APPROACH RESOURCES INC.

- NATURALLY RESOURCEFUL -

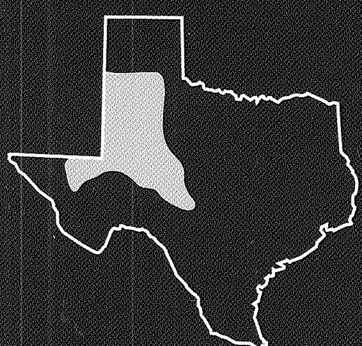
2012 ANNUAL REPORT

ABOUT THE COMPANY

We are an independent energy company headquartered in Fort Worth, Texas. Our strategy is to build long-term stockholder value by exploring for and developing oil and gas reserves in oil shale and tight gas sands in the West Texas Permian Basin. We have more than 167,000 gross acres in the Midland Basin of the greater Permian Basin, where we target stacked oil and liquids-rich formations at competitive operating and development costs. At December 31, 2012, our proved reserves totaled 95.5 MMBoe, made up of 39% oil, 30% NGLs and 31% natural gas. During 2012, we made significant progress in the Wolfcamp oil shale resource play, more than doubling our oil production and proved oil reserves, while reducing our costs to drill and complete horizontal Wolfcamp shale wells. Our efforts in 2012 laid the groundwork for accelerating development in the Wolfcamp, a rich resource base that we expect to fuel our growth for years to come.

CORE AREA OF OPERATION

PERMIAN BASIN – MIDLAND BASIN



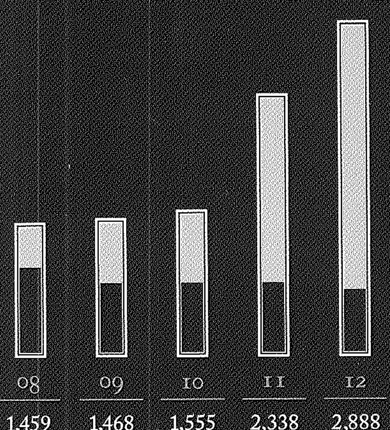
PROJECT PANGEA & PANGEA WEST

STACKED TARGETS:
Clearfork, Dean, Wolfcamp, Canyon Sands, Strawn, Ellenburger

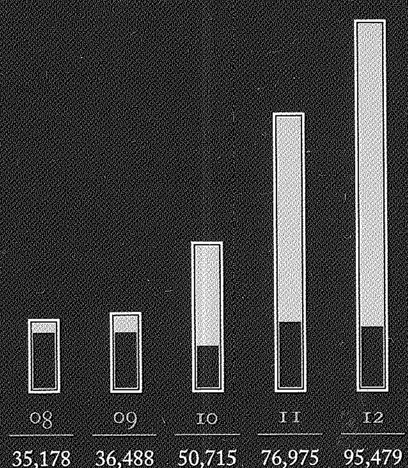
95.5 MMBoe proved reserves
167,000 gross (148,000 net) acres
2,096 identified horizontal Wolfcamp shale locations
2,983 total drilling and recompletion opportunities

PRODUCTION & RESERVES

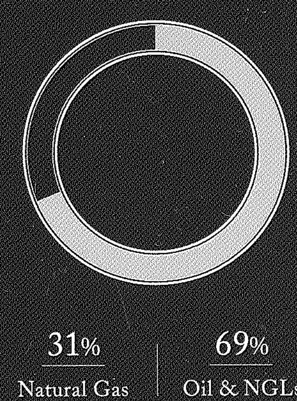
OIL & NGLs ■ □ NATURAL GAS



PRODUCTION
(MBoe)



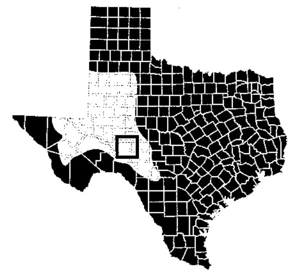
PROVED RESERVES
(MBoe)



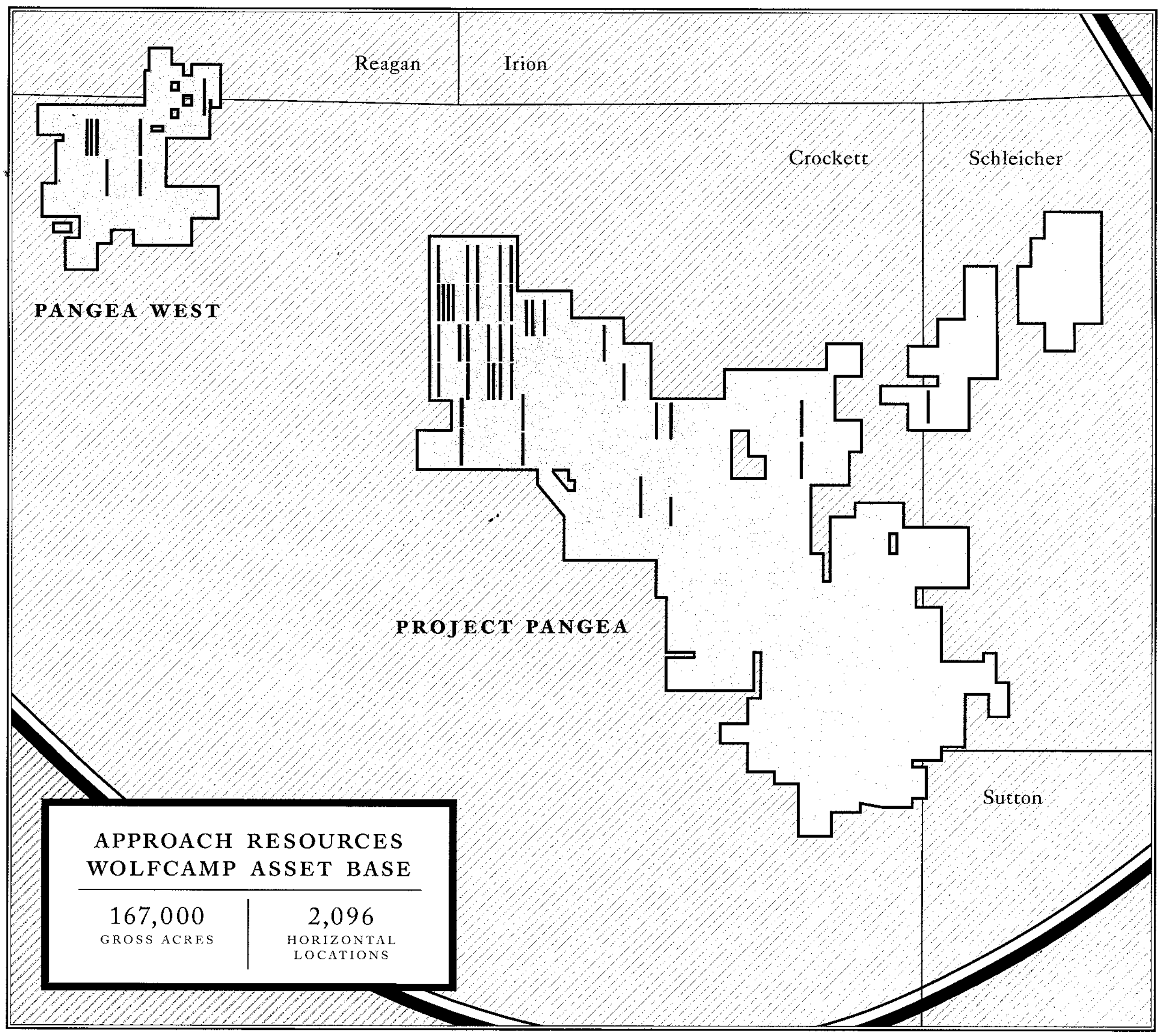
2012 RESERVE MIX

Estimated proved reserves and acreage are as of December 31, 2012. 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, 2012, which was filed with the Securities and Exchange Commission on February 28, 2013.

Since the beginning of our horizontal Wolfcamp pilot program in 2011, we have drilled more than 40 horizontal wells in total to the Wolfcamp A, B and C benches. We are rapidly climbing the learning curve on this play and well results are steadily improving.



APPROACH HORIZONTAL WOLFCAMP ACTIVITY



APPROACH ACREAGE (*Wolfcamp Oil Shale Resource Play*)

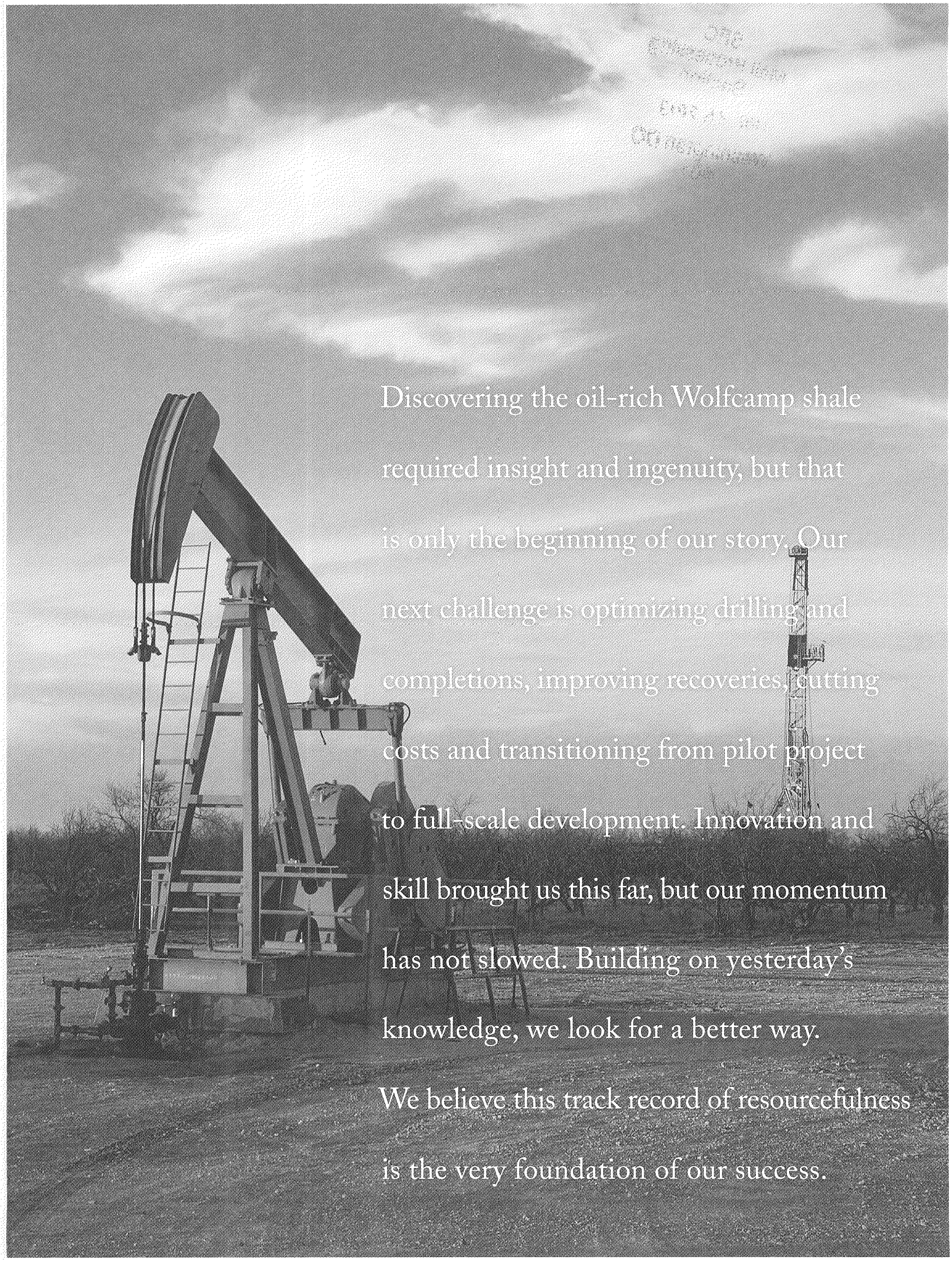
HORIZONTAL WELLS

"Our CEO, Ross Craft, may be a petroleum engineer by trade, but he has the mind of an exploration geologist. The Wolfcamp shale is not the first major oil field that he has discovered. It takes a creative and resourceful mind to see things differently, to piece together the data points, to form a hypothesis and persist in testing the hypothesis until value is realized."

– Qingming Yang,
CHIEF OPERATING OFFICER

SYSTEM	STRATIGRAPHIC UNIT
Permian	CLEARFORK / SPRABERRY
	DEAN
	WOLFCAMP
Pennsylvanian	CANYON
	STRAWN
Mississippian	
Devonian	
Silurian	
Ordovician	ELLENBURGER

WOLFCAMP A	703 IDENTIFIED LOCATIONS
WOLFCAMP B	690 IDENTIFIED LOCATIONS
WOLFCAMP C	703 IDENTIFIED LOCATIONS



Discovering the oil-rich Wolfcamp shale required insight and ingenuity, but that is only the beginning of our story. Our next challenge is optimizing drilling and completions, improving recoveries, cutting costs and transitioning from pilot project to full-scale development. Innovation and skill brought us this far, but our momentum has not slowed. Building on yesterday's knowledge, we look for a better way. We believe this track record of resourcefulness is the very foundation of our success.

Dear Fellow Stockholders:

IN 2012, YOUR TEAM MADE GREAT STRIDES in taking our Wolfcamp oil shale discovery from pilot phase to full-scale development. We continue to refine our processes, gaining efficiencies, reducing drill time and steadily improving our well results. And while we are pleased with our progress to date, we are intent on finding ways to improve. Our culture is one of continuous learning and continuous improvement that brings out the best in our employees, who are naturally, resourceful.

Financial strength and a sustainable capital structure remain important to us. At year-end 2012, we had a long-term debt-to-capital ratio of 14.3%. With many years of drilling ahead we will be opportunistic about securing capital and disciplined as we accelerate development of this resource. We believe this type of balanced approach is in the best interest of our stockholders and aligns with our financial management philosophy.

"As we continued to develop the oil and liquids-rich Wolfcamp shale, we doubled both our oil production and our oil reserves in 2012."

In 2012, our capital program funded the drilling of 46 wells: 23 horizontals targeting the Wolfcamp and the remainder verticals and recompletions targeting the Wolffork and deeper zones. As a result, we increased production 24% to 7.9 MBoe per day. More importantly, as we continued to develop the oil and liquids-rich Wolfcamp shale, we doubled both our oil production and our oil reserves in 2012. Over the past several years, we have transformed Approach from a natural gas producer to an oil and liquids-focused company, and we did so without overleveraging our balance sheet. At year-end 2012, our proved reserve mix was 69% oil and NGLs, compared to just 11% when we went public over five years ago.

After launching our horizontal Wolfcamp program in late 2010, we grew our proved reserves 52% in 2011 and another 24% in 2012. Significantly, our oil reserves surged 265% in 2011 and 106% in 2012. We replaced over 1,300% of our production in 2012 entirely through the drill bit. Additionally, we achieved these results at a very competitive drill-bit finding and development cost of $7.45 per Boe.

7.9

DAILY PRODUCTION
(MBoe/day)

95.5

PROVED RESERVES
(MMBoe)

69%

OIL & NGLs

167,000

GROSS ACRES

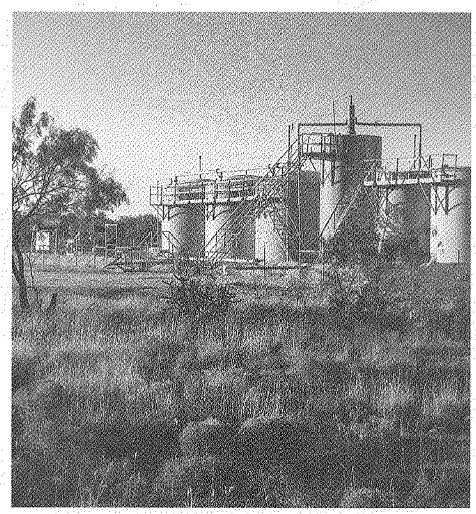
2,900+

POTENTIAL DRILLING AND RECOMPLETION LOCATIONS

Testing and Delineating the Wolfcamp

Approach was founded in 2002, and in 2004 began a program of vertical drilling in the Permian Basin. In order to reach our targeted zones, we drilled through hundreds of feet of Wolfcamp shale, a rock formation known throughout the industry as a low-permeability source rock.

From 2004 to 2010, we drilled more than 500 vertical wellbores to the Canyon, Strawn and Ellenburger formations, and collected data from surface casing to total depth. In 2010, we performed a detailed geological and petrophysical evaluation of the Clearfork, Dean and Wolfcamp shale formations, which we collectively refer to as the "Wolffork." In addition to electric logs, our study incorporated mud logs, whole core data, 3-D seismic and regional mapping. This study indicated that the entire Wolffork rock column, with combined thickness of approximately 2,500 feet, is full of hydrocarbons.



"Traditionally, operators did not spend the money to collect well data on rock formations shallower than their targeted horizons. But we took a different approach."

Currently, our drilling program is focused on the Wolfcamp oil shale formation, which ranges from 1,000 to 1,200 feet thick for the Wolfcamp A, B and C benches.

We initiated our horizontal Wolfcamp pilot program in early 2011, and we drilled 13 horizontal B bench wells and one C bench well. After the first series of horizontal wells, our initial producing rates and subsequent results confirmed that the Wolfcamp oil shale play is commercial.

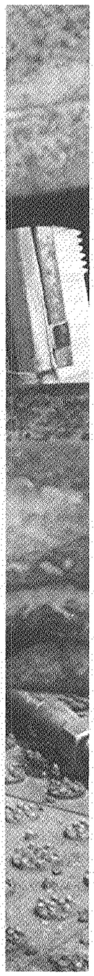
In 2012, we transitioned the Wolfcamp B bench into development mode. We also successfully tested the Wolfcamp A bench with two horizontal wells in Pangea West and a horizontal well in North Pangea. We expect to transition both Wolfcamp A and C benches into full development mode in 2013. With successful drilling, detailed correlations from hundreds of vertical wells, whole core data, and 3-D seismic data, we have de-risked 107,000 gross acres across our leasehold.

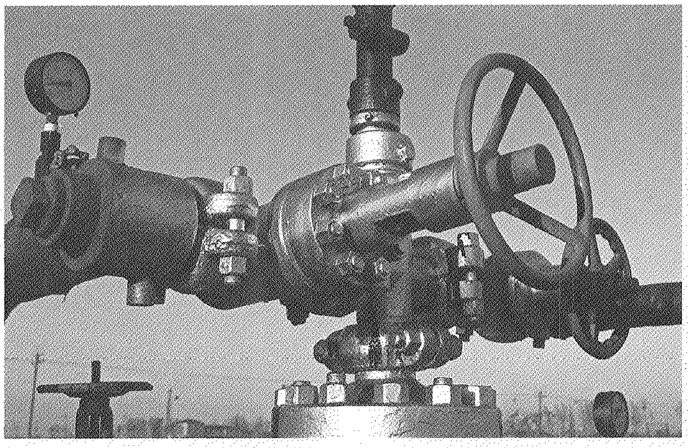
Along with our 2012 year-end results, we announced an updated drilling location count that reflects our field development plan. This plan is based on 120-acre horizontal spacing and multi-bench development. In full development mode, we anticipate using pad drilling to drill "stacked" wellbores aligned on top of each other in all three benches. At year-end 2012, we had identified approximately 700 horizontal well locations in each of the A, B and C benches, for a total of more than 2,000 identified horizontal Wolfcamp locations. Together with more than 800 vertical locations, the Wolfcamp opportunity represents more than 1 billion Boe of gross resource potential, and what we believe will be many years of drilling inventory.

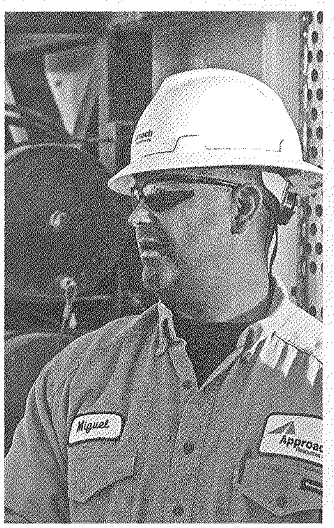
Laying the Groundwork

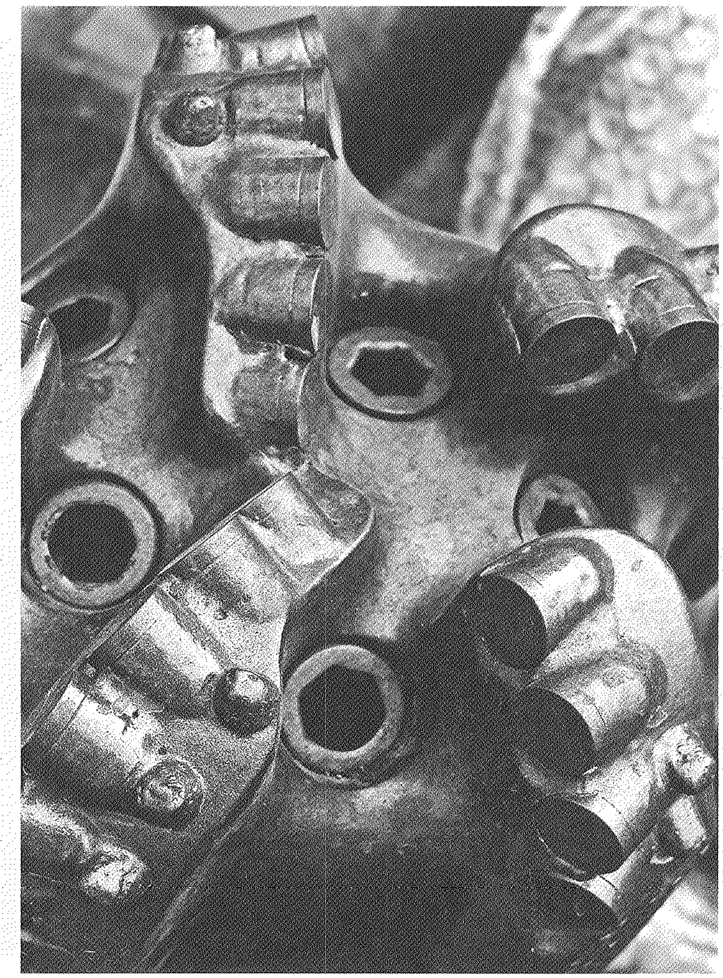
One of our highest priorities as we enter full manufacturing mode in the horizontal Wolfcamp is to hit our target cost of $5.5 million per well. At the beginning of 2012, the average cost for one of our horizontal Wolfcamp wells was approximately $7 million. In the second half of the year, we cut the average cost to $6.4 million. With improved processes, we have continued to drive this number down to approximately $6.2 million per well, and our goal is to cut it further, to $5.5 million per well or less, when our infrastructure systems are in place in North Project Pangea in early 2013.

