MILLER ENERGY RESOURCES, INC.
Form 10-K
July 16, 2012

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

FORM 10-K

(Mark One)
þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended: April 30, 2012
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from: to

MILLER ENERGY RESOURCES, INC.
(Exact name of registrant as specified in its charter)

Tennessee	001-34732	62-1028629
(State or Other Jurisdiction of Incorporation or Organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

9721 Cogdill Road, Suite 302, Knoxville, TN 37932
(Address of Principal Executive Office) (Zip Code)
(865) 223-6575
(Registrant's telephone number, including area code)

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 $0.0001 per share	New York Stock Exchange

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

None
(Title of Class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

¨ Yes þ 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 þ 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 þ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§229.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

þ Yes ¨ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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.

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

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

The aggregate market value of the outstanding common stock, other than shares held by persons who may be deemed affiliates of the registrant, computed by reference to the closing sales price for the registrant's common stock on October 31, 2011 (the last business day of the registrant's most recently completed second quarter), as reported on the New York Stock Exchange-Composite Index, was approximately $89,902,859. As of July 06, 2012, there were 41,945,393 shares of common stock of the registrant outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of registrant's proxy statement relating to registrant's 2012 annual meeting of stockholders have been incorporated by reference in Part II and Part III of this annual report on Form 10-K.

MILLER ENERGY RESOURCES, INC.

ANNUAL REPORT ON FORM 10-K
FOR THE YEAR ENDED APRIL 30, 2012

TABLE OF CONTENTS

		Page
FORWARD-LOOKING STATEMENTS		ii
GLOSSARY OF TERMS		ii
PART I		
Item 1.	Business	1
Item 1A.	Risk Factors	18
Item 1B.	Unresolved Staff Comments	27
Item 2.	Properties	1
Item 3.	Legal Proceedings	27
Item 4.	Mine Safety Disclosures	27
PART II		
Item 5.	Market for Registrant's Common Equity and Related Stockholder Matters and Issuer Purchases of Equity Securities	28
Item 6.	Selected Financial Data	30
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	31
Item 7A.	Quantitative and Qualitative Disclosures about Market Risk	44
Item 8.	Financial Statements and Supplementary Data	45
Item 9.	Changes in and Disagreements With Accountants on Accounting and Financial Disclosure	45
Item 9A.	Controls and Procedures	45
Item 9B.	Other Information	46
PART III		
Item 10.	Directors, Executive Officers and Corporate Governance	47
Item 11.	Executive Compensation	47
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	47
Item 13.	Certain Relationships and Related Transactions, and Director Independence	47
Item 14.	Principal Accounting Fees and Services	47
PART IV		
Item 15.	Exhibits, Financial Statement Schedules	48

Table of Contents

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

We have made forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 concerning the Company's operations, economic performance and financial condition in this annual report on Form 10-K, and may make other forward-looking statements from time to time in other public filings, press releases and discussions with our management,. These forward-looking statements include information concerning future production and reserves, schedules, plans, timing of development, contributions from oil and gas properties, marketing and midstream activities, and also include those statements preceded by, followed by or that otherwise include the words “may,” “could,” “believes,” “expects,” “anticipates,” “intends,” “estimates,” “p “target,” “goal,” “plans,” “objective,” “should” or similar expressions or variations on such expressions. For these statements, v claim the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that our expectations will prove to be correct. We undertake no obligation to publicly update or revise any forward-looking statements whether as a result of new information, future events or otherwise. These forward-looking statements involve risk and uncertainties. Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, the following risks and uncertainties:

