimated proved reserves recorded for Boomerang. Acreage amounts in this report exclude Boomerang.

Proved Oil and Gas Reserves

The following table sets forth summary information regarding our estimated proved reserves as of December 31, 2010. See Note 11 to our consolidated financial statements in this report for additional information. Our estimated total proved reserves of oil, NGLs and natural gas as of December 31, 2010, were 50.7 MMBoe, composed of 51% oil, condensate and NGLs and 49% natural gas. The proved developed portion of total proved reserves at year end 2010 was 51%. We determined the barrel of oil equivalent using the ratio of six Mcf of natural gas to one barrel of oil equivalent, and one barrel of NGLs to one barrel of oil equivalent.

Summary of Oil and Gas Reserves as of Fiscal-Year End
Based on Average Fiscal-Year Prices

	Reserves				
Reserves Category	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total (MBoe)	Percent (%)
Proved Developed					
Permian Basin	2,146	11,193	73,208	25,540	50.4%
East Texas Basin	—	—	1,531	255	0.5
Proved Undeveloped					
Permian Basin	2,805	9,506	62,555	22,737	44.8
East Texas Basin	—	—	13,095	2,183	4.3
TOTAL PROVED RESERVES	4,951	20,699	150,389	50,715	100.0%

The following table sets forth our estimated proved reserves, PV-10 and a reconciliation of PV-10 to the Standardized Measure at December 31, 2010. Our reserve estimates and our calculation of Standardized Measure and PV-10 are based on the 12-month average of the first-day-of-the-month pricing of $4.38 per MMBtu Henry Hub spot natural gas price, $79.40 per Bbl West Texas Intermediate posted oil price and

$39.25 per Bbl received for NGLs during 2010. All prices were adjusted for energy content, quality and basis differentials by area and were held constant through the lives of the properties.

	December 31, 2010				
Operating Area	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total (MBoe)	PV-10 (In millions)
Permian Basin	4,951	20,699	135,762	48,277	$ 327.0
East Texas Basin	—	—	14,626	2,438	(1.2)
Total	4,951	20,699	150,388	50,715	$ 325.8
Present value of future income tax discounted at 10%					(121.6)
Standardized measure of discounted future net cash flows					$ 204.2

PV-10 is our estimate of the present value of future net revenues from proved oil and gas reserves after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of future income taxes. PV-10 is a non-GAAP, financial measure and generally differs from the Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future cash flows. PV-10 should not be considered as an alternative to the Standardized Measure as computed under GAAP.

We believe PV-10 to be an important measure for evaluating the relative significance of our oil and gas properties and that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating our company. We believe that most other companies in the oil and gas industry calculate PV-10 on the same basis.

Changes to Proved Reserves

The following table sets forth the changes in our proved reserve volumes by operating area during the year ended December 31, 2010 (in MBoe).

Operating Area	Production	Extensions and Discoveries	Purchases of Minerals in Place	Revisions to Previous Estimates
Permian Basin	(1,520)	3,773	1,958	10,159
East Texas Basin	(36)	—	—	(107)
Total	(1,556)	3,773	1,958	10,052

Production. During 2010, we produced 1,556 MBoe (4.3 MBoe/d). Production volumes of 1,556 MBoe include two months of production from our acquisition of an additional 10% working interest in Cinco Terry from a non-operating partner in October 2010.

Extensions and discoveries. Extensions and discoveries primarily resulted from our development drilling in Cinco Terry and Ozona Northeast.

Purchases of Minerals in Place. Purchases of minerals in place are primarily due to the acquisition of a 10% working interest in Cinco Terry from a non-operating partner.

Revisions to Previous Estimates. Revisions to previous estimates are primarily attributable to 9.2 MMBoe of positive revisions due to planned processing upgrades on April 1, 2011. At that time, we will begin realizing NGL revenues from the gas stream in Ozona Northeast. Revisions to previous estimates also include 1.1 MMBoe of positive revisions resulting from an increase in the prices for oil, gas and NGLs, partially offset by 0.2 MMBoe of negative revisions resulting from performance evaluations of Permian Basin and East Texas Basin wells.

Preparation of Proved Reserves Estimates

Internal Controls Over Preparation of Proved Reserves Estimates

Our policies regarding internal controls over the recording of reserve estimates require reserve estimates to be in compliance with SEC rules, regulations and guidance and prepared in accordance with "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)" promulgated by the Society of Petroleum Engineers ("SPE standards"). Our proved reserves are estimated at the property level and compiled for reporting purposes by our corporate reservoir engineering staff, all of whom are independent of our operations team. We maintain our internal evaluations of our reserves in a secure reserve engineering database. The corporate reservoir engineering staff interacts with our internal staff of operations engineers and geoscience professionals and with accounting employees to obtain the necessary data for the reserves estimation process. Our internal professional staff works closely with our external engineers to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. All of the reserve information maintained in our secure reserve engineering database is provided to the external engineers. In addition, other pertinent data is provided such as seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures and relevant economic criteria. We make available all information requested, including our pertinent personnel, to the external engineers as part of their evaluation of our reserves.

Our Manger of Reservoir Engineering, John J. Marting, P.E., is the individual responsible for overseeing the preparation of our reserve estimates and for internal compliance of our reserve estimates with SEC rules, regulations and SPE standards. Mr. Marting has a Bachelor of Science degree in Petroleum Engineering (Cum Laude) from the University of Missouri-Rolla and over 30 years of industry experience. Mr. Marting reports directly to our Chief Executive Officer. Our senior management, including our Chief Executive Officer and Chief Financial Officer, reviews our reserves estimates before these estimates are finalized and disclosed in a public filing or presentation. Our Chief Executive Officer, J. Ross Craft, P.E., is a licensed Professional Engineer with a Bachelor of Science Degree in Petroleum Engineering from Texas A&M University and over 30 years of industry experience. Our Chief Financial Officer, Steven P. Smart, is a licensed Certified Public Accountant with over 30 years of industry experience.

For the years ended December 31, 2010, 2009, and 2008, we engaged DeGolyer and MacNaughton, independent petroleum engineers, to prepare independent estimates of the extent and value of the proved reserves associated with certain of our oil and gas properties. See *Third Party Reports* below for further information regarding DeGolyer and MacNaughton's report.

Technologies Used in Preparation of Proved Reserves Estimates

Estimates of reserves were prepared in compliance with SEC rules, regulations and guidance and SPE standards. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data and production history.

When applicable, the volumetric method was used to estimate the original oil in place ("OOIP") and the original gas in place ("OGIP"). Structure and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation. When adequate data were available and when circumstances justified, material balance and other engineering methods were used to estimate OOIP or OGIP.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP or OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties and the production histories. When applicable, material balance and other engineering methods were used to estimate recovery factors. An analysis of reservoir performance, including production rate, reservoir pressure and gas-oil ratio behavior, was used in the estimation of reserves.

Because our proved reserves are located in depletion-type reservoirs and reservoirs whose performance demonstrates a reliable decline in producing-rate trends, reserves were also estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-declining curves, reserves were estimated only to the limits of economic production or to the limit of the production licenses or leases as appropriate.

Reporting of Natural Gas Liquids ("NGLs")

We produce NGLs as part of the processing of our natural gas. The extraction of NGLs in the processing of natural gas reduces the volume of natural gas available for sale. At December 31, 2010, NGLs represented approximately 41% of our total proved reserves on a barrel of oil equivalent, or Boe basis. NGLs are products sold by the gallon. In reporting proved reserves and production of NGLs, we include these volumes and production as barrels of oil equivalent. The prices we received for a standard barrel of NGLs in 2010 averaged approximately 46% lower than the average prices for equivalent volumes of oil. We report all production information related to natural gas net of the effect of any reduction in natural gas volumes resulting from the processing of NGLs.

Third Party Reports

For the years ended December 31, 2010, 2009 and 2008, we engaged DeGolyer and MacNaughton, independent, third-party reserves engineers, to prepare estimates of the extent and value of the proved reserves of certain of our oil and gas properties. The estimates for 2010, 2009 and 2008 included a detailed review of 100% of our total reported proved reserves. DeGolyer and MacNaughton's report for 2010 is included as Exhibit 99.1 to this annual report on Form 10-K.

Proved Undeveloped Reserves

As of December 31, 2010, we had 24.9 MMBoe of proved undeveloped reserves ("PUDs"), which is an increase of 4 MMBoe or 19.2%, compared with 20.9 MMBoe of PUDs at December 31, 2009. Approximately 91% of our PUDs at December 31, 2010, were associated with our core development properties in the Permian Basin. The remaining 9% of our PUDs at year-end 2010 were associated with North Bald Prairie in East Texas. As a percent of our total proved reserves, our PUDs decreased from 57% in 2009 to 49% in 2010.

The following table sets forth our PUDs converted to proved developed reserves during 2010 and 2009 and the net investment required to convert PUDs to proved developed reserves during the year (dollars in thousands).

	Proved Undeveloped Reserves Converted to Proved Developed Reserves				Investment in Conversion of Proved Undeveloped Reserves to Proved Developed Reserves
Year Ended December 31,	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total (MBoe)	
2009	52	60	379	175	$ 3,537
2010	531	2,019	12,081	4,564	35,446
Total	583	2,079	12,460	4,739	$38,983

Estimated future development costs relating to the development of PUDs are projected to be approximately $31.2 million in 2011, $36.8 million in 2012 and $82 million in 2013. We monitor fluctuations in commodity prices, drilling and completion costs, operating expenses and drilling success to determine adjustments to our drilling and development program. Based on current expectations for cash flows, commodity prices and operating costs and expenses, all PUDs are scheduled to be drilled before the end of 2015.

We have 3 MMBoe of PUDs, or approximately 6% of our total proved reserves, that have been booked for five years or longer. These reserves are located in Ozona Northeast, where we drilled 15 gross (15 net) wells in 2010 and plan to drill 19 gross (19 net) vertical wells targeting the Wolffork and Canyon Sands in 2011. Despite the continued development drilling in Ozona Northeast in 2010 and 2011, the volume of PUDs in Ozona Northeast that will have been booked for five years or longer at December 31, 2011, may increase from December 31, 2010, and, depending on the timing and selection of locations to be drilled in Ozona Northeast in 2011, such increase might be material. We have a history of significant development activity in Ozona Northeast, as we have drilled over 345 gross (over 335 net) wells there since our first well in February 2004, and we intend to continue the development of PUDs in Ozona Northeast over time.

Oil and Gas Production, Production Prices and Production Costs

The following table sets forth summary information regarding natural gas, oil and NGL production, average sales prices and average production costs for the last three years. We determined the barrel of oil equivalent using the ratio of six Mcf of natural gas to one barrel of oil equivalent, and one barrel of NGLs to one barrel of oil equivalent.

	Years Ended December 31,		
Production	2010	2009	2008
Gas (MMcf)	6,290	6,320	7,092
Oil (MBbls)	246	206	175
NGLs (MBbls)	261	209	102
Total (MBoe)	1,556	1,468	1,459
Total (MBoe/d)	4.3	4.0	4.0
Average prices			
Gas (per Mcf)	$ 4.48	$ 3.70	$ 8.29
Oil (per Bbl)	75.67	54.97	93.79
NGLs (per Bbl)	41.19	28.32	45.46
Total (per Boe)	37.00	27.69	54.74
Realized gain on commodity derivatives (per Boe)	3.72	9.99	2.01
Total including derivative impact (per Boe)	$40.72	$37.68	$56.75
Production costs (per Boe)(1)	$ 4.25	$ 4.20	$ 4.32

(1) Production cost per Boe is composed of lease operating expenses excluding ad valorem taxes. Production cost per Boe also excludes severance and production taxes.

Drilling Activity — Prior Three Years

The following table sets forth information on our drilling activity for the last three years. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value.

	Years Ended December 31,					
	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	91.0	56.2	28.0	16.0	83.0	54.5
Dry	—	—	4.0	2.0	11.0	7.5
Exploratory wells:						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	2.0	0.5
Total wells:						
Productive	91.0	56.2	28.0	16.0	83.0	54.5
Dry	—	—	4.0	2.0	13.0	8.0

Of the 91 gross (56.2 net) productive wells drilled in 2010, five (3.5 net) wells were waiting on completion at December 31, 2010, and have since been completed as producers.

Although a well may be classified as productive upon completion, future changes in oil and gas prices, operating costs and production may result in the well becoming uneconomical.

Drilling Activity — Current

As of the date of this report, we had three rigs running in the Permian Basin targeting the Wolffork and Canyon Sands formations, including one rig drilling horizontal Wolfcamp wells.

Delivery Commitments

We are not committed to provide a fixed and determinable quantity of oil, gas or NGLs in the near future under existing agreements.

Producing Wells

The following table sets forth the number of producing wells in which we owned a working interest at December 31, 2010. Wells are classified as natural gas or oil according to their predominant production stream.

	Natural Gas Wells		Oil Wells		Total Wells		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Permian Basin	524.0	461.1	24.0	21.1	548.0	482.2	88.0%
East Texas Basin	9.0	4.5	—	—	9.0	4.5	50.0%
Total	533.0	465.6	24.0	21.1	557.0	486.7	87.4%

Acreage

The following table summarizes our developed and undeveloped acreage as of December 31, 2010.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Permian Basin	47,819	40,115	93,763	61,751	141,582	101,866
East Texas Basin	3,481	1,687	3,609	2,742	7,090	4,429
El Vado East	—	—	90,357	79,793	90,357	79,793
Total	51,300	41,802	187,729	144,286	239,029	186,088

Undeveloped Acreage Expirations

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2010, that will expire over the next three years by project area unless production is established prior to lease expiration dates.

	2011		2012		2013	
	Gross	Net	Gross	Net	Gross	Net
Permian Basin	20,652	16,734	15,129	7,921	27,021	21,909
East Texas Basin	—	—	282	253	—	—
El Vado East	90,357	79,793	—	—	—	—
Total	111,009	96,527	15,411	8,174	27,021	21,909

Undeveloped acreage in our El Vado East prospect is subject to an eight-well drilling commitment during the primary term of the mineral lease, which expired in April 2009. As of the filing of this annual report on Form 10-K, we had extended the primary term of the lease by force majeure, up to April 2013. If we meet the drilling commitment (as extended by force majeure), we will have two options to extend the primary term by one year each for $15 per net acre, for a total extension of two years at $30 per net acre. If we are not able to meet the drilling commitment during the extended primary term, and we are otherwise not able to negotiate appropriate extensions under the lease, the lease will expire. See Item 1. "Business — Regulation — New Mexico" for additional information on our New Mexico lease and the delays in drilling in New Mexico.

Item 3. ***Legal Proceedings.***

Approach Operating, LLC v. EnCana Oil & Gas (USA) Inc., Cause No. 29.070A, District Court of Limestone County, Texas. On July 2, 2009, our operating subsidiary filed a lawsuit against EnCana for breach of the JOA covering our North Bald Prairie project in East Texas and seeking damages for nonpayment of amounts owed under the JOA as well as declaratory relief. We contend that such amounts owed by EnCana are at least $2 million, plus attorneys' fees, costs and other amounts to which we might be entitled under law or in equity. As we previously have disclosed, in December 2008, EnCana notified us that it was exercising its right to become operator of record for joint interest wells in North Bald Prairie under an operator election agreement between the parties. EnCana contends that it does not owe us for part or all of joint interest billings incurred after EnCana provided us with notice of EnCana's election to assume operatorship in December 2008. EnCana also contends that certain of the disputed operations were unnecessary, while other charges are improper because we failed to obtain EnCana's consent under the JOA prior to undertaking the operations. We have informed the Court that we will transfer operatorship to EnCana when EnCana has made all payments it owes under the JOA. Regardless of the outcome of this proceeding, the JOA provides that either party (operator or non-operator) may propose the drilling of wells.

We also are involved in various other legal and regulatory proceedings arising in the normal course of business. While we cannot predict the outcome of these proceedings with certainty, we do not believe that an adverse result in any pending legal or regulatory proceeding, individually or in the aggregate, would be material to our consolidated financial condition or cash flows; however, an unfavorable outcome could have a material adverse effect on our results of operations for a specific interim period or year.

Item 4. ***(Removed and Reserved).***

PART II

Item 5. ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.***

Market Information

Our common stock is traded on NASDAQ in the United States under the symbol "AREX." During 2010, trading volume averaged 144,977 shares per day. The following table shows the quarterly high and low sale prices of our common stock as reported on NASDAQ for the past two years.

	Price Per Share	
	High	**Low**
2010		
First quarter	$ 9.65	$ 7.57
Second quarter	9.52	6.32
Third quarter	11.81	6.12
Fourth quarter	23.89	11.00
2009		
First quarter	$ 8.90	$ 3.20
Second quarter	10.47	5.13
Third quarter	9.77	6.38
Fourth quarter	10.19	6.24

Holders

As of February 28, 2011, there were 71 record holders of our common stock. In many instances, a record holder is a broker or other entity holding shares in street name for one or more customers who beneficially own the shares.

Dividends

We have not paid any cash dividends on our common stock. We do not expect to pay any cash or other dividends in the foreseeable future on our common stock, as we intend to reinvest cash flow generated by operations in our business. Our revolving credit facility currently restricts our ability to pay cash dividends on our common stock, and we may also enter into credit agreements or other borrowing arrangements in the future that restrict or limit our ability to pay cash dividends on our common stock.

Securities Authorized for Issuance under Equity Compensation Plans

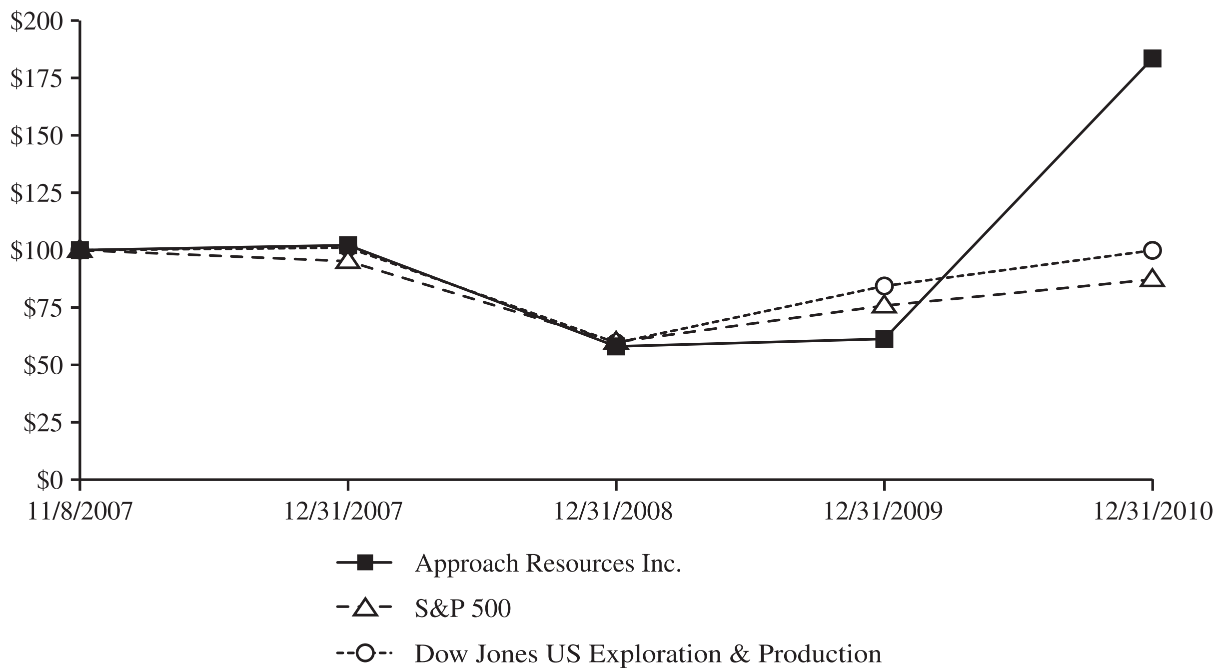
The following table sets forth information regarding securities authorized for issuance under equity compensation plans and individual compensation arrangements as of December 31, 2010.

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))(1) (c)
Equity compensation plans approved by stockholders	334,329	$7.01	691,080
Equity compensation plans not approved by stockholders	—	—	—

(1) Under our 2007 Stock Incentive Plan (the "2007 Plan" or "Plan"), and subject to adjustment for recapitalizations or reorganizations, the maximum number of shares of common stock that may be available for grant of awards under the 2007 Plan is 10% of the outstanding shares of our common stock, as adjusted on the first business day of each calendar year, plus shares of common stock that remain available for grant of awards under our prior plan. After adjustment for 10% of our outstanding shares of common stock on the first business day of 2011 as set forth in the 2007 Plan, we expect the number of shares remaining available for future issuance under the 2007 Plan under column (c) of above table to increase to 1,417,840.

Performance Graph

The following graph compares the cumulative return on a $100 investment in our common stock from November 8, 2007, through December 31, 2010, to that of the cumulative return on a $100 investment in the Standard & Poor's 500 ("S&P 500") index and the Dow Jones U.S. Exploration & Production Total Stock Market index for the same period. In calculating the cumulative return, reinvestment of dividends, if any, is assumed. This graph is not "soliciting material," is not deemed filed with the SEC and is not to be incorporated by reference in any of our filings under the Securities Act or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language in any such filing. This graph is included in accordance with the SEC's disclosure rules. This historic stock performance is not indicative of future stock performance.



	11/8/2007	12/31/2007	12/31/2008	12/31/2009	12/31/2010
Approach Resources Inc.	$100.00	$102.14	$58.06	$61.32	$183.48
S&P 500	100.00	95.15	59.95	75.81	87.23
D J U.S. Exploration & Production	100.00	101.09	59.62	84.37	99.89

Issuer Repurchases of Equity Securities

We adopted the 2007 Plan in June 2007. The 2007 Plan allows us to withhold shares of common stock to pay withholding taxes payable upon vesting of a restricted stock grant. The number of shares of common stock available for grants under the 2007 Plan is increased by the number of shares withheld as payment of such withholding taxes. The following table shows the number of shares of common stock withheld to satisfy the income tax withholding obligations arising upon the vesting of restricted shares issued to employees under the 2007 Plan.