In 2012, we invested $54 million – a very significant sum for a company our size – in infrastructure projects, including an equity investment in an oil pipeline, to automate operations and reduce future drilling, completion and operating costs. The most important cost-cutting measures are our water sourcing, transfer and disposal solutions. We have drilled multiple water wells to non-potable water formations found at about 700 feet below the surface. This water is non-potable, but when treated, it can work well for stimulation fluid. In addition, we have installed water transfer lines to connect water source wells with our completion facilities. With these measures, we can reduce and in some cases









eliminate certain costs of trucking water, as well as minimize or eliminate the use of fresh water resources. Finally, we have drilled multiple salt water disposal wells to the deep

"One of our highest priorities as we enter full manufacturing mode in the horizontal Wolfcamp is to hit our target cost of $5.5 million per well."

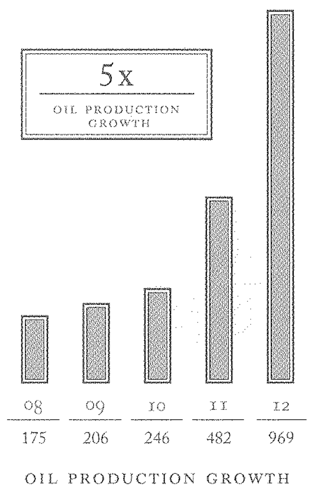
Ellenburger zone. Through these efforts, we believe we can reduce disposal fees from as high as $5.00 per barrel to less than $1.00 per barrel. In total, we expect these and other cost-cutting initiatives, including pad drilling, to reduce our drilling and completions costs by about $900,000 per horizontal well.

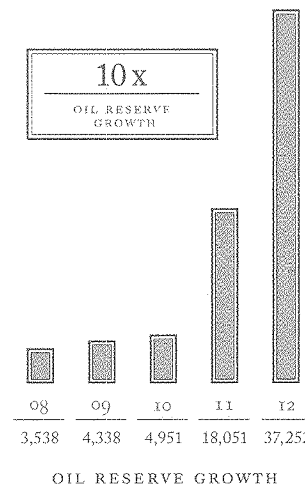
In early 2013, we also completed construction of an oil pipeline, gathering lines and offloading facilities in North Project Pangea and Pangea West through our equity investment in a midstream joint venture. We plan to begin moving our crude oil by pipeline rather than truck in the second quarter of 2013. As a result, we could see our oil transportation costs decrease significantly. All of the above-listed measures creates a win-win for the community and the Company. We are working hard to reduce our environmental footprint by preserving the community's drinking water and minimizing truck traffic and surface disturbance, all while lowering our capital and operating costs.

Accelerating Development

Looking ahead, we have laid out a three-rig program to drill 35 to 40 horizontal Wolfcamp shale wells in 2013, as well as 12 vertical Wolffork and Canyon Wolffork wells and recompletions. Significantly, the percentage of our capital directed toward horizontal Wolfcamp drilling has increased from 55% in 2012 to substantially all of our drilling capital in 2013, reflecting our growing confidence in the project. We expect production growth for 2013 to range from 25% to 35%, with much of the increase coming in the second half of the year. The projected growth is back-loaded in the second half of the year as a result of our pilot program to test pad drilling and completions using stacked wellbores during the first half of 2013.

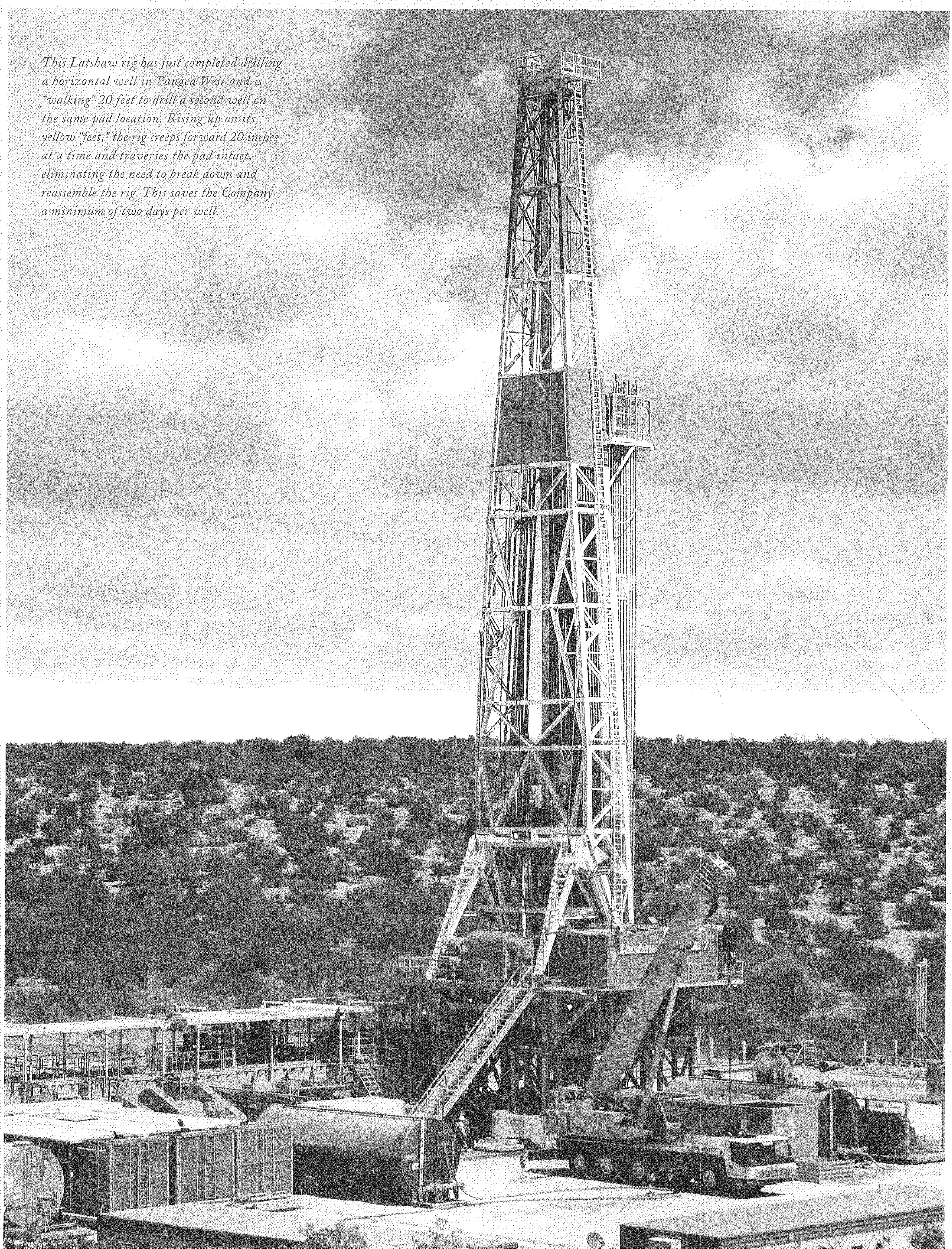
Through pad drilling and stacked wellbores, we expect to save time and money, as well as reduce surface disturbance. We believe that stacking the lateral wellbores in close proximity can result in enhanced oil and gas recovery by achieving optimal fracturing of the rock column. Recent estimates place the recovery factor in the Wolfcamp at 4% of the oil in place. If stacked laterals can increase the overall recovery factor by just 1%, this could equate to a 20% increase in our resource potential. We have completed and are flowing back our first four stacked laterals, configured as A/B bench pairs, and we have begun drilling our first A/C bench pair.





In the past five years, due to our oil-rich Wolfcamp discovery, our oil production has increased more than fivefold, while oil reserves are up more than tenfold.

As we continue to refine our operations, we also are planning to begin recycling flowback water used in our completions operations once our infrastructure systems are in place in North Project Pangea in early 2013. This is another initiative that, given success, will enable us to reduce our environmental impact and operating costs. With water recycling and other measures, we are employing the latest technologies and moving the play from pilot stage to low-cost manufacturing mode. All of these programs are important steps in our efforts to optimize our processes, drive down costs and gain economies of scale.



This Latshaw rig has just completed drilling a horizontal well in Pangea West and is "walking" 20 feet to drill a second well on the same pad location. Rising up on its yellow "feet," the rig creeps forward 20 inches at a time and traverses the pad intact, eliminating the need to break down and reassemble the rig. This saves the Company a minimum of two days per well.

The Vision

Not only does the Wolfcamp oil shale play present a great opportunity for Approach Resources, but it is impacting the oil and gas industry and the country as well. Approximately 450 rigs are now operating in the Permian Basin, which is about one-fourth of the country's entire onshore rig fleet. Since we introduced the Wolfcamp oil shale resource play concept in late 2010, many industry peers have joined us or stepped up their activity in the Permian, helping to prove up acreage and test the boundaries of the play. Although it is still early in the evaluation, current estimates indicate that the Wolfcamp oil shale resource play may have technically recoverable reserves ranging from 7 to 14 billion Boe, depending on how many acres prove to be prospective. At the upper end of estimates, the Wolfcamp would surpass Prudhoe Bay as the largest onshore US oil field discovery in history.

I am very proud of the Approach team. They are a very resourceful and talented group. Their hard work and dedication have helped us launch a potentially prolific oil resource play. Their resilience and determination have led us through the process of optimizing our drilling and completion techniques to the doorstep of full-scale development. Their continued innovation will help us meet the challenges ahead as we seek the most efficient and economical approach to unlocking the potential of this tremendous resource.

"The Wolfcamp appears destined to take its place alongside other key oil resource plays, such as the Eagle Ford and Bakken, as a major contributor toward reduced dependence on foreign oil."

During 2012, we were fortunate to have the support of our exceptional employees, business partners and fellow stockholders, and we thank you for your continued support and confidence in Approach Resources.

Sincerely,

J. ROSS CRAFT, P.E.

Director, President and
Chief Executive Officer

2013 Capital Program

$260 MIL	**25-35%**	**35-40**	**$5.5 MIL**
2013 PLANNED CAPITAL BUDGET	FORECASTED PRODUCTION GROWTH	HORIZONTAL WOLFCAMP WELLS	TARGETED HORIZONTAL WELL COSTS

Financial & Operating Data ($ in thousands, except per-share and per-unit amounts)

REVENUES (In Thousands)	2012	2011	2010
Oil	$ 82,087	$ 42,463	$ 18,640
NGLs	30,811	41,029	10,765
Gas	15,994	24,895	28,176
Total oil, NGL and gas sales	128,892	108,387	57,581
Realized gain on commodity derivatives	(108)	3,375	5,784
Total oil, NGL and gas sales including derivative impact	$ 128,784	$ 111,762	$ 63,365
PRODUCTION			
Oil (*MBbls*)	969	482	246
NGLs (*MBbls*)	904	798	261
Gas (*MMcf*)	6,089	6,345	6,290
Total (*MBoe*)	2,888	2,338	1,556
Total (*MBoe/d*)	7.9	6.4	4.3
AVERAGE PRICES			
Oil (*per Bbl*)	$ 84.70	$ 88.18	$ 75.67
NGLs (*per Bbl*)	34.09	51.39	41.19
Gas (*per Mcf*)	2.63	3.92	4.48
Total (*per Boe*)	$ 44.63	$ 46.37	$ 37.00
Realized gain on commodity derivatives (*per Boe*)	(0.03)	1.44	3.72
Total including derivative impact (*per Boe*)	$ 44.60	$ 47.81	$ 40.72
COSTS AND EXPENSES (per Boe)			
Lease operating	$ 6.58	$ 4.57	$ 4.25
Production and ad valorem taxes	3.20	3.61	3.17
Exploration	1.58	4.08	1.66
Impairment	–	7.90	1.68
General and administrative	8.62	7.66	7.34
Depletion, depreciation and amortization	20.91	13.89	14.28
FINANCIAL HIGHLIGHTS			
Net income	$ 6,384	$ 7,242	$ 7,462
Earnings per diluted share	$ 0.18	$ 0.25	$ 0.34
Adjusted net income*	$ 3,827	$ 19,501	$ 8,673
Adjusted earnings per diluted share	$ 0.11	$ 0.67	$ 0.39
EBITDAX*	$ 82,981	$ 79,411	$ 43,026
EBITDAX per diluted share	$ 2.37	$ 2.72	$ 1.94
Weighted average diluted shares outstanding	35,030	29,159	22,214
Total long-term debt	$ 106,000	$ 43,800	$ —
Stockholders' equity	$ 633,468	$ 467,449	$ 332,946
Total assets	$ 855,739	$ 607,894	$ 413,089

*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 page 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

Received SEC
APR 2 5 2013
Washington, DC 20549

(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, 2012

or

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

For the transition period from to

Commission file number: 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.

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ 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 29, 2012 was $758.4 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 February 22, 2013 was 39,024,869.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's proxy statement for its 2013 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, NGLs 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, NGLs 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 ("Boe"). NGLs are converted throughout this report at a rate of one barrel of NGLs to one Boe. The ratios of six Mcf of gas to one Boe and one barrel of NGLs to one Boe do not assume price equivalency and, given price differentials, the price for a Boe of natural gas or NGLs may differ significantly from the price of a barrel of oil. 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 disclaim any obligation to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise, unless required by law. 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:

- uncertainties in drilling, exploring for and producing oil and gas;
- uncertainty of commodity prices in oil, NGLs and gas;
- overall United States and global economic and financial market conditions;
- domestic and foreign demand and supply for oil, NGLs, gas and the products derived from such hydrocarbons;
- our inability to obtain additional financing necessary to fund our operations and capital expenditures and to meet our other obligations;
- the effects of government regulation and permitting and other legal requirements, including laws or regulations that could restrict or prohibit hydraulic fracturing;
- disruption of credit and capital markets;
- our financial position;
- our cash flows and liquidity;
- disruptions to, capacity constraints in or other limitations on the pipeline systems that deliver our oil, NGLs and gas and other processing and transportation considerations;
- marketing of oil, NGLs and gas;
- high costs, shortages, delivery delays or unavailability of drilling and completion equipment, materials, labor or other services;
- competition in the oil and gas industry;
- uncertainty regarding our future operating results;

- interpretation of 3-D seismic data;
- replacing our oil, NGL and gas reserves;
- our ability to retain and attract key personnel;
- our business strategy, including our ability to recover oil, NGLs and gas in place associated with our Wolfcamp oil shale resource play in the Permian Basin;
- development of our current asset base or property acquisitions;
- estimated quantities of oil, NGL and gas reserves;
- 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 gas reserves in oil shale and tight gas sands in the Midland Basin of the greater Permian Basin in West Texas, where we lease approximately 148,000 net acres. Our drilling targets include the Clearfork, Wolfcamp shale, Canyon Sands, Strawn and Ellenburger zones. We sometimes refer to the Clearfork and Wolfcamp zones together as the "Wolffork," and our development project in the Permian Basin as "Project Pangea," which includes the northwestern portion of Project Pangea that we refer to as "Pangea West." Our management and technical team have a proven track record of finding and developing reserves through advanced drilling and completion techniques. 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, 2012, our estimated proved reserves were 95.5 million barrels of oil equivalent ("MMBoe"). Substantially all of our proved reserves are located in Crockett and Schleicher Counties, Texas. Important characteristics of our proved reserves at December 31, 2012, include:

- 39% oil, 30% NGLs and 31% natural gas;
- 34% proved developed;
- 100% operated;
- Reserve life of more than 30 years based on 2012 production of 2.9 MMBoe;
- Standardized measure of discounted future net cash flows ("Standardized Measure") of $494.2 million; and
- PV-10 of $830.9 million.

PV-10 is our estimate of the present value of future net revenues from proved oil, NGL 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 financial measure that is not determined in accordance with accounting principles generally accepted in the United States ("GAAP"), 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.

At December 31, 2012, we owned and operated 594 producing oil and gas wells in the Permian Basin, and we had an estimated 2,983 identified drilling and recompletion locations, of which 359 were proved.

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.

2012 Activity

Our operations in 2012 focused on horizontal drilling in our Wolfcamp oil shale resource play in the Permian Basin. We drilled 26 horizontal wells in 2012, compared to 13 horizontal wells in 2011. Our early results in the Wolfcamp play led us to invest in building an infrastructure system that we believe will reduce drilling and completion costs, improve drilling and completion efficiencies, reduce fresh water use and ensure transportation for our crude oil production to market. We plan to continue to develop the Wolfcamp shale in Project Pangea in 2013. Focusing on the Wolfcamp shale allows us to use our operating, technical and regional expertise that is important to interpreting geological and operating trends, enhancing production rates and maximizing well recovery.

Production Growth

Production for 2012 totaled 2.9 MMBoe (7.9 MBoe/d), compared to 2.3 MMBoe (6.4 MBoe/d) in 2011, a 24% increase. Production for 2012 was 34% oil, 31% NGLs and 35% natural gas. Our continued development of Project Pangea increased oil production 101% in 2012, compared to 2011. On average, we operated two horizontal rigs and one vertical rig in 2012, and drilled a total of 46 gross (45.8 net) wells, of which 10 gross (9.9 net) were waiting on completion at December 31, 2012. We also recompleted 19 gross (19 net) wells in the Wolffork in 2012.

Reserve Growth

In 2012, our estimated proved reserves increased 24%, or 18.5 MMBoe, to 95.5 MMBoe from 77.0 MMBoe. Our proved reserves at year-end 2012 were 39% oil, 30% NGLs and 31% natural gas, compared to 23% oil, 38% NGLs and 39% natural gas at year-end 2011. During 2012, our proved oil reserves increased 19.2 MMBbls, or 106%, to 37.3 MMBbls from 18.1 MMBbls in 2011. Reserve growth, and especially our oil reserve growth, in 2012 was driven by results in our Wolfcamp oil shale resource play.

2012 Equity Offering

In September 2012, we sold 5.0 million shares of common stock in an underwritten public equity offering at $30.50 per share. In October 2012, the underwriters exercised their option and purchased an additional 325,000 shares. After deducting underwriting discounts and transaction costs of approximately $8.0 million, we received net proceeds of approximately $154.4 million. We used the proceeds of the 2012 equity offering to repay outstanding borrowings under our revolving credit facility, fund our capital expenditures for the development of our Wolfcamp oil shale resource play and for general working capital needs.

Plans for 2013

In September 2012, we announced a 2013 capital budget of $260 million, which includes three rigs to drill horizontal wells targeting the Wolfcamp shale. We expect that our horizontal drilling in Project Pangea in 2013 will include pad drilling, which we believe will improve operating efficiencies and resource recoveries, while reducing facilities costs and surface impact. We also may drill vertical wells targeting the Wolffork or recomplete Canyon Sands wells in the Wolffork during 2013. Our objectives for 2013 include advancing our understanding of optimal well spacing, testing multi-zone potential to enhance hydrocarbon recovery in our Wolffork targets and improving our cost structure.

Our 2013 capital budget is subject to change depending upon a number of factors, including additional data on our Wolfcamp oil shale resource play, results of horizontal and vertical drilling, completions and recompletions, including pad drilling, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil, NGLs and gas, 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, NGLs and gas. The price we receive for our oil, NGL 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, NGLs and gas, the proximity and capacity of gas pipelines and other transportation facilities, supply and demand for oil, NGLs 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.

The following table summarizes the top five purchasers of our oil, NGL and gas sales for 2012, excluding realized commodity derivative settlements.

Purchaser	Percent of Oil, NGL and Gas Sales
Shell Trading (US) Company ("Shell")	22%
BML, Inc. ("BML")	22
Belvan Partners, LP ("WTG")	20
DCP Midstream, LLC ("DCP")	17
Plains Marketing, LP ("Plains")	6
Total	87%

As of December 31, 2012, we had dedicated all of our oil production from northern Project Pangea and Pangea West for 10 years to an oil pipeline joint venture in which we own a 50% equity interest. In addition, as of December 31, 2012, we had contracted to sell all of our NGLs and natural gas production from Project Pangea to DCP through January 2016.

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.

Oil and Gas Leases

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil, NGLs and natural gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties generally range from 20% to 25%, resulting in a net revenue interest to us generally ranging from 80% to 75%.

Seasonality

Demand for oil, NGLs and natural gas generally decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

Competition

The oil and gas industry is highly competitive, and we compete for personnel, prospective properties, producing properties 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 end products on a worldwide basis. 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. It is not possible to predict whether such legislation or regulation may ultimately be adopted or its precise effects upon our future operations. Such laws and regulations may, however, substantially increase the costs of exploring for, developing or producing oil, NGLs and gas and may prevent or delay the commencement or continuation of our operations.

Hydraulic Fracturing

Hydraulic fracturing is an important process and has been commonly used in the completion of unconventional oil and gas wells in shale and tight sand formations since the 1950s. Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into rock formations to stimulate oil and gas production. It is important to us because it provides access to oil and gas reserves that previously were uneconomical to produce.

We currently use hydraulic fracturing to complete both horizontal and vertical wells in the Permian Basin. We engage third parties to provide hydraulic fracturing services to us for completion of these wells. While hydraulic fracturing is not required to maintain our leasehold acreage that is currently held by production from existing wells, it will be required in the future to develop the proved non-producing and proved undeveloped reserves associated with this acreage. All of our proved non-producing and proved undeveloped reserves associated with future drilling, completion and recompletion projects will require hydraulic fracturing.

We believe we have followed, and intend to continue to follow, applicable industry standard practices and legal requirements for groundwater protection in our operations that are subject to supervision by state regulators.

These protective measures include setting surface casing at a depth sufficient to protect fresh water zones as determined by applicable state regulatory agencies, and cementing the well to create a permanent isolating barrier between the casing pipe and surrounding geological formations. This aspect of well design is intended to prevent contact between the fracturing fluid and any aquifers during the hydraulic fracturing operations. For recompletions of existing wells, the production casing is pressure-tested before perforating the new completion interval.