- the potential for Miller to experience additional operating losses;
- high debt costs under our existing senior credit facility;
- potential limitations imposed by debt covenants under our senior credit facility on our growth and our ability to meet our business objectives;
- our need to enhance our management, systems, accounting, controls and reporting performance;
- uncertainties related to deficiencies identified by the SEC in certain Forms 8-K filed in 2010 and our Form 10-K for 2011;
- litigation risks;
- our ability to perform under the terms of our oil and gas leases, and exploration licenses with the Alaska DNR, including meeting the funding or work commitments of those agreements;
- our ability to successfully acquire, integrate and exploit new productive assets in the future;
- our ability to recover proved undeveloped reserves and convert probable and possible reserves to proved reserves;
- risks associated with the hedging of commodity prices;
- our dependence on third party transportation facilities;
- concentration risk in the market for the oil we produce in Alaska;
- the impact of natural disasters on our Cook Inlet Basin operations;
- adverse effects of the national and global economic downturns on our profitability;
- the imprecise nature of our reserve estimates;
- drilling risks;
- fluctuating oil and gas prices and the impact on our results from operations;
- the need to discover or acquire new reserves in the future to avoid declines in production;
- differences between the present value of cash flows from proved reserves and the market value of those reserves;
- the existence within the industry of risks that may be uninsurable;
- constraints on production and costs of compliance that may arise from current and future environmental, FERC and other statutes, rules and regulations at the state and federal level;
- the impact that future legislation could have on access to tax incentives currently enjoyed by Miller;
- that no dividends may be paid on our common stock for some time;
- cashless exercise provisions of outstanding warrants;
- market overhang related to restricted securities and outstanding options, and warrants;
- the impact of non-cash gains and losses from derivative accounting on future financial results; and
- risks to non-affiliate shareholders arising from the substantial ownership positions of affiliates.

Most of these factors are difficult to predict accurately and are generally beyond our control. You should consider the areas of risk described in connection with any forward-looking statements that may be made herein. Readers are cautioned not to place undue reliance on these forward-looking statements, and readers should carefully review this annual report in its entirety, including the risks described in Item 1A. Risk Factors. Except for our ongoing obligations to disclose material information under the Federal securities laws, we undertake no obligation to release publicly any revisions to any forward-

Table of Contents

looking statements, to report events or to report the occurrence of unanticipated events. These forward-looking statements speak only as of the date of this annual report, and you should not rely on these statements without also considering the risks and uncertainties associated with these statements and our business.

OTHER PERTINENT INFORMATION

We maintain our web site at www.millerenergyresources.com. On our website, you will find detailed information regarding our company, our locations and our leadership team, as well as information for shareholders and investors on our media and investor pages. Information on this web site is not a part of this annual report.

Unless specifically set forth to the contrary, when used in this annual report on Form 10-K, the terms “Miller Energy Resources,” "Miller," the "Company," "we," "us," "ours," and similar terms refers to our Tennessee corporation Miller Energy Resources, Inc., formerly known as Miller Petroleum, Inc., and our subsidiaries, Miller Rig & Equipment, LLC, Miller Drilling, TN LLC, Miller Energy Services, LLC, East Tennessee Consultants, Inc. ("ETC"), East Tennessee Consultants II, LLC ("ETCII"), Miller Energy GP, LLC, and Cook Inlet Energy, LLC ("CIE").

Our fiscal year end is April 30. The year ended April 30, 2012 is referred to as “fiscal 2012” or "2012," the year ended April 30, 2011 is referred to as “fiscal 2011” or "2011," the year ended April 30, 2010 is referred to as “fiscal 2010” or "2010" and the year ending April 30, 2013 is referred to as “fiscal 2013” or "2013."

GLOSSARY OF OIL AND NATURAL GAS TERMS

We are engaged in the business of exploring and producing oil and natural gas as well as exploiting our mid-stream assets that could entail electrical power sales, processing third party fluids and natural gas and waste disposal. Many of the terms used to describe our business are unique to the oil and gas industry. The definitions set forth below apply to the indicated terms as used in this annual report on Form 10-K.

3-D seismic. The method by which a three dimensional image of the earth's subsurface is created through the interpretation of reflection seismic data collected over a surface grid. 3-D seismic surveys allow for a more detailed understanding of the subsurface than do conventional surveys and contribute significantly to field appraisal, exploitation and production.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas corrected to standard temperature and pressure.

Bopd. Barrels of oil per day.

Boe. Barrels of oil equivalent in which six Mcf of natural gas equals one Bbl of oil.

Boe/d. Boe per day.

Mcf. One thousand cubic feet of natural gas corrected to standard temperature and pressure.

MMBbls. Million barrels of oil.