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
October 1, 2010 — October 31, 2010	—	—	—	—
November 1, 2010 — November 30, 2010	3,468	$15.68	—	—
December 1, 2010 — December 31, 2010	—	—	—	—
Total	3,468	$15.68	—	—

Item 6. *Selected Financial Data.*

The following table sets forth selected financial information for the five years ended December 31, 2010. All weighted average shares and per share data have been adjusted for the three-for-one stock split and the stock issuance resulting from the combination of Approach Oil & Gas Inc. under a contribution agreement in November 2007. This information should be read in conjunction with Item 7 of this report, "Management's Discussion and Analysis of Financial Condition and Results of Operations," and our consolidated financial statements, related notes and other financial information included in this report.

	Years Ended December 31,				
	2010	2009	2008	2007	2006
	(In thousands, except per-share data)				
Operating Results Data					
Revenues					
Oil, NGL and gas sales	$ 57,581	$ 40,648	$ 79,869	$ 39,114	$ 46,672
Expenses					
Lease operating	8,555	7,777	7,621	3,815	3,889
Severance and production taxes	2,990	1,996	4,202	1,659	1,736
Exploration	2,589	1,621	1,478	883	1,640
Impairment of unproved properties	2,622	2,964	6,379	267	558
General and administrative	11,422	10,617	8,881	12,667	2,416
Depletion, depreciation and amortization	22,224	24,660	23,710	13,098	14,551
Total expenses	50,402	49,635	52,271	32,389	24,790
Operating income (loss)	7,179	(8,987)	27,598	6,725	21,882
Other					
Impairment of investment	—	—	(917)	—	—
Interest expense, net	(2,189)	(1,787)	(1,269)	(5,219)	(3,814)
Realized gain on commodity derivatives	5,784	14,659	2,936	4,732	6,222
Unrealized gain (loss) on commodity derivatives	788	(9,899)	7,149	(3,637)	8,668
Income (loss) before provision (benefit) for income taxes	11,562	(6,014)	35,497	2,601	32,958
Provision (benefit) for income taxes	4,100	(785)	12,111	(108)	11,756
Net income (loss)	$ 7,462	$ (5,229)	$ 23,386	$ 2,709	$ 21,202
Earnings (loss) per share					
Basic	$ 0.34	$ (0.25)	$ 1.13	$ 0.25	$ 2.26
Diluted	$ 0.34	$ (0.25)	$ 1.12	$ 0.24	$ 2.20
Statement of Cash Flows Data					
Net cash provided by (used in)					
Operating activities	$ 42,377	$ 39,761	$ 56,381	$ 30,746	$ 34,305
Investing activities	(91,346)	(29,553)	(100,633)	(52,940)	(59,384)
Financing activities	69,748	(11,618)	43,750	22,062	26,771
Effect of Canadian exchange rate	1	18	(206)	6	—
Balance Sheet Data					
Cash and cash equivalents	$ 23,465	$ 2,685	$ 4,077	$ 4,785	$ 4,911
Other current assets	17,865	9,318	30,760	12,021	12,792
Property, equipment, net, successful efforts method	369,210	304,483	303,404	230,819	132,520
Other assets	2,549	2,440	—	1,101	86
Total assets	$413,089	$318,926	$ 338,241	$248,726	$150,309
Current liabilities	$ 29,240	$ 21,996	$ 30,775	$ 22,017	$ 15,421
Long-term debt	—	32,319	43,537	—	47,619
Other long-term liabilities	50,903	44,115	40,116	26,890	17,697
Stockholders' equity	332,946	220,496	223,813	199,819	69,572
Total liabilities and stockholders' equity	$413,089	$318,926	$ 338,241	$248,726	$150,309

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations.*

The following discussion is intended to assist in understanding our results of operations and our financial condition. Our consolidated financial statements and the accompanying notes included elsewhere in this report contain additional information that should be referred to when reviewing this material. Statements in this discussion may be forward-looking. These forward-looking statements involve risks and uncertainties, which could cause actual results to differ from those expressed. See "Cautionary Statement Regarding Forward-Looking Statements" at the beginning of this report and "Risk Factors" in Item 1.A for additional discussion of some of these factors and risks.

Overview

Approach Resources Inc. is an independent energy company engaged in the exploration, development, production and acquisition of oil and gas properties. We focus on oil and natural gas reserves in oil shale and tight sands. Our management and technical team has a proven track record of finding and developing reservoirs through advanced completion, fracturing and drilling techniques. Our core properties are primarily located in the Permian Basin in West Texas (Clearfork, Wolfcamp Shale, Canyon Sands, Strawn and Ellenburger). We also own interests in the East Texas Basin (Cotton Valley Sands and Cotton Valley Lime) and in the Chama Basin in Northern New Mexico (Mancos Shale). As the operator of all of our estimated proved reserves and production, we have a high degree of control over capital expenditures and other operating matters.

At December 31, 2010, we had estimated proved oil and gas reserves of 50.7 MMBoe. Important characteristics of our proved reserves at December 31, 2010, include:

- 51% oil and NGLs and 49% natural gas;
- 51% proved developed;
- 100% operated;
- Reserve life of over 30 years based on 2010 production of 1.6 MMBoe;
- Standardized after-tax measure of discounted future net cash flows ("Standardized Measure") of $204.2 million; and
- PV-10 of $325.8 million.

PV-10 is our estimate of the present value of future net revenues from proved oil and gas reserves after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates for future income taxes. Estimated future net revenues are discounted at an annual rate of 10% to determine their present value. PV-10 is a non-GAAP, financial measure and generally differs from the Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future cash flows. PV-10 should not be considered as an alternative to the Standardized Measure as computed under GAAP. See Item 2. "Properties — Proved Oil and Gas Reserves" for a reconciliation of PV-10 to the Standardized Measure.

Over 95% of our proved reserves and production at December 31, 2010, were located in the Permian Basin in Crockett and Schleicher Counties, Texas, where we owned working interests in 548 producing oil and gas wells. At December 31, 2010, we leased approximately 102,000 net acres in the Permian Basin. No proved reserves had been recorded for our Wolffork oil shale resource play in the Permian Basin as of December 31, 2010. In addition to our producing wells, we had an estimated 2,300 potential drilling locations in the Permian Basin at December 31, 2010, of which 311 were proved. We also had an estimated 480 potential Wolffork recompletion opportunities in the Permian Basin, none of which were proved. We owned working interests in nine producing gas wells in the East Texas Basin, and have identified 23 proved drilling locations in the East Texas Basin at December 31, 2010.

2010 Activity

During 2010, we drilled a total of 91 gross (56.2 net) wells in the Permian Basin with a 100% success rate. Production for 2010 totaled 1,556 MBoe (4.3 MBoe/d), compared to 1,468 MBoe (4 MBoe/d) in 2009, a 6% increase. Our costs incurred in 2010 totaled $90 million, and included $59.8 million for exploration and development drilling, $21.2 million, net of purchase price adjustments, for the purchase of an additional working interest in Cinco Terry and $9 million for acreage acquisitions in the Permian Basin. Additional highlights for 2010 include:

Wolffork Oil Shale Resource Play

We were founded in 2002 to explore and develop unconventional oil and gas reservoirs at a competitive cost structure. In 2004, we began to assemble underdeveloped acreage in the Permian Basin and began a drilling program targeting the Canyon Sands, Strawn and Ellenburger formations in 27,000 net acres. Since 2004, we have drilled approximately 525 wells in the Permian Basin and, as of March 1, 2011, we leased approximately 133,000 net acres in the Permian Basin. For a majority of our wells, we collected more log data, including mud logs that help identify hydrocarbon-bearing formations, than, based on our operating experience in the area, we believe is typical for the area where we operate. The log data indicated that hydrocarbons were present in the Clearfork and Wolfcamp Shale formations above the Canyon Sands, Strawn and Ellenburger zones.

In October 2010, we announced our Wolffork oil shale resource play. We performed a detailed geological and petrophysical evaluation using extensive regional mapping, 3-D seismic data from over 135,000 acres, whole-core data and well data from over 400 wellbores that we have drilled and completed while targeting the Canyon Sands, Strawn and Ellenburger zones at depths of 7,250 to 8,900 feet. The Wolffork is composed of three stacked pay zones, the Clearfork, Dean and Wolfcamp Shale formations, totaling more than 2,500 feet of potential gross pay. We believe that the Wolffork oil shale resource play will significantly enhance our opportunities in the Permian Basin, and we plan to continue our pilot program targeting the Wolffork in 2011 with a combination of vertical, horizontal and recompletion projects.

Acquisition of Acreage

We acquired approximately 41,500 gross (34,800 net) acres in the Permian Basin in Crockett and Schleicher Counties, Texas, during 2010. The acreage acquisitions joined our legacy asset in the southeast part of Project Pangea, Ozona Northeast, to Cinco Terry, in the northwest part of Project Pangea.

2010 Acquisition of Working Interest

In October 2010, we acquired a 10% working interest in Cinco Terry from a non-operating partner for $21.2 million, net of purchase price adjustments, which was funded with borrowings under our revolving credit facility. We believe the acquisition of additional interests in Cinco Terry increases our opportunities in this area and enhances our leverage to the reserve potential of the Wolffork oil shale resource play.

Proved Reserve and Production Growth

In 2010, our estimated proved reserves increased 39%, or 14.2 MMBoe, to 50.7 MMBoe from 36.5 MMBoe, and our production increased 6% to 4.3 MBoe/d. Planned processing upgrades contributed to the increase in proved reserves at year end 2010. On April 1, 2011, we will begin realizing NGL revenues from the liquids-rich gas stream in Ozona Northeast under a gas purchase and processing contract with DCP Midstream, LP. See Item 1. "Business — Markets and Customers." Development drilling and planned processing upgrades in Cinco Terry, the acquisition of an additional working interest in Cinco Terry and improved pricing also contributed to the increase in proved reserves at December 31, 2010. The increase in production is attributable to our drilling program in the Permian Basin during 2010. On average, we operated three rigs in 2010, and drilled a total of 91 gross (56.2 net) wells, with a 100% success rate.

Balanced Reserve Profile

Our proved reserve profile at year end 2010 was 51% oil and NGLs and 49% natural gas, compared to 23% oil and NGLs and 77% natural gas at year end 2009. During 2010, our proved oil and NGL reserves increased over 200%, or 17.2 MMBbls, to 25.6 MMBbls from 8.4 MMBbls in 2009. Our increase in proved oil and NGL reserves is primarily due to planned processing upgrades in Ozona Northeast. On April 1, 2011, we will begin realizing NGL revenues from the liquids-rich gas stream in Ozona Northeast.

2010 Equity Offering

In November 2010, we completed an equity offering and issued an aggregate of 6.6 million shares of our common stock at $16.25 per share in an underwritten public offering (the "2010 Offering"). After deducting underwriting discounts and transaction costs of approximately $5.7 million, we received net proceeds of approximately $101.8 million, which we intend to use to fund our capital expenditures for the Wolffork oil shale resource play, working interest and leasehold acquisitions in the Permian Basin and general working capital needs. Pending these uses, we used a portion of the proceeds of the 2010 Offering to repay all outstanding borrowings under our revolving credit facility.

Additional Working Interest Acquisition — 2011

In February 2011, we acquired a 38% working interest in Cinco Terry from two non-operating partners for $76 million, subject to usual and customary post-closing adjustments (the "Working Interest Acquisition"). The Working Interest Acquisition was funded with cash on hand and borrowings under our revolving credit facility. As a result of the Working Interest Acquisition, our working and net revenue interests in Cinco Terry are now approximately 100% and 76%, respectively. Our 2010 results of operations do not include production, revenues or costs from the Working Interest Acquisition. Further, our year-end 2010 estimated proved reserves, PV-10 and Standardized Measure do not include estimated proved reserves associated with the Working Interest Acquisition.

Plans for 2011

In November 2010, we announced a 2011 capital budget of approximately $100 million. In January 2011, we acquired approximately 10,900 contiguous, net acres approximately nine miles west of our existing acreage in northeast Crockett County, Texas. In addition, in March 2011, we announced the Working Interest Acquisition for $76 million. Given our recent activity, in March 2011 we increased our capital budget to $220 million, of which approximately $130 million will be allocated to drilling and recompletion projects in the Permian Basin and approximately $90 million will be allocated to the Working Interest Acquisition and lease extensions, renewals and lease acquisitions in the Permian Basin.

The 2011 drilling program includes operating one rig to drill 11 gross (11 net) horizontal wells targeting the Wolfcamp Shale, one rig to drill 19 gross (19 net) vertical wells targeting the Wolffork and Canyon Sands, one rig to drill 26 gross (26 net) vertical wells targeting the Canyon Sands (which we expect to recomplete in the Wolffork in 2012) and one workover rig to recomplete 10 gross (10 net) wells in the Wolffork. Our objectives for the 2011 drilling program include delineating the Clearfork and Wolfcamp Shale zones across Project Pangea, improving initial production rates by refining our stimulation strategy, advancing our understanding of optimal well spacing and hydrocarbon recovery and improving our cost structure.

Our 2011 capital budget is subject to change depending upon a number of factors, including additional data on our Wolffork oil shale resource play, results of Wolfcamp Shale and Wolffork drilling and recompletions, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil, gas and NGLs, the availability of sufficient capital resources for drilling prospects, our financial results and the availability of lease extensions and renewals on reasonable terms.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting policies generally accepted in the United States ("GAAP"). The preparation of our consolidated financial statements requires us to make estimates and assumptions that affect our reported results of operations and the amount of reported assets, liabilities and proved oil and gas reserves. Some accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. Actual results may differ from the estimates and assumptions used in the preparation of our consolidated financial statements. Described below are the most significant policies we apply in preparing our consolidated financial statements, some of which are subject to alternative treatments under GAAP. We also describe the most significant estimates and assumptions we make in applying these policies. See Note 1 to our consolidated financial statements.

Segment reporting is not applicable to us as we have a single, company-wide management team that administers all properties as a whole rather than by discrete operating segments. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis. We use the successful efforts method of accounting for our oil and gas activities.

Successful Efforts Method of Accounting

Accounting for oil and gas activities is subject to special, unique rules. We use the successful efforts method of accounting for our oil and gas activities. The significant principles for this method are:

- geological and geophysical evaluation costs are expensed as incurred;
- dry holes for exploratory wells are expensed, and dry holes for development wells are capitalized; and
- capitalized costs related to proved oil and gas properties, including wells and related equipment and facilities, are evaluated for impairment based on an analysis of undiscounted future net cash flows in accordance with ASC 360. If undiscounted cash flows are insufficient to recover the net capitalized costs related to proved properties, then we recognize an impairment charge in income from operations equal to the difference between the net capitalized costs related to proved properties and their estimated fair values based on the present value of the related future net cash flows. We noted no impairment of our proved properties based on our analysis for the years ended December 31, 2010, 2009 or 2008.

Proved Reserves

On December 31, 2008, the SEC released a Final Rule, *Modernization of Oil and Gas Reporting* (the "Final Rule"), approving revisions designed to modernize oil and gas reserve reporting requirements. The Final Rule became effective for our financial statements for the year ended December 31, 2009, and our 2009 year-end proved reserve estimates. The most significant revisions to the reporting requirements included:

- *Commodity prices.* Economic producibility of reserves is based on the unweighted, arithmetic average of the closing price on the first day of the month for the 12-month period prior to fiscal year end, unless prices are defined by contractual arrangements.
- *Undeveloped oil and gas reserves.* Reserves may be classified as "proved undeveloped" for undrilled areas beyond one offsetting drilling unit from a producing well if there is reasonable certainty that the quantities will be recovered.
- *Reliable technology.* The Final Rule permits the use of new technologies to establish the reasonable certainty of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes.
- *Unproved reserves.* Probable and possible reserves may be disclosed separately on a voluntary basis.
- *Preparation of reserves estimates.* Disclosure is required regarding the internal controls used to assure objectivity in the reserves estimation process and the qualifications of the technical person primarily responsible for preparing reserves estimates.
- *Third party reports.* We are required to file the report of any third party used to prepare or audit reserves our estimates.

In addition, in January 2010, the Financial Accounting Standards Board issued Accounting Standards Update 2010-03, "Oil and Gas Reserve Estimation and Disclosures" (the "Update") to provide consistency with the new reserve rules. The Update amends existing standards to align the reserves calculation and disclosure requirements under GAAP with the requirements in the SEC's reserve rules. We adopted the new standards effective December 31, 2009.

For the year ended December 31, 2010, we engaged DeGolyer and MacNaughton, independent petroleum engineers, to prepare independent estimates of the extent and value of the proved reserves associated with certain of our oil and gas properties in accordance with guidelines established by the SEC, including the Final Rule.

Estimates of proved oil and gas reserves directly impact financial accounting estimates including depletion, depreciation and amortization expense, evaluation of impairment of properties and the calculation of plugging and abandonment liabilities. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible — from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. The data for any reservoir may change substantially over time due to results from operational activity. Proved reserve volumes at December 31, 2010, were estimated based on the average of the closing price on the first day of each month for the 12-month period prior to December 31, 2010, for oil, natural gas and NGLs in accordance with the Final Rule. Changes in commodity prices and operations costs may increase or decrease estimates of proved oil, NGL and natural gas reserves. Depletion expense for our oil and gas properties is determined using our estimates of proved oil, NGL and natural gas reserves. A hypothetical 10% decline in our December 31, 2010, estimated proved reserves would have increased our depletion expense by approximately $587,000 for the year ended December 31, 2010.

See also Item 2. "Properties — Proved Oil and Gas Reserves" and Note 11 to our consolidated financial statements in this report for additional information regarding our estimated proved reserves.

Derivative Instruments and Commodity Derivative Activities

Unrealized gains and losses, at fair value, are included on our consolidated balance sheets as current or non-current assets or liabilities based on the anticipated timing of cash settlements under the related contracts. Changes in the fair value of our commodity derivative contracts are recorded in earnings as they occur and included in other income (expense) on our consolidated statements of operations. We estimate the fair values of swap contracts based on the present value of the difference in exchange-quoted forward price curves and contractual settlement prices multiplied by notional quantities. We internally valued the option contracts using industry-standard option pricing models and observable market inputs. We use our internal valuations to determine the fair values of the contracts that are reflected on our consolidated balance sheets. Realized gains and losses are also included in other income (expense) on our consolidated statements of operations.

We are exposed to credit losses in the event of nonperformance by the counterparties on our commodity derivatives positions and have considered the exposure in our internal valuations. However, we do not anticipate nonperformance by the counterparties over the term of the commodity derivatives positions.

Changes in the derivative's fair value are currently recognized in the statement of operations unless specific commodity derivative hedge accounting criteria are met and such strategies are designated. For qualifying cash-flow commodity derivatives, the gain or loss on the derivative is deferred in accumulated other comprehensive income to the extent the commodity derivative is effective. The ineffective portion of the commodity derivative is recognized immediately in the statement of operations. Gains and losses on commodity derivative instruments included in accumulated other comprehensive income are reclassified to oil and gas sales revenue in the period that the related production is delivered. Derivative contracts that do not qualify for commodity derivative accounting treatment are recorded as derivative assets and liabilities at fair value in the balance sheet, and the associated unrealized gains and losses are recorded as current income or expense in the statement of operations.

Historically, we have not designated our derivative instruments as cash-flow hedges. We record our open derivative instruments at fair value on our consolidated balance sheets as either unrealized gains or losses on commodity derivatives. We record changes in such fair value in earnings on our consolidated statements of operations under the caption entitled "unrealized gain (loss) on commodity derivatives."

Although we have not designated our derivative instruments as cash-flow hedges, we use those instruments to reduce our exposure to fluctuations in commodity prices related to our oil and gas production. Accordingly, we record realized gains and losses under those instruments in other revenues on our consolidated statements of operations. For the years ended December 31, 2010 and 2008, we recognized an unrealized gain of $788,000 and $7.1 million, respectively, from the change in the fair value of commodity derivatives. For the year ended December 31, 2009, we recognized an unrealized loss of $9.9 million from the change in the fair value of commodity derivatives. A hypothetical 10% increase in the NYMEX floating prices would have resulted in a $1.8 million decrease in the December 31, 2010, fair value recorded on our balance sheet, and a corresponding increase to the loss on commodity derivatives in our statement of operations.

Asset Retirement Obligation

Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives, in accordance with applicable federal, state and local laws. We determine our asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The retirement obligation is recorded as a liability at its estimated present value as of the asset's inception, with an offsetting increase to proved properties. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement.

Our liability is determined using significant assumptions, including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive lives of wells and our risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation.

Impairment of Long-Lived Assets

All of our long-lived assets are monitored for potential impairment when circumstances indicate that the carrying value of an asset may be greater than its future net cash flows. The evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for oil, gas and NGLs, future costs to produce these products, estimates of future oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates and other factors. The need to test an asset for impairment may result from significant declines in commodity prices or downward revisions to estimated quantities of oil and gas reserves. Any assets held for sale are reviewed for impairment when we approve the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges will be recorded. Based on the review of the recoverability of the carrying value of our unproved properties in our Boomerang project in Southwest Kentucky, we determined that we may not be able to recover costs associated with this project, and therefore have recorded impairment expense of $2.6 million, related to all of our remaining carrying costs in this project. At December 31, 2010, we had no estimated proved reserves recorded for Boomerang. Acreage amounts in this report exclude Boomerang.

Valuation of Share-Based Compensation

Our 2007 Plan allows grants of stock and options to employees and outside directors. Granting of awards may increase our general and administrative expenses subject to the size and timing of the grants. See Note 5 to our consolidated financial statements.