Injection rates and pressures are monitored at the surface during our hydraulic fracturing operations. Pressure is monitored on both the injection string and the immediate annulus to the injection string. We believe we have adequate procedures in place to address abrupt changes to the injection pressure or annular pressure.

Texas regulations currently require disclosure of the components in the solutions used in hydraulic fracturing operations. Over 99% (by mass) of the ingredients we use in hydraulic fracturing are water and sand. The remainder of the ingredients are chemical additives that are managed and used in accordance with applicable requirements.

Hydraulic fracturing requires the use of a significant amount of water. Upon flowback of the water, we dispose of it in a way that we believe minimizes the impact to nearby surface water by disposing into approved disposal facilities or injection wells. Currently our primary sources of water in Project Pangea are the nonpotable Santa Rosa and potable Edwards-Trinity (Plateau) aquifers. We use water from on-lease water wells that we have drilled, and we purchase water from off-lease water wells. We also plan to reuse and recycle flow-back and produced water in 2013.

For information regarding existing and proposed governmental regulations regarding hydraulic fracturing and related environmental matters, please read "Business — Regulation — Environmental Laws and Regulation" and "Business — Regulation — Hydraulic Fracturing." For related risks to our stockholders, please read "Risk Factors — Federal and state legislation and regulatory initiatives and private litigation relating to hydraulic fracturing could stop or delay our development project and result in materially increased costs and additional operating restrictions."

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 U.S. Department of Interior, the U.S. Department of Transportation (the "DOT") (Office of Pipeline Safety) and the U.S. Environmental Protection Agency (the "EPA"). 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, penalties or other remedies that are available to these federal, state and local authorities. However, we believe that we are currently in material compliance with federal, state and local rules, regulations and procedures, and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations.

Transportation and Sale of Oil

Sales of crude oil and condensate are not currently regulated and are made at negotiated prices. Our sales of crude oil are affected by the availability, terms and cost of transportation. Interstate transportation of oil by pipeline is regulated by the Federal Energy Regulation Commission ("FERC") pursuant to the Interstate Commerce Act ("ICA"), Energy Policy Act of 1992 ("EPAct 1992"), and the rules and regulations promulgated under those laws. The ICA and its regulations require that tariff rates for interstate service on oil pipelines, including interstate pipelines that transport crude oil and refined products, be just and reasonable and non-discriminatory and that such rates, terms and conditions of service be filed with FERC.

Intrastate oil pipeline transportation rates are also subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state-to-state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

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

The transportation of oil by truck is also subject to federal, state and local rules and regulations, including the Federal Motor Carrier Safety Act and the Homeland Security Act of 2002. Regulations under these statutes cover the security and transportation of hazardous materials and are administered by the DOT.

Transportation and Sale of Natural Gas and NGLs

FERC regulates interstate gas pipeline transportation rates and service conditions under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and regulations issued under those statutes. FERC also regulates interstate NGL pipelines under various federal laws and regulations. Although FERC does not regulate oil and gas producers such as us, FERC's actions are intended to facilitate 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.

Regulation of Production

Oil, NGL 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 state in which we operate, Texas, has 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, Texas imposes a severance tax on production and sales of oil, NGLs and gas within its jurisdiction. The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental Laws and 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, endangered species habitat, 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. The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. Any changes in environmental laws and regulations or re-interpretations of enforcement policies 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 or results of operations. Moreover, accidental releases or spills and ground water contamination may occur in the course of our operations, and we may incur significant costs and liabilities as a result of such releases, spills or contamination, including any third-party claims for damage to property, natural resources or persons. We maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. 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 environmental laws, rules and regulations that apply to our business operations.

Hazardous Substance Release

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 investigating releases of hazardous substances, 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 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 water 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 increase our operating expenses, which could have a material adverse effect on our business, financial condition and results of operations.

We currently own or lease 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 other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions at specified sources. In particular, on April 18, 2012, the EPA issued new regulations under the New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAP"). The new regulations are designed to reduce volatile organic compound ("VOC") emissions from hydraulically-fractured natural gas wells, storage tanks and other equipment. The regulations established a phase-in period that extends until January 2015. During the phase-in period, owners and operators of hydraulically-fractured natural gas wells (wells drilled principally for the production of natural gas) must either flare their emissions or use so-called "green completion" technology. Green completions allow for the recovery of natural gas that formerly would have been vented or flared. After January 2015, all newly fractured natural gas wells must use green completion technology. We do not expect that the NSPS or NESHAP will have a material adverse effect on our business, financial condition or results of operations. However, any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements or use specific equipment or technologies to control emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions. We believe that we currently are in substantial compliance with all air emissions regulations and that we hold all necessary and valid construction and operating permits for our current operations.

Greenhouse Gas Emissions

Congress has, from time-to-time, considered legislation to reduce emissions of GHGs. The current Congress is likely to continue to consider similar bills. Moreover, almost half of the states have already taken legal measures to reduce emissions of GHGs through the planned development of GHG emission inventories and/or regional GHG cap-and-trade programs or other mechanisms. Most cap-and-trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels such as refineries and gas processing plants, to acquire and surrender emission allowances corresponding with their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. Many states have enacted renewable portfolio standards, which require utilities to purchase a certain percentage of their energy from renewable fuel sources.

In addition, in December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In response to its endangerment finding, the EPA has adopted two sets of rules regarding possible future regulation of GHG emissions under the Clean Air Act, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which would regulate emissions of GHGs from large stationary sources of emissions such as power plants or industrial facilities. The motor vehicle rule was finalized in April 2010 and became effective in January 2011, but it does not require immediate reductions in GHG emissions. In March 2012, the EPA proposed GHG emissions standards for fossil fuel-powered electric utility generating units that would require new plants to meet an output-based standard of 1,000 pounds of carbon dioxide equivalent per megawatt-hour. If the proposed regulation is adopted, it could have a significant impact on the electrical generation industry and may favor the use of natural gas over other fossil fuels such as coal in new plants. The EPA has also indicated that it will propose new GHG emissions standards for refineries, but specific proposed regulations are not expected to be issued until mid-2013.

In December 2010, the EPA enacted final rules on mandatory reporting of GHGs. In November and December 2011, the EPA published amendments to the rule containing technical and clarifying changes to certain GHG reporting requirements and a six-month extension for reporting GHG emissions from petroleum and natural gas industry sources. Under the amended rule, certain onshore oil and natural gas production, processing, transmission, storage and distribution facilities are required to report their GHG emissions on an annual basis beginning on September 28, 2012. Our operations in the Permian Basin are subject to the EPA's mandatory reporting rules and we believe that we are in substantial compliance with such rules. We do not expect that the EPA's mandatory GHG reporting requirements will have a material adverse effect on our business, financial condition or results of operations.

The adoption of additional legislation or regulatory programs to monitor or reduce GHG emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, acquire emissions allowances or comply with new regulatory requirements. In addition, the EPA has stated that the data collected from GHG emissions reporting programs may be the basis for future regulatory action to establish substantive GHG emissions factors. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our future business, financial condition and results of operations.

Water Discharges

The Federal Water Pollution Control Act (the "Clean Water Act") and analogous state laws, impose restrictions and strict controls on the discharge of pollutants and fill material, 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, an analogous state agency, or, in the case of fill material, the United States Army Corps of Engineers. 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.

In October 2011, the EPA announced that it intends to develop national standards for wastewater discharges produced by natural gas extraction from shale and coalbed methane formations. The EPA is expected to issue proposed regulations establishing wastewater discharge standards for coalbed methane wastewater in 2013 and for shale gas wastewater in 2014. For shale gas wastewater, the EPA will consider imposing pre-treatment standards for discharges to a wastewater treatment facility. Produced and other flowback water from our current operations in the Permian Basin is typically re-injected into underground formations that do not contain potable water. To the extent that re-injection is not available for our operations and discharge to wastewater treatment facilities is required, new standards from the EPA could increase the cost of disposing wastewater in connection with our operations.

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

The federal Safe Drinking Water Act ("SDWA") and the Underground Injection Control program (the "UIC program") promulgated under the SDWA 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 Railroad Commission of Texas ("RRC"). Permits must be obtained before drilling salt water disposal wells, and casing integrity monitoring must be conducted periodically to ensure the casing is not leaking saltwater to groundwater. Contamination of groundwater by oil and gas drilling, production and related operations may result in fines, penalties and remediation costs, among other sanctions and liabilities under the SDWA 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.

Hydraulic Fracturing

Hydraulic fracturing is the subject of significant focus among some environmentalists, regulators and the general public. Concerns over potential hazards associated with the use of hydraulic fracturing and its impact on the environment have been raised at all levels, including federal, state and local, as well as internationally. There have been claims that hydraulic fracturing may contaminate groundwater, reduce air quality or cause earthquakes. Hydraulic fracturing requires the use and disposal of water, and public concern has been growing over its possible effects on drinking water supplies, as well as the adequacy of water supply.

The Energy Policy Act of 2005, which exempts hydraulic fracturing from regulation under the SDWA, prohibits the use of diesel fuel in the fracturing process without a UIC permit. In the past, legislation has been introduced in, but not passed by, Congress that would amend the SDWA to repeal this exemption. If similar legislation were enacted, it could require hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting and recordkeeping obligations and meet plugging and abandonment requirements. Future federal legislation could also require the reporting and public disclosure of chemical additives used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemical additives used in the fracturing process could adversely affect groundwater. If federal legislation regulating hydraulic fracturing is adopted in the future, it could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

In 2010, the EPA asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the UIC program by posting a requirement on its website that requires facilities to obtain permits to use diesel fuel in hydraulic fracturing operations. Industry groups filed suit challenging the EPA's decision as a "final agency action" and, therefore, a violation of the notice-and-comment rulemaking procedures of the Administrative Procedures Act. In February 2012, the EPA and industry reached a settlement under which the EPA will modify the informal policy posted on its website concerning the need for permits under the UIC program. However, the settlement does not reflect agreement on the issue of hydraulic fracturing regulation under the SDWA, and the EPA's continued assertion of its regulatory authority under the SDWA could result in extensive requirements that could cause additional costs and delays in the hydraulic fracturing process.

In addition to the above actions of the EPA, certain members of the Congress have called upon (i) the Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources; (ii) the Securities and Exchange Commission (the "SEC") to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shale by means of hydraulic fracturing; and (iii) the Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. The SEC has issued subpoenas to certain shale gas producers requesting information on proved reserve estimates from shale gas wells and the actual productivity of producing shale gas wells. The media has also reported that the New York attorney general has issued subpoenas to certain oil and gas companies seeking information regarding shale gas wells.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has also begun a study of the potential environmental impacts of hydraulic fracturing. The EPA issued a progress report in December 2012, and final results are expected in 2014. In addition, the U.S. Department of Energy conducted an investigation into practices the agency could recommend to better protect the environment from using hydraulic fracturing. The Shale Gas Subcommittee of the Secretary of Energy Advisory Board released its "90-day" report on August 18, 2011, and its final report on November 18, 2011, proposing recommendations to reduce the potential environmental impacts from shale gas production. Also, the U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands. These ongoing or proposed investigations and studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing.

Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances or otherwise require the public disclosure of chemicals used in hydraulic fracturing. For example, pursuant to legislation adopted by the State of Texas in June 2011, the RRC enacted a rule in December 2011, requiring disclosure to the RRC and the public of certain information regarding additives, chemical ingredients, concentrations and water volumes used in hydraulic fracturing. In addition to state law, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general and hydraulic fracturing in particular.

If these or any other new laws or regulations that significantly restrict hydraulic fracturing are adopted, it could become more difficult or costly for us to drill and produce oil and gas from shale and tight sands formations and become easier for third parties opposing hydraulic fracturing to initiate legal proceedings. In addition, if hydraulic fracturing is regulated at the federal level, fracturing activities could become subject to delays, additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and higher costs. These new laws or regulations could cause us to incur substantial delays or suspensions of operations and compliance costs and could have a material adverse effect on our business, financial condition and results of operations.

Compliance

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, 2012. 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 2013. 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.

Threatened and Endangered Species, Migratory Birds and Natural Resources

Various state and federal statutes 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.

Employees

As of February 15, 2013, we had 95 full-time employees, 53 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 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 ones 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 Gas Industry and Our Business

Drilling, 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.

Our future financial condition and results of operations will depend on the success of our drilling, exploration and production activities. These activities are subject to numerous risks beyond our control, including the risk that drilling will not result in economic oil and gas production or increases in reserves. Many factors may curtail, delay or cancel our scheduled development projects, including:

- decline in oil, NGL and gas prices;
- compliance with governmental regulations, which may include limitations on hydraulic fracturing, access to water or the discharge of greenhouse gases;
- inadequate capital resources;
- limited transportation services and infrastructure to deliver the oil and gas we produce to market;
- inability to attract and retain qualified personnel;
- unavailability or high cost of drilling and completion equipment, services or materials;
- 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.

Oil, NGL and gas prices are volatile, and a decline in oil, NGL 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, NGLs 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, NGLs and gas fluctuate widely in response to relatively minor changes in the supply and demand for these commodities, market uncertainty and a variety of additional factors beyond our control, such as:

- domestic and foreign supply of oil, NGLs and gas;
- domestic and foreign consumer demand for oil, NGLs 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;
- weather conditions, including unseasonably warm winter weather and tropical storms; and
- technological advances affecting oil, NGL and gas consumption.

Further, oil, NGL and gas prices do not necessarily fluctuate in direct relationship to each other, and these prices continued to be volatile in 2012. Advanced drilling and completion technologies, such as horizontal drilling and hydraulic fracturing, have resulted in increased investment by oil and gas producers in developing U.S. shale gas and, more recently, tight oil projects. 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 impair our estimated proved reserves and could have a material adverse effect on our business, financial condition and results of operations. Further, if oil, NGL or gas 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.

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 after-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, NGL and gas production and lower commodity prices, and consequently reduce our revenues, cash flows from operations and our profitability.

If gas prices remain low or decline further, or if oil and NGL prices decline, we may be required to write down the carrying values of our properties. Current SEC rules also could require us to write down our proved undeveloped reserves in the future.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on prevailing commodity prices and specific market factors and circumstances at the time of impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our properties. A write-down is a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken. In addition, current SEC rules require that proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years, unless specific circumstances justify a longer time. This rule may limit our potential to book additional proved undeveloped reserves as we pursue our development projects. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill those wells within the required timeframe. For example, for the year ended December 31, 2012, we reclassified 8.9 MMBoe of proved undeveloped reserves as probable undeveloped. These reserves were attributable to vertical Canyon locations in southeast Project Pangea. We postponed development of these deeper locations beyond five years from initial booking to integrate their development with the shallower Wolfcamp and Wolffork target zones.

Changes in the differential between 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 other, relevant benchmark prices, such as WTI NYMEX or WTI Cushing. The difference between a benchmark price and the price we reference in our sales contracts is called a basis differential. For example, due to increasing oil production in the Permian Basin and shortage of takeaway capacity in the area, the average monthly difference between WTI Cushing and WTI Midland (which is typically subtracted from our crude oil sales price) reached a high of approximately $14.00/Bbl in the first quarter of 2013. Although this differential narrowed in the latter part of the first quarter of 2013, we cannot accurately predict movement of oil and gas differentials and we may not be able to effectively manage this risk through derivatives or hedging transactions.

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 production, we enter into oil, NGL and gas price and basis differential commodity derivative agreements. While intended to reduce the effects of volatile commodity prices and basis differentials, such transactions may limit our potential gains and increase our potential losses if commodity 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 lower than expected, there is change 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.

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

Our oil and gas drilling, production and gathering operations are subject to complex and stringent laws and regulations. To operate in compliance with these laws and regulations, we must obtain and maintain numerous permits and approvals from various federal, state and local governmental authorities. We may incur substantial costs to comply with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations apply to our operations. Such costs could have a material adverse effect on our business, financial condition and results of operations. Failure to comply with laws and regulations applicable to our operations, including any evolving interpretation and enforcement by government authorities, could have a material adverse effect on our business, financial condition and results of operations. See “Business — Regulation” for a further description of the laws and regulations that affect us.

Federal and state legislation and regulatory initiatives and private litigation relating to hydraulic fracturing could stop or delay our development project and result in materially increased costs and additional operating restrictions.

All of our proved non-producing and proved undeveloped reserves associated with future drilling, completion and recompletion projects will require hydraulic fracturing. See Item 1. “Business — Hydraulic Fracturing” for a discussion of the importance of hydraulic fracturing to our business, and Item 1. “Business — Regulation — Hydraulic Fracturing” for a discussion of regulatory developments regarding hydraulic fracturing. If these or any other new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to drill and produce from, as well as make it easier for third parties opposing hydraulic fracturing to initiate legal proceedings. In addition, if hydraulic fracturing is regulated at the federal level, fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to permitting delays and increases in costs. These developments, as well as new laws or regulations, could cause us to incur substantial compliance costs, and compliance or the consequences of our failure to comply could have a material adverse effect on our financial condition and results of operations. In addition, if we are unable to use hydraulic fracturing in completing our wells or hydraulic fracturing becomes prohibited or significantly regulated or restricted, we could lose the ability to drill and complete the projects for our proved reserves and maintain our current leasehold acreage, which would have a material adverse effect on our future business, financial condition and operating results.

Our operations substantially depend on the availability of water. Restrictions on our ability to obtain, dispose of or recycle water may impact our ability to execute our drilling and development plans in a timely or cost-effective manner.

Water is an essential component of our drilling and hydraulic fracturing processes. Historically, we have been able to secure water from local landowners and other sources for use in our operations. During the last two years, West Texas has experienced extreme drought conditions. As a result of the severe drought, some local water districts may begin restricting the use of water under their jurisdiction for drilling and hydraulic fracturing to protect the local water supply. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil, NGLs and gas, which could have an adverse effect on our business, financial condition and results of operations.

Moreover, new environmental initiatives and regulations could include restrictions on disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of oil and gas. Compliance with environmental regulations and permit requirements for the withdrawal, storage and use of surface water or ground water necessary for hydraulic fracturing of our wells may increase our operating costs and cause delays, interruptions or cessation of our operations, the extent of which cannot be predicted, and all of which would have an adverse effect on our business, financial condition, results of operations and cash flows.

Climate change legislation or regulations regulating emissions of GHGs and VOCs 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 some 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.

In addition, in December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA has also issued final regulations under the NSPS and NESHAP designed to reduce VOCs. See Item 1. "Business — Regulation — Environmental Laws and Regulations — Greenhouse Gase Emissions" and "— Air Emissions" for a discussion of regulatory developments regarding GHG and VOC emissions.

The adoption of legislation or regulatory programs to reduce GHG or VOC emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce GHG or VOC emissions could have a material adverse effect on our business, financial condition and results of operations.

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, some of which have been used for exploration, production or development activities for many years and by third parties not under our control. In particular, the number of private, civil lawsuits involving hydraulic fracturing has risen in recent years. Since late 2009, multiple private lawsuits alleging ground water contamination have been filed in the U.S. against oil and gas companies, primarily by landowners who leased oil and gas rights to defendants, or by landowners who live close to areas where hydraulic fracturing has taken place. 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.

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

The President's proposed budget for fiscal year 2013 contains 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 (i) elimination of current deductions for intangible drilling costs ("IDCs"); (ii) repeal of the percentage depletion allowance for oil and gas properties; (iii) elimination of the deduction for certain U.S. production activities; and (iv) 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. In particular, we estimate that the elimination of the current deductibility of IDCs could impact our cash flows from operations by over $400 million over a five-year period from 2013 through 2017.

Our business requires significant capital expenditures and we may not be able to obtain needed capital or financing on satisfactory terms or at all.

Our exploration, development and acquisition activities require substantial capital expenditures. For example, according to our year-end 2012 reserve report, the estimated capital required to develop our current proved oil and gas reserves is $1 billion. Historically, we have funded our capital expenditures through a combination of cash flows from operations, borrowings under our credit facility and public equity financings. Future cash flows are subject to a number of variables, including the production from existing wells, prices of oil, NGLs and gas and our success in developing and producing new reserves. We do not expect our cash flow from operations to be sufficient to cover our current expected capital expenditure budget and we may have limited ability to obtain the additional capital necessary to sustain our operations at current levels. We may not be able to obtain debt or equity financing on favorable terms or at all. The failure to obtain additional financing could cause us to scale back our exploration and development operations, which in turn could lead to a decline in our oil and gas production and reserves, and in some areas a loss of properties.

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

At December 31, 2012, we had $106 million outstanding under our revolving credit facility, and our borrowing base was $280 million. 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.

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

We began drilling wells in the Wolfcamp play relatively recently. The wells that have been drilled or recompleted in these areas represent a very small sample of our large acreage position, and we cannot assure you that our new horizontal or vertical wells or recompletions of existing Canyon wells will be successful. As of December 31, 2012, we had proved reserves of 60.1 MMBoe attributable to the Wolfcamp play. Accordingly, we have limited information on the amount of reserves that will ultimately be recovered from our Wolfcamp wells. We continue to gather data about our prospects in the Wolfcamp 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.

Failure to effectively execute and manage our single major development project, Project Pangea, could result in significant delays, cost overruns, limitation of our growth, damage to our reputation and a material adverse effect on our business, financial condition and results of operations.

We have an extensive inventory of identified drilling locations in our development project (Project Pangea) in the Wolfcamp oil shale resource play major; however, Project Pangea is our core asset and our only development project. As we achieve more results in Project Pangea, we have expanded our horizontal development project there. This level of development activity requires significant effort from our management and technical personnel and places additional requirements on our financial resources and internal operating and financial controls. Our ability to successfully develop and manage this project will depend on, among other things:

- the extent of our success in drilling and completing horizontal Wolfcamp wells;
- our ability to control costs and manage drilling and completion risks;
- our ability to finance development of the project;
- our ability to attract, retain and train qualified personnel with the skills required to develop the project in a timely and cost-effective manner; and
- our ability to implement and maintain effective operating and financial controls and reporting systems necessary to develop and operate the project.

We may not be able to compensate for, or fully mitigate, these risks.

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 concentrated in two counties in Texas: Crockett and Schleicher. As a result of this concentration, we are disproportionately exposed to the natural decline of production from these fields 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, service delays, natural disasters or other events that impact this area.