MMcf. Million cubic feet of natural gas correct to standard temperature and pressure.

Completion. The installation of permanent equipment for the production of oil or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Development well. A well drilled within the proved areas of oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

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

Exploratory well. 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 natural gas in another reservoir.

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

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

Midstream. Refers to oil and gas infrastructure or operations relating to the transportation of sales-quality crude oil and gas production facilities to market. Used to contrast to upstream (exploration & production) or downstream (refining,

iii

Table of Contents

manufacturing and sales).
Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.
Oil and gas lease or lease. An agreement between a mineral owner, the lessor, and a lessee which conveys the right to the lessee to explore for and produce oil and gas from the leased lands. Oil and gas leases usually have a primary term during which the lessee must establish production of oil and or gas. If production is established within the primary term, the term of the lease generally continues in effect so long as production occurs on the lease. Leases generally provide for a royalty to be paid to the lessor from the gross proceeds from the sale of production.
Proved developed producing reserves ("PDP"). Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and capable of production.
Proved developed non-producing reserves ("PDNP"). Proved crude oil and natural gas reserves that are developed behind pipe, shut-in or that can be recovered through improved recovery only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells that were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to the start of production.
Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved reserves. The quantities of oil and gas that, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible. We provide information on two types of proved reserves - developed and undeveloped.
Proved undeveloped reserves ("PUD"). Reasonably certain reserves in drilling units immediately adjacent to the drilling unit containing a producing well as well as areas beyond one offsetting drilling unit from a producing well.
Reservoir. A porous or permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.
Royalty interest. A right to oil, gas, or other minerals that is not burdened by the costs to develop or operate the related property.
Working interest. An interest in an oil and gas property that is burdened with the costs of development and operation of the property.
Upstream. Refers to oil and gas infrastructure or operations relating to the exploration and production of crude oil and gas and its processing into sales-quality crude or gas. Used to contrast to midstream (transportation and ancillary services) or downstream (refining, manufacturing and sales).

Table of Contents

PART I

ITEM 1 AND 2. BUSINESS AND PROPERTIES.

Overview

We are an independent exploration and production company that utilizes seismic data and other technologies for geophysical exploration and development of oil and gas wells in the Appalachian region of East Tennessee and in southcentral Alaska. During fiscal 2012, we continued to develop our oil and gas operations acquired from Pacific Energy Resources ("Pacific Energy") in December 2009 through a bankruptcy proceeding, including onshore and offshore production and processing facilities, the offshore Osprey platform, and approximately 700,000 lease or exploration license acres of land, along with hundreds of miles of 2-D and 3-D geologic seismic data, miscellaneous roads, pads, pipelines and facilities. Our mission is to grow a profitable exploration and production company for the long-term benefit of our shareholders by focusing on the development of our reserves, continued expansion of our oil and natural gas properties and increase in our production and related cash flow. We intend to accomplish these objectives through the execution of the following core strategies:

- Develop Acquired Acreage. We will focus on organically growing production through drilling for our own benefit on existing leases and acreage in the exploration licenses with a view towards retaining the majority of working interest in the new wells. This strategy will allow us to maintain operational control, which we believe will translate to long-term benefits;
- Increase Production. We plan on increasing oil and gas production through the maintenance, repair and optimization of wells located in the Cook Inlet Basin and development of wells in the Appalachian region of East Tennessee. Our management team expects to employ the latest available technologies to explore and develop our properties;
- Expand Our Revenue Stream. We intend on fully exploiting our mid-stream facilities, such as our injection wells and the Kustatan Production Facility, our ability to engage in the commercial disposal of waste generated by oil and gas operations, and our capacity to process third party fluids and natural gas and to offer excess electrical power to net users in the Cook Inlet area; and
- Pursue Strategic Acquisitions. We have significantly increased our oil and gas properties through strategic low-cost / high-value acquisitions. Under the same strategy, our management team plans to continually seek opportunities that meet our criteria for risk, reward, rate of return, and growth potential. We plan to leverage our management team's expertise to pursue value-creating acquisitions when the opportunities arise, subject to the availability of sufficient capital.