We measure and record compensation expense for all share-based payment awards to employees and outside directors based on estimated grant-date fair values. Compensation costs for awards granted are recognized over the requisite service period based on the grant-date fair value.

There were no stock option grants during the years ended December 31, 2010 and 2009. The fair value of each option granted during the year ended December 31, 2008, was estimated using an option-pricing model with the following weighted average assumptions.

	2008
Expected dividends	—
Expected volatility	64%
Risk-free interest rate	2.7%
Expected life	6 years

We have not paid out dividends historically, thus the dividend yields are estimated at zero percent.

Since our shares were not publicly traded prior to our initial public offering on November 8, 2007, we used an average of historical volatility rates based upon other companies within our industry. Management believes that these average historical volatility rates were the best available indicator of expected volatility.

The risk-free interest rate is the implied yield available for zero-coupon U.S. government issues with a remaining term of five years.

The expected lives of our options are determined based on the term of the option using the simplified method outlined in Staff Accounting Bulletin 110.

Assumptions are reviewed each time there is a new grant and may be impacted by actual fluctuation in our stock price, movements in market interest rates and option terms. The use of different assumptions produces a different fair value for the options granted or modified and impacts the amount of compensation expense recognized on the consolidated statement of operations.

Effects of Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2010, 2009 or 2008. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and may increase the cost to acquire or replace property, plant and equipment. It may also increase the cost of labor or supplies.

Results of Operations

The following table sets forth summary information regarding natural gas, oil and NGL revenues, production, average product prices and average production costs and expenses for the last three years. We determined the barrel of oil equivalent using the ratio of six Mcf of natural gas to one barrel of oil equivalent, and one barrel of NGLs to one barrel of oil equivalent.

	Years Ended December 31,		
	2010	2009	2008
Revenues (in thousands)			
Gas	$28,176	$23,406	$58,819
Oil	18,640	11,323	16,413
NGLs	10,765	5,919	4,637
Total oil, NGL and gas sales	57,581	40,648	79,869
Realized gain on commodity derivatives	5,784	14,659	2,936
Total oil, NGL and gas sales including derivative impact	$63,365	$55,307	$82,805
Production			
Gas (MMcf)	6,290	6,320	7,092
Oil (MBbls)	246	206	175
NGLs (MBbls)	261	209	102
Total (MBoe)	1,556	1,468	1,459
Total (MBoe/d)	4.3	4.0	4.0
Average prices			
Gas (per Mcf)	$ 4.48	$ 3.70	$ 8.29
Oil (per Bbl)	75.67	54.97	93.79
NGLs (per Bbl)	41.19	28.32	45.46
Total (per Boe)	37.00	27.69	54.74
Realized gain on commodity derivatives (per Boe)	3.72	9.99	2.01
Total including derivative impact (per Boe)	$ 40.72	$ 37.68	$ 56.75
Costs and expenses (per Boe)			
Lease operating(1)	$ 5.50	$ 5.30	$ 5.22
Severance and production taxes	1.92	1.36	2.88
Exploration	1.66	1.10	1.01
Impairment of unproved properties	1.68	2.02	4.37
General and administrative	7.34	7.23	6.09
Depletion, depreciation and amortization	14.28	16.80	16.25

(1) Lease operating expenses per Boe include ad valorem taxes.

Oil, NGL and gas sales. Oil, NGL and gas sales increased $16.9 million, or 42%, in 2010 to $57.6 million from $40.6 million in 2009. Of the $16.9 million increase in oil, NGL and gas sales in 2010, approximately $11.9 million was attributable to an increase in prices we received for our natural gas, oil and NGL production, and approximately $5 million was attributable to an increase in production volumes. In 2010, the average price we received for our production, before the effect of commodity derivatives, increased to $37.00 per Boe from $27.69 per Boe, or a 34% increase. Subject to commodity prices, we expect oil, NGL and gas sales to increase in 2011 due to increased production volumes from our drilling program in the Permian Basin, the Working Interest Acquisition and realization of NGL revenues in Ozona Northeast.

Oil, NGL and gas sales decreased $39.2 million, or 49.2%, in 2009 to $40.6 million from $79.9 million in 2008. The decrease in oil, NGL and gas sales principally resulted from sharp decreases in the price we received for our natural gas, oil and NGL production. The average price we received for our production, before the effect of commodity derivatives, decreased to $27.69 per Boe from $54.74 per Boe, or a 49.4% decrease. Of the $39.2 million decrease in oil, NGL and gas sales, approximately $41.1 million was attributable to a decrease in oil, NGL and gas prices, partially offset by $1.9 million in oil, NGL and gas sales attributable to a slight increase in production volumes over the prior year. The following table summarizes our oil, NGL and gas sales for each of the last three years (in thousands).

	Years Ended December 31,		
Revenues	**2010**	**2009**	**2008**
Gas	$28,176	$23,406	$58,819
Oil	18,640	11,323	16,413
NGLs	10,765	5,919	4,637
Total oil, NGL and gas sales	57,581	40,648	79,869
Realized gain on commodity derivatives	5,784	14,659	2,936
Total oil, NGL and gas sales including derivative impact	$63,365	$55,307	$82,805

Oil, NGL and gas production. Production for 2010 totaled 1,556 MBoe (4.3 MBoe/d), compared to 1,468 MBoe (4 MBoe/d) in 2009, a 6% increase. Oil and NGL production for 2010 increased 22% to 507 MBbls, compared to 415 MBbls produced in 2009. Production for 2010 was 67% natural gas and 33% oil and NGLs, compared to 72% natural gas and 28% oil and NGLs in 2009. Production volumes for 2010 increased as a result of our ongoing development activities in the Permian Basin, partially offset by the natural decline of our production. We expect production to materially increase in 2011 due to the Working Interest Acquisition and our expected drilling program in the Permian Basin. Production for 2009 totaled 1,468 MBoe (4 MBoe/d), compared to 1,459 MBoe (4 MBoe/d) in 2008. Production for 2009 was 72% natural gas and 28% oil and NGLs, compared to 81% natural gas and 19% oil and NGLs for 2008. The following table summarizes our production for each of the last three years.

	Years Ended December 31,		
Production	**2010**	**2009**	**2008**
Gas (MMcf)	6,290	6,320	7,092
Oil (MBbls)	246	206	175
NGLs (MBbls)	261	209	102
Total (MBoe)	1,556	1,468	1,459
Total (MBoe/d)	4.3	4.0	4.0

Commodity derivative activities. Realized gains from our commodity derivative activity increased our earnings by $5.8 million, $14.7 million and $2.9 million for 2010, 2009 and 2008, respectively. Realized gains and losses are derived from the relative movement of gas prices in relation to the fixed notional pricing of our commodity derivatives positions or the range of prices in our collars for the respective years. The unrealized gain on commodity derivatives was $788,000 and $7.1 million for 2010 and 2008, respectively, and the unrealized loss on commodity derivatives was $9.9 million for 2009. As natural gas commodity prices increase or decrease, the fair value of the open portion of those positions decreases or increases. The unrealized loss for 2009 primarily resulted from the settlement of derivative contracts which were outstanding at December 31, 2008.

Historically, we have not designated our derivative instruments as cash-flow hedges. We record our open derivative instruments at fair value on our consolidated balance sheets as either unrealized gains or losses on commodity derivatives. We record changes in such fair value in earnings on our consolidated statements of operations under the caption entitled “unrealized gain (loss) on commodity derivatives.” The following table summarizes the prices we received for gas, oil and NGLs for each of the last three years.

Average prices	Years Ended December 31, 2010	2009	2008
Gas (per Mcf)	$ 4.48	$ 3.70	$ 8.29
Oil (per Bbl)	75.67	54.97	93.79
NGLs (per Bbl)	41.19	28.32	45.46
Total (per Boe)	37.00	27.69	54.74
Realized gain on commodity derivatives (per Boe)	3.72	9.99	2.01
Total including derivative impact (per Boe)	$40.72	$37.68	$56.75

Lease operating expense. Our lease operating expense (“LOE”) for 2010 was $8.6 million ($5.50 per Boe), compared to $7.8 million ($5.30 per Boe) for 2009. The increase in LOE per Boe over the prior year period was primarily due to an increase in water hauling and insurance and ad valorem taxes, partially offset by a decrease in compressor rental and repair over the prior year period. Compressor related expenses declined due to the release of a rental amine plant during the second half of 2009 and lower negotiated compressor rentals. Ad valorem taxes and water hauling, insurance and other LOE increased as a result of an increase in the number of wells from our continued development in the Permian Basin. For 2011, we expect LOE per BOE to be relatively consistent despite higher service costs, which we expect will be partially offset by increased production volumes.

LOE increased $156,000, or 2%, for 2009 to $7.8 million ($5.30 per Boe) from $7.6 million ($5.22 per Boe) for 2008. Increases in ad valorem taxes and pumpers and supervision costs were partially offset by decreases in well repair and maintenance and workover costs. Following is a summary of lease operating expenses (per Boe):

	Year Ended December 31,				Year Ended December 31,			
	2010	2009	Change	% Change	2009	2008	Change	% Change
Compressor rental and repair	$1.45	$1.62	$(0.17)	(10.5)%	$1.62	$1.66	$(0.04)	(2.4)%
Ad valorem taxes	1.24	1.20	0.04	3.3	1.20	0.82	0.38	46.3
Water hauling, insurance and other	1.16	0.86	0.30	34.9	0.86	0.85	0.01	1.2
Pumpers and supervision	1.01	1.00	0.01	1.0	1.00	0.86	0.14	16.3
Well repair and maintenance	0.54	0.56	(0.02)	(3.6)	0.56	0.80	(0.24)	(30.0)
Workovers	0.10	0.06	0.04	66.7	0.06	0.23	(0.17)	(73.9)
Total	$5.50	$5.30	$ 0.20	3.8%	$5.30	$5.22	$ 0.08	1.5%

Severance and production taxes. Our severance and production taxes increased $1 million, or 50%, for 2010 to $3 million from $2 million for 2009. The increase in severance and production taxes was primarily a function of the increase in oil, NGL and gas sales between 2010 and 2009. Severance and production taxes amounted to approximately 5.2% and 4.9% of oil, NGL and gas sales for the respective periods. For 2011, we expect severance and production taxes as a percent of oil, NGL and gas sales will remain relatively consistent compared to the severance and production taxes for 2010.

In 2009, our severance and production taxes decreased $2.2 million, or 52.5%, for 2009 to $2 million from $4.2 million for 2008. The decrease in production taxes was a function of the decrease in oil, NGL and gas sales between 2009 and 2008. Severance and production taxes amounted to approximately 4.9% and 5.3% of oil, NGL and gas sales for 2009 and 2008, respectively.

Exploration expense. We recorded $2.6 million and $1.6 million of exploration expense for 2010 and 2009, respectively. Exploration expense for 2010 resulted primarily from 3-D seismic acquisition in Cinco Terry and lease renewals in Ozona Northeast, Cinco Terry and Kentucky. Exploration expense for the 2009 period resulted primarily from the expiration of leases for approximately 2,300 net acres in Ozona Northeast and Cinco Terry. We also recorded $1.5 million of exploration expense for 2008. Exploration expense for 2008 resulted from one dry hole drilled in Ozona Northeast and $965,000 of lease extensions in Ozona Northeast.

Impairment of unproved properties. We review our long-lived assets to be held and used, including proved and unproved oil and gas properties accounted for under the successful efforts method of accounting. As a result of this review of the recoverability of the carrying value of our assets, we recorded an impairment of unproved oil and gas properties of $2.6 million, $3 million and $6.4 million in 2010, 2009 and 2008, respectively. The 2010 impairment resulted from a write-off of $2.6 million in costs in our Boomerang project, and represented the remaining carrying value we had recorded for the project. The 2009 impairment resulted from a write-off of $3 million in costs in Northeast British Columbia, and represented the remaining carrying value we had recorded for the project. The 2008 impairment resulted from a write-off of $2.3 million of drilling costs incurred for three test wells in our Boomerang project and $4.1 related to the drilling and completion of three wells in our Northeast British Columbia project.

General and administrative expenses. Our general and administrative expenses ("G&A") increased $805,000, or 8%, to $11.4 million ($7.34 per Boe) for 2010, from $10.6 million ($7.23 per Boe) for 2009. The increase in G&A was principally due to higher share-based compensation, salaries and benefits. For 2011, we expect G&A to be slightly higher as compared to 2010 as result of staffing increases that continued to occur throughout 2010.

G&A increased $1.7 million, or 19.5%, to $10.6 million ($7.23 per Boe) for 2009 from $8.9 million ($6.09 per Boe) for 2008. Our G&A for 2009 included higher share-based compensation, as well as higher salaries, related employee benefit costs attributable to an increase in staff from the prior year period and a severance payment to a former officer. Our G&A for 2009 also included an increase in franchise taxes. Following is a summary of G&A (in millions):

	Year Ended December 31,				Year Ended December 31,			
	2010	2009	Change	% Change	2009	2008	Change	% Change
Salaries and benefits	$ 5.1	$ 4.9	$ 0.2	4.1%	$ 4.9	$4.0	$ 0.9	22.5%
Share-based compensation	2.6	1.8	0.8	44.4	1.8	1.1	0.7	63.6
Professional fees	1.3	1.4	(0.1)	(7.1)	1.4	1.4	—	—
Cash incentive compensation	0.5	0.5	—	—	0.5	1.0	(0.5)	(50.0)
Rent expense	0.5	0.5	—	—	0.5	0.3	0.2	66.7
Data processing	0.4	0.6	(0.2)	(33.3)	0.6	0.2	0.4	200.0
State franchise taxes	0.2	0.4	(0.2)	(50.0)	0.4	—	0.4	100.0
Other	0.8	0.5	0.3	60.0	0.5	0.9	(0.4)	(44.4)
Total	$11.4	$10.6	$ 0.8	7.5%	$10.6	$8.9	$ 1.7	19.1%

Depletion, depreciation and amortization expense. Our depletion, depreciation and amortization expense ("DD&A") decreased $2.4 million, or 9.9%, to $22.2 million for 2010, from $24.7 million for 2009. Our DD&A per Boe decreased by $2.52, or 15%, to $14.28 per Boe for 2010, compared to $16.80 per Boe for 2009. The decrease in DD&A was primarily attributable to an increase in estimated proved developed reserves at December 31, 2010, partially offset by higher capital costs over the prior year. Our estimated proved developed reserves at December 31, 2010, increased primarily due to expected NGL recoveries in Ozona Northeast beginning April 1, 2011, higher commodity prices and well performance and results of development drilling in Cinco Terry.

DD&A increased $950,000, or 4%, to $24.7 million for 2009 from $23.7 million for 2008. Our DD&A per Boe increased by $0.55, or 3.4%, to $16.80 per Boe for 2009 compared to $16.25 per Boe for 2008. The increase in DD&A was primarily attributable to an increase in oil and gas property costs, partially offset by an increase in estimated proved oil and gas reserves.

Interest expense, net. Our interest expense, net, increased $402,000, or 22.5%, to $2.2 million for 2010, from $1.8 million for 2009. This increase was the result of higher average notes payable balances outstanding as well as an increase in amortization of $268,000 for deferred loan costs during 2010. The weighted average interest rate applicable to our outstanding borrowings during 2010 and 2009, was 3.4% and 3.2%, respectively.

Our interest expense increased $518,000, or 40.8%, to $1.8 million for 2009 from $1.3 million for 2008. This increase was substantially the result of our higher average debt level during 2009. The weighted average interest rate applicable to our outstanding borrowings during 2009 and 2008, was 3.2% and 4.8%, respectively.

Income taxes. Our income taxes increased $4.9 million to $4.1 million for 2010, from a benefit of $785,000 for 2009. The increase in income taxes was due to higher pre-tax income in 2010, partially offset by higher taxes in 2009 from a change in our estimated income tax provision for the year ended December 31, 2008. Our effective income tax rate for 2010 was 35.5%, compared with 13.1% for 2009. The lower effective tax rate in the 2009 period primarily resulted from an increased impact of permanent differences from book and taxable income, partially offset by an increase in our estimated income taxes for the year ended December 31, 2008.

Our income taxes decreased to a benefit of $785,000 for 2009 compared with expense of $12.1 million for 2008. Our effective income tax rate for 2009 was 13.1%, compared with 34.1% for 2008. The decrease in the effective rate resulted primarily from a change in our estimated income tax expenses for 2008, along with an increased impact of permanent differences between book and taxable income and increased effective state income tax rates.

Liquidity and Capital Resources

We generally will rely on cash generated from operations, borrowings under our revolving credit facility and, to the extent that credit and capital market conditions will allow, future public equity and debt offerings to satisfy our liquidity needs. Our ability to fund planned capital expenditures and to make acquisitions depends upon our future operating performance, availability of borrowings under our revolving credit facility, and more broadly, on the availability of equity and debt financing, which is affected by prevailing economic conditions in our industry and financial, business and other factors, some of which are beyond our control. We cannot predict whether additional liquidity from equity or debt financings beyond our revolving credit facility will be available on acceptable terms, or at all, in the foreseeable future.

Our cash flow from operations is driven by commodity prices, production volumes and the effect of commodity derivatives. Prices for oil and gas are affected by national and international economic and political environments, national and global supply and demand for hydrocarbons, seasonal influences of weather and other factors beyond our control. Cash flows from operations are primarily used to fund exploration and development of our oil and gas properties.

We believe we have adequate liquidity from cash generated from operations and unused borrowing capacity under our revolving credit facility for current working capital needs and maintenance of our current drilling program. However, we may determine to access the public or private equity or debt markets for future development of reserves, acquisitions, additional working capital or other liquidity needs, if such financing is available on acceptable terms. We cannot guarantee that such financing will be available on acceptable terms or at all.

Liquidity

We define liquidity as funds available under our revolving credit facility plus year-end net cash and cash equivalents. At December 31, 2010, we had no long-term debt outstanding under our revolving credit facility, compared to $32.3 million and $43.5 million in long-term debt outstanding at December 31, 2009 and 2008, respectively. The following table summarizes our liquidity position at December 31, 2010, 2009 and 2008 (in thousands).

	Year Ended December 31,		
	2010	2009	2008
Borrowing base	$150,000	$115,000	$100,000
Cash and cash equivalents	23,465	2,685	4,077
Long-term debt	—	(32,319)	(43,537)
Unused letters of credit	(350)	(400)	(400)
Liquidity	$173,115	$ 84,966	$ 60,140

In November 2010, we issued 6.6 million shares of common stock at $16.25 per share in the 2010 Offering. After deducting underwriting discounts and estimated transaction costs of approximately $5.7 million, we received net proceeds of approximately $101.8 million, which we intend to use to fund our capital expenditures for the development of our Wolffork oil shale resource play, working interest and leasehold acquisitions in the Permian Basin and general working capital needs. Pending these uses, we used a portion of the proceeds of the 2010 Offering to repay all outstanding borrowings under our revolving credit facility. In 2009, while commodity prices were low and demand for natural gas was reduced, we decreased our capital spending in order to preserve our liquidity and improve our financial position. As a result, we paid down our long-term debt and increased our liquidity by over 40%, from $60.5 million at December 31, 2008, to $85.4 million at December 31, 2009.

In February 2011, we acquired an additional 38% working interest in Cinco Terry from two non-operating partners for $76 million. The Working Interest Acquisition was funded with borrowings under our revolving credit facility and cash on hand, which will materially decrease liquidity available to us in 2011 and beyond. After giving effect to the financing of the Working Interest Acquisition, we had approximately $67 million in outstanding borrowings under our revolving credit facility at February 28, 2011. We believe we have adequate liquidity from cash generated from operations and unused borrowing capacity under our revolving credit facility for current working capital needs and maintenance of our current drilling program. However, we may determine to access the public or private equity or debt markets for future development of reserves, acquisitions, additional working capital or other liquidity needs, if such financing is available on acceptable terms. We cannot guarantee that such financing will be available on acceptable terms or at all.

Working Capital

Our working capital is affected primarily by our cash and cash equivalents balance and our capital spending program. At December 31, 2010, we had a working capital surplus of $12.1 million as compared to a working capital deficit of $10 million and a working capital surplus of $4.1 million at December 31, 2009 and 2008, respectively. The surplus for 2010 was largely caused by the increase in our cash balance. As a result of the Working Interest Acquisition and our planned capital expenditure budget for 2011, we expect to operate and end the year 2011 with a working capital deficit. Our working capital deficits have been historically attributable to accrued liabilities and have been more than offset by liquidity available under our revolving credit facility. To the extent we operate or end the year 2011 with a working capital deficit, we expect such deficit to be more than offset by liquidity available under our revolving credit facility.

Cash Flows

The following table summarizes our sources and uses of funds for the periods noted (in thousands).

	Year Ended December 31,		
	2010	2009	2008
Cash flows provided by operating activities	$ 42,377	$ 39,761	$ 56,381
Cash flows used in investing activities	(91,346)	(29,553)	(100,633)
Cash flows provided by (used in) financing activities	69,748	(11,618)	43,750
Effect of Canadian exchange rate	1	18	(206)
Net decrease in cash and cash equivalents	$ 20,780	$ (1,392)	$ (708)

For 2010, our primary sources of cash were from operating activities and the 2010 Offering. Approximately $42.4 million of cash from operations was used to fund a portion of our drilling program and pay down our long-term debt. In the 2010 Offering, we sold 6,612,500 shares of common stock. After deducting underwriting discounts and estimated transaction costs of approximately $5.7 million, we received net proceeds of approximately $101.8 million. We intend to use proceeds from the 2010 Offering to fund our capital expenditures for the development of our Wolffork oil shale resource play, working interest and leasehold acquisitions in the Permian Basin and general working capital needs. Pending these uses, we used a portion of the proceeds of the 2010 Offering to repay all outstanding borrowings under our revolving credit facility.