Because of our geographic concentration, our purchaser base is limited, and the loss of one of our key purchasers or their inability to take our oil, NGLs or gas or could adversely affect our financial results.

In 2012, Shell, BML, WTG, DCP and Plains collectively accounted for 87% of our total oil, NGL and gas sales, excluding realized commodity derivative settlements. As of December 31, 2012, we had dedicated all of our oil production from northern Project Pangea and Pangea West for 10 years to an oil pipeline joint venture in which we own a 50% equity interest. In addition, as of December 31, 2012, we had contracted to sell all of our NGL and natural gas production from Project Pangea to DCP through January 2016. To the extent that any of our major purchasers reduces their purchases of oil, NGLs or gas, is unable to take our oil, NGLs or gas due to infrastructure or capacity limitations or defaults on their obligations to us, we would be adversely affected unless we were able to make comparably favorable arrangements with other purchasers. 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. The loss of any of these individuals, or the inability to attract, train and retain additional qualified personnel, 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 and the ability to attract, train and retain additional qualified 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 Qingming Yang, our Chief Operating Officer; J. Curtis Henderson, our Executive Vice President and General Counsel; 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. In addition, our ability to manage our growth, if any, will require us to effectively train, motivate and manage our existing 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.

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

Market conditions or the unavailability of satisfactory oil, NGL and gas processing and transportation services and infrastructure may hinder our access to oil, NGL and gas markets or delay our production or sales. Although currently we control the gathering systems for our operations in the Permian Basin, we do not have such control over the regional or downstream pipelines in and out of the Permian Basin. The availability of a ready market for our oil, NGL and gas production depends on a number of factors, including market demand and the proximity of our reserves to pipelines or trucking and rail 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 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 that we produce, 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, transportation, pipeline capacity or significant delay in construction of necessary gathering and transportation facilities, could adversely affect our business, financial condition and results of operations.

The unavailability or high cost of drilling rigs, equipment, materials, personnel and oilfield services could adversely affect our ability to execute our drilling 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 equipment, oilfield services 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. If the availability of equipment, crews, materials and services in the Permian Basin is 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.

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 skilled personnel. Many of our competitors are major and large independent oil and gas companies that have 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 develop and operate our current project, acquire additional prospects and discover reserves in the future will depend on our ability to hire and retain qualified personnel, evaluate and select suitable properties and consummate transactions and 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 attracting and retaining qualified personnel, acquiring prospective reserves, developing reserves, marketing oil, NGLs and gas and raising additional capital.

Our identified drilling locations are scheduled to be drilled over many years, making them susceptible to uncertainties that could prevent them from being drilled or delay their drilling. In certain instances, this could prevent drilling and production before the expiration date of leases for such locations.

Our management team has identified drilling locations as an estimation of our future development activities on our existing acreage. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these identified drilling locations depends on a number of uncertainties, including oil, NGL and gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system, marketing and transportation constraints, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the identified drilling locations we have identified will ever be drilled or if we will be able to produce oil or gas from these or any other identified drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the identified locations are obtained, the leases for such acreage will expire. Therefore, our actual drilling activities may materially differ from those presently identified.

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 Wolfcamp 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, 3-D seismic and micro-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 Wolfcamp 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 Wolfcamp and other zones will depend on the effective use of advanced drilling and completion techniques, the scope of our development project (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.

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 production, revenues 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.

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

As of December 31, 2012, 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 2013 and 2016. 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. Acreage set to expire over the next three years accounts for 95% of our net undeveloped acreage, 17.2% of our proved undeveloped reserves and 11.3% of our total proved 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 reserves 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 reserves 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, 2012, approximately 66% 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.

The non-GAAP financial measure, 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 oil, NGL and gas prices decline by 10% from $94.71 per Bbl of oil, $37.88 per Bbl of NGLs and $2.74 per MMBtu of gas, to $85.24 per Bbl of oil, $34.09 per Bbl of NGLs and $2.47 per MMBtu of gas, then our PV-10 as of December 31, 2012, would decrease from $830.9 million to approximately $633.7 million. The average market price received for our production for the month of December 2012 was $76.47 per Bbl of oil, $28.71 per Bbl of NGLs and $3.22 per Mcf of gas (after basis differential and Btu adjustments). Actual future net revenues also will be affected by factors such as the amount and timing of actual production, prevailing operating and development costs, supply and demand for oil and gas, increases or decreases in consumption and changes in governmental regulations or taxation.

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.

Operating hazards 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, surface and subsurface pollution and contamination, 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. 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 development projects.

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 gas 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.

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*

Our operations are focused on the Wolfcamp oil shale resource play in the Permian Basin in West Texas. We also have minor operations in the East Texas Basin in East Texas. The following table is a summary of data for our operating areas for the year ended December 31, 2012.

Operating Area	Total Gross Acres	Total Net Acres	Average Daily Production (Boe/d)	Percentage of Production	Proved Reserves (MBoe)	Percentage of Proved Reserves
Permian Basin	167,407	147,537	7.84	99.4%	95,342	99.9%
East Texas Basin	6,194	3,389	0.05	0.6%	137	0.1%
Total	173,601	150,926	7.89	100.0%	95,479	100.0%

Permian Basin — Project Pangea and Pangea West

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 167,000 gross (148,000 net) acres as of year-end 2012. At December 31, 2012, we owned interests in approximately 594 gross (583.2 net) wells, all of which we operate. As of December 31, 2012, we had working and net revenue interests of approximately 100% and 76%, respectively, across Project Pangea and Pangea West.

Our acreage position in the Permian Basin is characterized by several commercial hydrocarbon zones. Our drilling targets include the Clearfork, Wolfcamp shale, Canyon Sands, Strawn and Ellenburger zones. 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.

In 2010, we performed a detailed geological and petrophysical evaluation of the Clearfork, Dean and Wolfcamp shale formations, or "Wolffork," above the Canyon Sands, Strawn and Ellenburger. In our evaluation we used logs, 3-D seismic, whole core data and regional mapping. The Wolffork is made up of three stacked pay zones, the Clearfork, Dean and Wolfcamp Shale formations with combined gross pay thickness of approximately 2,500 feet, which were deposited across Project Pangea and Pangea West by a combination of suspension, debris flow and turbidite processes. 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 Wolfcamp shale has gross pay thickness of approximately 1,000 to 1,200 feet across our acreage position. The Wolfcamp shale is a source rock that we believe has significant potential for hydrocarbons. The Wolfcamp shale is 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. To better define and study this extensive column of rock, we have classified the Wolfcamp into four zones or "benches," the A, B, C and D. Effectively developing the Wolfcamp shale may involve up to three lateral wellbores, each targeting a different interval, the Wolfcamp A, B and C.

We currently estimate that we have 2,983 drilling and recompletion locations targeting the horizontal Wolfcamp shale and the vertical Wolffork, 189 of which are proved, including:

- 2,096 horizontal Wolfcamp locations;

- 329 vertical Wolffork locations;
- 398 vertical Canyon Wolffork locations; and
- 160 Wolffork recompletions

We also have identified 170 proved drilling locations targeting the Canyon Sands and deeper zones, and therefore our proved drilling locations in the Permian Basin total 359. The timing of drilling our identified locations is subject to a number of uncertainties and will be influenced by several factors, including commodity prices, capital requirements, well-spacing requirements and a continuation of the results from both our horizontal and vertical drilling.

In the Permian Basin, we consider the Wolffork interval to be a resource play. As such, the mapping of the gross interval for each of the producing formations under our acreage position is the main factor we considered in identifying our locations. In the general region and immediately around our acreage position, publicly available well data exists from a large number of vertical wells that have allowed us to define the areal extent of each of the producing intervals, whether the whole vertical Wolffork section or the targeted Clearfork and Wolfcamp shale. In addition to this publicly available well data, we have also used internally generated information from cores, 3-D seismic, open-hole logging and reservoir engineering to estimate the extent of the targeted intervals, the ability of such intervals to produce commercial quantities of hydrocarbons and the viability of identified locations. The timing of drilling our identified locations will be influenced by several factors, including commodity prices, capital requirements, RRC well-spacing requirements and a continuation of the positive results from both our horizontal and vertical drilling and development activities.

As of December 31, 2012, we had estimated proved reserves of 95.3 MMBoe in the Permian Basin, made up of 39% oil, 31% NGLs and 30% natural gas. Our Permian proved reserves increased 24%, and oil proved reserves increased 106%, over year-end 2011. Reserve growth in 2012 was driven by results in our Wolfcamp oil shale resource play.

During 2012 in the Permian Basin, we incurred $240.8 million to drill 46 gross (45.8 net) wells, of which 10 gross (9.9 net) wells were waiting on completion at December 31, 2012.

East Texas Basin — North Bald Prairie

Cotton Valley Sands and Cotton Valley Lime

In July 2007, we entered into a joint 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. We have 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 6,200 gross (3,400 net) acre project. In 2012, EnCana assigned its interest in the project to a third party. As of December 31, 2012, we had estimated proved reserves of 820 MMcf in North Bald Prairie. Average daily production in 2012 was 320 Mcf/d, or a total of 117 MMcf.

Our primary targets in North Bald Prairie are the Cotton Valley Sands and Cotton Valley Lime. These are 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.

Proved Oil and Gas Reserves

The following table sets forth summary information regarding our estimated proved reserves as of December 31, 2012. See Note 10 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, 2012, were 95.5 MMBoe, made up of 39% oil, 30% NGLs and 31% natural gas. The proved developed portion of total proved reserves at year end 2012 was 34%. Natural gas is converted at a rate of six Mcf of gas to one barrel of oil equivalent ("Boe"). NGLs are converted at a rate of one barrel of NGLs to one Boe. The ratios of six Mcf of gas to one Boe and one barrel of NGLs to one Boe do not assume price equivalency and, given price differentials, the price for a Boe of natural gas or NGLs may differ significantly from the price of a barrel of oil.

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	8,816	11,761	72,359	32,637	34.2%
East Texas Basin	—	—	819	137	0.1
Proved Undeveloped					
Permian Basin	28,436	17,339	101,582	62,705	65.7
Total Proved Reserves	37,252	29,100	174,760	95,479	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, 2012. 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 $94.71 per Bbl West Texas Intermediate posted oil price, $37.88 per Bbl received for NGLs and $2.74 per MMBtu Henry Hub spot natural gas price during 2012. 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, 2012				
Operating Area	**Oil (MBbls)**	**NGLs (MBbls)**	**Natural Gas (MMcf)**	**Total (MBoe)**	**PV-10 (in millions)**
Permian Basin	37,252	29,100	173,940	95,342	$ 830,435
East Texas Basin	—	—	820	137	487
Total	37,252	29,100	174,760	95,479	830,922
Present value of future income tax discounted at 10%					(336,702)
Standardized measure of discounted future net cash flows					$ 494,220

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 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, 2012 (in MBoe).

Operating Area	Production	Extensions and Discoveries	Revisions to Previous Estimates
Permian Basin	(2,868)	38,861	(17,413)
East Texas Basin	(20)	—	(56)
Total	(2,888)	38,861	(17,469)

We produced 2.9 MMBoe during 2012, 99% of which is attributable to our assets in the Permian Basin. Extensions and discoveries for 2012 of 38.9 MMBoe were primarily attributable to our development project in the Wolfcamp oil shale resource play in the Permian Basin. During 2012, we recorded downward revisions totaling 17.5 MMBoe, including the reclassification of 8.9 MMBoe of proved undeveloped reserves to probable undeveloped. These reserves were attributable to vertical Canyon locations in southeast Project Pangea. Due to our horizontal Wolfcamp development project, including pad drilling, postponement of these deeper locations beyond five years from initial booking is necessary to integrate their development with the shallower Wolfcamp and Wolffork target zones. We expect this integrated development to minimize surface impact and maximize reservoir recoveries. Revisions also include 3.3 MMBoe of performance revisions primarily related to vertical Canyon wells in Project Pangea, 2.9 MMBoe of revisions resulting from technical evaluations and revisions of 2.4 MMBoe due to lower natural gas and NGL prices.

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 Manager of Reservoir Engineering, Brandon L. Hudson, 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. Hudson has a Bachelor of Science degree in Mechanical Engineering from University of Texas at Austin and a Master of Science degree in Petroleum Engineering from Louisiana State University and 10 years of industry experience. Mr. Hudson reports directly to our Chief Executive Officer. Our senior management, including our Chief Executive Officer and Chief Financial Officer, reviews and approves our reserves estimates, including future development costs, 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 more than 30 years of industry experience. Our Chief Financial Officer, Steven P. Smart, is a licensed Certified Public Accountant with more than 30 years of industry experience.

For the years ended December 31, 2012, 2011, and 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 2012, DeGolyer and MacNaughton reported to the Audit Committee of our Board of Directors and to our Manager of Reservoir Engineering. The Audit Committee meets with the independent engineering firm before the preparation of the firm's final report to, among other things, review and consider the processes used by the engineers in the preparation of the report and any matters of importance that arose in the preparation of the report, including whether the independent engineering firm encountered any material problems or difficulties in the preparation of their report. The Audit Committee's review specifically includes difficulties with the scope or timeliness of the information furnished to them by the Company or any restrictions or access to information placed upon them by any Company personnel, any other difficulties in dealing with any Company personnel in the preparation of the report and any other matters of concern relating to the preparation of the report. The Audit Committee also determines whether the Company or its management or senior engineering personnel had similar or other problems or concerns regarding the independent engineering firm and the preparation of their report. 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. For our properties, structure and isopach maps were constructed to delineate each reservoir. Electrical logs, radioactivity logs, seismic data and other available data were used to prepare these maps. Parameters of area, porosity and water saturation were estimated and applied to the isopach maps to obtain estimates of original oil in place or original gas in place. For developed producing wells whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were determined using decline curve analysis. Reserves for producing wells whose performance was not yet established and for undeveloped locations were estimated using type curves. The parameters needed to develop these type curves such as initial decline rate, "b" factor and final decline rate were based on nearby wells producing from the same reservoir and with a similar completion for which more data were available.

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, 2012, NGLs represented approximately 30% of our total proved reserves on a Boe basis. NGLs are products sold by the gallon. In reporting proved reserves and production of NGLs, we include these volumes and production as Boe. The prices we received for a standard barrel of NGLs in 2012 averaged approximately 60% 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, 2012, 2011, and 2010, 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, including 100% of our total reported proved reserves. DeGolyer and MacNaughton's report for 2012 is included as Exhibit 99.1 to this annual report on Form 10-K.

Proved Undeveloped Reserves

As of December 31, 2012, we had 62.7 MMBoe of proved undeveloped ("PUD") reserves, which is an increase of 19.3 MMBoe or 44%, compared with 43.4 MMBoe of PUD reserves at December 31, 2011. All of our PUD reserves at December 31, 2012, were associated with our core development project, Project Pangea. As a percent of our total proved reserves, our PUD reserves increased from 56% in 2011 to 66% in 2012 due to our ongoing development of our Wolfcamp oil shale resource play.

The following table summarizes the changes in our PUD reserves during 2012.

	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Balance — December 31, 2011	12,509	15,178	94,064	43,364
Extensions and discoveries	18,514	7,349	41,781	32,827
Revisions to previous estimates	(1,301)	(4,520)	(30,581)	(10,918)
Conversion to proved developed reserves	(1,286)	(668)	(3,682)	(2,568)
Balance — December 31, 2012	28,436	17,339	101,582	62,705

The following table sets forth our PUD reserves converted to proved developed reserves during 2012, 2011 and 2010 and the net investment required to convert PUD reserves to proved developed reserves during the year.

	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)	(in thousands)
2010	589	2,134	12,728	4,845	$ 37,070
2011	263	660	3,583	1,520	33,783
2012	1,286	668	3,682	2,568	52,008
Total	2,138	3,462	19,993	8,933	$122,861

Estimated future development costs relating to the development of PUD reserves are projected to be approximately $239.6 million in 2013, $291.2 million in 2014 and $335.5 million in 2015. 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 PUD reserves are scheduled to be drilled before the end of 2017.

At December 31, 2012, we had 4.5 MMBoe of PUD reserves, or 4.7% of our total proved reserves and 7.2% of our total PUD reserves, that have been booked for five years or longer. Substantially all of the PUD reserves that have been booked for five years or longer are associated with our deep, tight sandstone (Canyon Sands) locations in Project Pangea. This tight sandstone reservoir is approximately 7,250 to 8,500 feet deep and lies under approximately 100,000 gross acres across Project Pangea.

We have a historical record of drilling our deep, tight sandstone reserves in Project Pangea. From 2004 through December 31, 2012, we have drilled and completed more than 500 tight sands wells in the Permian Basin since 2004. According to IHS, a provider of global market and economic information, this makes us the second most active driller of tight sands (Canyon Sands) wells in West Texas since we began drilling in the area in 2004.

Based on our more recent Wolfcamp and Wolffork drilling activity in Project Pangea since 2010, we believe that the PUD reserves that have been booked for five years or longer have additional reserves above the tight sands. To maximize wellbore utility and reservoir potential, our objective is to develop these multi-zone reserves together as part of Project Pangea. Developing these reserves on an integrated basis should allow us to maximize reservoir potential, prevent waste and minimize surface impact and use of other critical resources such as fresh water for fracture stimulation.

To prepare for larger scale development of Project Pangea, in 2012 we accelerated our investment in infrastructure in Project Pangea, spending $44.3 million on infrastructure, projects and equipment, plus an additional $10 million in equity investment in a joint venture for pipeline and facilities construction, for a total of $54.3 million. This represents 18% of total capital costs and equity investment in Project Pangea in 2012.

Oil and Gas Production, Production Prices and Production Costs

The following table sets forth summary information regarding oil, NGL and gas production, average sales prices and average production costs for the last three years. We determined the Boe using the ratio of six Mcf of natural gas to one Boe, and one barrel of NGLs to one Boe. The ratios of six Mcf of natural gas to one Boe and one barrel of NGLs to one Boe do not assume price equivalency and, given price differentials, the price for a Boe for natural gas or NGLs may differ significantly from the price for a barrel of oil.

	Years Ended December 31,		
	2012	2011	2010
Production			
Oil (MBbls)	969	482	246
NGLs (MBbls)	904	798	261
Gas (MMcf)	6,089	6,345	6,290
Total (MBoe)	2,888	2,338	1,556
Total (MBoe/d)	7.9	6.4	4.3
Average prices			
Oil (per Bbl)	$84.70	$88.18	$75.67
NGLs (per Bbl)	34.09	51.39	41.19
Gas (per Mcf)	2.63	3.92	4.48
Total (per Boe)	44.63	46.37	37.00
Realized gain on commodity derivatives (per Boe)	(0.03)	1.44	3.72
Total including derivative impact (per Boe)	$44.60	$47.81	$40.72
Production costs (per Boe)(1)	$ 6.58	$ 4.57	$ 4.25

(1) Production cost per Boe is made up of lease operating expenses. Production cost per Boe excludes production and ad valorem 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,					
	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	46.0	45.8	69.0	64.2	91.0	56.2
Dry	—	—	2.0	2.0	—	—
Exploratory wells:						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total wells:						
Productive	46.0	45.8	69.0	64.2	91.0	56.2
Dry	—	—	2.0	2.0	—	—

Of the 46 gross (45.8 net) wells drilled in 2012, 10 gross (9.9 net) wells were waiting on completion at December 31, 2012. Of the two gross (two net) dry wells drilled in 2011, one was completed as a salt water disposal well and one replacement well was drilled during the first three months of 2012.

Although a well may be classified as productive upon completion, future changes in oil, NGL 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 horizontal rigs running in the Permian Basin and targeting the Wolfcamp shale.

Delivery Commitments

We are not committed to provide a fixed and determinable quantity of oil, NGLs or gas in the near future under existing agreements. However, as of December 31, 2012, we had (1) dedicated all of our oil production from northern Project Pangea and Pangea West for 10 years to an oil pipeline joint venture in which we own a 50% equity interest, and (2) contracted to sell all of our NGLs and natural gas production from Project Pangea to DCP through January 2016.

Producing Wells

The following table sets forth the number of producing wells in which we owned a working interest at December 31, 2012. 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	525.0	514.7	69.0	68.5	594.0	583.2	98.2%
East Texas Basin	5.0	2.5	—	—	5.0	2.5	50.0%
Total	530.0	517.2	69.0	68.5	599.0	585.7	97.8%

Acreage

The following table summarizes our developed and undeveloped acreage as of December 31, 2012.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Permian Basin	75,371	66,977	92,036	80,560	167,407	147,537
East Texas Basin	3,504	1,682	2,690	1,707	6,194	3,389
Total	78,875	68,659	94,726	82,267	173,601	150,926

Undeveloped Acreage Expirations

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2012, that will expire over the next three years by project area unless production is established before lease expiration dates. Gross amounts may be more than net amounts in a particular year due to timing of expirations.

	2013		2014		2015	
	Gross	Net	Gross	Net	Gross	Net
Permian Basin	21,157	17,028	41,018	35,250	26,143	24,461
East Texas Basin	393	274	2,298	1,428	—	4
Total	21,550	17,302	43,316	36,678	26,143	24,465

The expiring acreage set forth in the table above accounts for 95% of our net undeveloped acreage, 17.2% of our PUD reserves and 11.3% of our total proved reserves. We are continually engaged in a combination of drilling and development and discussions with mineral lessors for lease extensions, renewals, new drilling and development units and new leases to address the expiration of undeveloped acreage that occurs in the normal course of our business.

ITEM 3. *LEGAL PROCEEDINGS*

We are involved in various 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 business, financial condition or cash flows.

ITEM 4. *MINE SAFETY DISCLOSURES*

Not applicable.