For a more in-depth discussion of our fiscal 2012 results and the Company's capital resources and liquidity, please see Part II, Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations of this Form 10-K.

Recent Developments

Apollo Investment Corporation Credit Facility

On June 29, 2012 (the “Closing Date”), the Company entered into a loan agreement (the “Loan Agreement”) with Apollo Investment Corporation (“Apollo”), as administrative agent and lender, along with other lenders party to the Loan Agreement from time to time (the “Lenders”). The loan agreement provides for a credit facility of up to $100 million (the “Credit Facility”) with an initial borrowing base of $55 million, of which $40 million was available upon the Closing Date. The remaining $15 million of the initial borrowing base will be made available following the satisfaction of certain conditions by the Company, most notably, the Company demonstrating to Apollo's satisfaction that it can raise at least $15 million in equity (the"Equity Requirement") and the delivery of audited year-end financial statements for fiscal year 2012. The Credit Facility matures on June 29, 2017 and is secured by substantially all the assets of the Company and its subsidiaries. Amounts outstanding under the Credit Facility bear interest at the rate of 18% per annum.

Draws under the Credit Facility may be made once per fiscal quarter (other than the draw of the remaining $15 million of the borrowing base not drawn on the Closing Date, which may be drawn by the Company upon satisfaction of the Equity Requirement and other relevant conditions). Increases in the borrowing base are subject to the discretion of Apollo. The borrowing base may be redetermined up to once per calendar quarter, following a request by the Company, or at the discretion of Apollo.

The Loan Agreement contains interest coverage, asset coverage, minimum gross production and leverage covenants, as well as other affirmative and negative covenants. In connection with the Loan Agreement, the Company has granted Apollo a right of first refusal to provide debt financing for the acquisition, development, exploration or operation of any oil and gas related properties including wells during the term of the Credit Facility and one year thereafter. Under the Loan Agreement, the Company must prioritize certain oil and gas development projects over others, and will be restricted from spending its cash on lower priority projects prior to the completion of those with a higher priority. A list of priorities was negotiated in connection with the closing of the Loan Agreement, and that list can only be changed with the consent of Apollo and the majority of the Lenders (as measured by the relative portion of the commitments held under the Loan Agreement from time to time).

On June 29, 2012, we, along with all of our subsidiaries, also entered into a Guarantee and Collateral Agreement (the “Guarantee”) with Apollo, for the benefit of the Lenders. We granted a security interest in substantially all of our subsidiaries' assets to secure the performance of our obligations under the Loan Agreement and the Guarantee.

The Company used $26.2 million of the initial $40 million loan made available under the Credit Facility to repay in full the amounts outstanding (including accrued interest) under the prior Loan Agreement, dated June 13, 2011 (the “Prior Loan Agreement”), between the Company, as borrower, Guggenheim Corporate Funding, LLC, as administrative agent and lender, and Citibank, N.A. and Bristol Investment Fund, as lenders. The Prior Loan Agreement and all related documents and security interests arising under them were terminated immediately upon that repayment.

Loan proceeds of $10.8 million were used to redeem the Company's outstanding Series A Cumulative Preferred Stock issued on April 6, 2012 as described below; while proceeds of $2.8 million were used to pay a non-refundable structuring fee to Apollo for the Loan Agreement. The remaining proceeds of $0.2 million were used to pay certain outstanding payables of the Company.

For a full description of the terms of the Credit Facility, please see Note 16 - Subsequent Events in the Notes to Consolidated Statements set forth in Part IV, Item 15 of this Form 10-K.

Private Placement of Series A Cumulative Preferred Stock

On April 6, 2012, we issued a new class of Series A Cumulative Preferred Stock (the "Preferred Stock") to 20 accredited and institutional investors in a private offering exempt from registration under the Securities Act of 1933, as amended. We received gross proceeds of $10 million and paid a finder's fee of $0.1 million to Dimirak Securities Corporation ("Dimirak"), a broker-dealer and member of FINRA. Mr. Boruff, our Chief Executive Officer, is a director and 49% owner of Dimirak.