In 2009, our primary sources of cash were from operating activities. Approximately $39.8 million of cash from operations was used to fund our drilling program and 3-D seismic operations and pay down our long-term debt.

In 2008, our primary sources of cash were from financing and operating activities. Approximately $43.5 million from borrowings (net of payments) under our revolving credit facility and $56.4 million cash from operations were used to fund our drilling program and the acquisition of a 95% working interest below the top of the Strawn formation and rights to 75 miles of gathering system in Ozona Northeast.

Operating Activities

During 2010, our cash flows from operations, borrowings under our revolving credit facility and available cash were used primarily for drilling activities in Cinco Terry and Ozona Northeast, leasehold acquisitions and a 3-D seismic program in our Permian Basin operations. Cash flows from operating activities increased by 6.8%, or $2.7 million, to $42.4 million from 2009 partially due to a 42% increase in oil and gas sales in 2010. Cash flows provided by operating activities also were affected by an increase in cash flows used by working capital during 2010.

For 2009, our cash flow from operations, borrowings under our revolving credit facility and available cash were used for drilling activities, 3-D seismic operations and for the payment of a portion of our long-term debt. The $39.8 million in cash flows generated in the 2009 period decreased $16.7 million from the same period in 2008 due primarily to a $39.2 million decline in oil and gas sales, partially offset by a $10 million decrease in working capital components and a net increase of $12.5 million in other cash income and expense items.

For 2008, our cash flow from operations, borrowings under our revolving credit facility and available cash were used for drilling activities. The $56.4 million in cash flow generated during 2008 period increased by $25.7 million from 2007 due primarily to an increase in oil, NGL and gas sales and a decrease in general and administrative expenses. Partially offsetting the increase in oil, NGL and gas sales and decrease in general administrative expenses was a reduction in working capital and an increase in LOE and production taxes in the 2008 period compared to the 2007 period.

Investing Activities

Cash flows used in investing activities increased by $61.8 million for 2010 as compared to 2009, which primarily reflects expenditures for drilling and acquisitions in our core operating area in the Permian Basin. During 2010, we drilled a total of 91 gross (56.2 net) wells, compared to 32 gross (18 net) wells in 2009. Also in 2010, we acquired a 10% working interest in Cinco Terry from a non-operating partner for $21.2 million, net of purchase price adjustments.

Cash flows used in investing activities decreased by $71.1 million in 2009 as compared to 2008, which primarily reflects reduced expenditures for drilling and development of our oil and gas properties. We substantially decreased our drilling activity in 2009 as a result of low commodity prices and to preserve liquidity. We drilled 32 gross (18 net) wells in 2009. In 2008, we drilled or participated in 96 gross (62.5 net) wells.

The majority of our cash flows used in investing activities for the years ended 2010, 2009 and 2008 have been used for drilling and acquisitions in our core operating area in the Permian Basin and East Texas Basin. The following table is a summary of capital expenditures related to our oil and gas properties (in thousands).

	Years Ended December 31,		
	2010	2009	2008
Permian Basin	$56,211	$26,398	$ 63,725
Permian Basin Acquisitions	21,179	—	10,346
Subtotal	77,390	26,398	74,071
East Texas Basin	101	1,554	15,871
Exploratory Projects	285	237	3,459
Inventory	1,636	(1,959)	2,365
Lease acquisition, geological, geophysical and other	11,604	2,760	4,323
Total	$91,016	$28,990	$100,089

Financing Activities

We borrowed $121.8 million under our revolving credit facility in 2010 compared to $67.4 million in 2009 and $121.7 million in 2008. We repaid a total of $154.1 million, $78.6 million and $78.2 million of amounts outstanding under our revolving credit facility for 2010, 2009 and 2008, respectively.

In the 2010 Offering, we issued 6.6 million shares of common stock at $16.25 per share in an underwritten public offering. After deducting underwriting discounts and estimated transaction costs of approximately $5.7 million, we received net proceeds of approximately $101.8 million, which we intend to use to fund our capital expenditures for the development of our Wolffork oil shale resource play, working interest and leasehold acquisitions in the Permian Basin and general working capital needs. Pending these uses, we used a portion of the proceeds of the 2010 Offering to repay all outstanding borrowings under our revolving credit facility.

Our current goal is to manage our borrowings to help us maintain financial flexibility and liquidity, and to avoid the problems associated with highly-leveraged companies with large interest costs and possible debt reductions restricting ongoing operations.

We believe we have adequate liquidity from cash generated from operations and unused borrowing capacity under our revolving credit facility for current working capital needs and maintenance of our current drilling program. However, we may determine to access the public or private equity or debt markets for future development of reserves, acquisitions, additional working capital or other liquidity needs, if such financing is available on acceptable terms. We cannot guarantee that such financing will be available on acceptable terms or at all.

2011 Capital Expenditures

In November 2010, we announced a 2011 capital budget of $100 million. In January 2011, we acquired approximately 10,900 contiguous, net acres approximately nine miles west of our existing acreage in northeast Crockett County, Texas. In addition, in February 2011, we acquired the remaining 38% working interest in Cinco Terry from two non-operating partners for approximately $76 million. Given our recent activity, in March 2011 we increased our capital budget to $220 million, of which $130 million is allocated to drilling and recompletion projects in the Permian Basin and approximately $90 million will be allocated to lease extensions and renewals in the Permian Basin as well as the recent acreage and Working Interest Acquisition.

Our 2011 capital budget is subject to change depending upon a number of factors, including additional data on our Wolffork oil shale resource play, results of Wolfcamp Shale and Wolffork drilling and recompletions, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil, gas and NGLs, the availability of sufficient capital resources for drilling prospects, our financial results and the availability of lease extensions and renewals on reasonable terms.

Revolving Credit Facility

We have a $200 million revolving credit facility with a borrowing base set at $150 million. The borrowing base is redetermined semi-annually on or before each April 1 and October 1 based on our oil and gas reserves. We or the lenders can each request one additional borrowing base redetermination each calendar year.

Currently, the maturity date under our revolving credit facility is July 31, 2012. Borrowings bear interest based on the agent bank's prime rate plus an applicable margin ranging from 1.25% to 2.25%, or the sum of the Eurodollar rate plus an applicable margin ranging from 2.25% to 3.25%. Margins vary based on the borrowings outstanding compared to the borrowing base. In addition, we pay an annual commitment of 0.50% of non-used borrowings available under our revolving credit facility.

We had no outstanding borrowings under our revolving credit facility at December 31, 2010. We had outstanding unused letters of credit under our revolving credit facility totaling $350,000 at December 31, 2010, which reduce amounts available for borrowing under our revolving credit facility.

Loans under our revolving credit facility are secured by first priority liens on substantially all of our West Texas assets and are guaranteed by our subsidiaries.

At February 28, 2011, we had $67 million in outstanding borrowings under our revolving credit facility, with a weighted average interest rate of 4.75%.

Covenants

Our credit agreement contains two principal financial covenants:

- a consolidated modified current ratio covenant that requires us to maintain a ratio of not less than 1.0 to 1.0 at all times. The consolidated modified current ratio is calculated by dividing Consolidated Current Assets (as defined in the credit agreement) by Consolidated Current Liabilities (as defined in the credit agreement). As defined more specifically in the credit agreement, the consolidated modified current ratio is calculated as current assets less current unrealized gains on commodity derivatives plus the available borrowing base at the respective balance sheet date, divided by current liabilities less current unrealized losses on commodity derivatives at the respective balance sheet date.
- a consolidated funded debt to consolidated EBITDAX ratio covenant that requires us to maintain a ratio of not more than 3.5 to 1.0 at the end of each fiscal quarter. The consolidated funded debt to consolidated EBITDAX ratio is calculated by dividing Consolidated Funded Debt (as defined in the credit agreement) by Consolidated EBITDAX (as defined in the credit agreement). As defined more specifically in the credit agreement, consolidated EBITDAX is calculated as net income (loss), plus (1) exploration expense, (2) depletion, depreciation and amortization expense, (3) share-based compensation expense, (4) unrealized loss on commodity derivatives, (5) interest expense, (6) income and franchise taxes and (7) certain other non-cash expenses, less (1) gains or losses from sales or dispositions of assets, (2) unrealized gain on commodity derivatives and (3) extraordinary or non-recurring gains. For purposes of calculating this ratio, consolidated EBITDAX for a fiscal quarter is annualized pursuant to the credit agreement.

Our credit agreement also restricts cash dividends and other restricted payments, transactions with affiliates, incurrence of other debt, consolidations and mergers, the level of operating leases, assets sales, investments in other entities and liens on properties.

In addition, our credit agreement contains customary events of default that would permit our lenders to accelerate the debt under our credit agreement if not cured within applicable grace periods, including, among others, failure to make payments of principal or interest when due, materially incorrect representations and warranties, failure to make mandatory prepayments in the event of borrowing base deficiencies, breach of covenants, defaults upon other obligations in excess of $500,000, events of bankruptcy, the occurrence of one or more unstayed judgments in excess of $500,000 not covered by an acceptable policy of insurance, failure to pay any obligation in excess of $500,000 owed under any derivatives transaction or in any amount if the obligation under the derivatives transaction is secured by collateral under the credit agreement, any event of default by the Company occurs under any agreement entered into in connection with a derivatives transaction, liens securing the loans under the credit agreement cease to be in place, a Change in Control (as more specifically defined in the credit agreement) of the Company occurs, and dissolution of the Company.

At December 31, 2010, we were in compliance with all of our covenants and had not committed any acts of default under the credit agreement.

To date we have experienced no disruptions in our ability to access our revolving credit facility. However, our lenders have substantial ability to reduce our borrowing base on the basis of subjective factors, including the loan collateral value that each lender, in its discretion and using the methodology, assumptions and discount rates as such lender customarily uses in evaluating oil and gas properties, assigns to our properties.

Contractual Obligations

As of December 31, 2010, our contractual obligations consisted of daywork drilling contracts, operating lease obligations, asset retirement obligations and employment agreements with our executive officers.

We periodically enter into contractual arrangements under which we are committed to expend funds to drill wells in the future, including agreements to secure drilling rig services, which require us to make future minimum payments to the rig operators. We record drilling commitments in the periods in which well capital expenditures are incurred or rig services are provided. Our commitment under daywork drilling contracts was $4.3 million at December 31, 2010.

In April 2007, we signed a five-year lease for approximately 13,000 square feet of office space in Fort Worth, Texas. In August 2008, we expanded our office space under an amendment to the lease to approximately 18,000 square feet. In December 2010, we expanded our office space under an amendment to the lease to approximately 23,400 square feet. In January 2011, we began rent payments of approximately $9,000 per month, bringing our total office lease payment to approximately $45,000 per month.

Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives, in accordance with applicable federal, state and local laws. We determine our asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The retirement obligation is recorded as a liability at its estimated present value as of the asset's inception, with an offsetting increase to proved properties. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement.

At December 31, 2010, we had outstanding employment agreements with two of our executive officers that contained automatic renewal provisions providing that such agreements may be automatically renewed for successive terms of one year unless the employment is terminated at the end of the term by written notice given to the employee not less than 60 days prior to the end of such term. Our maximum commitment under the employment agreements, which would apply if the employees covered by these agreements were each terminated without cause, was approximately $757,000 at December 31, 2010.

The following table summarizes these commitments as of December 31, 2010 (in thousands).

	Payments Due By Period				
Contractual Obligations	**Total**	**Less than 1 Year**	**1-3 Years**	**3-5 Years**	**More than 5 Years**
Daywork drilling contracts(1)	$ 4,338	$4,338	$ —	$—	$ —
Operating lease obligations(2)	1,021	548	473	—	—
Asset retirement obligations(3)	5,416	—	—	—	5,416
Employment agreements with executive officers(4)	757	757	—	—	—
Total	$11,532	$5,643	$473	$—	$5,416

(1) At December 31, 2010, daywork drilling contracts related to two drilling rigs were contracted through March 31, 2011, and June 30, 2011, respectively. In March 2011, we renewed a daywork drilling contract for a third rig through August 2011 at a rate of $10,500 per day.

(2) Operating lease obligations are for office space and equipment.

(3) See Note 1 to our consolidated financial statements for a discussion of our asset retirement obligations.

(4) As of January 24, 2011, we had entered into amended and restated or new employment agreements, each with two-year initial terms, with five executive officers. We estimate that our maximum commitment under these employment agreements, which would apply if the employees covered by these agreements were all terminated without cause, was approximately $4 million as of the date of this report. This estimate assumes the maximum potential bonus for 2011 is earned by each employee during 2011 with no prorated amounts due to partial year of service.

Off-Balance Sheet Arrangements

From time to time, we enter into off-balance sheet arrangements and transactions that can give rise to off-balance sheet obligations. As of December 31, 2010, the off-balance sheet arrangements and transactions that we have entered into include undrawn letters of credit, operating lease agreements and gas transportation commitments. We do not believe that these arrangements are reasonably likely to materially affect our liquidity or availability of, or requirements for, capital resources.

General Trends and Outlook

Our financial results depend upon many factors, particularly the price of oil and gas. Commodity prices are affected by changes in market demand, which is impacted by overall economic activity, weather, pipeline capacity constraints, estimates of inventory storage levels, gas price differentials and other factors. As a result, we cannot accurately predict future oil and gas prices, and therefore, we cannot determine what effect increases or decreases will have on our capital program, production volumes and future revenues. A substantial or extended decline in oil and gas prices could have a material adverse effect on our business, financial condition, results of operations, quantities of oil and gas reserves that may be economically produced and liquidity that may be accessed through our borrowing base under our revolving credit facility and through capital markets.

In addition to production volumes and commodity prices, finding and developing sufficient amounts of oil and gas reserves at economical costs are critical to our long-term success. Future finding and development costs are subject to changes in the industry, including the costs of acquiring, drilling and completing our projects. We focus our efforts on increasing oil and gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our future cash flow from operations will depend on our ability to manage our overall cost structure.

Like all oil and gas production companies, we face the challenge of natural production declines. Oil and gas production from a given well naturally decreases over time. Additionally, our reserves have a rapid initial decline. We attempt to overcome this natural decline by drilling to develop and identify additional reserves, farm-ins or other joint drilling ventures, and by acquisitions. However, during times of severe price declines, we may from time to time reduce current capital expenditures and curtail drilling operations in order to preserve liquidity. A material reduction in capital expenditures and drilling activities could materially reduce our production volumes and revenues and increase future expected costs necessary to develop existing reserves.

We also face the challenge of financing exploration, development and future acquisitions. We believe we have adequate liquidity from cash generated from operations and unused borrowing capacity under our revolving credit facility for current working capital needs and maintenance of our current drilling program. However, we may determine to access the public or private equity or debt markets for future development of reserves, acquisitions, additional working capital or other liquidity needs, if such financing is available on acceptable terms. We cannot guarantee that such financing will be available on acceptable terms or at all.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk.*

Some of the information below contains forward-looking statements. The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil and gas prices, and other related factors. The disclosure is not meant to be a precise indicator of expected future losses, but rather an indicator of reasonably possible losses. This forward-looking information provides an indicator of how we view and manage our ongoing market risk exposures. Our market risk sensitive instruments were entered into for commodity derivative and investment purposes, not for trading purposes.

Proved Reserves

Estimates of proved oil and gas reserves directly impact financial accounting estimates including depletion, depreciation and amortization expense, evaluation of impairment of properties and the calculation of plugging and abandonment liabilities. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible — from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. The data for any reservoir may change substantially over time due to results from operational activity. Proved reserve volumes at December 31, 2010, were estimated based on the average of the closing price on the first day of each month for the 12-month period prior to December 31, 2010, for natural gas, oil and NGLs in accordance with SEC rules. Changes in commodity prices and operations costs may increase or decrease estimates of proved oil, NGL and natural gas reserves. Depletion expense for our oil and gas properties is determined using our estimates of proved oil, NGL and natural gas reserves. A hypothetical 10% decline in our December 31, 2010, estimated proved reserves would have increased our depletion expense by approximately $587,000 for the year ended December 31, 2010.

Commodity Price Risk

Given the current economic outlook, we expect commodity prices to remain volatile. Even modest decreases in commodity prices can materially affect our revenues and cash flow. In addition, if commodity prices remain suppressed for a significant amount of time, we could be required under successful efforts accounting rules to perform a write down of our oil and gas properties.

We enter into financial swaps to reduce the risk of commodity price fluctuations. We do not designate such instruments as cash flow hedges. Accordingly, we record open commodity derivative positions on our consolidated balance sheets at fair value and recognize changes in such fair values as income (expense) on our consolidated statements of operations as they occur.

At December 31, 2010, we had the following commodity derivative positions outstanding:

	Volume (MMBtu)		$/MMBtu
Period	**Monthly**	**Total**	**Fixed**
NYMEX — Henry Hub			
Price swaps 2011	230,000	2,760,000	$ 4.86
Price call 2012	230,000	2,760,000	$ 6.00
WAHA basis differential			
Basis swaps 2011	300,000	3,600,000	$(0.53)

At December 31, 2010 and December 31, 2009, the fair value of our open derivative contracts was a net liability of approximately $1.1 million and $1.9 million, respectively.

JPMorgan Chase Bank, National Association and KeyBank National Association are currently the only counterparties to our commodity derivatives positions. We are exposed to credit losses in the event of nonperformance by counterparties on our commodity derivatives positions. However, we do not anticipate nonperformance by the counterparties over the term of the commodity derivatives positions. JPMorgan is the administrative agent and a participant, and KeyBank is the documentation agent and a participant, in our revolving credit facility and the collateral for the outstanding borrowings under our revolving credit facility is used as collateral for our commodity derivatives.

Unrealized gains and losses, at fair value, are included on our consolidated balance sheets as current or non-current assets or liabilities based on the anticipated timing of cash settlements under the related contracts. Changes in the fair value of our commodity derivative contracts are recorded in earnings as they occur and included in other income (expense) on our consolidated statements of operations. We estimate the fair values of swap contracts based on the present value of the difference in exchange-quoted forward price curves and contractual settlement prices multiplied by notional quantities. We internally valued the option contracts using industry-standard option pricing models and observable market inputs. We use our internal valuations to determine the fair values of the contracts that are reflected on our consolidated balance sheets. Realized gains and losses are also included in other income (expense) on our consolidated statements of operations.

For the year ended December 31, 2010 and 2008, we recognized an unrealized gain of $788,000 and $7.1 million, respectively, from the change in the fair value of commodity derivatives. For the year ended December 31, 2009, we recognized an unrealized loss of $9.9 million from the change in the fair value of commodity derivatives. A hypothetical 10% increase in the NYMEX floating prices would have resulted in a $1.8 million decrease in the December 31, 2010, fair value recorded on our balance sheet, and a corresponding increase to the loss on commodity derivatives in our statement of operations.

To estimate the fair value of our commodity derivatives positions, we use market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach for recurring fair value measurements and attempt to use the best available information. We determine the fair value based upon the hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and lowest priority to unobservable inputs (Level 3 measurement). The three levels of fair value hierarchy are as follows:

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. At December 31, 2010, we had no Level 1 measurements.
- Level 2 — Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies.

  These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Our derivatives, which consist primarily of commodity swaps and collars, are valued using commodity market data which is derived by combining raw inputs and quantitative models and processes to generate forward curves. Where observable inputs are available, directly or indirectly, for substantially the full term of the asset or liability, the instrument is categorized in Level 2. At December 31, 2010, all of our commodity derivatives were valued using Level 2 measurements.
- Level 3 — Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. At December 31, 2010, our Level 3 measurements were used to calculate our asset retirement obligation and our impairment analysis of proved properties at December 31, 2010.

Item 8. ***Financial Statements and Supplementary Data.***

Our consolidated financial statements and supplemental data are included in this report beginning on page F-1.

Item 9. ***Changes in and Disagreements With Accountants on Accounting and Financial Disclosure.***

We had no changes in, and no disagreements with our accountants on, accounting and financial disclosure.

Item 9A. ***Controls and Procedures.***

Disclosure Controls and Procedures

Our management, with the participation of our President and Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2010. Based on this evaluation, our President and Chief Executive Officer and Chief Financial Officer have concluded that, as of December 31, 2010, our disclosure controls and procedures were effective, in that they ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is (1) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and (2) accumulated and communicated to our management, including our President and Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Internal Control over Financial Reporting

Management's Annual Report on Internal Control Over Financial Reporting and Attestation Report of Registered Public Accounting Firm

Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, we have included a report of management's assessment of the design and effectiveness of our internal controls as part of this annual report on Form 10-K for the fiscal year ended December 31, 2010. Hein & Associates LLP ("Hein"), our independent registered public accounting firm, also attested to, and reported on, our internal control over financial reporting. Management's report and Hein's attestation report are referenced on page F-1 under the captions "Management's Report on Internal Control over Financial Reporting" and "Report of Independent Registered Public Accounting Firm — Internal Control over Financial Reporting" and are incorporated herein by reference.

Changes in Internal Control over Financial Reporting

No changes to our internal control over financial reporting occurred during the quarter ended December 31, 2010, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act).

Item 9B. ***Other Information.***

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance.***

Information required under Item 10 of this report will be contained under the captions "Election of Directors — Directors," "Executive Officers" and "Corporate Governance" to be provided in our proxy statement for our 2011 annual meeting of stockholders to be filed with the SEC on or before April 30, 2011, which are incorporated herein by reference. Additional information regarding our corporate governance guidelines as well as the complete texts of our Code of Conduct and the charters of our Audit Committee and our Compensation and Nominating Committee may be found on our website at *www.approachresources.com.*

Item 11. ***Executive Compensation.***

Information required by Item 11 of this report will be contained under the caption "Executive Compensation" in our proxy statement for our 2011 annual meeting of stockholders to be filed with the SEC on or before April 30, 2011, which is incorporated herein by reference.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.***

Information required by Item 12 of this report will be contained under the caption "Stock Ownership Matters" in our proxy statement for our 2011 annual meeting of stockholders to be filed with the SEC on or before April 30, 2011, which is incorporated herein by reference.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence.***

Information required by Item 13 of this report will be contained under the captions "Certain Relationships and Related Party Transactions" and "Corporate Governance — Board Independence" in our definitive proxy statement for our 2011 annual meeting of stockholders to be filed with the SEC on or before April 30, 2011, which are incorporated herein by reference.