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 2012, trading volume averaged 534,757 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
2012		
First quarter	$38.92	$29.77
Second quarter	39.18	22.36
Third quarter	34.84	24.08
Fourth quarter	30.76	22.50
2011		
First quarter	$34.72	$22.58
Second quarter	34.93	19.13
Third quarter	28.37	15.55
Fourth quarter	33.48	14.14

Holders

As of February 25, 2013, there were 115 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 into 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

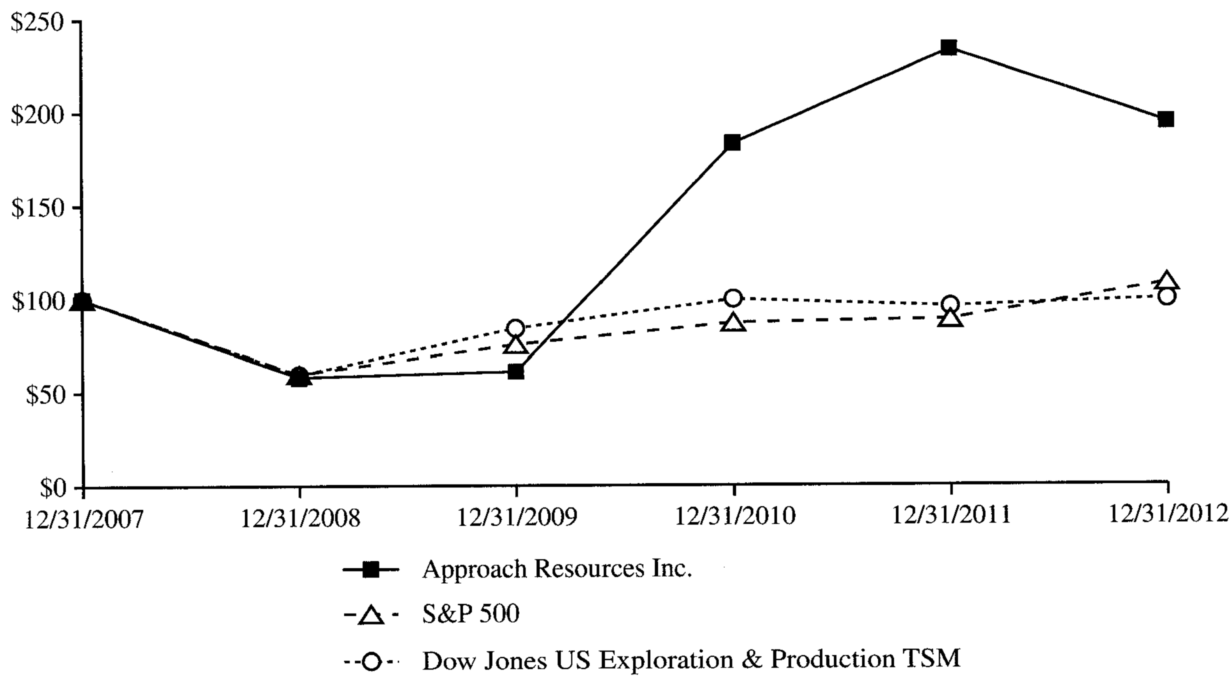
The following table sets forth information regarding securities authorized for issuance under equity compensation plans and individual compensation arrangements as of December 31, 2012.

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	43,275	$12.38	2,062,854
Equity compensation plans not approved by stockholders	—	—	—

Performance Graph

The following graph compares the cumulative return on a $100 investment in our common stock from December 31, 2007, through December 31, 2012, 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.

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN
Among Approach Resources Inc., the S&P 500 Index, and the Dow Jones U.S. Exploration & Production Total Stock Market Index



	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/31/2011	12/31/2012
Approach Resources Inc.	$100.00	$58.06	$61.32	$183.48	$233.60	$ 194.48
S&P 500	100.00	59.95	75.81	87.23	89.07	108.59
D J U.S. Exploration & Production	100.00	59.62	84.37	99.89	95.80	99.66

Issuer Repurchases of Equity Securities

Our 2007 Plan allows us to withhold shares of common stock to pay withholding taxes payable upon vesting of a restricted stock grant. 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, 2012 — October 31, 2012	—	—	—	—
November 1, 2012 — November 30, 2012	962	$23.14	—	—
December 1, 2012 — December 31, 2012	79,022	$24.92	—	—
Total	79,984	$24.84	—	—

ITEM 6. *SELECTED FINANCIAL DATA*

The following table sets forth selected financial information for the five years ended December 31, 2012. 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,				
	2012	2011	2010	2009	2008
	(in thousands, except per-share data)				
Operating Results Data					
Revenues					
Oil, NGL and gas sales	$ 128,892	$ 108,387	$ 57,581	$ 40,648	$ 79,869
Expenses					
Lease operating(1)	19,002	10,687	6,620	6,018	6,425
Production and ad valorem taxes(1)	9,255	8,447	4,925	3,755	5,398
Exploration	4,550	9,546	2,589	1,621	1,478
Impairment	—	18,476	2,622	2,964	6,379
General and administrative	24,903	17,900	11,422	10,617	8,881
Depletion, depreciation and amortization	60,381	32,475	22,224	24,660	23,710
Total expenses	118,091	97,531	50,402	49,635	52,271
Operating income (loss)	10,801	10,856	7,179	(8,987)	27,598
Other					
Impairment of investment	—	—	—	—	(917)
Interest expense, net	(4,737)	(3,402)	(2,189)	(1,787)	(1,269)
Equity in losses of investee	(108)	—	—	—	—
Realized (loss) gain on commodity derivatives	(108)	3,375	5,784	14,659	2,936
Unrealized gain (loss) on commodity derivatives	3,874	(347)	788	(9,899)	7,149
Gain on sale of oil and gas properties, net of foreign currency transaction loss	—	248	—	—	—
Income (loss) before provision (benefit) for income taxes	9,722	10,730	11,562	(6,014)	35,497
Provision (benefit) for income taxes	3,338	3,488	4,100	(785)	12,111
Net income (loss)	$ 6,384	$ 7,242	$ 7,462	$ (5,229)	$ 23,386
Earnings (loss) per share					
Basic	$ 0.18	$ 0.25	$ 0.34	$ (0.25)	$ 1.13
Diluted	$ 0.18	$ 0.25	$ 0.34	$ (0.25)	$ 1.12
Statement of Cash Flows Data					
Net cash provided by (used in)					
Operating activities	$ 90,585	$ 95,770	$ 42,377	$ 39,761	$ 56,381
Investing activities	(307,414)	(284,758)	(91,346)	(29,553)	(100,633)
Financing activities	217,295	165,843	69,748	(11,618)	43,750
Effect of Canadian exchange rate	—	(19)	1	18	(206)
Balance Sheet Data					
Cash and cash equivalents	$ 767	$ 301	$ 23,465	$ 2,685	$ 4,077
Other current assets	14,889	11,085	17,865	9,318	30,760
Property, equipment, net, successful efforts method	828,467	595,284	369,210	304,483	303,404
Equity method investment	9,892	—	—	—	—
Other assets	1,724	1,224	2,549	2,440	—
Total assets	$ 855,739	$ 607,894	$413,089	$318,926	$ 338,241
Current liabilities	$ 60,247	$ 43,625	$ 29,240	$ 21,996	$ 30,775
Long-term debt	106,000	43,800	—	32,319	43,537
Other long-term liabilities	56,024	53,020	50,903	44,115	40,116
Stockholders' equity	633,468	467,449	332,946	220,496	223,813
Total liabilities and stockholders' equity	$ 855,739	$ 607,894	$413,089	$318,926	$ 338,241

(1) Amounts related to ad valorem taxes have been reclassified from lease operating to production and ad valorem taxes for all years presented. This reclassification has no impact on net income (loss) reported herein.

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 1A. 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 gas reserves in oil shale and tight gas sands in the Permian Basin in West Texas, where we lease approximately 148,000 net acres. Our drilling targets include the Clearfork, Wolfcamp shale, Canyon Sands, Strawn and Ellenburger zones. We sometimes refer to the Clearfork and Wolfcamp zones together as the "Wolffork," and our development project in the Permian Basin as "Project Pangea," which includes "Pangea West." Our management and technical team have a proven track record of finding and developing reserves through advanced drilling and completion techniques. 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, 2012, our estimated proved reserves were 95.5 million barrels of oil equivalent ("MMBoe"). Substantially all of our proved reserves are located in Crockett and Schleicher Counties, Texas. Important characteristics of our proved reserves at December 31, 2012, include:

- 39% oil, 30% NGLs and 31% natural gas;
- 34% proved developed;
- 100% operated;
- Reserve life of more than 30 years based on 2012 production of 2.9 MMBoe;
- Standardized Measure of $494.2 million; and
- PV-10 of $830.9 million.

At December 31, 2012, we owned and operated 594 producing oil and gas wells in the Permian Basin, and we had an estimated 2,983 identified drilling and recompletion locations, of which 359 were proved. We also owned working interests in nine producing gas wells in the East Texas Basin.

2012 Activity

Our operations in 2012 focused on horizontal drilling in our Wolfcamp oil shale resource play in the Permian Basin. We drilled 26 horizontal wells in 2012, compared to 13 horizontal wells in 2011. Our early results in the Wolfcamp play led us to invest in building an infrastructure system that we believe will reduce drilling and completion costs, improve drilling and completion efficiencies, reduce fresh water use and ensure transportation for our crude oil production to market. We plan to continue to develop the Wolfcamp shale in Project Pangea in 2013. Focusing on the Wolfcamp shale allows us to use our operating, technical and regional expertise that is important to interpreting geological and operating trends, enhancing production rates and maximizing well recovery.

Production Growth

Production for 2012 totaled 2.9 MMBoe (7.9 MBoe/d), compared to 2.3 MMBoe (6.4 MBoe/d) in 2011, a 24% increase. Production for 2012 was 34% oil, 31% NGLs and 35% natural gas. Our continued development of

Project Pangea increased oil production 101% in 2012, compared to 2011. On average, we operated two horizontal rigs and one vertical rig in 2012, and drilled a total of 46 gross (45.8 net) wells, of which 10 gross (9.9 net) were waiting on completion at December 31, 2012. We also recompleted 18 gross (18 net) wells in the Wolffork in 2012.

Reserve Growth

In 2012, our estimated proved reserves increased 24%, or 18.5 MMBoe, to 95.5 MMBoe from 77.0 MMBoe. Our proved reserves at year-end 2012 were 39% oil, 30% NGLs and 31% natural gas, compared to 23% oil, 38% NGLs and 39% natural gas at year-end 2011. During 2012, our proved oil reserves increased 19.2 MMBbls, or 106%, to 37.3 MMBbls from 18.1 MMBbls in 2011. Reserve growth, and especially our oil reserve growth, in 2012 was driven by results in our Wolfcamp oil shale resource play.

2012 Equity Offering

In September 2012, we completed the 2012 Offering and sold 5.0 million shares of common stock at $30.50 per share. In October 2012, the underwriters exercised their option and purchased an additional 325,000 shares. After deducting underwriting discounts and transaction costs of approximately $8.0 million, we received net proceeds of approximately $154.4 million. We used the proceeds of the 2012 equity offering to repay outstanding borrowings under our revolving credit facility, fund our capital expenditures for the development of our Wolfcamp oil shale resource play and for general working capital needs.

Plans for 2013

In September 2012, we announced a 2013 capital budget of $260 million, which includes three rigs to drill horizontal wells targeting the Wolfcamp shale. We expect that our horizontal drilling in Project Pangea in 2013 will include pad drilling, which we believe will improve operating efficiencies and resource recoveries, while reducing facilities costs and surface impact. We also may drill vertical wells targeting the Wolffork or recomplete Canyon Sands wells in the Wolffork during 2013. Our objectives for 2013 include advancing our understanding of optimal well spacing, testing multi-zone potential to enhance hydrocarbon recovery in our Wolffork targets and improving our cost structure.

Our 2013 capital budget is subject to change depending upon a number of factors, including additional data on our Wolfcamp oil shale resource play, results of horizontal and vertical drilling, completions and recompletions, including pad drilling, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil, NGLs and gas, 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 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 significant 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.

Proved Reserves

For the year ended December 31, 2012, we engaged DeGolyer and MacNaughton, independent petroleum engineers, to prepare independent estimates of the extent and value of 100% of our reported proved reserves, in accordance with rules and guidelines established by the SEC.

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, 2012, 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, 2012, for oil, NGLs and gas 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 gas reserves. A hypothetical 10% decline in our December 31, 2012, estimated proved reserves would have increased our depletion expense by approximately $1.9 million for the year ended December 31, 2012.

See also Item 2. "Properties — Proved Oil and Gas Reserves" and Note 10 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 year ended December 31, 2011, we recognized an unrealized loss of $347,000 from the change in the fair value of commodity derivatives. For the years ended December 31, 2012 and 2010, we recognized an unrealized gain of $3.9 million and $788,000, respectively, from the change in the fair value of commodity derivatives. A hypothetical 10% increase in the NYMEX floating prices would have resulted in a $5.4 million decrease in the December 31, 2012, fair value recorded on our balance sheet and a corresponding decrease to the gain 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, NGLs and gas, future costs to produce these products, estimates of future oil and 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.

Provision for Income Taxes

We estimate our provision for income taxes using historical tax basis information from prior years' income tax returns, along with the estimated changes to such bases from current period activity and enacted tax rates. Additionally, we compare liabilities to actual settlements of such assets or liabilities during the current period to identify considerations that might affect the current period's estimate.

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.

In accordance with GAAP, we calculate the fair value of share-based compensation using various valuation methods. The valuation methods require the use of estimates to derive the inputs necessary to determine fair value. We use (i) the Black-Scholes option price model to measure the fair value of stock options, (ii) the closing stock price on the date of grant for the fair value of restricted stock awards, including performance-based awards, and (iii) the Monte Carlo simulation method for the fair value of market-based awards.

Equity Method Investments

For investments in which we have the ability to exercise significant influence but do not have control, we follow the equity method of accounting. In September 2012, we entered into a joint venture to build an oil pipeline in Crockett and Reagan Counties, Texas, which will be used to transport our oil to market. In October 2012, we made an initial contribution of $10 million to the joint venture for pipeline and facilities construction. This initial contribution was recorded at cost. Our equity investment is classified as a noncurrent asset on our consolidated balance sheet at December 31, 2012. Our share of the investee's losses was recorded on our consolidated statement of operations for the year ended December 31, 2012.

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, 2012, 2011 or 2010. 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 and equipment. It may also increase the cost of labor or supplies.

Results of Operations

The following table sets forth summary information regarding oil, NGL and gas revenues, production, average product prices and average production costs and expenses for the last three years. We determined the Boe using the ratio of six Mcf of natural gas to one Boe, and one barrel of NGLs to one Boe. The ratios of six Mcf of natural gas to one Boe and one barrel of NGLs to one Boe do not assume price equivalency and, given price differentials, the price for a Boe for natural gas or NGLs may differ significantly from the price for a barrel of oil.

	Years Ended December 31,		
	2012	2011	2010
Revenues (in thousands)			
Oil	$ 82,087	$ 42,463	$18,640
NGLs	30,811	41,029	10,765
Gas	15,994	24,895	28,176
Total oil, NGL and gas sales	128,892	108,387	57,581
Realized (loss) gain on commodity derivatives	(108)	3,375	5,784
Total oil, NGL and gas sales including derivative impact	$128,784	$111,762	$63,365
Production			
Oil (MBbls)	969	482	246
NGLs (MBbls)	904	798	261
Gas (MMcf)	6,089	6,345	6,290
Total (MBoe)	2,888	2,338	1,556
Total (MBoe/d)	7.9	6.4	4.3
Average prices			
Oil (per Bbl)	$ 84.70	$ 88.18	$ 75.67
NGLs (per Bbl)	34.09	51.39	41.19
Gas (per Mcf)	2.63	3.92	4.48
Total (per Boe)	$ 44.63	$ 46.37	$ 37.00
Realized (loss) gain on commodity derivatives (per Boe)	(0.03)	1.44	3.72
Total including derivative impact (per Boe)	$ 44.60	$ 47.81	$ 40.72
Costs and expenses (per Boe)			
Lease operating	$ 6.58	$ 4.57	$ 4.25
Production and ad valorem taxes(1)	3.20	3.61	3.17
Exploration	1.58	4.08	1.66
Impairment	—	7.90	1.68
General and administrative	8.62	7.66	7.34
Depletion, depreciation and amortization	20.91	13.89	14.28

(1) Amounts related to ad valorem taxes have been reclassified from lease operating to production and ad valorem taxes for all years presented. This reclassification has no impact on net income (loss) reported herein.

Oil, NGL and gas sales. Oil, NGL and gas sales increased $20.5 million, or 19%, to $128.9 million from $108.4 million in 2011. The increase in oil, NGL and gas sales was due to an increase in production volumes, partially offset by a decrease in average prices received. Production volumes increased as a result of our development of Project Pangea in the Permian Basin. In 2012, the average price we received for our production, before the effect of commodity derivatives, decreased to $44.63 per Boe from $46.37 per Boe, or a 4% decrease. Subject to commodity prices, we expect oil, NGL and gas sales to increase in 2013 due to increased production volumes from our development project in the Permian Basin.

Oil, NGL and gas sales increased $50.8 million, or 88%, in 2011 to $108.4 million from $57.6 million in 2010. Of the $50.8 million increase in oil, NGL and gas sales, approximately $48.6 million was attributable to an increase in production volumes and $2.2 million was attributable to an increase in prices. In 2011, the average price we received for our production, before the effect of commodity derivatives, increased to $46.37 per Boe from $37.00 per Boe, or a 25% increase.

The following table summarizes our oil, NGL and gas sales for each of the last three years (in thousands).

	Years Ended December 31,		
Revenues	**2012**	**2011**	**2010**
Oil	$ 82,087	$ 42,463	$18,640
NGLs	30,811	41,029	10,765
Gas	15,994	24,895	28,176
Total oil, NGL and gas sales	128,892	108,387	57,581
Realized (loss) gain on commodity derivatives	(108)	3,375	5,784
Total oil, NGL and gas sales including derivative impact	$128,784	$111,762	$63,365

The following table summarizes the prices we received for oil, NGLs and gas for each of the last three years.

	Years Ended December 31,		
Average prices	**2012**	**2011**	**2010**
Oil (per Bbl)	$84.70	$88.18	$75.67
NGLs (per Bbl)	34.09	51.39	41.19
Gas (per Mcf)	2.63	3.92	4.48
Total (per Boe)	$44.63	$46.37	$37.00
Realized (loss) gain on commodity derivatives (per Boe)	(0.03)	1.44	3.72
Total including derivative impact (per Boe)	$44.60	$47.81	$40.72

Net income. Net income for 2012 was $6.4 million, or $0.18 per diluted share, compared to net income of $7.2 million, or $0.25 per diluted share for 2011 and net income of $7.5 million, or $0.34 per diluted share for 2010. Net income decreased slightly over the three-year period due to higher expenses, partially offset by higher revenues. Net income per share decreased over the three-year period due to higher weighted average shares outstanding resulting from equity financings in 2011 and 2012.

Oil, NGL and gas production. Production for 2012 totaled 2,888 MBoe (7.9 MBoe/d), compared to 2,338 MBoe (6.4 MBoe/d) produced in 2011, an increase of 24%. Production for 2012 was 34% oil, 31% NGLs and 35% natural gas, compared to 21% oil, 34% NGLs and 45% natural gas in 2011. The increase in production in 2012 is the result of our continued development of our Permian Basin properties. We expect 2013 production will increase over 2012 due to our planned drilling and development activities in the Permian Basin.

Production for 2011 totaled 2,338 MBoe (6.4 MBoe/d), compared to 1,556 MBoe (4.3 MBoe/d) produced in 2010, an increase of 50%. Production for 2011 was 21% oil, 34% NGLs and 45% natural gas, compared to 16% oil, 17% NGLs and 67% natural gas in 2010. The increase in production in 2011 is the result of our continued development of our Permian Basin properties, the acquisition of the remaining 38% working interest in Project Pangea and NGL processing in the southeast portion of Project Pangea; however, production was impacted during the second half of 2011 by oil takeaway constraints due to increased industry activity in the Permian Basin and a shortage of oil trucking capacity.

The following table summarizes our production for each of the last three years.

Production	Years Ended December 31, 2012	2011	2010
Oil (MBbls)	969	482	246
NGLs (MBbls)	904	798	261
Gas (MMcf)	6,089	6,345	6,290
Total (MBoe)	2,888	2,338	1,556
Total (MBoe/d)	7.9	6.4	4.3

Commodity derivative activities. Realized loss from our commodity derivative activity decreased our earnings by $108,000 for 2012, compared to realized gains in 2011 and 2010 that increased our earnings by $3.4 million and $5.8 million, respectively. Realized gains and losses are derived from the relative movement of commodity 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 loss on commodity derivatives was $347,000 for 2011, and the unrealized gain on commodity derivatives was $3.9 million and $788,000 for 2012 and 2010, respectively. As commodity prices increase or decrease, the fair value of the open portion of those positions decreases or increases.

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."

Lease operating expense. Our lease operating expenses ("LOE") increased $8.3 million, or 78%, for 2012, to $19.0 million ($6.58 per Boe) from $10.7 million ($4.57 per Boe) for 2011. The increase in LOE per Boe in 2012 over 2011 was primarily due to an increase in workover, compression, water hauling and well repair and maintenance expenses.

Our LOE for 2011 was $10.7 million ($4.57 per Boe), compared to $6.6 million ($4.25 per Boe) for 2010. The increase in LOE for 2011 was primarily attributable to the acquisition of the remaining 38% working interest in Project Pangea, which increased our working interest to approximately 100%. The increase in LOE per Boe in 2011 over 2010 was primarily due to an increase in well repair and maintenance, partially offset by a decrease in compressor rental and repair and water hauling, insurance and other LOE.

The following table summarizes LOE per Boe.

	Year Ended December 31,				Year Ended December 31,			
	2012	2011	Change	% Change	2011	2010	Change	% Change
Compressor rental and repair	$1.91	$1.36	$ 0.55	40.4%	$1.36	$1.45	$(0.09)	(6.2)%
Water hauling, insurance and other	1.61	1.08	0.53	49.1	1.08	1.06	0.02	1.9
Well repair and maintenance	1.31	1.00	0.31	31.0	1.00	0.64	0.36	56.3
Pumpers and supervision	1.00	1.05	(0.05)	(4.8)	1.05	1.01	0.04	4.0
Workovers	0.75	0.08	0.67	837.5	0.08	0.09	(0.01)	(11.1)
Total	$6.58	$4.57	$ 2.01	44.0%	$4.57	$4.25	$ 0.32	7.5%

Production and ad valorem taxes. Our 2012 production and ad valorem taxes increased approximately $808,000, or 9.6%, to $9.3 million from $8.4 million for 2011. The increase in production and ad valorem taxes was primarily the result of an increase in oil, NGL and gas sales over 2011. Production and ad valorem taxes were approximately 7.2% and 7.8% of oil, NGL and gas sales for the respective periods. Ad valorem taxes were reclassified from LOE to production and ad valorem taxes in 2012 for all periods presented.

Our production and ad valorem taxes increased $3.5 million, or 71.4%, for 2011 to $8.4 million from $4.9 million for 2010. The increase in production and ad valorem taxes was primarily the result of an increase in oil, NGL and gas sales over 2010. Production and ad valorem taxes were approximately 7.8% and 8.6% of oil, NGL and gas sales for the respective periods.

Exploration expense. We recorded $4.6 million of exploration expense for 2012. Exploration expense for 2012 resulted primarily from the acquisition of 3-D seismic data and lease extensions in the Permian Basin. We recorded $9.5 million and $2.6 million of exploration expense for 2011 and 2010, respectively. Exploration expense for 2011 resulted primarily from lease extensions and expirations in the Permian Basin and the acquisition of 3-D seismic data in Pangea West. During 2011, we extended the acreage terms for an additional four years for approximately 9,200 acres in the northwest area of Project Pangea for $3.2 million, or approximately $350 per acre. Further, approximately 5,000 acres in the southeast area of Project Pangea expired during 2011 resulting in approximately $1.2 million of exploration expense. Exploration expense for 2010 resulted primarily from 3-D seismic acquisition in northwest Project Pangea and lease renewals in Project Pangea and Kentucky.

Impairment. We review our long-lived assets, including proved and unproved oil and gas properties, accounted for under the successful efforts method of accounting. We recorded no impairment expense during the twelve months ended December 31, 2012. We recorded an impairment of oil and gas properties of $18.5 million and $2.6 million in 2011 and 2010, respectively. Due to ongoing, low natural gas prices and to the further decline in natural gas prices during the twelve months ended December 31, 2011, we recorded an impairment expense to our oil and gas properties in the East Texas Basin of $15.2 million in 2011. At December 31, 2011, we had $2.7 million recorded for our properties in the East Texas Basin, which is the estimated fair value at December 31, 2011. We also recorded an impairment expense of $3.3 million, which was all of our remaining carrying costs associated with our unproved properties in Northern New Mexico. The 2010 impairment resulted from a write-off of $2.6 million in costs in our Southwest Kentucky project, and represented the remaining carrying value we had recorded for the project.

General and administrative expenses. Our general and administrative expenses ("G&A") increased $7.0 million, or 39%, to $24.9 million ($8.62 per Boe) for 2012 from $17.9 million ($7.66 per Boe) for 2011. The increase in G&A in 2012 over 2011 was primarily due to higher share-based compensation, professional fees and salaries and benefits. For 2013, we expect G&A to be higher, compared to 2012, as a result of higher share-based compensation and staffing increases. However, we expect G&A to be consistent on a per Boe basis.

Our G&A increased $6.5 million, or 57%, to $17.9 million ($7.66 per Boe) for 2011 from $11.4 million ($7.34 per Boe) for 2010. The increase in G&A in 2011 over 2010 was primarily due to higher salaries and benefits, and share-based compensation.

The following table summarizes G&A (in millions).

	Year Ended December 31,				Year Ended December 31,			
	2012	2011	Change	% Change	2011	2010	Change	% Change
Salaries and benefits	$10.5	$ 8.1	$2.4	29.6%	$ 8.1	$ 5.3	$2.8	52.8%
Share-based compensation	7.5	4.7	2.8	59.6	4.7	2.6	2.1	80.8
Professional fees	2.1	1.4	0.7	50.0	1.4	1.3	0.1	7.7
Other	4.8	3.7	1.1	29.7	3.7	2.2	1.5	68.2
Total	$24.9	$17.9	$7.0	39.1%	$17.9	$11.4	$6.5	57.0%

Depletion, depreciation and amortization expense. Our depletion, depreciation and amortization expense ("DD&A") increased $27.9 million, or 86%, to $60.4 million for 2012, from $32.5 million for 2011. Our DD&A per Boe increased by $7.02, or 51%, to $20.91 per Boe for 2012, compared to $13.89 per Boe for 2011. The increase in DD&A and DD&A per Boe in 2012 over 2011 was primarily attributable to increases in production and oil and gas property carrying costs, relative to estimated proved developed reserves. The increase in oil and gas property carrying costs reflects our drilling and development program of the Wolfcamp oil shale resource play.

DD&A increased $10.3 million, or 46%, to $32.5 million for 2011, from $22.2 million for 2010. Our DD&A per Boe decreased by $0.39, or 3%, to $13.89 per Boe for 2011, compared to $14.28 per Boe for 2010. The increase in DD&A was primarily attributable to higher capitalized costs over 2010, partially offset by an increase in estimated proved developed reserves.

Interest expense, net. The following table sets forth interest expense, weighted average interest rates and weighted average debt balances for the years ended December 31, 2012, 2011 and 2010 (dollars in thousands). Interest expense below includes amortization of loan origination fees.

	Year Ended December 31,		
	2012	2011	2010
Interest expense	$ 4,737	$ 3,402	$ 2,189
Weighted average interest rate	3.2%	3.1%	3.4%
Weighted average debt balance	$108,296	$78,810	$41,374

Income taxes. Our effective income tax rate for 2012 and 2011 was 34.3% and 32.5%, respectively. The higher income tax rate in 2012 was a result of a decrease in permanent differences from book and taxable income.

Our income taxes decreased $612,000 to $3.5 million for 2011, from $4.1 million for 2010. The decrease in income taxes was due to lower pre-tax income in 2011 and a lower effective income tax rate. Our effective income tax rate for 2011 and 2010 was 32.5% and 35.5%, respectively. The lower income tax rate in 2011 was a result of an increase in the impact of permanent differences from book and taxable income.

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 development project. However, we may determine to use various financing sources, including the issuance of common stock, preferred stock, debt, convertible securities and other securities 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. Using some of these financing sources may require approval from the lenders under our revolving credit facility.

Liquidity

We define liquidity as funds available under our revolving credit facility plus year-end net cash and cash equivalents. We had $106.0 million and $43.8 million in long-term debt outstanding under our revolving credit facility at December 31, 2012, and 2011, respectively. We had no long-term debt outstanding under our revolving credit facility at December 31, 2010.

The following table summarizes our liquidity position at December 31, 2012, 2011 and 2010 (in thousands).

	Year Ended December 31,		
	2012	2011	2010
Borrowing base	$ 280,000	$260,000	$150,000
Cash and cash equivalents	767	301	23,465
Long-term debt	(106,000)	(43,800)	—
Undrawn letters of credit	(325)	(350)	(350)
Liquidity	$ 174,442	$216,151	$173,115

Working Capital

Our working capital is affected primarily by our cash and cash equivalents balance and our capital spending program. At December 31, 2012, we had a working capital deficit of $44.6 million, compared to a working capital deficit of $32.2 million and a working capital surplus of $12.1 million at December 31, 2011 and 2010, respectively. The change in working capital during 2012 and 2011 is primarily attributable to increases in accounts payable and accrued liabilities to fund capital expended on our development project. Our working capital deficits have been historically attributable to accounts payable and accrued liabilities and have been more than offset by liquidity available under our revolving credit facility. To the extent we operate or end 2013 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,		
	2012	2011	2010
Cash flows provided by operating activities	$ 90,585	$ 95,770	$ 42,377
Cash flows used in investing activities	(307,414)	(284,758)	(91,346)
Cash flows provided by financing activities	217,295	165,843	69,748
Effect of Canadian exchange rate	—	(19)	1
Net increase (decrease) in cash and cash equivalents	$ 466	$ (23,164)	$ 20,780

For 2012, our primary sources of cash were from operating activities and financing activities. Approximately $90.6 million of cash from operations and $217.3 million of cash from financing activities were used to fund our development project in the Permian Basin. In September, we sold 5.0 million shares of common stock, and in October 2012, the underwriters exercised their option and purchased an additional 325,000 shares. After deducting underwriting discounts and estimated transaction costs of approximately $8.0 million, we received net proceeds of approximately $154.4 million. We used the proceeds of the offering to repay outstanding borrowings under our revolving credit facility, fund our capital expenditures for the development of our Wolfcamp oil shale resource play and for general working capital needs.

For 2011, our primary sources of cash were from operating activities and financing activities. Approximately $95.8 million of cash from operations and $165.8 million of cash from financing activities were used to fund a portion of our development project and the Working Interest Acquisition. In November 2011, we sold 4.6 million shares of common stock. After deducting underwriting discounts and estimated transaction costs of approximately $6.6 million, we received net proceeds of approximately $122.2 million. We used the proceeds of the offering to repay outstanding borrowings under our revolving credit facility, fund our capital expenditures for the Wolfcamp oil shale resource play, fund working interest and leasehold acquisitions in the Permian Basin and for general working capital needs.

For 2010, our primary sources of cash were from operating activities and financing activities. Approximately $42.4 million of cash from operations was used to fund a portion of our development project and pay down our long-term debt. In November 2010, we sold 6.6 million 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 used a portion of the proceeds of the offering to repay all outstanding borrowings under our revolving credit facility, and to fund our capital expenditures for the Wolfcamp oil shale resource play, working interest and leasehold acquisitions in the Permian Basin and general working capital needs.

Operating Activities

For 2012, our cash flows from operations, borrowings under our revolving credit facility and available cash were used primarily for drilling and development activities and leasehold acquisitions in the Permian Basin. Cash flows from operating activities decreased by $5.2 million, or 5%, to $90.6 million in 2012 from $95.8 million in 2011. The decrease in cash flows from operating activities in 2012 versus 2011 was primarily due to a decrease in cash flows provided by working capital, lower average realized NGL and gas prices, partially offset by higher production volumes in 2012 due to our development project in the Wolfcamp oil shale resource play.

For 2011, our cash flows from operations, borrowings under our revolving credit facility and available cash were used primarily for drilling and development activities and leasehold acquisitions in the Permian Basin and the acquisition of 38% working interest in Project Pangea from non-operating partners for $70.8 million, after post-closing adjustments. Cash flows from operating activities increased by $53.4 million, or 126%, to $95.8 million from $42.4 million in 2010, primarily due to an 88% increase in oil, NGL and gas sales in 2011.

For 2010, our cash flows from operations, borrowings under our revolving credit facility and available cash were used primarily for drilling and development activities in Project Pangea, 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.

Investing Activities

During the years ended December 31, 2012, 2011 and 2010, we invested $296.9 million, $284.6 million and $91.0 million, respectively, for capital expenditures on oil and natural gas properties. Cash flows used in investing activities were higher during the year ended December 31, 2012 over 2011, primarily due to drilling and development ($240.4 million), infrastructure projects, equipment and 3-D seismic data acquisition ($47.5 million) and lease acquisitions and extensions ($9 million), all in Project Pangea. Cash flows used in investing activities were substantially higher during the year ended December 31, 2011 over 2010, primarily due to the acquisition of 38% working interest in Project Pangea from non-operating partners for $70.8 million, after post-closing adjustments, and expenditures for drilling and lease acquisitions and extensions in the Permian Basin.

The following table is a summary of capital expenditures related to our oil and gas properties (in thousands).

	Years Ended December 31,		
	2012	2011	2010
Permian Basin	$240,357	$172,077	$56,211
Permian Basin acquisitions	—	70,827	21,179
Subtotal	240,357	242,904	77,390
East Texas Basin	—	560	101
Exploratory projects	—	445	285
Infrastructure projects, equipment and inventory	44,278	8,695	1,636
Lease acquisition, geological and geophysical	12,292	31,970	11,604
Total	$296,927	$284,574	$91,016

Additionally, in September 2012, we entered into a joint venture to build an oil pipeline in Crockett and Reagan Counties, Texas, which will be used to transport our oil to market. In October 2012, we made an initial contribution of $10 million to the joint venture for pipeline and facilities construction. Future capital contributions are discretionary.

Financing Activities

The following is a description of our financing activities. During 2012, 2011 and 2010 we completed the following capital markets activities:

- In September 2012, we completed a public offering of 5.0 million shares of our common stock at $30.50 per share, and in October 2012, the underwriters exercised their option and purchased an additional 325,000 shares. We received net proceeds of approximately $154.4 million, and used the proceeds to repay outstanding borrowings under our revolving credit facility, fund our capital expenditures for the development of our Wolfcamp oil shale resource play and for general working capital needs.
- In November 2011, we completed an equity offering and issued an aggregate of 4.6 million shares of our common stock at $28 per share, and we received net proceeds of approximately $122.2 million. We used the proceeds of the 2011 equity offering to repay outstanding borrowings under our revolving credit facility, fund our capital expenditures for the Wolfcamp oil shale resource play, fund working interest and leasehold acquisitions in the Permian Basin and for general working capital needs.
- In November 2010, we issued 6.6 million shares of our common stock at $16.25 per share, and we received net proceeds of approximately $101.8 million. We used the proceeds of the 2010 equity offering to repay all outstanding borrowings under our revolving credit facility, and to fund our capital expenditures for the Wolfcamp oil shale resource play, working interest and leasehold acquisitions in the Permian Basin and general working capital needs.

We borrowed $304.6 million under our revolving credit facility in 2012, compared to $246.8 million and $121.8 million in 2011 and 2010, respectively. We repaid a total of $242.4 million, $203 million and $154.1 million of amounts outstanding under our revolving credit facility for 2012, 2011 and 2010, respectively. 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.

2013 Capital Expenditures

In September 2012, we announced a 2013 capital budget of $260 million, which includes three rigs to drill horizontal wells targeting the Wolfcamp shale. We expect that our horizontal drilling in Project Pangea in 2013 will include pad drilling, which we believe will improve operating efficiencies and resource recoveries while reducing facilities costs and surface impact. We also may drill vertical wells targeting the Wolffork or recomplete Canyon Sands wells in the Wolffork during 2013. Our objectives for 2013 include advancing our understanding of optimal well spacing, testing multi-zone potential to enhance hydrocarbon recovery in our Wolffork targets and improving our cost structure.

Our 2013 capital budget is subject to change depending upon a number of factors, including additional data on our Wolfcamp oil shale resource play, results of horizontal and vertical drilling, completions and recompletions, including pad drilling, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil, NGLs and gas, 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 $300 million revolving credit facility with a borrowing base set at $280 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, 2014. Borrowings bear interest based on the agent bank's prime rate plus an applicable margin ranging from 0.75% to 1.75%, or the sum of the Eurodollar rate plus an applicable margin ranging from 1.75% to 2.75%. 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.

We had outstanding borrowings of $106 million and $43.8 million under our revolving credit facility at December 31, 2012, and 2011, respectively. The interest rate applicable to our revolving credit facility at December 31, 2012, and 2011, was 2.7% and 3.7%, respectively. We also had outstanding unused letters of credit under our revolving credit facility totaling $325,000 at December 31, 2012, 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, a pledge of our equity interests in our subsidiaries, 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 4.0 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, asset 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, 2012, 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, 2012, our contractual obligations include long-term debt, 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 $5.4 million at December 31, 2012.

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 August 2012, we further expanded our office space under a third amendment to the lease to approximately 27,000 square feet and extended the term of the lease to December 31, 2017. In December 2012, we began rent payments under the third amendment, bringing our total office lease payment to approximately $51,000 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, 2012, we had outstanding employment agreements with each of our five 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 $4.9 million at December 31, 2012.

The following table summarizes these commitments as of December 31, 2012 (in thousands).

	Payments Due By Period				
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Long-term debt(1)	$106,000	$ —	$106,000	$ —	$ —
Daywork drilling contracts(2)	5,443	5,443	—	—	—
Operating lease obligations(3)	3,221	633	1,949	639	—
Asset retirement obligations(4)	7,431	—	—	—	7,431
Employment agreements with executive officers	4,908	4,908	—	—	—
Total	$127,003	$10,984	$107,949	$639	$7,431

(1) Borrowings under our credit agreement.

(2) At December 31, 2012, daywork drilling contracts related to four drilling rigs were contracted through January 4, 2013, February 28, 2013, April 18, 2013 and July 6, 2013, respectively.

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

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

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, 2012, 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, NGLs and gas. Commodity prices are affected by changes in market demand, which is impacted by domestic and foreign supply of oil, NGLs and gas, overall domestic 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 oil and gas producing countries, weather and technological advances affecting oil, NGL and gas consumption. As a result, we cannot accurately predict future oil, NGL 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, NGL 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 development project. 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, 2012, 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, 2012, for oil, NGLs and natural gas 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, 2012, estimated proved reserves would have increased our depletion expense by approximately $1.9 million for the year ended December 31, 2012.

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 write down our oil and gas properties.

We enter into financial swaps and options 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.

The table below summarizes our commodity derivatives positions outstanding at December 31, 2012.

Commodity and Time Period	Contract Type	Volume Transacted	Contract Price
Crude Oil			
2013	Collar	650 Bbls/d	$90.00/Bbl – $105.80/Bbl
2013	Collar	450 Bbls/d	$90.00/Bbl – $101.45/Bbl
2014	Collar	550 Bbls/d	$90.00/Bbl – $105.50/Bbl
Natural Gas			
2013	Swap	200,000 MMBtu/month	$3.54/MMBtu
2013	Swap	190,000 MMBtu/month	$3.80/MMBtu

Subsequent to December 31, 2012, we added to our 2013 commodity derivatives positions with a crude oil collar contract covering 1,200 Bbls/d for February 2013 through December 2013 at a contract floor of $90.35/Bbl and a ceiling of $100.35/Bbl. We also added to our 2013 commodity derivatives positions with a Midland/Cushing basis differential swap covering 2,300 Bbls/d from March 2013 through December 2013 at a price of $1.10/Bbl.

At December 31, 2012 and December 31, 2011, the fair value of our open derivative contracts was an asset of approximately $2.4 million and a liability of approximately $1.4 million, respectively.

JPMorgan Chase Bank, N.A. 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. 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 years ended December 31, 2012 and 2010, we recognized an unrealized gain of $3.9 million and $788,000 from the change in the fair value of commodity derivatives, respectively. For the year ended December 31, 2011, we recognized an unrealized loss of $347,000 from the change in the fair value of commodity derivatives. A hypothetical 10% increase in the NYMEX floating prices would have resulted in a $5.4 million decrease in the December 31, 2012, fair value recorded on our balance sheet, and a corresponding decrease to the gain 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, 2012, 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, 2012, 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, 2012, our Level 3 measurements were used to calculate our asset retirement obligation at December 31, 2012. Additionally, Level 3 measurements were used to calculate our estimated fair value of our oil and gas properties in the East Texas Basin. We valued these properties by estimating future discounted net cash flows of reserves using forward market prices adjusted for locational basis differentials and other costs.

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, 2012. Based on this evaluation, our President and Chief Executive Officer and Chief Financial Officer have concluded that, as of December 31, 2012, 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, 2012. 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, 2012, 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 2013 annual meeting of stockholders to be filed with the SEC on or before April 30, 2013, 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 definitive proxy statement for our 2013 annual meeting of stockholders to be filed with the SEC on or before April 30, 2013, 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 definitive proxy statement for our 2013 annual meeting of stockholders to be filed with the SEC on or before April 30, 2013, 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 2013 annual meeting of stockholders to be filed with the SEC on or before April 30, 2013, 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 2013 annual meeting of stockholders to be filed with the SEC on or before April 30, 2013, 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 66 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 to reference oil, condensate or NGLs.

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

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, 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 project — The means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

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.
Hydraulic fracturing	The technique designed to improve a well's production rates by pumping a mixture of water and sand (in our case, over 99% by mass) and chemical additives (in our case, less than 1% by mass) into the formation and rupturing the rock, creating an artificial channel.
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 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 Boe, and one Bbl of NGLs to one Boe.
Mcf	Thousand cubic feet of natural gas.
MMBoe	Million barrels of oil equivalent, determined using the ratio of six Mcf of gas to one Boe, and one Bbl of NGLs to one Boe.
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, 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.

"Recompletion" or to "recomplete" a well	The addition of production from another interval or formation in an existing wellbore.
Reserve life	This index is calculated by dividing year-end 2012 estimated proved reserves by 2012 production of 2,888 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.
Tight gas sands	A sandstone 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: February 28, 2013

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 February 28, 2013.

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, 2012. 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, 2012, 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
February 28, 2013

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, 2012, 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, 2012, 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, 2012 and 2011, and the related consolidated statements of operations, changes in stockholders' equity and cash flows for each of the three years in the period ended December 31, 2012 and our report dated February 28, 2013 expressed an unqualified opinion.

*/s/ **HEIN** & ASSOCIATES LLP*

Dallas, Texas
February 28, 2013

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, 2012 and 2011, and the related consolidated statements of operations, changes in stockholders' equity and cash flows for each of the three years in the period ended December 31, 2012. 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, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with U.S. generally accepted accounting principles.