Item 14. ***Principal Accounting Fees and Services.***

Information required by Item 14 of this report will be contained under the caption "Independent Registered Public Accountants" in our definitive proxy statement for our 2011 annual meeting of stockholders to be filed with the SEC on or before April 30, 2011, which is incorporated herein by reference.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules.***

(a) Documents filed as part of this report

(1) and (2) Financial Statements and Financial Statement Schedules.

See "Index to Consolidated Financial Statements" on page F-1.

(3) Exhibits.

See "Index to Exhibits" on page 68 for a description of the exhibits filed as part of this report.

GLOSSARY AND SELECTED ABBREVIATIONS

The following is a description of the meanings of some of the oil and gas industry terms used in this report.

3-D seismic. (Three Dimensional Seismic Data) Geophysical data that depicts the subsurface strata in three dimensions. 3-D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than two dimensional seismic data.

Basin. A large natural depression on the earth's surface in which sediments generally brought by water accumulate.

Bbl. One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to oil, condensate or natural gas liquids.

Boe. Barrel of oil equivalent, determined using the ratio of six Mcf of gas to one Bbl of oil equivalent, and one Bbl of NGLs to one Bbl of oil equivalent.

Btu or British Thermal Unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The installation of permanent equipment for production of oil or gas, or, in the case of a dry well, for reporting to the appropriate authority that the well has been abandoned.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells that are capable of production.

Developed oil and gas reserves. Has the meaning given to such term in Rule 4-10(a)(6) of Regulation S-X, which defines proved reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Development well. 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 or well. An exploratory, development or extension well that proved to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Dry hole costs. Costs incurred in drilling a well, assuming a well is not successful, including plugging and abandonment costs.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir.

Extension well. A well drilled to extend the limits of a known reservoir.

Farm-in. An arrangement in which the owner or lessee of mineral rights (the first party) assigns a working interest to an operator (the second party), the consideration for which is specified exploration and/or development activities. The first party retains an overriding royalty, working interest or other type of economic interest in the mineral production. The arrangement from the viewpoint of the second party is termed a "farm-in" arrangement.

Field. An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Fracing or Fracture stimulation technology. The technique of improving a well's production or injection rates by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to keep the channel open, so that fluids or gases may more easily flow through the formation.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Lease operating expenses. The expenses of lifting oil or gas from a producing formation to the surface, and the transportation and marketing thereof, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short lived assets, maintenance, allocated overhead costs, ad valorem taxes and other expenses incidental to production, but excluding lease acquisition or drilling or completion expenses.

LNG. Liquefied natural gas.

MBbls. Thousand barrels of oil or other liquid hydrocarbons.

MBoe. Thousand barrels of oil equivalent, determined using the ratio of six Mcf of gas to one Bbl of oil equivalent, and one Bbl of NGLs to one Bbl of oil equivalent.

Mcf. Thousand cubic feet of natural gas.

MMBoe. Million barrels of oil equivalent, determined using the ratio of six Mcf of gas to one Bbl of oil, condensate or gas liquids.

MMBtu. Million British thermal units.

MMcf. Million cubic feet of gas.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or wells, as the case may be.

NGLs. Natural gas liquids. The portions of gas from a reservoir that are liquefied at the surface in separators, field facilities or gas processing plants.

NYMEX. New York Mercantile Exchange.

Play. A set of known or postulated oil and/or gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, migration pathways, timing, trapping mechanism and hydrocarbon type.

Productive well. An exploratory, development or extension well that is not a dry well.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed producing reserves. Proved developed oil and gas reserves that are expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved oil and gas reserves. Has the meaning given to such term in Rule 4-10(a)(22) of Regulation S-X, which defines proved reserves as follows:

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible — from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations — prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PV-10. An estimate of the present value of the future net revenues from proved oil and gas reserves after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of federal income taxes. The estimated future net revenues are discounted at an annual rate of 10% to determine their "present value." The present value is shown to indicate the effect of time on the value of the revenue stream and should not be construed as being the fair market value of the properties. Estimates of PV-10 are made using oil and gas prices and operating costs at the date indicated and held constant for the life of the reserves.

Reserve life. This index is calculated by dividing year-end 2010 estimated proved reserves by 2010 production of 1,556 MBoe to estimate the number of years of remaining production.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Spacing. The distance between wells producing from the same reservoir. Spacing is expressed in terms of acres, e.g., 40-acre spacing, and is established by regulatory agencies.

Standardized measure. The present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the period end date) without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depletion, depreciation and amortization and discounted using an annual discount rate of 10%. Standardized measure does not give effect to derivative transactions.

Successful well (and wells included in drilling success rate). A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Tight gas sands. A formation with low permeability that produces natural gas with low flow rates for long periods of time.

Unconventional resources or reserves. Natural gas or oil resources or reserves from (i) low-permeability sandstone and shale formations, such as tight gas and gas shales, respectively, and (ii) coalbed methane.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or gas regardless of whether such acreage contains proved reserves.

Undeveloped oil and gas reserves. Has the meaning given to such term in Rule 4-10(a)(31) of Regulation S-X, which defines proved undeveloped reserves as follows:

> Undeveloped oil and gas reserves are reserves of any category 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.
>
> > (i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
> >
> > (ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.
> >
> > (iii) Under no circumstances shall estimates for undeveloped reserves be 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 projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.

Workover. Operations on a producing well to restore or increase production.

/d. “Per day” when used with volumetric units or dollars.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

APPROACH RESOURCES INC.

By: /s/ J. Ross Craft

J. Ross Craft
President and Chief Executive Officer

Date: March 11, 2011

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated and on March 11, 2011.

Signature	Title
/s/ J. Ross Craft J. Ross Craft	President, Chief Executive Officer and Director (Principal Executive Officer)
/s/ Steven P. Smart Steven P. Smart	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)
/s/ Bryan H. Lawrence Bryan H. Lawrence	Director and Chairman of the Board of Directors
/s/ Alan D. Bell Alan D. Bell	Director
/s/ James H. Brandi James H. Brandi	Director
/s/ James C. Crain James C. Crain	Director
/s/ Sheldon B. Lubar Sheldon B. Lubar	Director
/s/ Christopher J. Whyte Christopher J. Whyte	Director

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS OF APPROACH RESOURCES INC.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934). Our internal control over financial reporting is designed to provide reasonable assurance to management and our board of directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2010. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework.* Based on our assessment, we believe that, as of December 31, 2010, our internal control over financial reporting is effective based on those criteria.

By: /s/ J. Ross Craft
J. Ross Craft
President and Chief Executive Officer

By: /s/ Steven P. Smart
Steven P. Smart
Executive Vice President and Chief Financial Officer

Fort Worth, Texas
March 11, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Approach Resources Inc.

We have audited Approach Resources Inc. and subsidiaries' (collectively, the "Company") internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Approach Resources Inc. and subsidiaries as of December 31, 2010 and 2009, and the related consolidated statements of operations, changes in stockholders' equity, cash flows and comprehensive income for each of the three years in the period ended December 31, 2010, and our report dated March 11, 2011, expressed an unqualified opinion.

/s/ ***HEIN*** *& ASSOCIATES LLP*
Dallas, Texas
March 11, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
Approach Resources Inc.

We have audited the accompanying consolidated balance sheets of Approach Resources Inc. and subsidiaries (collectively, the "Company") as of December 31, 2010 and 2009, and the related consolidated statements of operations, changes in stockholders' equity, cash flows and comprehensive income for each of the three years in the period ended December 31, 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Approach Resources Inc. and subsidiaries as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 11, 2011 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

*/s/ **HEIN** & ASSOCIATES LLP*
Dallas, Texas
March 11, 2011

Approach Resources Inc. and Subsidiaries

Consolidated Balance Sheets
(In thousands, except shares and per-share amounts)

	December 31, 2010	December 31, 2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 23,465	$ 2,685
Accounts receivable:		
Joint interest owners	8,319	3,088
Oil and gas sales	6,044	4,607
Unrealized gain on commodity derivatives	862	786
Prepaid expenses and other current assets	322	582
Deferred income taxes — current	2,318	255
Total current assets	41,330	12,003
PROPERTIES AND EQUIPMENT:		
Oil and gas properties, at cost, using the successful efforts method of accounting	474,917	388,508
Furniture, fixtures and equipment	1,077	824
	475,994	389,332
Less accumulated depletion, depreciation and amortization	(106,784)	(84,849)
Net properties and equipment	369,210	304,483
OTHER ASSETS	2,549	2,440
Total assets	$ 413,089	$318,926
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Advances from non-operators	$ 509	$ 2,689
Accounts payable	11,426	3,074
Oil and gas sales payable	5,534	3,774
Accrued liabilities	10,686	10,935
Unrealized loss on commodity derivatives	1,085	1,524
Total current liabilities	29,240	21,996
NON-CURRENT LIABILITIES:		
Long-term debt	—	32,319
Unrealized loss on commodity derivatives	871	1,144
Deferred income taxes	44,616	38,374
Asset retirement obligations	5,416	4,597
Total liabilities	80,143	98,430
COMMITMENTS AND CONTINGENCIES (Note 9)		
STOCKHOLDERS' EQUITY :		
Preferred stock, $0.01 par value, 10,000,000 shares authorized none outstanding	—	—
Common stock, $0.01 par value, 90,000,000 shares authorized, 28,226,890 and 20,959,285 issued and outstanding, respectively	282	209
Additional paid-in capital	273,912	168,993
Retained earnings	58,986	51,524
Accumulated other comprehensive loss	(234)	(230)
Total stockholders' equity	332,946	220,496
Total liabilities and stockholders' equity	$ 413,089	$318,926

See accompanying notes to these consolidated financial statements.

Approach Resources Inc. and Subsidiaries

Consolidated Statements of Operations
(In thousands, except shares and per-share amounts)

	Years Ended December 31,		
	2010	2009	2008
REVENUES:			
Oil, NGL and gas sales	$ 57,581	$ 40,648	$ 79,869
EXPENSES:			
Lease operating	8,555	7,777	7,621
Severance and production taxes	2,990	1,996	4,202
Exploration	2,589	1,621	1,478
Impairment of unproved properties	2,622	2,964	6,379
General and administrative	11,422	10,617	8,881
Depletion, depreciation and amortization	22,224	24,660	23,710
Total expenses	50,402	49,635	52,271
OPERATING INCOME (LOSS)	7,179	(8,987)	27,598
OTHER:			
Impairment of investment	—	—	(917)
Interest expense, net	(2,189)	(1,787)	(1,269)
Realized gain on commodity derivatives	5,784	14,659	2,936
Unrealized gain (loss) on commodity derivatives	788	(9,899)	7,149
INCOME (LOSS) BEFORE INCOME TAX PROVISION (BENEFIT)	11,562	(6,014)	35,497
INCOME TAX PROVISION (BENEFIT)	4,100	(785)	12,111
NET INCOME (LOSS)	$ 7,462	$ (5,229)	$ 23,386
EARNINGS (LOSS) PER SHARE:			
Basic	$ 0.34	$ (0.25)	$ 1.13
Diluted	$ 0.34	$ (0.25)	$ 1.12
WEIGHTED AVERAGE SHARES OUTSTANDING:			
Basic	22,065,797	20,869,832	20,647,339
Diluted	22,214,070	20,869,832	20,824,905

See accompanying notes to these consolidated financial statements.

Approach Resources Inc. and Subsidiaries

Consolidated Statements of Changes in Stockholders' Equity for the Years Ended December 31, 2008, 2009 and 2010 (In thousands, except shares and per-share amounts)

	Common Stock		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
	Shares	Amount				
BALANCES, January 1, 2008	20,622,746	$206	$166,141	$33,367	$ 105	$199,819
Issuance of stock upon exercise of stock options	63,459	1	212	—	—	213
Restricted stock issuance	29,152	—	—	—	—	—
Share-based compensation expense	—	—	1,100	—	—	1,100
Surrender of restricted shares for payment of income taxes	—	—	(54)	—	—	(54)
Adjustment to additional paid-in capital for tax shortfall upon vesting of restricted shares	—	—	(50)	—	—	(50)
Net income	—	—	—	23,386	—	23,386
Foreign currency translation adjustments, net of related income tax of $256	—	—	—	—	(601)	(601)
BALANCES, December 31, 2008	20,715,357	207	167,349	56,753	(496)	223,813
Issuance of common shares to directors for compensation	50,845	—	378	—	—	378
Restricted stock issuance, net of cancellations	202,040	2	(2)	—	—	—
Share-based compensation expense	—	—	1,448	—	—	1,448
Surrender of restricted shares for payment of income taxes	(8,957)	—	(68)	—	—	(68)
Adjustment to additional paid-in capital for tax shortfall upon vesting of restricted shares	—	—	(112)	—	—	(112)
Net loss	—	—	—	(5,229)	—	(5,229)
Foreign currency translation adjustments, net of related income tax of $118	—	—	—	—	266	266
BALANCES, December 31, 2009	20,959,285	209	168,993	51,524	(230)	220,496
Issuance of common stock upon exercise of options	58,798	1	750	—	—	751
Issuance of common stock, net of issuance costs	6,612,500	66	101,698	—	—	101,764
Issuance of common shares to directors for compensation	46,347	—	380	—	—	380
Restricted stock issuance, net of cancellations	560,870	6	(6)	—	—	—
Share-based compensation expense	—	—	2,248	—	—	2,248
Surrender of restricted shares for payment of income taxes	(10,910)	—	(89)	—	—	(89)
Adjustment to additional paid-in capital for tax shortfall upon vesting of restricted shares	—	—	(62)	—	—	(62)
Net income	—	—	—	7,462	—	7,462
Foreign currency translation adjustments, net of related income tax of $2	—	—	—	—	(4)	(4)
BALANCES, December 31, 2010	28,226,890	$282	$273,912	$58,986	$(234)	$332,946

See accompanying notes to these consolidated financial statements.

Approach Resources Inc. and Subsidiaries

Consolidated Statements of Cash Flows
(In thousands, except shares and per-share amounts)

	For the Years Ended December 31,		
	2010	2009	2008
OPERATING ACTIVITIES:			
Net income (loss)	$ 7,462	$ (5,229)	$ 23,386
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization	22,224	24,660	23,710
Unrealized (gain) loss on commodity derivatives	(788)	9,899	(7,149)
Impairment of unproved properties	2,622	2,964	6,379
Impairment of investment	—	—	917
Exploration expense	2,589	1,621	1,478
Share-based compensation expense	2,628	1,826	1,100
Deferred income taxes	4,100	(785)	12,148
Changes in operating assets and liabilities:			
Accounts receivable	(6,581)	12,352	(11,501)
Prepaid expenses and other current assets	527	71	(38)
Accounts payable	6,083	(7,863)	8,051
Oil and gas sales payable	1,760	(857)	2,837
Accrued liabilities	(249)	1,102	(4,937)
Cash provided by operating activities	42,377	39,761	56,381
INVESTING ACTIVITIES:			
Additions to oil and gas properties	(91,016)	(28,990)	(100,089)
Additions to furniture, fixtures and equipment, net	(330)	(563)	(544)
Cash used in investing activities	(91,346)	(29,553)	(100,633)
FINANCING ACTIVITIES:			
Loan origination fees	(448)	(400)	—
Borrowings under credit facility	121,800	67,407	121,687
Repayment of amounts outstanding under credit facility	(154,119)	(78,625)	(78,150)
Proceeds from issuance of common stock, net offering costs	101,764	—	—
Proceeds from stock option exercises	751	—	213
Cash provided by (used in) financing activities	69,748	(11,618)	43,750
CHANGE IN CASH AND CASH EQUIVALENTS	20,779	(1,410)	(502)
EFFECT OF FOREIGN CURRENCY TRANSLATION ON CASH AND CASH EQUIVALENTS	1	18	(206)
CASH AND CASH EQUIVALENTS, beginning of year	2,685	4,077	4,785
CASH AND CASH EQUIVALENTS, end of year	$ 23,465	$ 2,685	$ 4,077
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid for interest	$ 1,920	$ 1,790	$ 894
Cash paid for income taxes	$ —	$ —	$ 397
SUPPLEMENTAL DISCLOSURE OF NON-CASH TRANSACTION:			
Acquisition of oil and gas properties	$ 132	$ —	$ 509
Asset retirement obligations capitalized	$ 604	$ 170	$ 3,504

See accompanying notes to these consolidated financial statements.

Approach Resources Inc. and Subsidiaries

Consolidated Statements of Comprehensive Income
(In thousands)

	For the Years Ended December 31,		
	2010	2009	2008
Net income (loss)	$7,462	$(5,229)	$23,386
Other comprehensive income (loss):			
Foreign currency translation, net of related income tax	(4)	266	(601)
Total comprehensive income (loss)	$7,458	$(4,963)	$22,785

See accompanying notes to these consolidated financial statements.

Approach Resources Inc. and Subsidiaries

Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

Organization and Nature of Operations

Approach Resources Inc. ("Approach," "ARI," the "Company," "we," "us" or "our") is an independent energy company engaged in the exploration, development, production and acquisition of oil and gas properties. We focus on finding and developing oil and natural gas reserves in oil shale and tight sands. Our properties are primarily located in the Permian Basin in West Texas. We also own interests in the East Texas Basin and New Mexico.

Consolidation, Basis of Presentation and Significant Estimates

The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America and include the accounts of the Company and its wholly-owned subsidiaries. Intercompany accounts and transactions are eliminated. In preparing the accompanying financial statements, management has made certain estimates and assumptions that affect reported amounts in the financial statements and disclosures of contingencies. Actual results may differ from those estimates. Significant assumptions are required in the valuation of proved oil and natural gas reserves, which affect our estimate of depletion expense as well as our impairment analyses. Significant assumptions also are required in our estimation of accrued liabilities, share-based compensation and asset retirement obligations. It is at least reasonably possible these estimates could be revised in the near term, and these revisions could be material.

Cash and Cash Equivalents

We consider all highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents. At times, the amount of cash and cash equivalents on deposit in financial institutions exceeds federally insured limits. We monitor the soundness of the financial institutions and believe the Company's risk is negligible.

Financial Instruments

The carrying amounts of financial instruments including cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities and long-term debt approximate fair value, as of December 31, 2010 and 2009. See Note 7 for commodity derivative fair value disclosures.

Oil and Gas Properties and Operations

Capitalized Costs. Our oil and gas properties comprised the following (in thousands):

	December 31,	
	2010	**2009**
Mineral interests in properties:		
Unproved properties	$ 19,963	$ 10,990
Proved properties	15,317	12,319
Wells and related equipment and facilities	430,810	361,573
Support equipment	3,098	1,462
Uncompleted wells, equipment and facilities	5,729	2,164
Total costs	474,917	388,508
Less accumulated depreciation, depletion and amortization	(106,127)	(84,347)
Net capitalized costs	$ 368,790	$304,161

We follow the successful efforts method of accounting for our oil and gas producing activities. Costs to acquire mineral interests in oil and gas properties and to drill and equip development wells and related asset retirement costs are capitalized. Costs to drill exploratory wells are capitalized pending determination of whether the wells have proved reserves. If we determine that the wells do not have proved reserves, the costs are charged to expense. There were no exploratory wells capitalized pending determination of whether the wells have proved reserves at December 31, 2010 or 2009. Geological and geophysical costs, including seismic studies and costs of carrying and retaining unproved properties are charged to expense as incurred. We capitalize interest on expenditures for significant exploration and development projects that last more than six months while activities are in progress to bring the assets to their intended use. Through December 31, 2010, we have capitalized no interest costs because our exploration and development projects generally last less than six months. Costs incurred to maintain wells and related equipment are charged to expense as incurred.

On the sale or retirement of a complete unit of a proved property, the cost and related accumulated depreciation, depletion and amortization are eliminated from the property accounts, and the resultant gain or loss is recognized. On the retirement or sale of a partial unit of proved property, the cost is charged to accumulated depreciation, depletion and amortization with a resulting gain or loss recognized in income.

Capitalized amounts attributable to proved oil and gas properties are depleted by the unit-of-production method over proved reserves using the unit conversion ratio of six Mcf of gas to one barrel of oil equivalent, and one barrel of NGLs to one barrel of oil equivalent. Depreciation and depletion expense for oil and gas producing property and related equipment was $22.0 million, $24.5 million and $23.6 million for the years ended December 31, 2010, 2009 and 2008, respectively.

Unproved oil and gas properties that are individually significant are periodically assessed for impairment of value, and a loss is recognized at the time of impairment by providing an impairment allowance. We recorded an impairment of $2.6 and $3 million during the years ended December 31, 2010 and 2009, respectively, related to our assessment of unproved properties. The 2010 impairment resulted from a write-off of $2.6 million in costs in our Boomerang project in Kentucky and represented the remaining carrying value we had recorded for the project. The 2009 impairment resulted from a write-off of $3 million in costs in Northeast British Columbia, and represented the remaining carrying value we had recorded for the project. We also recorded an impairment during the year ended 2008, which resulted from write-offs related to drilling costs in our Boomerang project and drilling and completion costs in our Northeast British Columbia project. During the year ended December 31, 2008, we determined that the future cash flows from drilling costs relating to these projects will not exceed the capitalized costs due to market factors.

Capitalized costs related to proved oil and gas properties, including wells and related equipment and facilities, are evaluated for impairment based on an analysis of undiscounted future net cash flows in accordance with ASC 360, formerly Statement of Financial Accounting Standards 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. If undiscounted cash flows are insufficient to recover the net capitalized costs related to proved properties, then we recognize an impairment charge in income from operations equal to the difference between the net capitalized costs related to proved properties and their estimated fair values based on the present value of the related future net cash flows. We noted no impairment of our proved properties based on our analysis for the years ended December 31, 2010, 2009 or 2008.

On the sale of an entire interest in an unproved property for cash or cash equivalent, gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property had been assessed individually. If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained.

Oil and Gas Operations

Revenue and Accounts Receivable. We recognize revenue for our production when the quantities are delivered to or collected by the respective purchaser. Prices for such production are defined in sales contracts and are readily determinable based on certain publicly available indices. All transportation costs are included in lease operating expense.

Accounts receivable, joint interest owners, consist of uncollateralized joint interest owner obligations due within 30 days of the invoice date. Accounts receivable, oil and gas sales, consist of uncollateralized accrued revenues due under normal trade terms, generally requiring payment within 30 to 60 days of production. No interest is charged on past-due balances. Payments made on all accounts receivable are applied to the earliest unpaid items. We review accounts receivable periodically and reduce the carrying amount by a valuation allowance that reflects our best estimate of the amount that may not be collectible. No such allowance was considered necessary at December 31, 2010 or 2009.

Oil and Gas Sales Payable. Oil and gas sales payable represents amounts collected from purchasers for oil and gas sales which are either revenues due to other revenue interest owners or severance taxes due to the respective state or local tax authorities. Generally, we are required to remit amounts due under these liabilities within 30 days of the end of the month in which the related production occurred.

Advances from Non-Operators. Advances from non-operators represent amounts collected in advance for joint operating activities. Such amounts are applied to joint interest accounts receivable as related costs are incurred.

Production Costs. Production costs, including compressor rental and repair, pumpers' salaries, saltwater disposal, ad valorem taxes, insurance, repairs and maintenance, expensed workovers and other operating expenses are expensed as incurred and included in lease operating expense on our consolidated statements of operations.

Exploration expenses. Exploration expenses include dry hole costs, lease extensions, delay rentals and geological and geophysical costs.

Dependence on Major Customers. For the years ended December 31, 2010, 2009 and 2008, we sold substantially all of our oil and gas produced to three purchasers. Additionally, substantially all of our accounts receivable related to oil and gas sales were due from those three purchasers at December 31, 2010 and 2009. We believe that there are potential alternative purchasers and that it may be necessary to establish relationships with new purchasers. However, there can be no assurance that we can establish such relationships and that those relationships will result in increased purchasers. Although we are exposed to a concentration of credit risk, we believe that all of our purchasers are credit worthy.

Dependence on Suppliers. Our industry is cyclical, and from time to time there is a shortage of drilling rigs, equipment, services, supplies and qualified personnel. During these periods, the costs and delivery times of rigs, equipment, services and supplies are substantially greater. If the unavailability or high cost of drilling rigs, equipment, services, supplies or qualified personnel were particularly severe in the areas where we operate, we could be materially and adversely affected. We believe that there are potential alternative providers of drilling and completion services and that it may be necessary to establish relationships with new contractors. However, there can be no assurance that we can establish such relationships and that those relationships will result in increased availability of drilling rigs or other services.

Other Property. Furniture, fixtures and equipment are carried at cost. Depreciation of furniture, fixtures and equipment is provided using the straight-line method over estimated useful lives ranging from three to ten years. Gain or loss on retirement or sale or other disposition of assets is included in income in the period of disposition. Depreciation expense for other property and equipment was $233,000, $204,000 and $134,000 for the years ended December 31, 2010, 2009 and 2008, respectively.

Income Taxes. We are subject to U.S. federal income taxes along with state income taxes in Texas and New Mexico. When tax returns are filed, it is highly certain that some positions taken would be sustained upon examination by the taxing authorities, while others are subject to uncertainty about the merits of the position taken or the amount of the position that would be ultimately sustained. The benefit of a tax position is recognized in the financial statements in the period during which, based on all available evidence, management believes it is more likely than not that the position will be sustained upon examination, including the resolution of appeals or litigation processes, if any. Tax positions taken are not offset or aggregated with other positions. Tax positions that meet the more-likely-than-not recognition threshold are measured as the largest amount of tax benefit that is more than 50% likely of being realized upon settlement with the applicable taxing authority. The portion of the benefits associated with tax positions taken that exceeds the amount measured as described above is reflected as a liability for unrecognized tax benefits in the accompanying balance sheet along with any associated interest and penalties that would be payable to the taxing authorities upon examination. Interest and penalties associated with unrecognized tax benefits are classified as additional income taxes in the consolidated statement of income.

Based on our analysis, we did not have any uncertain tax positions as of December 31, 2010 or 2009. The Company's income tax returns are subject to examination by the relevant taxing authorities as follows: U.S. Federal income tax returns for tax years 2007 and forward, Texas income and margin tax returns for tax years 2007 and forward and New Mexico income tax returns for years 2007 and forward. There are currently no income tax examinations underway for these jurisdictions.

Deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to the differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using the tax rate in effect for the year in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the year of the enacted tax rate change.

Derivative Activity. All derivative instruments are recorded on the balance sheet at fair value. Changes in the instruments' fair values are recognized in the statement of operations immediately unless specific commodity derivative accounting criteria are met. For qualifying cash flow commodity derivatives, the gain or loss on the derivative is deferred in accumulated other comprehensive income to the extent the commodity derivative is effective. The ineffective portion of the commodity derivative is recognized immediately in the statement of operations. Gains and losses on commodity derivative instruments included in cumulative other comprehensive income are reclassified to oil and natural gas sales revenue in the period that the related production is delivered. Derivative contracts that do not qualify for commodity derivative accounting treatment are recorded as derivative assets and liabilities at fair value in the balance sheet, and the associated unrealized gains and losses are recorded as current income or expense in the statement of operations.

Historically, we have not designated our derivative instruments as cash-flow hedges. We record our open derivative instruments at fair value on our consolidated balance sheets as either unrealized gains or losses on commodity derivatives. We record changes in such fair value in earnings on our consolidated statements of operations under the caption entitled "unrealized gain (loss) on commodity derivatives."

Although we have not designated our derivative instruments as cash-flow hedges, we use those instruments to reduce our exposure to fluctuations in commodity prices related to our natural gas and oil production. Unrealized gains and losses, at fair value, are included on our consolidated balance sheets as current or non-current assets or liabilities based on the anticipated timing of cash settlements under the related contracts. Changes in the fair value of our commodity derivative contracts are recorded in earnings as they occur and included in other income (expense) on our consolidated statements of operations. Realized gains and losses are also included in other income (expense) on our consolidated statements of operations.

Accrued Liabilities. Following is a summary of our accrued liabilities at December 31, 2010 and 2009 (in thousands):

	2010	2009
Capital expenditures accrued	$ 8,924	$ 9,362
Operating expenses and other	1,762	1,517
Income taxes payable	—	56
Total	$10,686	$10,935

Asset Retirement Obligations. Our asset retirement obligations relate to future plugging and abandonment expenses on oil and gas properties. Based on the expected timing of payments, the full asset retirement obligation is classified as non-current. There were no significant changes to the asset retirement obligations for the years ended December 31, 2010, 2009 and 2008.

Foreign Currency Translation. The functional currency of the countries in which we operate is the U.S. dollar in the United States and the Canadian Dollar in Canada. Assets and liabilities of our Canadian subsidiary that are denominated in currencies other than the Canadian Dollar are translated at current exchange rates. Gains and losses resulting from such translations, along with gains or losses realized from transactions denominated in currencies other than the Canadian Dollar are included in operating results on our statements of operations. For purposes of consolidation, we translate the assets and liabilities of our Canadian Subsidiary into U.S. Dollars at current exchange rates while revenues and expenses are translated at the average rates in effect for the period. The related translation gains and losses are included in accumulated other comprehensive income within stockholders' equity on our consolidated balance sheets. During the years ended December 31, 2010 and 2008 we recognized translation losses of $4,000 and $601,000, net of the related income taxes, respectively. During the year ended December 31, 2009, we recognized translation gains, net of related income tax of $266,000.

Share-Based Compensation. We measure and record compensation expense for all share-based payment awards to employees and outside directors based on estimated grant date fair values. We recognize compensation costs for awards granted over the requisite service period based on the grant date fair value.

Earnings Per Common Share. We report basic earnings per common share, which excludes the effect of potentially dilutive securities, and diluted earnings per common share, which includes the effect of all potentially dilutive securities unless their impact is anti-dilutive. The following are reconciliations of the numerators and denominators of our basic and diluted earnings per share, (dollars in thousands, except per-share amounts):

	For the Years Ended December 31,		
	2010	**2009**	**2008**
Income (numerator):			
Net income (loss) — basic	$ 7,462	$ (5,229)	$ 23,386
Weighted average shares (denominator):			
Weighted average shares — basic	22,065,797	20,869,832	20,647,339
Dilution effect of share-based compensation, treasury method(1)	148,273	—	177,566
Weighted average shares — diluted	22,214,070	20,869,832	20,824,905
Earnings (loss) per share:			
Basic	$ 0.34	$ (0.25)	$ 1.13
Diluted	$ 0.34	$ (0.25)	$ 1.12

(1) Approximately 410,000 options to purchase our common stock were excluded from this calculation because they were anti-dilutive, during the year ended December 31, 2009.

2. Working Interest Acquisitions

In October 2010, we acquired an additional 10% working interest in Cinco Terry in Crockett County, Texas. The properties were acquired from a non-operating partner for $21.5 million, subject to post-closing adjustments. Funding was provided through borrowings under our revolving credit facility. The following is a summary of the purchase price and its allocation (in thousands):

Purchase price:	
Cash paid	$21,500
Asset retirement obligations assumed	132
Post-closing purchase price adjustments	(453)
Total	$21,179
Allocation:	
Wells, equipment and related facilities	$15,613
Mineral interests in oil and gas properties	5,566
Total	$21,179

Our 2010 oil, NGL and gas revenues included approximately $1.3 million related to this acquisition. Our 2010 net income included approximately $477,000 related to his acquisition.

In February 2011, we acquired an additional 38% working interest in Cinco Terry from two non-operating partners for $76 million, subject to usual and customary post-closing adjustments. We funded the acquisition with cash on hand and borrowings under our revolving credit facility. Our 2010 results of operations do not include any production, revenues or costs from this acquisition. Further, our 2010 estimated proved reserves do not include reserves associated with this acquisition.

The following condensed unaudited pro forma information gives effect to these acquisitions as if they had occurred on January 1, 2009. The pro forma information has been included in the notes as required by U.S. generally accepted accounting principles and is provided for comparison purposes only. The pro forma financial information is not necessarily indicative of the financial results that would have occurred had these acquisitions been effective on the dates as indicated and should not be viewed as indicative of operations in the future.

	Unaudited Pro Forma Financial Data	
	Years Ended December 31,	
	2010	2009
	(Dollars in thousands, except per-share amounts)	
Oil, NGL and gas sales	$86,114	$57,221
Total operating expenses	$63,384	$63,333
Net income (loss)	$15,714	$(5,207)
Earnings (loss) per share — basic	$ 0.71	$ (0.25)
Earnings (loss) per share — diluted	$ 0.71	$ (0.25)

3. Public Equity Offering

On November 10, 2010, we completed a public offering of 5,750,000 shares of our common stock. The underwriters were granted an option to purchase up to 862,500 additional shares of our common stock. The underwriters fully exercised this option and purchased the additional shares on November 11, 2010. After deducting underwriting discounts and transaction costs of approximately $5.7 million, we received net proceeds of approximately $101.8 million. We intend to use the proceeds to fund our capital expenditures for the Wolffork oil shale resource play, working interest and leasehold acquisitions in the Permian Basin and general working capital needs. Pending these uses, we used a portion of the proceeds of the 2010 equity offering to repay all outstanding borrowings under our revolving credit facility.

4. Revolving Credit Facility

We have a $200 million revolving credit facility with a borrowing base set at $150 million. The borrowing base is redetermined semi-annually on or before each April 1 and October 1 based on our oil and gas reserves. We or the lenders can each request one additional borrowing base redetermination each calendar year.

The maturity date under our revolving credit facility is July 31, 2012. Borrowings bear interest based on the agent bank's prime rate plus an applicable margin ranging from 1.25% to 2.25%, or the sum of the Eurodollar rate plus an applicable margin ranging from 2.25% to 3.25%. Margins vary based on the borrowings outstanding compared to the borrowing base. In addition, we pay an annual commitment of 0.50% of unused borrowings available under our revolving credit facility.

Effective February 1, 2010, we entered into a seventh amendment to our credit agreement, which replaced The Frost National Bank as the administrative agent under the credit agreement with JPMorgan Chase Bank, N.A., as successor agent.

Effective May 3, 2010, we entered into an eighth amendment to our credit agreement, which (i) extended the maturity date of the credit agreement by one year to July 31, 2012, (ii) increased the Company's commodity derivatives limit from 75% to 85% of annual projected production from proved developed producing oil and gas properties, (iii) reaffirmed the borrowing base and lenders' aggregate commitment of $115 million and (iv) transferred Fortis Capital Corp.'s interest in the credit agreement to BNP Paribas.

Effective October 21, 2010, we entered into a ninth amendment to our credit agreement, which increased the borrowing base and lenders' aggregate commitment under the credit agreement to $150 million from $115 million.

We had no outstanding borrowings at December 31, 2010. We had outstanding borrowings of $32.3 million under our revolving credit facility at December 31, 2009. The interest rate applicable to our revolving credit facility at December 31, 2010, was 4.75%. We also had outstanding unused letters of credit under our revolving credit facility totaling $350,000 at December 31, 2010, which reduce amounts available for borrowing under our revolving credit facility.

Loans under our revolving credit facility are secured by first priority liens on substantially all of our West Texas assets and are guaranteed by our subsidiaries.

Covenants

Our credit agreement contains two principal financial covenants:

- a consolidated modified current ratio covenant that requires us to maintain a ratio of not less than 1.0 to 1.0 at all times. The consolidated modified current ratio is calculated by dividing Consolidated Current Assets (as defined in the credit agreement) by Consolidated Current Liabilities (as defined in the credit agreement). As defined more specifically in the credit agreement, the consolidated modified current ratio is calculated as current assets less current unrealized gains on commodity derivatives plus the available borrowing base at the respective balance sheet date, divided by current liabilities less current unrealized losses on commodity derivatives at the respective balance sheet date.
- a consolidated funded debt to consolidated EBITDAX ratio covenant that requires us to maintain a ratio of not more than 3.5 to 1.0 at the end of each fiscal quarter. The consolidated funded debt to consolidated EBITDAX ratio is calculated by dividing Consolidated Funded Debt (as defined in the credit agreement) by Consolidated EBITDAX (as defined in the credit agreement). As defined more

specifically in the credit agreement, consolidated EBITDAX is calculated as net income (loss), plus (1) exploration expense, (2) depletion, depreciation and amortization expense, (3) share-based compensation expense, (4) unrealized loss on commodity derivatives, (5) interest expense, (6) income and franchise taxes and (7) certain other noncash expenses, less (1) gains or losses from sales or dispositions of assets, (2) unrealized gain on commodity derivatives and (3) extraordinary or nonrecurring gains. For purposes of calculating this ratio, consolidated EBITDAX for a fiscal quarter is annualized pursuant to the credit agreement.

Our credit agreement also restricts cash dividends and other restricted payments, transactions with affiliates, incurrence of other debt, consolidations and mergers, the level of operating leases, assets sales, investments in other entities and liens on properties.

In addition, our credit agreement contains customary events of default that would permit our lenders to accelerate the debt under our credit agreement if not cured within applicable grace periods, including, among others, failure to make payments of principal or interest when due, materially incorrect representations and warranties, failure to make mandatory prepayments in the event of borrowing base deficiencies, breach of covenants, defaults upon other obligations in excess of $500,000, events of bankruptcy, the occurrence of one or more unstayed judgments in excess of $500,000 not covered by an acceptable policy of insurance, failure to pay any obligation in excess of $500,000 owed under any derivatives transaction or in any amount if the obligation under the derivatives transaction is secured by collateral under the credit agreement, any event of default by the Company occurs under any agreement entered into in connection with a derivatives transaction, liens securing the loans under the credit agreement cease to be in place, a Change in Control (as defined in the credit agreement) of the Company occurs, and dissolution of the Company.

At December 31, 2010, we were in compliance with all of our covenants and had not committed any acts of default under the credit agreement.

5. Share-Based Compensation

In June 2007, the board of directors and stockholders approved the 2007 Stock Incentive Plan ("the 2007 Plan"). Under the 2007 Plan, we may grant restricted stock, stock options, stock appreciation rights, restricted stock units, performance awards, unrestricted stock awards and other incentive awards. The 2007 Plan reserves 10 percent of our outstanding common shares as adjusted on January 1 of each year, plus shares of common stock that were available for grant of awards under our prior plan. Awards of any stock options are to be priced at not less than the fair market value at the date of the grant. The vesting period of any stock award is to be determined by the board or an authorized committee at the time of the grant. The term of each stock option is to be fixed at the time of grant and may not exceed 10 years. Shares issued upon stock options exercised are issued as new shares.

Share-based compensation expense amounted to $2.6 million, $1.8 million and $1.1 million for the years ended December 31, 2010, 2009 and 2008, respectively. Such amounts represent the estimated fair value of stock awards for which the requisite service period elapsed during those periods. Included in share-based compensation expense for the years ended December 31, 2010 and 2009, was $381,000 and $377,000, respectively, related to grants to nonemployee directors.

Stock Options

There were no stock option grants during the years ended December 31, 2010 and 2009. The fair value of each option granted was estimated using an option-pricing model with the following weighted average assumptions during the year ended December 31, 2008.

	2008
Expected dividends	—
Expected volatility	64%
Risk-free interest rate	2.7%
Expected life	6 years

We have not paid out dividends historically, thus the dividend yields are estimated at zero percent.

Since our shares were not publicly traded prior to our initial public offering on November 8, 2007, we used an average of historical volatility rates based upon other companies within our industry for awards in 2008. Management believes that these average historical volatility rates are currently the best available indicator of expected volatility.

The risk-free interest rate is the implied yield available for zero-coupon U.S. government issues with a remaining term of five years.

The expected lives of our options are determined based on the term of the option using the simplified method outlined in Staff Accounting Bulletin 110.

Assumptions are reviewed each time there is a new grant and may be impacted by actual fluctuation in our stock price, movements in market interest rates and option terms. The use of different assumptions produces a different fair value for the options granted or modified and impacts the amount of compensation expense recognized on the consolidated statement of operations.

The following table summarizes stock options outstanding and activity as of and for the years ended December 31, 2010, 2009 and 2008, (dollars in thousands):

	Shares Subject to Stock Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value
Outstanding at January 1, 2008	479,991	$ 7.07	8.02	$2,779
Granted	74,345	$14.90		
Exercised	(63,459)	$ 3.33		
Canceled	(56,575)	$12.40		
Outstanding at December 31, 2008	434,302	$ 8.47	7.34	$ 837
Granted	—	$ —		
Exercised	—	$ —		
Canceled	(24,975)	$12.00		
Outstanding at December 31, 2009	409,327	$ 8.03	6.10	$ —
Granted	—	$ —		
Exercised	(58,798)	$12.76		
Canceled	(16,200)	$12.00		
Outstanding at December 31, 2010	334,329	$ 7.01	4.87	$4,567
Exercisable (fully vested) at December 31, 2010	280,607	$ 5.49	4.42	$4,941

The fair market value of the stock options granted during the year ended December 31, 2008, was $8.96 per share. Total unrecognized share-based compensation expense from unvested stock options as of December 31, 2010 and 2009, was $44,000 and $529,000, respectively, and will be recognized over a remaining service period of 0.25 and 1.25 years, respectively. The intrinsic value of the options exercised during the years ended December 31, 2010 and 2008, was $608,000 and $770,000, respectively. There was no tax benefit recognized in relation to the stock options exercised.

Nonvested Shares

Share grants totaling 568,142 shares, 204,790 shares and 35,948 shares with an approximate aggregate fair market value of $4.3 million, $1.7 million and $733,000 at the time of grant were granted to employees during the years ended December 31, 2010, 2009 and 2008, respectively. Included in the share grants for 2010 are 400,000 shares awarded to our executive officers. The aggregate fair market value of these shares on the grant date was $2.7 million to be expensed over a service period of approximately five years, subject to certain performance restrictions. A summary of the status of nonvested shares for the years ended December 31, 2010, 2009 and 2008, is presented below:

	Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2008	42,500	$16.50
Granted	35,948	20.39
Vested	(21,250)	16.50
Canceled	(1,175)	15.48
Nonvested at December 31, 2008	56,023	18.96
Granted	204,790	8.40
Vested	(32,182)	18.07
Canceled	(2,751)	12.39
Nonvested at December 31, 2009	225,880	9.73
Granted	568,142	7.71
Vested	(77,969)	10.07
Canceled	(7,272)	9.51
Nonvested at December 31, 2010	708,781	$ 8.04

As of December 31, 2010, unrecognized compensation expense related to the nonvested shares amounted to $4.3 million, which will be recognized over a remaining service period of four years.

In March 2011, 204,000 shares with an aggregate fair market value of $6.5 million on the grant date were awarded to our executive officers. The fair market value of these awards will be expensed over a service period of approximately four years, subject to certain performance criteria.