We have also audited, in accordance with standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 28, 2013 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

*/s/ **HEIN** & ASSOCIATES LLP*

Dallas, Texas
February 28, 2013

Approach Resources Inc. and Subsidiaries

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

	December 31, 2012	December 31, 2011
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 767	$ 301
Accounts receivable:		
Joint interest owners	215	179
Oil, NGL and gas sales	12,575	10,060
Unrealized gain on commodity derivatives	1,552	—
Prepaid expenses and other current assets	547	342
Deferred income taxes — current	—	504
Total current assets	15,656	11,386
PROPERTIES AND EQUIPMENT:		
Oil and gas properties, at cost, using the successful efforts method of accounting	1,025,440	732,659
Furniture, fixtures and equipment	2,108	1,621
	1,027,548	734,280
Less accumulated depletion, depreciation and amortization	(199,081)	(138,996)
Net properties and equipment	828,467	595,284
Equity method investment	9,892	—
Unrealized gain on commodity derivatives	881	—
Other assets	843	1,224
Total assets	$ 855,739	$ 607,894
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 24,916	$ 12,599
Oil, NGL and gas sales payable	4,960	4,748
Deferred income taxes — current	531	
Accrued liabilities	29,840	24,837
Unrealized loss on commodity derivatives	—	1,441
Total current liabilities	60,247	43,625
NON-CURRENT LIABILITIES:		
Long-term debt	106,000	43,800
Deferred income taxes	48,593	46,290
Asset retirement obligations	7,431	6,730
Total liabilities	222,271	140,445
COMMITMENTS AND CONTINGENCIES (Note 8)		
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, 38,829,368 and 33,093,594 issued and outstanding, respectively	388	331
Additional paid-in capital	560,468	400,890
Retained earnings	72,612	66,228
Total stockholders' equity	633,468	467,449
Total liabilities and stockholders' equity	$ 855,739	$ 607,894

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, 2012	2011	2010
REVENUES:			
Oil, NGL and gas sales	$ 128,892	$ 108,387	$ 57,581
EXPENSES:			
Lease operating	19,002	10,687	6,620
Production and ad valorem taxes	9,255	8,447	4,925
Exploration	4,550	9,546	2,589
Impairment	—	18,476	2,622
General and administrative	24,903	17,900	11,422
Depletion, depreciation and amortization	60,381	32,475	22,224
Total expenses	118,091	97,531	50,402
OPERATING INCOME	10,801	10,856	7,179
OTHER:			
Interest expense, net	(4,737)	(3,402)	(2,189)
Equity in losses of investee	(108)	—	—
Realized (loss) gain on commodity derivatives	(108)	3,375	5,784
Unrealized gain (loss) on commodity derivatives	3,874	(347)	788
Gain on sale of oil and gas properties, net of foreign currency transaction loss	—	248	—
INCOME BEFORE INCOME TAX PROVISION	9,722	10,730	11,562
INCOME TAX PROVISION	3,338	3,488	4,100
NET INCOME	$ 6,384	$ 7,242	$ 7,462
EARNINGS PER SHARE:			
Basic	$ 0.18	$ 0.25	$ 0.34
Diluted	$ 0.18	$ 0.25	$ 0.34
WEIGHTED AVERAGE SHARES OUTSTANDING:			
Basic	34,965,182	28,930,792	22,065,797
Diluted	35,030,323	29,158,598	22,214,070

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, 2010, 2011 and 2012 (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, 2010	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
Issuance of common stock upon exercise of options	74,241	1	1,008	—	—	1,009
Issuance of common stock, net of issuance costs	4,600,000	46	122,104	—	—	122,150
Issuance of common shares to directors for compensation	18,446	—	420	—	—	420
Restricted stock issuance, net of cancellations	205,475	2	(2)	—	—	—
Share-based compensation expense	—	—	4,263	—	—	4,263
Surrender of restricted shares for payment of income taxes	(31,458)	—	(815)	—	—	(815)
Net income	—	—	—	7,242	—	7,242
Foreign currency transaction and translation adjustments, net of related income tax of $85	—	—	—	—	234	234
BALANCES, December 31, 2011	33,093,594	331	400,890	66,228	—	467,449
Issuance of common stock upon exercise of options	216,822	2	796	—	—	798
Issuance of common stock, net of issuance costs	5,325,000	53	154,364	—	—	154,417
Issuance of common shares to directors for compensation	16,935	—	535	—	—	535
Restricted stock issuance, net of cancellations	293,382	2	(2)	—	—	—
Share-based compensation expense	—	—	6,930	—	—	6,930
Surrender of restricted shares for payment of income taxes	(116,365)	—	(3,045)	—	—	(3,045)
Net income	—	—	—	6,384	—	6,384
BALANCES, December 31, 2012	38,829,368	$388	$560,468	$72,612	$ —	$633,468

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, 2012	2011	2010
OPERATING ACTIVITIES:			
Net income	$ 6,384	$ 7,242	$ 7,462
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation and amortization	60,381	32,475	22,224
Unrealized (gain) loss on commodity derivatives	(3,874)	347	(788)
Impairment	—	18,476	2,622
Gain on sale of oil and gas properties, net of foreign currency transaction loss	—	(248)	—
Exploration expense	4,550	9,546	2,589
Share-based compensation expense	7,465	4,683	2,628
Deferred income taxes	3,338	3,488	4,100
Equity in losses of investee	108	—	—
Changes in operating assets and liabilities:			
Accounts receivable	(2,550)	6,168	(6,581)
Prepaid expenses and other current assets	296	378	527
Accounts payable	9,271	(151)	6,083
Oil, NGL and gas sales payable	212	(786)	1,760
Accrued liabilities	5,004	14,152	(249)
Cash provided by operating activities	90,585	95,770	42,377
INVESTING ACTIVITIES:			
Additions to oil and gas properties	(296,927)	(284,574)	(91,016)
Contribution to equity method investment	(10,000)	—	—
Proceeds from gain on sale of oil and gas properties, net	—	360	—
Additions to furniture, fixtures and equipment, net	(487)	(544)	(330)
Cash used in investing activities	(307,414)	(284,758)	(91,346)
FINANCING ACTIVITIES:			
Borrowings under credit facility	304,600	246,800	121,800
Repayment of amounts outstanding under credit facility	(242,400)	(203,000)	(154,119)
Proceeds from issuance of common stock, net offering costs	154,417	122,150	101,764
Proceeds from issuance of common stock upon exercise of stock options	798	1,009	751
Loan origination fees	(120)	(1,116)	(448)
Cash provided by financing activities	217,295	165,843	69,748
CHANGE IN CASH AND CASH EQUIVALENTS	466	(23,145)	20,779
EFFECT OF FOREIGN CURRENCY TRANSLATION ON CASH AND CASH EQUIVALENTS	—	(19)	1
CASH AND CASH EQUIVALENTS, beginning of year	301	23,465	2,685
CASH AND CASH EQUIVALENTS, end of year	$ 767	$ 301	$ 23,465
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid for interest	$ 4,192	$ 2,856	$ 1,920
SUPPLEMENTAL DISCLOSURE OF NON-CASH TRANSACTION:			
Acquisition of oil and gas properties	$ —	$ 547	$ 132
Asset retirement obligations capitalized	$ 409	$ 1,190	$ 604

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," 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.

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, commodity derivatives, income tax provision, 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. Certain prior year amounts have been reclassified to conform to current year presentation. These classifications have no impact on the net income or loss reported.

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, 2012 and 2011. 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,	
	2012	**2011**
Mineral interests in properties:		
Unproved leasehold costs	$ 49,148	$ 46,813
Proved leasehold costs	32,252	26,845
Wells and related equipment and facilities	908,456	626,564
Support equipment	6,753	5,135
Uncompleted wells, equipment and facilities	28,831	27,302
Total costs	1,025,440	732,659
Less accumulated depreciation, depletion and amortization	(197,751)	(137,980)
Net capitalized costs	$ 827,689	$ 594,679

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, 2012 or 2011. 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 and while these expenditures are excluded from our depletable base. Through December 31, 2012, we have capitalized no interest costs because our individual wells and infrastructure projects are generally developed in 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 ("Boe"), and one barrel of NGLs to one Boe. The ratios of six Mcf of natural gas to one Boe and one barrel of NGLs to one Boe do not assume price equivalency and, given price differentials, the price for a Boe for natural gas may differ significantly from the price for a barrel of oil. Depreciation, depletion and amortization expense for oil and gas producing property and related equipment was $60.0 million, $32.1 million and $22.0 million for the years ended December 31, 2012, 2011 and 2010, respectively.

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. For 2011, we recorded an impairment expense of $15.2 million, which was attributable to our oil and gas properties in the East Texas Basin. At December 31, 2011, we had $2.7 million recorded for the East Texas Basin, which was the estimated fair value at December 31, 2011. We noted no impairment of our proved properties based on our analysis for the years ended December 31, 2010 and 2012.

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. For 2011, we recorded an impairment expense of $3.3 million, related to all of our remaining carrying costs associated with our unproved properties in Northern New Mexico. For 2010, we recorded an impairment of $2.6 million, which resulted from a write-off of $2.6 million in costs associated with our Boomerang project in Kentucky and represented the remaining carrying value we had recorded for the project.

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. During 2011, we sold our working interest in Northeast British Columbia for net proceeds of $360,000. The gain on the sale of this interest, net of foreign currency, was $248,000, and is included under "Other" on the consolidated statement of operations for the year ended December 31, 2011.

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.

Accounts receivable, joint interest owners, consist of uncollateralized joint interest owner obligations due within 30 days of the invoice date. Accounts receivable, oil, NGL 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, 2012 or 2011.

Oil, NGL and Gas Sales Payable. Oil, NGL and gas sales payable represents amounts collected from purchasers for oil, NGL 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.

Production Costs. Production costs, including compressor rental and repair, pumpers' and supervisors' salaries, saltwater disposal, 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, 2012, 2011 and 2010, we sold substantially all of our oil and gas produced to seven purchasers. Additionally, substantially all of our accounts receivable related to oil and gas sales were due from those seven purchasers at December 31, 2012 and 2011. As of December 31, 2012, we had dedicated substantially all of our oil production to the oil pipeline joint venture in which we own a 50% equity interest for 10 years. In addition, at December 31, 2012, we had contracted to sell substantially all of our NGLs and natural gas production to one purchaser through January 2016. 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.

Equity Method Investment. For investments in which we have the ability to exercise significant influence but do not control, we follow the equity method of accounting. In September 2012, we entered into a joint venture to build an oil pipeline in Crocket and Reagan Counties, Texas, which will be used to transport our oil to market. The joint venture will purchase our dedicated crude oil production from certain of our acreage in Crockett County for ten years, subject to certain terms and conditions. In October 2012, we made our initial contribution of $10 million to the joint venture for pipeline and facilities construction. Our initial contribution was recorded at cost and is included in noncurrent assets on our consolidated balance sheet at December 31, 2012. Our share of the investee earnings was recorded on our consolidated statement of operations for the year ended December 31, 2012. Our 50% equity interest in the joint venture is classified as "Equity method investment" on our consolidated balance sheet at December 31, 2012, and is held by our wholly-owned subsidiary, Approach Midstream Holdings LLC.

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 area 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 $333,000, $372,000 and $233,000 for the years ended December 31, 2012, 2011 and 2010, 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, 2012 or 2011. 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 2009 and forward, Texas income and margin tax returns for tax years 2009 and forward and New Mexico income tax returns for years 2009 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, NGL 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, 2012 and 2011 (in thousands):

	2012	2011
Capital expenditures accrued	$25,526	$20,512
Operating expenses and other	4,314	4,325
Total	$29,840	$24,837

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, 2012, 2011 and 2010.

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. We recognized no translation gains or losses during the year ended December 31, 2012, since we sold our working interest in northeast British Columbia in 2011. During the years ended December 31, 2011 and 2010, we recognized a translation loss of $20,000 and $4,000, net of the related income taxes, respectively.

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,		
	2012	2011	2010
Income (numerator):			
Net income — basic	$ 6,384	$ 7,242	$ 7,462
Weighted average shares (denominator):			
Weighted average shares — basic	34,965,182	28,930,792	22,065,797
Dilution effect of share-based compensation, treasury method	65,141	227,806	148,273
Weighted average shares — diluted	35,030,323	29,158,598	22,214,070
Earnings per share:			
Basic	$ 0.18	$ 0.25	$ 0.34
Diluted	$ 0.18	$ 0.25	$ 0.34

2. Working Interest Acquisitions

In February 2011, we acquired 38% working interest in northwest Project Pangea from two non-operating partners for $70.8 million, after customary post-closing adjustments (the "38% Working Interest Acquisition"). We funded the 38% Working Interest Acquisition with cash on hand and borrowings under our revolving credit facility. Our 2011 oil, NGL and gas sales and net income included approximately $25.5 million and $8.4 million, respectively, related to this acquisition.

In October 2010, we acquired a 10% working interest in northwest Project Pangea from a non-operating partner for $21.2 million, after post-closing adjustments (the "10% Working Interest Acquisition"). Funding was provided through borrowings under our revolving credit facility. Our 2010 oil, NGL and gas sales and net income included approximately $1.3 million and $477,000, respectively, related to this acquisition.

The following table represents the allocation of the total purchase price of the 38% Working Interest Acquisition and the 10% Working Interest Acquisition (in thousands).

	38% Working Interest Acquisition	10% Working Interest Acquisition
Purchase price:		
Acquisition price	$76,000	$21,500
Asset retirement obligations assumed	547	132
Post-closing purchase price adjustments	(5,720)	(453)
Total	$70,827	$21,179
Allocation:		
Wells, equipment and related facilities	$51,447	$15,613
Mineral interests in oil and gas properties	19,380	5,566
Total	$70,827	$21,179

The following condensed unaudited pro forma information gives effect to these acquisitions as if they had occurred on January 1, 2010. 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,	
	2011	2010
	(dollars in thousands, except per-share amounts)	
Oil, NGL and gas sales	$113,041	$86,114
Total operating expenses	$100,125	$63,384
Net income (loss)	$ 7,186	$15,714
Earnings (loss) per share — basic	$ 0.25	$ 0.71
Earnings (loss) per share — diluted	$ 0.25	$ 0.71

3. Public Equity Offerings

On September 19, 2012, we completed a public offering of 5,000,000 shares of our common stock. The underwriters exercised their option and purchased an additional 325,000 shares on October 3, 2012. After deducting underwriting discounts and transaction costs of approximately $8.0 million, we received net proceeds of approximately $154.4 million. We used the proceeds of the 2012 equity offering to repay outstanding borrowings under our revolving credit facility, fund our capital expenditures for the Wolfcamp oil shale resource play and for general working capital needs.

On November 15, 2011, we completed a public offering of 4,000,000 shares of our common stock. The underwriters were granted an option to purchase up to 600,000 additional shares of our common stock. The underwriters fully exercised this option and purchased the additional shares on November 16, 2011. After deducting underwriting discounts and transaction costs of approximately $6.6 million, we received net proceeds of approximately $122.2 million. We used the proceeds of the 2011 equity offering to repay outstanding borrowings under our revolving credit facility, fund our capital expenditures for the Wolfcamp oil shale resource play, fund working interest and leasehold acquisitions in the Permian Basin and for general working capital needs.

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 used the proceeds of the 2010 equity offering to repay all outstanding borrowings under our revolving credit facility, and to fund our capital expenditures for the Wolfcamp oil shale resource play, working interest and leasehold acquisitions in the Permian Basin and general working capital needs.

4. Revolving Credit Facility

We have a $300 million revolving credit facility with a borrowing base set at $280 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, 2014. Borrowings bear interest based on the agent bank's prime rate plus an applicable margin ranging from 0.75% to 1.75%, or the sum of the Eurodollar rate plus an applicable margin ranging from 1.75% to 2.75%. 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 April 26, 2012, the lenders increased the borrowing base under our credit agreement to $270 million from $260 million.

Effective September 7, 2012, we entered into a thirteenth amendment to our credit agreement, which permits the Company to enter into thirty-six (36) month derivatives contracts on up to 100% of projected production from proved developed producing ("PDP") reserves, compared to 85% under the former credit agreement, and sixty (60) – month derivatives contracts on up to 85% of projected production from PDP reserves, compared to thirty-six (36) months under the former credit agreement.

Effective November 16, 2012, we entered into a fourteenth amendment to our credit agreement, which increased the aggregate limit on the Company's permitted indebtedness evidenced by the issuance of unsecured senior notes from $200 million to $400 million, eliminated the borrowing base reduction associated with the issuance of senior unsecured notes for notes issued before October 1, 2013, and added Approach Services, LLC and Approach Midstream Holdings LLC, wholly-owned subsidiaries of the Company, as guarantors under the credit agreement.

Effective October 11, 2012, the lenders increased the borrowing base under the credit agreement to $280 million from $270 million.

We had outstanding borrowings of $106.0 million and $43.8 million under our revolving credit facility at December 31, 2012, and 2011, respectively. The interest rate applicable to our revolving credit facility at December 31, 2012, and 2011 was 2.7% and 3.7%, respectively. We also had outstanding unused letters of credit under our revolving credit facility totaling $325,000 at December 31, 2012, 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, a pledge of our equity interests in our subsidiaries, 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 4.0 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, asset 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, 2012, 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. Under a Second Amendment to the 2007 Plan effective May 31, 2012, the maximum number of shares of common stock available for the grant of awards under the 2007 Plan after May 31, 2012, is 2,100,000. 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 $7.5 million, $4.7 million and $2.6 million for the years ended December 31, 2012, 2011 and 2010, 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, 2012, 2011 and 2010, was $535,000, $420,000 and $381,000, respectively, related to grants to nonemployee directors.

Stock Options

There were no stock option grants during the years ended December 31, 2012, 2011 and 2010. As of December 31, 2012, all stock options are fully vested.

The following table summarizes stock options outstanding and activity as of and for the years ended December 31, 2012, 2011 and 2010, (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, 2010	409,327	$ 8.03	5.41	$ —
Granted	—	$ —		
Exercised	(58,798)	$12.76		
Canceled	(16,191)	$12.00		
Outstanding at December 31, 2010	334,338	$ 7.01	3.85	$4,567
Granted	—	—		
Exercised	(74,241)	$13.59		
Canceled	—	—		
Outstanding at December 31, 2011	260,097	$ 5.13	1.94	$6,315
Granted	—			
Exercised	(216,822)	$ 3.68		
Canceled	—			
Outstanding at December 31, 2012	43,275	$12.38	4.88	$ 547
Exercisable (fully vested) at December 31, 2012	43,275	$12.38	4.88	$ 547

The intrinsic value of the options exercised during the years ended December 31, 2012, 2011 and 2010, was $7.0 million, $1.1 million and $608,000, respectively. The tax benefit recognized related to the stock option exercises was $358,000 and $141,000 in the years ended December 31, 2011 and 2010, respectively. There was no tax benefit recognized related to the stock option exercises in the year ended December 31, 2012.

Nonvested Shares

Share grants totaling 316,279 shares, 256,317 shares and 568,142 shares with an approximate aggregate fair market value of $10.4 million, $8.1 million and $4.3 million at the time of grant were granted to employees during the years ended December 31, 2012, 2011 and 2010, respectively. Included in the share grants for 2012, 2011 and 2010, are 129,890 shares, 204,000 shares and 400,000 shares, respectively, awarded to our executive officers. The aggregate fair market value of these shares on the grant date was $4.8 million, $6.5 million and $2.7 million, respectively, to be expensed over a remaining service period of approximately three years, subject to certain performance restrictions.

A summary of the status of nonvested shares for the years ended December 31, 2012, 2011 and 2010, is presented below:

	Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2010	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
Granted	256,317	31.54
Vested	(124,134)	9.93
Canceled	(50,842)	12.03
Nonvested at December 31, 2011	790,122	15.06
Granted	316,279	32.94
Vested	(333,957)	14.57
Canceled	(19,365)	23.74
Nonvested at December 31, 2012	753,079	$22.35

As of December 31, 2012, unrecognized compensation expense related to the nonvested shares amounted to $10.3 million, which will be recognized over a remaining service period of three years.

Subsequent Restricted Share Award

Subsequent to December 31, 2012, 183,673 restricted shares were awarded to our executive officers. The number of shares awarded assumes that the Company will achieve certain threshold performance and maximum total shareholder return conditions. The aggregate fair market value of these shares on the grant date was $4.5 million, to be expensed over a remaining service period of approximately four years, subject to certain threshold performance and three-year total shareholder return conditions.

6. Income Taxes

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

	Years Ended December 31,		
	2012	2011	2010
Deferred:			
Federal	$3,359	$3,199	$3,917
State	(21)	289	183
Total deferred provision for income taxes	$3,338	$3,488	$4,100

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

	Years Ended December 31,		
	2012	2011	2010
Statutory tax at 34%	$3,306	$3,648	$3,931
State taxes, net of federal impact	(21)	289	184
Permanent differences(1)	53	(289)	53
Other differences	—	(160)	(68)
Total	$3,338	$3,488	$4,100

(1) Amounts primarily relate to share-based compensation expense and stock option exercises.

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 $48.6 million and $46.3 million at December 31, 2012 and 2011, respectively. At December 31, 2012, $531,000 of deferred taxes expected to be realized within one year were included in current liabilities. At December 31, 2011, $504,000 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,	
	2012	2011
Deferred tax assets:		
Net operating loss carryforwards	$ 27,353	$ 31,052
Unrealized loss on commodity derivatives	—	504
Other	542	866
Total deferred tax assets	27,895	32,422
Deferred tax liabilities:		
Difference in depreciation, depletion and capitalization methods—oil and gas properties	(76,170)	(78,174)
Unrealized gain on commodity derivatives	(849)	—
Total deferred tax liabilities	(77,019)	(78,174)
Net deferred tax liability	$(49,124)	$(45,752)

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

Expiration Dates	Amounts	Stock Option Adjustments	Total
2023	$ 1,523	$ —	$ 1,523
2024	1,082	—	1,082
2025	2,594	—	2,594
2026	1,683	—	1,683
2027	1,020	—	1,020
2028	1,308	—	1,308
2029	3,299	—	3,299
2030	12,605	750	13,355
2031	18,642	2,984	21,626
2032	34,673	1,043	35,716
Total	$78,429	$4,777	$83,206

As of December 31, 2012, we had net operating loss carryfowards of approximately $83.2 million, of which approximately $4.8 million was generated from the benefit of stock options. When these benefits are realized, they will be credited to additional paid-in capital.

7. Derivatives

At December 31, 2012, we had the following commodity derivatives positions outstanding:

Commodity and Time Period	Contract Type	Volume Transacted	Contract Price
Crude Oil			
2013	Collar	650 Bbls/d	$90.00/Bbl – $105.80/Bbl
2013	Collar	450 Bbls/d	$90.00/Bbl – $101.45/Bbl
2014	Collar	550 Bbls/d	$90.00/Bbl – $105.50/Bbl
Natural Gas			
2013	Swap	200,000 MMBtu/month	$3.54/MMBtu
2013	Swap	190,000 MMBtu/month	$3.80/MMBtu

Subsequent to December 31, 2012, we added to our 2013 commodity derivatives positions with a crude oil collar contract covering 1,200 Bbls/d for February 2013 through December 2013 at a contract floor of $90.35/Bbl and a ceiling of $100.35/Bbl. We also added to our 2013 commodity derivatives positions with a Midland/ Cushing basis differential swap covering 2,300 Bbls/d from March 2013 through December 2013 at a price of $1.10/Bbl.

The following summarizes the fair value of our open commodity derivatives as of December 31, 2012 and 2011 (in thousands):

	Asset Derivatives			Liability Derivatives		
		Fair Value			Fair Value	
	Balance Sheet Location	December 31, 2012	December 31, 2011	Balance Sheet Location	December 31, 2012	December 31, 2011
Derivatives not designated as hedging instruments						
Commodity derivatives	Unrealized gain on commodity derivatives . . .	$2,433	$—	Unrealized loss on commodity derivatives . . .	$—	$1,441

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

	Income Statement Location	Year Ended December 31,		
		2012	2011	2010
Derivatives not designated as hedging instruments				
Commodity derivatives	Unrealized gain (loss) on commodity derivatives	$3,874	$ (347)	$ 788
	Realized (loss) gain on commodity derivatives	(108)	3,375	5,784
		$3,766	$3,028	$6,572

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 value 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, 2012, 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, 2012, 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, 2012, our Level 3 measurements were limited to our asset retirement obligation. Additionally, Level 3 measurements were used to calculate our estimated fair value of our oil and gas properties in the East Texas Basin. We valued these properties by estimating future discounted net cash flows of reserves using forward market prices adjusted for locational basis differentials and other costs.