6. Income Taxes

Our provision (benefit) for income taxes comprised the following (in thousands):

	Years Ended December 31,		
	2010	2009	2008
Current:			
Federal	$ —	$ —	$ (214)
State	—	—	177
Total current	$ —	$ —	$ (37)
Deferred:			
Federal	$3,917	$(1,056)	$11,919
State	183	271	229
Total deferred	$4,100	$ (785)	$12,148
Provision (benefit) for income taxes	$4,100	$ (785)	$12,111

Total income tax expense (benefit) differed from the amounts computed by applying the U.S. Federal statutory tax rates to pre-tax income (in thousands):

	Years Ended December 31,		
	2010	2009	2008
Statutory tax at 34%	$3,931	$(2,045)	$12,069
State taxes, net of federal impact	184	72	199
Permanent differences(1)	53	231	235
Other differences	(68)	957(2)	(392)
Total	$4,100	$ (785)	$12,111

(1) Amounts primarily relate to share-based compensation expense.

(2) Approximately $600,000 relates to a change in our estimated income tax for the year ended December 31, 2008.

Deferred tax assets and liabilities are the result of temporary differences between the financial statement carrying values and tax bases of assets and liabilities. Our net deferred tax assets and liabilities are recorded as a long-term liability of $44.6 million and $38.4 million at December 31, 2010 and 2009, respectively. At December 31, 2010 and 2009, $2.3 million and $255,000 of deferred taxes expected to be realized within one year were included in current assets. Significant components of net deferred tax assets and liabilities are (in thousands):

	Years Ended December 31,	
	2010	2009
Deferred tax assets:		
Net operating loss carryforwards	$ 13,587	$ 7,214
Unrealized loss on commodity derivatives	381	301
Other	1,148	362
Total deferred tax assets	15,116	7,877
Deferred tax liability:		
Difference in depreciation, depletion and capitalization methods — oil and gas properties	(57,414)	(45,996)
Net deferred tax liability	$(42,298)	$(38,119)

Net operating loss carryforwards for tax purposes have the following expiration dates (in thousands):

Expiration Dates	Amounts
2023	$ 1,523
2024	1,082
2025	2,594
2026	1,683
2027	1,020
2028	1,309
2029	3,299
2030	26,538
Total	$39,048

7. Derivatives

At December 31, 2010, we had the following commodity derivatives positions outstanding:

	Volume (MMBtu)		$/MMBtu
Period	Monthly	Total	Fixed
NYMEX — Henry Hub			
Price swaps 2011	230,000	2,760,000	$ 4.86
Price call 2012	230,000	2,760,000	$ 6.00
WAHA basis differential			
Basis swaps 2011	300,000	3,600,000	$(0.53)

The following summarizes the fair value of our open commodity derivatives as of December 31, 2010 and December 31, 2009 (in thousands):

	Asset Derivatives			Liability Derivatives		
		Fair Value			Fair Value	
	Balance Sheet Location	December 31, 2010	December 31, 2009	Balance Sheet Location	December 31, 2010	December 31, 2009
Derivatives not designated as hedging instruments						
Commodity derivatives	Unrealized gain on commodity derivatives	$862	$786	Unrealized loss on commodity derivatives	$1,956	$2,668

The following summarizes the change in the fair value of our commodity derivatives (in thousands):

	Income Statement Location	Fair Value		
		Year Ended December 31,		
		2010	2009	2008
Derivatives not designated as hedging instruments				
Commodity derivatives	Unrealized gain (loss) on commodity derivatives	$ 788	$ (9,899)	$ 7,149
	Realized gain on commodity derivatives	5,784	14,659	2,936
		$6,572	$ 4,760	$10,085

Unrealized gains and losses, at fair value, are included on our consolidated balance sheets as current or non-current assets or liabilities based on the anticipated timing of cash settlements under the related contracts.

Changes in the fair value of our commodity derivative contracts are recorded in earnings as they occur and included in other income (expense) on our consolidated statements of operations. We estimate the fair values of swap contracts based on the present value of the difference in exchange-quoted forward price curves and contractual settlement prices multiplied by notional quantities. We internally valued the option contracts using industry-standard option pricing models and observable market inputs. We use our internal valuations to determine the fair values of the contracts that are reflected on our consolidated balance sheets. Realized gains and losses are also included in other income (expense) on our consolidated statements of operations.

We are exposed to credit losses in the event of nonperformance by the counterparties on our commodity derivatives positions and have considered the exposure in our internal valuations. However, we do not anticipate nonperformance by the counterparties over the term of the commodity derivatives positions.

To estimate the fair value of our commodity derivatives positions, we use market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach for recurring fair value measurements and attempt to use the best available information. We determine the fair value based upon the hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and lowest priority to unobservable inputs (Level 3 measurement). The three levels of fair value hierarchy are as follows:

- Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. At December 31, 2010, we had no Level 1 measurements.
- Level 2 — Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Our derivatives, which consist primarily of commodity swaps and collars, are valued using commodity market data which is derived by combining raw inputs and quantitative models and processes to generate forward curves. Where observable inputs are available, directly or indirectly, for substantially the full term of the asset or liability, the instrument is categorized in Level 2. At December 31, 2010, all of our commodity derivatives were valued using Level 2 measurements.
- Level 3 — Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. At December 31, 2010, our Level 3 measurements were limited to our asset retirement obligation.

8. Canadian Unconventional Gas Investment

In May 2007, we acquired shares of common stock of a Canadian-based private exploration company focused on tight gas and shale gas opportunities in Canada. Our investment amounted to approximately $917,000 and is a non-controlling interest accounted for using the cost method. We have written off the carrying value of our minority equity investment in the Canadian operator by recognizing a non-cash charge to earnings because we believe we will not recover our investment.

9. Commitments and Contingencies

We periodically enter into contractual arrangements under which we are committed to expend funds to drill wells in the future, including agreements to secure drilling rig services, which require us to make future minimum payments to the rig operators. We record drilling commitments in the periods in which well capital expenditures are incurred or rig services are provided. Our commitment under daywork drilling contracts was $4.3 million at December 31, 2010.

At December 31, 2010, we had employment agreements with two of our officers. These agreements are automatically renewed for successive terms of one year unless employment is terminated at the end of the term by written notice given to the employee not less than 60 days prior to the end of such term. Our maximum commitment under the employment agreements, which would apply if the executives covered by these agreements were each terminated without cause, was approximately $757,000 at December 31, 2010. As of January 24, 2011, we had entered into amended and restated or new employment agreements, each with two-year initial terms, with five executive officers. We estimate that our maximum commitment under these employment agreements, which would apply if the employees covered by these agreements were all terminated without cause, was approximately $4 million as of the date of this report. This estimate assumes the maximum potential bonus for 2011 is earned by each employee during 2011 with no prorated amounts due to partial year of service.

We lease our office space in Fort Worth, Texas, under a non-cancelable agreement that expires on December 31, 2012. We also have non-cancelable operating lease commitments related to office equipment that expire by 2012. The following is a schedule by years of future minimum rental payments required under our operating lease arrangements as of December 31, 2010 (in thousands):

2011	$ 548
2012	473
Total	$1,021

Rent expense under our lease arrangements amounted to $463,000, $461,000 and $299,000 for the years ended December 31, 2010, 2009 and 2008, respectively.

Litigation

Approach Operating, LLC v. EnCana Oil & Gas (USA) Inc., Cause No. 29.070A, District Court of Limestone County, Texas. On July 2, 2009 our operating subsidiary filed a lawsuit against EnCana Oil & Gas (USA) Inc. ("EnCana") for breach of the JOA covering our North Bald Prairie project in East Texas and seeking damages for nonpayment of amounts owed under the joint operating agreement ("JOA") as well as declaratory relief. We contend that such amounts owed by EnCana are at least $2 million, plus attorneys' fees, costs and other amounts to which we might be entitled under law or in equity. The amount owed to us is included in other non-current assets on our balance sheet at December 31, 2010. As we previously have disclosed, in December 2008, EnCana notified us that it was exercising its right to become operator of record for joint interest wells in North Bald Prairie under an operator election agreement between the parties. EnCana contends that it does not owe us for part or all of joint interest billings incurred after EnCana provided us with notice of EnCana's election to assume operatorship in December 2008. EnCana also contends that certain of the disputed operations were unnecessary, while other charges are improper because we failed to obtain EnCana's consent under the JOA prior to undertaking the operations. We have informed the Court that we will transfer operatorship to EnCana when EnCana has made all payments it owes under the JOA.

We also are involved in various other legal and regulatory proceedings arising in the normal course of business. While we cannot predict the outcome of these proceedings with certainty, we do not believe that an adverse result in any pending legal or regulatory proceeding, individually or in the aggregate, would be material to our consolidated financial condition or cash flows; however, an unfavorable outcome could have a material adverse effect on our results of operations for a specific interim period or year.

Environmental Issues

We are engaged in oil and gas exploration and production and may become subject to certain liabilities as they relate to environmental clean up of well sites or other environmental restoration procedures as they relate to the drilling of oil and gas wells and the operation thereof. In connection with our acquisition of existing or previously drilled well bores, we may not be aware of what environmental safeguards were taken at the time such wells were drilled or during such time the wells were operated. Should it be determined that a liability exists with respect to any environmental clean up or restoration, we would be responsible for curing such a violation. No claim has been made, nor are we aware of any liability that exists, as it relates to any environmental clean up, restoration or the violation of any rules or regulations relating thereto.

10. Oil and Gas Producing Activities

Set forth below is certain information regarding the costs incurred for oil and gas property acquisition, development and exploration activities (in thousands):

	For the Years Ended December 31,		
	2010	2009	2008
Property acquisition costs:			
Unproved properties	$12,528	$ 1,081	$ 2,695
Proved properties	2,055	57	12,189
Exploration costs	2,874	1,483	5,007
Development costs(1)	72,528	28,121	84,193
Total costs incurred	$89,985	$30,742	$104,084

(1) For the years ended December 31, 2010, 2009 and 2008, development costs include $604,000, $170,000 and $3.5 million in non-cash asset retirement obligations, respectively.

Set forth below is certain information regarding the results of operations for oil and gas producing activities (in thousands):

	For the Years Ended December 31,		
	2010	2009	2008
Revenues	$ 57,581	$ 40,648	$ 79,869
Production costs	(11,545)	(9,773)	(11,823)
Exploration expense	(2,589)	(1,621)	(1,478)
Impairment	(2,622)	(2,964)	(6,379)
Depletion	(21,991)	(24,456)	(23,576)
Income tax expense	(6,527)	(636)	(12,690)
Results of operations	$ 12,307	$ 1,198	$ 23,923

11. Disclosures About Oil and Gas Producing Activities (unaudited)

Proved Reserves

The estimates of proved reserves and related valuations for the years ended December 31, 2010, 2009 and 2008, were prepared by DeGolyer and MacNaughton, independent petroleum engineers. Each year's estimate of proved reserves and related valuations were also prepared in accordance with then-current provisions of ASC 932 and Statement of Financial Accounting Standards 69, or SFAS 69, Disclosures about Oil and Gas Producing Activities.

Estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors. All of our estimated oil and natural gas reserves are attributable to properties within the United States. A summary of Approach's changes in quantities of proved oil, NGL and natural gas reserves for the years ended December 31, 2008, 2009 and 2010, are as follows:

Proved Developed and Proved Undeveloped Reserves	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Balance—December 31, 2007	2,088	1,120	161,151	30,066
Extensions and discoveries	1,656	1,572	22,879	7,041
Purchases of minerals in place	67	—	7,312	1,286
Production	(175)	(102)	(7,092)	(1,459)
Revisions to previous estimates	(98)	239	(11,383)	(1,756)
Balance—December 31, 2008	3,538	2,829	172,867	35,178
Extensions and discoveries	1,392	1,290	14,301	5,066
Purchases of minerals in place	—	—	—	—
Production	(206)	(209)	(6,320)	(1,468)
Revisions to previous estimates	(386)	184	(12,514)	(2,288)
Balance—December 31, 2009	4,338	4,094	168,334	36,488
Extensions and discoveries	984	1,395	8,365	3,773
Purchases of minerals in place	383	786	4,736	1,958
Production	(247)	(261)	(6,290)	(1,556)
Revisions to previous estimates	(507)	14,685	(24,756)	10,052
Balance—December 31, 2010	4,951	20,699	150,389	50,715
Proved Developed Reserves:				
December 31, 2008	1,454	1,560	84,217	17,050
December 31, 2009	1,239	1,879	74,804	15,585
December 31, 2010	2,146	11,193	74,739	25,795

The following is a discussion of the material changes in our proved reserve quantities for the years ended December 31, 2010, 2009 and 2008:

Year Ended December 31, 2010

Our drilling programs in Cinco Terry and Ozona Northeast resulted in our classification of reserves as proved, which accounts for the additional quantities listed under extensions and discoveries. For the year ended December 31, 2010, we recorded a 10,052 MBoe positive revision to our previous estimate, resulting from 9,190 MBoe attributable to planned processing upgrades in Ozona Northeast and 1,117 MBoe attributable to an increase in commodity prices, partially offset by 255 MBoe of negative performance revisions. On April 1, 2011, we will begin realizing NGL revenues from the natural gas production in Ozona Northeast under a gas purchase and processing contract with DCP Midstream, LP. The commodity prices used to estimate our proved reserves at December 31, 2010, increased to $4.38/MMBtu of gas, $39.25/Bbl of NGLs and $79.40/Bbl of oil from $3.87/MMBtu of natural gas, $27.20/Bbl of NGLs and $56.04/Bbl of oil at December 31, 2009. The negative revision of 255 MBoe, primarily related to producing properties in our North Bald Prairie field in East Texas. Well performance data collected during 2010 for North Bald Prairie indicated that these assets underperformed our year-end 2010 decline estimates. Accordingly, we removed

910 MMcf (152 MBoe) from proved reserves recorded for North Bald Prairie. We also removed 58 MBoe and 45 MBoe in Cinco Terry and Ozona Northeast, respectively, due to performance revisions.

Year Ended December 31, 2009

Our drilling programs in Cinco Terry and Ozona Northeast resulted in our classification of reserves as proved, which accounts for the additional quantities listed under extensions and discoveries. For the year ended December 31, 2009, of the 2,288 MBoe downward revision of our previous estimate, 1,692 MBoe and 596 MBoe relate to price and performance revisions, respectively. The gas price used to estimate our proved reserves decreased from $6.04 per Mcf at December 31, 2008, to $3.88 per Mcf at December 31, 2009. The performance revision primarily related to producing properties in our North Bald Prairie field in East Texas. Well performance data collected during 2009 for North Bald Prairie indicate that these assets underperformed our year-end 2008 decline estimates. Accordingly, we removed 4,514 MMcf from proved reserves recorded for North Bald Prairie. We also removed 103 MBoe in Ozona Northeast due to performance revisions. Partially offsetting the removal of 856 MBoe from proved reserves recorded for North Bald Prairie and Ozona Northeast was a positive performance revision of 260 MBoe in our Cinco Terry field in West Texas.

Year Ended December 31, 2008

Our drilling programs in Ozona Northeast, Cinco Terry and North Bald Prairie resulted in our classification of reserves as proved, which accounts for the additional quantities listed under extensions and discoveries. Additionally, during 2008 we acquired 1,285 MBoe of proved reserves in Ozona Northeast, which accounts for the additional proved reserve quantities listed as purchases of minerals in place. Downward revisions to proved reserves of 1,234 MBoe are the result of a significant decline in commodity prices during the third and fourth quarters of 2008. The gas price used to estimate our proved reserves decreased from $8.10 per Mcf at December 31, 2007 to $6.04 per Mcf at December 31, 2008. Downward revisions to proved reserves of 522 MBoe, which represents 1.7% of the our estimated proved reserves of 30,067 MBoe at December 31, 2007, was based on the accumulation of additional production results that occurred during 2008 in Ozona Northeast and North Bald Prairie. Wells that primarily were responsible for downward revisions had little production history (as proved developed producing wells) or no production history (as proved undeveloped locations) when reserves for those wells and locations were booked at December 31, 2007. At December 31, 2008, after recording and reviewing a year's worth of production history, we determined to revise the estimated ultimate recoveries for these wells downward.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves and the changes in standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves were prepared in accordance with then-current provisions of ASC 932 and SFAS 69. Future cash inflows were computed by applying the average on the closing price on the first day of each month for the 12-month period prior to December 31, 2010, to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and natural gas reserves at year end, based on year-end costs and assuming continuation of existing economic conditions.

Future income tax expenses are calculated by applying appropriate year-end tax rates to future pre-tax net cash flows relating to proved oil and natural gas reserves, less the tax basis of properties involved.

Future income tax expenses give effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and natural gas reserves. Future net cash flows are discounted at a rate of 10% annually to derive the standardized measure of discounted future net cash flows. This calculation procedure does not necessarily result in an estimate of the fair market value of Approach's oil and natural gas properties.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows (in thousands):

	Years Ended December 31,		
	2010	2009	2008
Future cash flows	$1,804,477	$1,007,703	$1,248,661
Future production costs	(499,321)	(358,276)	(411,177)
Future development costs	(259,005)	(213,161)	(201,259)
Future income tax expense	(282,628)	(88,796)	(157,503)
Future net cash flows	763,523	347,470	478,722
10% annual discount for estimated timing of cash flows	(559,291)	(267,479)	(336,087)
Standardized measure of discounted future net cash flows	$ 204,232	$ 79,991	$ 142,635

Future cash flows as shown above were reported without consideration for the effects of commodity derivative transactions outstanding at each period end.

Changes in Standardized Measure of Discounted Future Net Cash Flows

The changes in the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows (in thousands):

	Years Ended December 31,		
	2010	2009	2008
Balance, beginning of period	$ 79,991	$142,635	$ 215,960
Net change in sales and transfer prices and in production (lifting) costs related to future production	120,520	(89,649)	(148,739)
Changes in estimated future development costs	(65,718)	(29,647)	(72,754)
Sales and transfers of oil and gas produced during the period	(46,031)	(30,877)	(68,037)
Net change due to extensions, discoveries and improved recovery	30,240	26,648	58,249
Net change due to purchase of minerals in place	15,696	—	10,632
Net change due to revisions in quantity estimates	80,564	(12,034)	(14,526)
Previously estimated development costs incurred during the period	40,265	28,121	89,942
Accretion of discount	17,166	18,743	29,369
Other	4,171	(3,449)	(8,712)
Net change in income taxes	(72,632)	29,500	51,251
Standardized measure of discounted future net cash flows	$204,232	$ 79,991	$ 142,635

The commodity prices in effect at December 31, 2010, 2009 and 2008, inclusive of adjustments for quality and location used in determining future net revenues related to the standardized measure calculation are as follows:

	2010	2009	2008
Oil (per Bbl)	$79.40	$56.04	$39.60
Natural gas liquids (per Bbl)	$39.25	$27.20	$23.00
Gas (per Mcf)	$ 4.38	$ 3.88	$ 6.04

12. Supplementary Data

Selected Quarterly Financial Data (unaudited), (dollars in thousands, except per-share amounts):

	2010 Quarters Ended			
	December 31	September 30	June 30	March 31
Net revenue	$ 16,290	$ 14,916	$ 13,155	$ 13,220
Net operating expenses	(15,493)	(12,350)	(10,191)	(12,368)
Interest expense, net	(558)	(615)	(550)	(466)
Realized gain on commodity derivates	2,171	1,615	1,768	230
Unrealized (loss) gain on commodity derivatives	(2,094)	(312)	(1,901)	5,095
Income before income taxes	316	3,254	2,281	5,711
Income tax provision	55	1,167	730	2,148
Net income	$ 261	$ 2,087	$ 1,551	$ 3,563
Basic net income applicable to common stockholders per common share	$ 0.01	$ 0.10	$ 0.07	$ 0.17
Diluted net income applicable to common stockholders per common share	$ 0.01	$ 0.10	$ 0.07	$ 0.17

	2009 Quarters Ended			
	December 31	September 30	June 30	March 31
Net revenue	$ 11,881	$ 8,787	$ 9,915	$ 10,065
Net operating expenses	(15,650)	(10,715)	(10,713)	(12,557)
Interest expense, net	(434)	(451)	(457)	(445)
Realized gain on commodity derivates	2,763	4,271	4,444	3,181
Unrealized (loss) gain on commodity derivatives	(1,310)	(6,414)	(4,320)	2,145
(Loss) income before income taxes	(2,750)	(4,522)	(1,131)	2,389
Income tax (benefit) provision	(468)	(1,378)	(460)	1,521
Net (loss) income	$ (2,282)	$ (3,144)	$ (671)	$ 868
Basic net (loss) income applicable to common stockholders per common share	$ (0.11)	$ (0.15)	$ (0.03)	$ 0.04
Diluted net (loss) income applicable to common stockholders per common share	$ (0.11)	$ (0.15)	$ (0.03)	$ 0.04

	2008 Quarters Ended			
	December 31	September 30	June 30	March 31
Net revenue	$ 14,692	$22,015	$ 24,144	$19,018
Impairment of non-producing properties	(6,379)	—	—	—
Net operating expenses	(14,485)	(9,749)	(11,855)	(9,803)
Interest expense, net	(355)	(423)	(343)	(148)
Impairment of investment	(917)	—	—	—
Realized gain (loss) on commodity derivates	3,612	(195)	(542)	61
Unrealized gain (loss) on commodity derivatives	3,089	18,611	(9,672)	(4,879)
(Loss) income before income taxes	(743)	30,259	1,732	4,249
Income tax (benefit) provision	(591)	10,411	804	1,487
Net (loss) income	$ (152)	$19,848	$ 928	$ 2,762
Basic net (loss) income applicable to common stockholders per common share	$ (0.01)	$ 0.96	$ 0.04	$ 0.13
Diluted net (loss) income applicable to common stockholders per common share	$ (0.01)	$ 0.95	$ 0.04	$ 0.13

Approach Resources Inc.
Index to Exhibits

Exhibit Number	Description of Exhibit
2.1	Purchase and Sale Agreement dated October 29, 2010, between Magnum Hunter Resources Corporation and Approach Oil & Gas Inc. (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K filed November 2, 2010, and incorporated herein by reference).
2.2	Purchase and Sale Agreement dated February 23, 2011, between J. Cleo Thompson and James Cleo Thompson, Jr. L.P., Wes-Tex Drilling Company, L.P. and Approach Oil & Gas Inc. (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K filed March 1, 2011, and incorporated herein by reference).
3.1	Restated Certificate of Incorporation of Approach Resources Inc. (filed as Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q filed December 13, 2007, and incorporated herein by reference).
3.2	Restated Bylaws of Approach Resources Inc. (filed as Exhibit 3.2 to the Company's Quarterly Report on Form 10-Q filed December 13, 2007, and incorporated herein by reference).
4.1	Specimen Common Stock Certificate (filed as Exhibit 4.1 to the Company's Registration Statement on Form S-1/A filed October 18, 2007 (File No. 333-144512), and incorporated herein by reference).
10.1	Form of Indemnity Agreement between Approach Resources Inc. and each of its directors and officers (filed as Exhibit 10.1 to the Company's Registration Statement on Form S-1/A filed September 13, 2007 (File No. 333-144512), and incorporated herein by reference).
10.2	First Amendment to Form of Indemnity Agreement between Approach Resources Inc. and each of its directors and officers (filed as Exhibit 10.5 to the Company's Current Report on Form 8-K filed December 31, 2008, and incorporated herein by reference).
10.3†	Amended and Restated Employment Agreement by and between Approach Resources Inc. and J. Ross Craft dated January 1, 2011 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed January 6, 2011, and incorporated herein by reference).
10.4†	Amended and Restated Employment Agreement by and between Approach Resources Inc. and Steven P. Smart dated January 1, 2011 (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed January 6, 2011, and incorporated herein by reference).
10.5†	Employment Agreement by and between Approach Resources Inc. and J. Curtis Henderson dated January 1, 2011 (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K filed January 6, 2011, and incorporated herein by reference).
10.6†	Employment Agreement by and between Approach Resources Inc. and Qingming Yang dated January 24, 2011 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed January 28, 2011, and incorporated herein by reference).
10.7†	Employment Agreement by and between Approach Resources Inc. and Ralph P. Manoushagian dated January 24, 2011 (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed January 28, 2011, and incorporated herein by reference).
10.8†	Approach Resources Inc. 2007 Stock Incentive Plan, effective as of June 28, 2007 (filed as Exhibit 10.6 to the Company's Registration Statement on Form S-1 filed July 12, 2007, and incorporated herein by reference).
10.9†	First Amendment dated December 31, 2008, to Approach Resources Inc. 2007 Stock Incentive Plan, effective as of June 28, 2007 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed December 31, 2008, and incorporated herein by reference).
10.10	Form of Business Opportunities Agreement among Approach Resources Inc. and the other signatories thereto (filed as Exhibit 10.11 to the Company's Registration Statement on Form S-1/A filed October 18, 2007 (File No. 333-144512), and incorporated herein by reference).
10.11†	Form of Option Agreement under 2003 Stock Option Plan (filed as Exhibit 10.12 to the Company's Registration Statement on Form S-1 filed July 12, 2007, and incorporated herein by reference).

Exhibit Number	Description of Exhibit
10.12†	Form of Summary of Stock Option Grant under Approach Resources Inc. 2007 Stock Incentive Plan (filed as Exhibit 10.14 to the Company's Registration Statement on Form S-1/A filed October 18, 2007 (File No. 333-144512), and incorporated herein by reference).
10.13†	Form of Restricted Stock Award Agreement under Approach Resources Inc. 2007 Stock Incentive Plan (filed as Exhibit 10.10 to the Company's Quarterly Report on Form 10-Q filed November 6, 2008, and incorporated herein by reference).
*10.14†	Form of Performance-Based, Time-Vesting Restricted Stock Award Agreement under Approach Resources Inc. 2007 Stock Incentive Plan.
10.15	Registration Rights Agreement dated as of November 14, 2007, by and among Approach Resources Inc. and investors identified therein (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K/A filed December 3, 2007, and incorporated herein by reference).
10.16	Gas Purchase Contract dated May 1, 2004, between Ozona Pipeline Energy Company, as Buyer, and Approach Resources I, L.P. and certain other parties identified therein (filed as Exhibit 10.18 to the Company's Registration Statement on Form S-1/A filed September 13, 2007 (File No. 333-144512), and incorporated herein by reference).
10.17	Agreement Regarding Gas Purchase Contract dated May 26, 2005, between Ozona Pipeline Energy Company, as Buyer, and Approach Resources I, L.P. and certain other parties identified therein (filed as Exhibit 10.19 to the Company's Registration Statement on Form S-1/A filed September 13, 2007 (File No. 333-144512), and incorporated herein by reference).
10.19	Gas Purchase Agreement dated as of November 21, 2007, between WTG Benedum Joint Venture, as Buyer, and Approach Oil & Gas Inc. and Approach Operating, LLC, as Seller (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed November 28, 2007, and incorporated herein by reference).
10.20	Gas Purchase Contract dated as of January 1, 2011, between Approach Resources I, LP and Approach Oil & Gas Inc., as Seller, and DCP Midstream, LP, as Buyer (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed January 14, 2011, and incorporated herein by reference).
10.21	Carry and Earning Agreement dated July 13, 2007, by and between Approach Oil & Gas Inc. and EnCana Oil & Gas (USA) Inc. (filed as Exhibit 10.22 to the Company's Registration Statement on Form S-1/A filed September 13, 2007 (File No. 333-144512), and incorporated herein by reference).
10.22	Oil & Gas Lease dated February 27, 2007, between the lessors identified therein and Approach Oil & Gas Inc., as successor to Lynx Production Company, Inc. (filed as Exhibit 10.23 to the Company's Registration Statement on Form S-1/A filed September 13, 2007 (File No. 333-144512), and incorporated herein by reference).
10.23	Amendment dated as of January 1, 2009, to Oil & Gas Lease dated February 27, 2007, between the lessors identified therein and Approach Oil & Gas Inc., as successor to Lynx Production Company, Inc. (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed October 20, 2009, and incorporated herein by reference).
10.24	Specimen Oil and Gas Lease for Boomerang prospect between lessors and Approach Oil & Gas Inc., as successor to The Keeton Group, LLC, as lessee (filed as Exhibit 10.24 to the Company's Registration Statement on Form S-1/A filed September 13, 2007 (File No. 333-144512), and incorporated herein by reference).
10.25	$200,000,000 Revolving Credit Agreement dated as of January 18, 2008, among Approach Resources Inc., as borrower, The Frost National Bank, as administrative agent and lender, and the financial institutions named therein (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed January 25, 2008, and incorporated herein by reference).

Exhibit Number	Description of Exhibit
10.26	Amendment No. 1 dated February 19, 2008, to Credit Agreement dated as of January 18, 2008, among Approach Resources Inc., as borrower, The Frost National Bank, and JPMorgan Chase Bank, NA, as lenders, and Approach Oil & Gas Inc., Approach Oil & Gas (Canada) Inc. and Approach Resources I, LP, as guarantors (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed February 22, 2008, and incorporated herein by reference).
10.27	Amendment No. 2 dated May 6, 2008, to Credit Agreement dated as of January 18, 2008, among Approach Resources Inc., as borrower, The Frost National Bank, as administrative agent and lender, JPMorgan Chase Bank, NA, as lender, and Approach Oil & Gas Inc., Approach Oil & Gas (Canada) Inc. and Approach Resources I, LP, as guarantors (filed as Exhibit 99.1 to the Company's Current Report on Form 8-K filed August 28, 2008, and incorporated herein by reference).
10.28	Amendment No. 3 dated August 26, 2008, to Credit Agreement dated as of January 18, 2008, among Approach Resources Inc., as borrower, The Frost National Bank, as administrative agent and lender, JPMorgan Chase Bank, NA, Fortis Capital Corp. and KeyBank National Association, as lenders, and Approach Oil & Gas Inc., Approach Oil & Gas (Canada) Inc. and Approach Resources I, LP, as guarantors (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed August 28, 2008, and incorporated herein by reference).
10.29	Amendment No. 4 dated April 8, 2009, to Credit Agreement dated as of January 18, 2008, among Approach Resources Inc., as borrower, The Frost National Bank, as administrative agent and lender, JPMorgan Chase Bank, NA, Fortis Capital Corp. and KeyBank National Association, as lenders, and Approach Oil & Gas Inc., Approach Oil & Gas (Canada) Inc. and Approach Resources I, LP, as guarantors (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed April 16, 2009, and incorporated herein by reference).
10.30	Amendment No. 5 dated July 8, 2009, to Credit Agreement dated as of January 18, 2008, among Approach Resources Inc., as borrower, The Frost National Bank, as administrative agent and lender, JPMorgan Chase Bank, NA, Fortis Capital Corp. and KeyBank National Association, as lenders, and Approach Oil & Gas Inc., Approach Oil & Gas (Canada) Inc. and Approach Resources I, LP, as guarantors (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed July 14, 2009, and incorporated herein by reference).
10.31	Amendment No. 6 dated as of October 30, 2009, to Credit Agreement dated as of January 18, 2008, among Approach Resources Inc., as borrower, The Frost National Bank, as administrative agent and lender, JPMorgan Chase Bank, NA, Fortis Capital Corp. and KeyBank National Association, as lenders, and Approach Oil & Gas Inc., Approach Oil & Gas (Canada) Inc. and Approach Resources I, LP, as guarantors (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed November 3, 2009, and incorporated herein by reference).
10.32	Amendment No. 7 dated as of February 1, 2010, to Credit Agreement dated as of January 18, 2008, among Approach Resources Inc., as borrower, The Frost National Bank, as administrative agent and lender, JPMorgan Chase Bank, N.A., as successor agent and lender, Fortis Capital Corp. and KeyBank National Association, as lenders, and Approach Oil & Gas Inc., Approach Oil & Gas (Canada) Inc. and Approach Resources I, LP, as guarantors (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed February 4, 2010, and incorporated herein by reference).
10.33	Amendment No. 8 dated as of May 3, 2010, to Credit Agreement dated as of January 18, 2008, among Approach Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as administrative agent and lender, The Frost National Bank, BNP Paribas and KeyBank National Association, as lenders, Fortis Capital Corp., as departing lender and Approach Oil & Gas Inc., Approach Oil & Gas (Canada) Inc. and Approach Resources I, LP, as guarantors (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed May 6, 2010, and incorporated herein by reference).

Exhibit Number	Description of Exhibit
10.34	Amendment No. 9 dated as of October 21, 2010, to Credit Agreement dated as of January 18, 2008, among Approach Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as administrative agent and lender, The Frost National Bank, BNP Paribas and KeyBank National Association, as lenders, and Approach Oil & Gas Inc., Approach Oil & Gas (Canada) Inc. and Approach Resources I, LP, as guarantors (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed October 26, 2010, and incorporated herein by reference).
14.1	Code of Conduct (filed as Exhibit 14.1 to the Company's Annual Report on Form 10-K filed March 28, 2008, and incorporated herein by reference).
21.1	Subsidiaries (filed as Exhibit 21.1 to the Company's Annual Report on Form 10-K filed March 13, 2010, and incorporated herein by reference).
*23.1	Consent of Hein & Associates LLP.
*23.2	Consent of DeGolyer and MacNaughton.
*31.1	Certification by the President and Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification by the President and Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification by the Chief Financial Officer Pursuant to U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*99.1	Report of DeGolyer and MacNaughton.

* Filed herewith.

† Denotes management contract or compensatory plan or arrangement.

Supplemental Non-GAAP Financial Information

This annual report to stockholders contains certain financial measures that are non-GAAP financial measures within the meaning of Regulation G. We have provided reconciliations below of each non-GAAP financial measure presented herein to its most directly comparable GAAP financial measure. Please note that the non-GAAP financial measures presented herein may not be comparable to similarly titled measures used by other companies, including the Company's peers. We encourage you to review the non-GAAP financial measures presented herein along with the Company's audited financial statements for the year ended December 31, 2010, which are included in the immediately preceding Form 10-K.

Adjusted Net Income and Adjusted Net Income per Diluted Share

Adjusted net income and adjusted net income per diluted share exclude the following items:

(i) impairment of unproved properties and investment,

(ii) unrealized, pre-tax gain or loss on commodity derivatives, and

(iii) related income taxes.

The amounts included in the calculation of adjusted net income and adjusted net income per diluted share below were computed in accordance with GAAP. We believe adjusted net income and adjusted net income per diluted share are useful to investors because they provide readers with a more meaningful measure of our profitability before recording certain items whose timing or amount cannot be reasonably determined. However, these measures are provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes), included in our SEC filings.

The following table provides a reconciliation of adjusted net income and adjusted net income per diluted share to net income for the years ended December 31, 2010, 2009 and 2008 (in thousands, except per-share amounts):

	Years Ended December 31,		
	2010	2009	2008
Net income (loss)	$7,462	$(5,229)	$23,386
Adjustments for certain non-cash items:			
Impairment of unproved properties	2,622	2,964	6,379
Impairment of investment	—	—	917
Unrealized (gain) loss on commodity derivatives	(788)	9,899	(7,149)
Related income tax effect	(623)	(4,373)	(50)
Adjusted net income	$8,673	$ 3,261	$23,483
Adjusted net income per diluted share	$ 0.39	$ 0.16	$ 1.13

EBITDAX and EBITDAX per Diluted Share

We define EBITDAX as net income, plus (1) exploration expense, (2) impairment of unproved properties, (3) depletion, depreciation and amortization expense, (4) share-based compensation expense, (5) impairment of investment, (6) unrealized (gain) loss on commodity derivatives, (7) interest expense and (8) income taxes. EBITDAX is not a measure of net income or cash flow as determined by GAAP. The amounts included in the calculation of EBITDAX and EBITDAX per diluted share below were computed in accordance with GAAP. EBITDAX is presented this report and reconciled to the GAAP measure of net income because of its wide acceptance by the investment community as a financial indicator of a company's ability to internally fund development and exploration activities. These measures are provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes), included in our SEC filings.

The following table provides a reconciliation of EBITDAX and EBITDAX per diluted share to net income for the years ended December 31, 2010, 2009 and 2008 (in thousands, except per-share amounts):

	Years Ended December 31,		
	2010	2009	2008
Net income (loss)	$ 7,462	$ (5,229)	$23,386
Exploration	2,589	1,621	1,478
Impairment of unproved properties	2,622	2,964	6,379
Depletion, depreciation and amortization	22,224	24,660	23,710
Share-based compensation	2,628	1,826	1,100
Impairment of investment	—	—	917
Unrealized (gain) loss on commodity derivatives	(788)	9,899	(7,149)
Interest expense, net	2,189	1,787	1,269
Income tax provision (benefit)	4,100	(785)	12,111
EBITDAX	$43,026	$36,743	$63,201
EBITDAX per diluted share	$ 1.94	$ 1.75	$ 3.03

2010 Production Replacement

Although production replacement is not considered a non-GAAP financial measure within the meaning of Regulation G, we provide a summary of our production replacement calculation below.

We use production replacement ratios as an indicator of the Company's potential ability to replace annual production volumes and grow our reserves. However, these production replacement ratios have limitations. These ratios can vary from year to year for the Company and among other oil and gas companies based on the extent and timing of discoveries and property acquisitions. In addition, since these ratios do not incorporate the cost or timing of future production of new reserves, they should not be used as a measure of value creation.

Production replacement is calculated by dividing net proved reserve additions of 15.8 MMBoe (the sum of extensions and discoveries, purchases and revisions) by production of 1.6 MMBoe. Natural gas is converted at a rate of six Mcf of gas to one barrel of oil equivalent. NGLs are at a rate of one barrel of NGLs to one barrel of oil equivalent.

Reserve summary (MBoe)	
Balance — December 31, 2009	36,488
Extensions and discoveries	3,773
Purchases of minerals in place	1,958
Production	(1,556)
Revisions to previous estimates	
NGL recovery-related revisions	9,190
Price-related revisions	1,117
Performance-related revisions	(255)
Total revisions to previous estimates	10,052
Balance — December 31, 2010	50,715
Production replacement ratio	
Production replacement	1,014%

Finding and Development Costs

All-in finding and development ("F&D") costs are calculated by dividing the sum of property acquisition costs, exploration costs and development costs for the year by the sum of reserve extensions and discoveries, purchases of minerals in place and total revisions for the year.

All-in F&D costs, excluding price-related revisions, are calculated by dividing the sum of property acquisition costs, exploration costs and development costs for the year by the sum of reserve extensions and discoveries, purchases of minerals in place and total revisions less price-related revisions for the year.

All-in F&D costs, including the change in future development costs, are calculated by dividing the sum of property acquisition costs, exploration costs, development costs and the change in future development costs from the prior year by the sum of reserve extensions and discoveries, purchases of minerals in place and total revisions for the year.

Drill-bit F&D costs are calculated by dividing the sum of exploration costs and development costs for the year by the total of reserve extensions and discoveries for the year.

We believe that providing the above measures of F&D cost is useful to assist in an evaluation of how much it costs the Company, on a per Boe basis, to add proved reserves. However, these measures are provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes), included in our SEC filings. Due to various factors, including timing differences, F&D costs do not necessarily reflect precisely the costs associated with particular reserves. For example, exploration costs may be recorded in periods before the periods in which related increases in reserves are recorded, and development costs may be recorded in periods after the periods in which related increases in reserves are recorded. In addition, changes in commodity prices can affect the magnitude of recorded increases (or decreases) in reserves independent of the related costs of such increases. All-in F&D costs at December 31, 2010, were materially lower than the Company's historical all-in F&D costs due to the increase in proved reserves resulting from future processing of NGLs in Ozona Northeast at no additional capital cost.

As a result of the above factors and various factors that could materially affect the timing and amounts of future increases in reserves and the timing and amounts of future costs, including factors disclosed in our SEC filings, we cannot assure you that the Company's future F&D costs will not differ materially from those set forth above. Further, the methods used by us to calculate F&D costs may differ significantly from methods used by other companies to compute similar measures. As a result, our F&D costs may not be comparable to similar measures provided by other companies.

The following table reflects the reconciliation of our estimated F&D costs for the year ended December 31, 2010, to the information required by paragraphs 11 and 21 of ASC 932-235. Natural gas is converted at a rate of six Mcf of gas to one barrel of oil equivalent. NGLs are converted at a rate of one barrel of NGLs to one barrel of oil equivalent. Amounts in $/Boe may be converted to $/Mcfe at a rate of six to one ($0.06 per Boe equals $0.01 per Mcfe).

Cost summary (in thousands)	
Property acquisition costs	
Unproved properties	$ 8,931
Proved properties	85
Working interest acreage acquisition	5,566
Exploration costs	2,874
Development costs	56,916
Working interest acquisition costs	15,613
Total costs incurred	$ 89,985
Future development costs (in thousands)	
2009	$213,161
2010	259,005
Change in future development costs	$ 45,844
Reserve summary (MBoe)	
Balance — December 31, 2009	36,488
Extensions and discoveries	3,773
Purchases of minerals in place	1,958
Production	(1,556)
Revisions to previous estimates	
NGL recovery-related revisions	9,190
Price-related revisions	1,117
Performance-related revisions	(255)
Total revisions to previous estimates	10,052
Balance — December 31, 2010	50,715
Finding and development costs ($/Boe)	
All-in F&D cost	$ 5.70
All-in F&D cost, excluding price-related revisions	6.14
All-in F&D costs, including change in future development costs	8.61
Drill-bit F&D cost	15.85

If you are not familiar with the oil and gas terms or abbreviations used in this report, please refer to the definitions of these terms and abbreviations under the caption "Glossary" at the end of Item 15 of our annual report on Form 10-K filed with the SEC on March 11, 2011.

CORPORATE DATA

BOARD OF DIRECTORS

BRYAN H. LAWRENCE
Chairman of the Board of Directors

J. ROSS CRAFT
President, Chief Executive Officer and Director

ALAN D. BELL (1)
Director, Audit Committee Chairman

JAMES H. BRANDI (1) (2)
Director, Compensation and Nominating Committee Chairman

JAMES C. CRAIN (1) (2)
Director

SHELDON B. LUBAR (2)
Director

CHRISTOPHER J. WHYTE (1)
Director

(1) Member of the Audit Committee
(2) Member of the Compensation & Nominating Committee

EXECUTIVE OFFICERS

J. ROSS CRAFT
President, Chief Executive Officer and Director

STEVEN P. SMART
Executive Vice President and Chief Financial Officer

J. CURTIS HENDERSON
Executive Vice President and General Counsel

QINGMING YANG
Executive Vice President – Business Development and Geosciences

RALPH P. MANOUSHAGIAN
Executive Vice President – Land

CORPORATE HEADQUARTERS

One Ridgmar Centre
6500 West Freeway, Suite 800
Fort Worth, Texas 76116
817.989.9000 *telephone*
817.989.9001 *facsimile*

STOCK LISTING

Approach Resources Inc. is traded on the NASDAQ Global Select Market under the ticker symbol AREX.

INDEPENDENT ACCOUNTANTS

Hein & Associates LLP
Dallas, Texas

OUTSIDE LEGAL COUNSEL

Thompson & Knight LLP
Dallas, Texas

TRANSFER AGENT AND REGISTRAR

American Stock Transfer
& Trust Company
59 Maiden Lane
Plaza Level
New York, New York 10038
800.937.5449

WEBSITE

www.approachresources.com

A copy of our Annual Report on Form 10-K, as filed with the Securities and Exchange Commission, is available without charge upon request. Please direct your request to Approach Resources Inc., Attention: Investor Relations, One Ridgmar Centre, 6500 West Freeway, Suite 800, Fort Worth, Texas 76116, 817.989.9000.

Approach Resources Inc.

ONE RIDGMAR CENTRE / 6500 WEST FREEWAY, SUITE 800
FORT WORTH, TX 76116