8. Commitments and Contingencies

In September 2012, we entered into a joint venture to build an oil pipeline in Crockett and Reagan Counties, Texas, which will be used to transport our oil to market. The joint venture will purchase our oil production from certain acreage in Crockett County, Texas, which production we have dedicated to the joint venture for 10 years subject to certain conditions. In October 2012, we made an initial capital contribution of $10 million to the joint venture for pipeline and facilities construction. Additional capital contributions are at the discretion of the Company.

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 $5.4 million at December 31, 2012.

At December 31, 2012, we had employment agreements with all five of our executive 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 $4.9 million at December 31, 2012. This estimate assumes the maximum potential bonus for 2013 is earned by each employee during 2013.

We lease our office space in Fort Worth, Texas, under a non-cancelable agreement that expires on December 31, 2017. We also have non-cancelable operating lease commitments related to office equipment that expire by 2017. The following is a schedule by years of future minimum rental payments required under our operating lease arrangements as of December 31, 2012 (in thousands):

2013	$ 633
2014 – 2017	2,588
Total	$3,221

Rent expense under our lease arrangements amounted to $716,000, $630,000 and $463,000 for the years ended December 31, 2012, 2011 and 2010, respectively.

Litigation

We are involved in various 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.

Environmental Issues

We are engaged in oil and gas exploration and production and may become subject to certain liabilities or damages as they relate to environmental clean up of well sites or other environmental restoration or ground water contamination, in connection with drilling or operating oil and gas wells. 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, restoration or contamination, we would be responsible for curing such a violation or paying damages. No claim has been made, nor are we aware of any liability that exists, as it relates to any environmental clean up, restoration, contamination or the violation of any rules or regulations relating thereto.

9. 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,		
	2012	2011	2010
Property acquisition costs:			
Unproved properties	$ 2,335	$ 17,361	$ 8,931
Proved properties	5,407	5,063	86
Working interest acquisitions	—	70,827	21,179
Exploration costs	4,550	9,991	2,874
Development costs(1)	285,039	182,522	56,915
Total costs incurred	$297,331	$285,764	$89,985

(1) For the years ended December 31, 2012, 2011 and 2010, development costs include $409,000, $1.2 million and $604,000 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,		
	2012	2011	2010
Revenues	$128,892	$108,387	$ 57,581
Production costs	(28,257)	(19,134)	(11,545)
Exploration expense	(4,550)	(9,546)	(2,589)
Impairment	—	(18,476)	(2,622)
Depletion	(60,381)	(31,858)	(21,991)
Income tax expense	(12,139)	(9,546)	(6,527)
Results of operations	$ 23,565	$ 19,827	$ 12,307

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

Proved Reserves

All of our estimated oil and natural gas reserves are attributable to properties within the United States, primarily in the Permian Basin in West Texas. The estimates of proved reserves and related valuations for the years ended December 31, 2012, 2011 and 2010, 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 rules and guidelines established by the Securities and Exchange Commission and the Financial Accounting Standards Board.

The following table summarizes the prices used in the reserve estimates for 2012, 2011 and 2010. Commodity prices used for the reserve estimates, adjusted for basis differentials, grade and quality, are as follows:

	2012	2011	2010
Oil (per Bbl)	$90.21	$89.65	$74.90
Natural gas liquids (per Bbl)	$37.88	$49.63	$39.25
Gas (per Mcf)	$ 2.62	$ 3.97	$ 4.13

Oil, NGL and natural gas reserve estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and natural gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

The following table provides a summary of the changes of the total proved reserves for the years ended December 31, 2012, 2011 and 2010, as well as proved developed and proved undeveloped reserves at the beginning and end of each respective year.

Total Proved Reserves	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total (MBoe)
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
Extensions and discoveries	11,847	7,010	40,146	25,548
Purchases of minerals in place	2,200	4,284	24,083	10,498
Production	(482)	(798)	(6,345)	(2,338)
Revisions to previous estimates	(465)	(2,072)	(29,466)	(7,448)
Balance — December 31, 2011	18,051	29,123	178,807	76,975
Extensions and discoveries	21,993	8,639	49,372	38,861
Production	(969)	(904)	(6,089)	(2,888)
Revisions to previous estimates	(1,823)	(7,758)	(47,330)	(17,469)
Balance — December 31, 2012	37,252	29,100	174,760	95,479
Proved Developed Reserves:				
January 1, 2010	1,239	1,879	74,804	15,585
December 31, 2010	2,146	11,193	74,739	25,795
January 1, 2011	2,146	11,193	74,739	25,795
December 31, 2011	5,542	13,945	84,743	33,611
January 1, 2012	5,542	13,945	84,743	33,611
December 31, 2012	8,816	11,761	73,178	32,774
Proved Undeveloped Reserves:				
January 1, 2010	3,099	2,215	93,530	20,903
December 31, 2010	2,805	9,506	75,650	24,920
January 1, 2011	2,805	9,506	75,650	24,920
December 31, 2011	12,509	15,178	94,064	43,365
January 1, 2012	12,509	15,178	94,064	43,365
December 31, 2012	28,436	17,339	101,582	62,705

The following is a discussion of the material changes in our proved reserve quantities for the years ended December 31, 2012, 2011 and 2010:

Year Ended December 31, 2012

We produced 2.9 MMBoe during 2012, 99.4% of which is attributable to our assets in the Permian Basin. Extensions and discoveries of 38.9 MMBoe for 2012 were primarily attributable to ongoing development of Project Pangea in the Wolfcamp oil shale resource play in the Permian Basin. We recorded downward revisions of 17.5 MMBoe to the December 31, 2011, estimates of our proved reserves at year end 2012. Downward revisions of 17.5 MMBoe include 8.9 MMBoe of deeper, Canyon reserves in southeast Project Pangea that we reclassified to probable undeveloped. Due to our horizontal Wolfcamp development project, including pad drilling, postponement of these deeper Canyon locations beyond five years from initial booking is necessary in order to integrate their development with shallower Wolffork target zones. Revisions in 2012 also include 3.3 MMBoe of performance revisions related to vertical Canyon wells in Project Pangea, 2.9 MMBoe of revisions resulting from technical evaluations and 2.4 MMBoe of revisions resulting from lower natural gas and NGL prices in 2012.

Year Ended December 31, 2011

We produced 2.4 MMBoe during 2011, 99% of which is attributable to our assets in the Permian Basin. Extensions and discoveries of 25.5 MMBoe for 2011 include 24.2 MMBoe attributable to our Wolfcamp oil shale resource play in the Permian Basin. During 2011, we acquired approximately 10.5 MMBoe of proved reserves through the 38% Working Interest Acquisition. We recorded downward revisions of 7.5 MMBoe to the December 31, 2010, estimates of our proved reserves at year end 2011. Downward revisions of 7.5 MMBoe include 5.6 MMBoe of economic revisions in southeast Project Pangea in the Permian Basin and 2.2 MMBoe of proved undeveloped reserves in the East Texas Basin that, due to ongoing, low natural gas prices, we did not expect to develop by year-end 2013. Also included in the revisions were 0.3 MMBoe of positive revisions resulting from higher oil and NGL prices using the average 12-month price in 2011.

Year Ended December 31, 2010

Our drilling and development activities in Project Pangea in the Permian Basin 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 10.1 MMBoe positive revision to our previous estimate, resulting from 9.2 MMBoe attributable to planned processing upgrades in southeast Project Pangea and 1.1 MMBoe attributable to an increase in commodity prices, partially offset by 0.2 MMBoe of negative performance revisions. On April 1, 2011, we began realizing NGL revenues from the natural gas production in southeast Project Pangea 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 0.1 MMBoe, primarily related to producing properties in our North Bald Prairie field in the East Texas Basin. Well performance data collected during 2010 for North Bald Prairie indicated that these assets underperformed our year-end 2010 decline estimates. Accordingly, we removed 0.9 Bcf (0.2 MMBoe) from proved reserves recorded for North Bald Prairie. We also removed 0.1 MMBoe in Project Pangea due to performance revisions.

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

The standardized measure of discounted future net cash flows is computed by applying the 12-month unweighted average of the first-day-of-the-month pricing for oil and natural gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and natural gas reserves less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows. Future income taxes are calculated by comparing undiscounted future cash flows to the tax basis of oil and natural gas properties plus available carryforwards and credits and applying the current tax rates to the difference.

Discounted future cash flow estimates like those shown below are not intended to represent estimates of the fair value of oil and natural gas properties. Estimates of fair value would also consider probable and possible reserves, anticipated future oil and natural gas prices, interest rates, changes in development and production costs and risks associated with future production. Because of these and other considerations, any estimate of fair value is necessarily subjective and imprecise.

The following table provides the standardized measure of discounted future net cash flows at December 31, 2012, 2011 and 2010:

	Years Ended December 31,		
	2012	2011	2010
Future cash flows	$ 4,920,231	$ 3,772,633	$1,804,477
Future production costs	(1,220,403)	(1,012,044)	(499,321)
Future development costs	(1,025,193)	(625,994)	(259,005)
Future income tax expense	(692,528)	(583,961)	(282,628)
Future net cash flows	1,982,107	1,550,634	763,523
10% annual discount for estimated timing of cash flows	(1,487,887)	(1,136,253)	(559,291)
Standardized measure of discounted future net cash flows	$ 494,220	$ 414,381	$ 204,232

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,		
	2012	2011	2010
Balance, beginning of period	$ 414,381	$ 204,232	$ 79,991
Net change in sales and transfer prices and in production (lifting) costs related to future production	147,421	334,104	120,520
Changes in estimated future development costs	(486,435)	(395,037)	(65,718)
Sales and transfers of oil and gas produced during the period	(100,634)	(89,253)	(46,031)
Net change due to extensions, discoveries and improved recovery	467,822	291,501	30,240
Net change due to purchase of minerals in place	—	119,780	15,696
Net change due to revisions in quantity estimates	(210,296)	(84,988)	80,564
Previously estimated development costs incurred during the period	285,039	182,522	40,265
Accretion of discount	60,162	32,793	17,166
Other	(11,281)	(38,107)	4,171
Net change in income taxes	(71,959)	(143,166)	(72,632)
Standardized measure of discounted future net cash flows	$ 494,220	$ 414,381	$204,232

11. Supplementary Data

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

	2012 Quarters Ended			
	December 31	September 30	June 30	March 31
Net revenue	$ 35,309	$ 33,038	$ 29,927	$ 30,618
Net operating expenses	(36,777)	(31,340)	(26,095)	(23,879)
Interest expense, net	(926)	(1,544)	(1,380)	(887)
Loss on equity investment	(108)	—	—	—
Realized (loss) gain on commodity derivatives	(408)	423	361	(484)
Unrealized gain (loss) on commodity derivatives	1,292	(4,185)	9,439	(2,672)
(Loss) income before income tax (benefit)	(1,618)	(3,608)	12,252	2,696
Income tax (benefit) provision	(781)	(1,253)	4,390	982
Net (loss) income	$ (837)	$ (2,355)	$ 7,862	$ 1,714
Basic net (loss) income applicable to common stockholders per common share	$ (0.02)	$ (0.07)	$ 0.23	$ 0.05
Diluted net (loss) income applicable to common stockholders per common share	$ (0.02)	$ (0.07)	$ 0.23	$ 0.05

	2011 Quarters Ended			
	December 31	September 30	June 30	March 31
Net revenue	$ 31,123	$ 27,958	$ 29,123	$ 20,183
Net operating expenses	(42,339)	(19,092)	(18,170)	(17,930)
Interest expense, net	(1,010)	(1,016)	(863)	(513)
Realized gain on commodity derivatives	1,720	1,392	66	197
Unrealized (loss) gain on commodity derivatives	(4,168)	1,739	2,231	(149)
(Loss) gain on sale of oil and gas properties	(243)	—	3	488
(Loss) income before income (benefit) tax	(14,917)	10,981	12,390	2,276
Income tax (benefit) provision	(5,632)	3,908	4,400	812
Net (loss) income	$ (9,285)	$ 7,073	$ 7,990	$ 1,464
Basic net (loss) income applicable to common stockholders per common share	$ (0.30)	$ 0.25	$ 0.28	$ 0.05
Diluted net (loss) income applicable to common stockholders per common share	$ (0.30)	$ 0.25	$ 0.28	$ 0.05

	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 derivatives	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

Approach Resources Inc.
Index to Exhibits

Exhibit Number	Description of Exhibit
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 Amended and Restated Indemnity Agreement between Approach Resources Inc. and each of its directors and officers (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed May 7, 2012 (File No. 333-144512), and incorporated herein by reference).
10.2†	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).
10.3†	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).
10.4†	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).
10.5†	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).
10.6†	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).
10.7†	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).
10.8†	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).
10.9	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).
10.10†	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).
10.11†	Form of Performance-Based, Time-Vesting Restricted Stock Award Agreement under Approach Resources Inc. 2007 Stock Incentive Plan (filed as Exhibit 10.14 to the Company's Annual Report on Form 10-K filed March 11, 2011, and incorporated herein by reference).

Exhibit Number	Description of Exhibit
10.12†	Form of TSR-Based Restricted Stock Award Agreement under Approach Resources Inc. 2007 Stock Incentive Plan (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed February 20, 2012, and incorporated herein by reference).
10.13	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).
10.14	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).
10.15	Specimen Oil and Gas Lease for University Lands (filed as Exhibit 10.19 to the Company's Annual Report on Form 10-K filed March 12, 2012, and incorporated herein by reference).
10.16	$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).
10.17	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).
10.18	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).
10.19	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).
10.20	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).

Exhibit Number	Description of Exhibit
10.21	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).
10.22	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).
10.23	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).
10.24	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).
10.25	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).
10.26	Amendment No. 10 dated as of May 4, 2011, 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, KeyBank National Association and Royal Bank of Canada, 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 May 4, 2011, and incorporated herein by reference).
10.27	Amendment No. 11 dated as of October 7, 2011, 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, KeyBank National Association, Royal Bank of Canada and Wells Fargo Bank, N.A., 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 11, 2011, and incorporated herein by reference).

Exhibit Number	Description of Exhibit
10.28	Amendment No. 12 dated as of December 20, 2011, 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, KeyBank National Association, The Frost National Bank, Royal Bank of Canada and Wells Fargo Bank, N.A., as lenders, BNP Paribas, 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 December 21, 2011, and incorporated herein by reference).
10.29	Amendment No. 13 dated as of September 7, 2012, 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, KeyBank National Association, The Frost National Bank, Royal Bank of Canada and Wells Fargo Bank, N.A., 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 September 13, 2012, and incorporated herein by reference).
10.30	Amendment No. 14 dated as of November 16, 2012, 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, KeyBank National Association, The Frost National Bank, Royal Bank of Canada and Wells Fargo Bank, N.A., as lenders, and Approach Oil & Gas Inc., Approach Resources I, LP, Approach Services, LLC and Approach Midstream Holdings LLC, as guarantors (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed November 21, 2012, and incorporated herein by reference).
10.31	Second Amendment to the Approach Resources Inc. 2007 Stock Incentive Plan, effective as of May 31, 2012 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed June 1, 2012, and incorporated herein by reference).
10.32	Crude Oil Purchase Agreement dated as of September 12, 2012, between Approach Operating LLC and Approach Oil & Gas Inc., as Seller, and Wildcat Permian Services LLC, as Buyer (pursuant to a request for confidential treatment, portions of this exhibit have been redacted and have been provided separately to the Securities and Exchange Commission)(filed as Exhibit 10.4 of the Company's Quarterly Report on Form 10-Q for the three months ended September 30, 2012 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.
*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.

Approach Resources Inc.
Index to Exhibits — continued

Exhibit Number	Description of Exhibit
*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.
*101.INS	XBRL Instance Document.
*101.SCH	XBRL Taxonomy Extension Schema Document.
*101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
*101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
*101. PRE	XBRL Taxonomy Extension Presentation Linkbase Document.
*101. DEF	XBRL Taxonomy Extension Definition Linkbase Document.

* Filed herewith.

† Denotes management contract or compensatory plan or arrangement.

Supplemental Non-GAAP Financial Information and Cautionary Statements

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, 2012, which are included in the immediately preceding Form 10-K. If you are not familiar with the oil and gas terms or abbreviations used in this supplement, please refer to the definitions of these terms and abbreviations under the caption "Glossary and Selected Abbreviations" at the end of Item 15 of our annual report on Form 10-K filed with the SEC on February 28, 2013.

In addition, the SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves that meet the SEC's definitions for such terms, and price and cost sensitivities for such reserves, and prohibits disclosure of resources that do not constitute such reserves. The Company uses the terms "estimated ultimate recovery," "EUR," reserve or resource "potential," "upside" or other descriptions of volumes of reserves potentially recoverable through additional drilling or recovery techniques that the SEC's rules may prohibit the Company from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved, probable and possible reserves and accordingly are subject to substantially greater risk of being actually realized by the Company.

Potential drilling locations and resource potential estimates have not been risked by the Company. Actual locations drilled and quantities that may be ultimately recovered from the Company's interest may differ substantially from the Company's estimates. There is no commitment by the Company to drill all of the drilling locations that have been attributed to these quantities. Factors affecting ultimate recovery include the scope of the Company's ongoing 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 actual drilling results, as well as geological and mechanical factors. Estimates of unproved reserves, type/decline curves, per well EUR and resource potential may change significantly as development of the Company's oil and gas assets provides additional data.

Adjusted Net Income and Adjusted Net Income per Diluted Share

Adjusted net income and adjusted net income per diluted share exclude (1) impairment, (2) unrealized (gain) loss on commodity derivatives, (3) loss (gain) on sale of oil and gas properties, and (4) related 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, 2012, 2011 and 2010 (in thousands, except per-share amounts):

	Years Ended December 31,		
	2012	2011	2010
Net income	$ 6,384	$ 7,242	$7,462
Adjustments for certain non-cash items:			
Impairment	—	18,476	2,622
Unrealized (gain) loss on commodity derivatives	(3,874)	347	(788)
Gain on sale of oil and gas properties, net of foreign currency transaction loss	—	(248)	—
Related income tax effect	1,317	(6,316)	(623)
Adjusted net income	$ 3,827	$19,501	$8,673
Adjusted net income per diluted share	$ 0.11	$ 0.67	$ 0.39

EBITDAX and EBITDAX per Diluted Share

We define EBITDAX as net income, plus (1) exploration expense, (2) impairment, (3) depletion, depreciation and amortization expense, (4) share-based compensation expense, (5) unrealized (gain) loss on commodity derivatives, (6) loss (gain) on sale of oil and gas properties, (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, 2012, 2011 and 2010 (in thousands, except per-share amounts):

	Years Ended December 31,		
	2012	2011	2010
Net income	$ 6,384	$ 7,242	$ 7,462
Exploration	4,550	9,546	2,589
Impairment	—	18,476	2,622
Depletion, depreciation and amortization	60,381	32,475	22,224
Share-based compensation	7,465	4,683	2,628
Unrealized (gain) loss on commodity derivatives	(3,874)	347	(788)
Gain on sale of oil and gas properties, net of foreign currency transaction loss	—	(248)	—
Interest expense, net	4,737	3,402	2,189
Income tax provision	3,338	3,488	4,100
EBITDAX	$82,981	$79,411	$43,026
EBITDAX per diluted share	$ 2.37	$ 2.72	$ 1.94

Long-Term Debt-to-Capital

Long-term debt-to-capital ratio is calculated as of December 31, 2012, and by dividing long-term debt (GAAP) by the sum of total stockholders' equity (GAAP) and long-term debt (GAAP). We use the long-term debt-to-capital ratio as a measurement of our overall financial leverage. However, this ratio has limitations. This ratio can vary from year-to-year for the Company and can vary among companies based on what is or is not included in the ratio on a company's financial statements. This ratio is 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 and posted on our website.

The table below summarizes our long-term debt-to-capital ratio at December 31, 2012 and 2011 (in thousands).

	December 31, 2012	December 31, 2011
Long-term debt	$106,000	$ 43,800
Total stockholders' equity	633,468	467,449
	$739,468	$511,249
Long-term debt-to-capital	14.3%	8.6%

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 reserve extensions and discoveries of 38.9 MMBoe by production of 2.9 MMBoe. 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.

Reserve summary (MBoe)	
Balance — December 31, 2011	76,975
Extensions and discoveries	38,861
Production	(2,888)
Revisions to previous estimates	(17,469)
Balance — December 31, 2012	95,479
Reserve replacement ratio	
Drill-bit	1,346%
(Extensions and discoveries / Production)	

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.

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.

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 filings with the SEC, 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, 2012, 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). Amounts may not convert exactly in all cases due to rounding.

Cost summary (in thousands)	
Property acquisition costs	
Unproved properties	$ 2,335
Proved properties	5,407
Exploration costs	4,550
Development costs	285,039
Total costs incurred	$297,331
Reserve summary (MBoe)	
Balance — December 31, 2011	76,975
Extensions and discoveries	38,861
Production	(2,888)
Revisions to previous estimates	(17,469)
Balance — December 31, 2012	95,479
Finding and development costs ($/Boe)	
All-in F&D cost	$ 13.90
All-in F&D cost, excluding 2.4 MMBoe of price-related revisions	$ 12.50
Drill-bit F&D cost	$ 7.45

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][2]
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 and Nominating Committee*

EXECUTIVE OFFICERS

J. ROSS CRAFT
President, Chief Executive Officer and Director

QINGMING YANG
Chief Operating Officer

J. CURTIS HENDERSON
Executive Vice President and General Counsel

STEVEN P. SMART
Executive Vice President and Chief Financial Officer

RALPH P. MANOUSHAGIAN
Executive Vice President – Land

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STOCK LISTING

APPROACH RESOURCES INC. is traded on the NASDAQ Global Select Market under the ticker symbol AREX.

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Dallas, Texas

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Dallas, Texas

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WEBSITE

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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.

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