The Preferred Stock is non-convertible and redeemable by us, at our discretion. Holders of the Preferred Stock are entitled to dividends of 10% per annum, payable in cash or in kind, at our election, with any unpaid dividends accumulated and paid upon liquidation or redemption. Purchasers of the Preferred Stock were also issued warrants to purchase an aggregate amount of 1,000,000 shares of our common stock, at an above-market exercise price of $5.28 per share.

Under the terms of the offering, the Preferred Stock must be redeemed by us within 30 days following the refinancing and repayment of our existing credit facility. If the Preferred Stock is not redeemed by us within 30 days of the repayment, purchasers of the shares will receive, as liquidated damages, a reduction in the exercise price of the warrants from $5.28 per share to $3.00 per share. Further, we are subject to an increased redemption premium if the Preferred Stock is not redeemed within 180 days of issuance. For a full description of the designations, rights and preferences of the Preferred Stock and a description of the warrants, please see Note 3 - Derivative Instruments and Note 8 - Capital Stock in the Notes to Consolidated Statements set forth in Part IV, Item 15 of this Form 10-K.

Renegotiated Alaska Crude Oil Sales Contract

On March 9, 2012, we entered into a crude oil sales agreement with an independent refiner and marketer of petroleum products whereby that company agreed to purchase all crude oil produced by us, subject to a minimum of 200 bbls/day and a maximum of 24,000 bbls/day. The agreement strategically aligned the terms of our pricing with the ANS Index, which has historically averaged approximately $8 - $10 higher per barrel than WTI, as defined below. The newly negotiated price for each delivery of oil is equal to the higher of the arithmetic average of the published daily New York Mercantile Exchange (“NYMEX”) Settlement Prices for Light Sweet Crude Oil delivered at Cushing, Oklahoma ("WTI") for the applicable front month NYMEX Contract published each business day in the calendar month of delivery or the ANS Index Midpoint Price if it is at least $2.285/barrel greater than the WTI Index Price, subject to certain adjustments.

Under the agreement, we are also responsible for paying taxes on the sale or on production or handling of the oil prior to delivery. The contract may be opened for renegotiation if the quality of the oil changes, certain volume reductions or increases, changes to the Cook Inlet Spill Prevention and Response, Inc. ("CISPRI") charges, or closure of the purchaser's Alaska refinery.

Table of Contents

Geographic Area Overview

We currently focus our efforts on activities in the Cook Inlet and Susitna Basins of Alaska as well as the Appalachian region of East Tennessee.

The following table sets forth certain key information for each of our operating areas. Additional data and discussion is provided in Part II, Item 7 of this Form 10-K.

	2012 Production	Percentage of Total 2012 Production	2012 Oil and Gas Revenues	4/30/2012 Estimated Proved Reserves	Percentage of Total Estimated Proved Reserves
	(In Boe)		(In thousands)	(In MBoe)	
Cook Inlet [1]	333,420	90%	$30,700	9,157	99%
Appalachian region	38,423	10%	1,793	137	1%
Total	371,843	100%	$32,493	9,294	100%

[1] Cook Inlet production excludes 33,956 boe of fuel gas.

Alaska Region

Overview

The Cook Inlet Basin contains large oil and gas deposits including multiple offshore fields. In 2012 there were 16 platforms in the Cook Inlet, the oldest of which is the XTO A platform first installed by Royal Dutch Shell Plc in 1964, and the newest of which is the Osprey platform installed by Forest Oil Corporation in 2000, and acquired by us in December 2009. Southcentral Alaska has a well-developed oil and gas pipeline infrastructure to bring Cook Inlet oil and gas to market. This system is isolated from the main North American gas pipeline system. Much of the value-added hydrocarbon processing occurs on the east side of Cook Inlet in an industrial cluster located in Nikiski, which is the northern part of the city of Kenai. The Tesoro refinery, ConocoPhillips LNG plant, BP GTL plant, Agrium, Inc. fertilizer plant, and numerous docks, tanks and pipelines are all located in Nikiski. The Susitna Basin is a large area to the north of Anchorage in southcentral Alaska. It is perhaps best known for its coal seams in the sedimentary basin that lies underneath the basin and could become a new source of much-needed natural gas.

Cook Inlet and Susitna Basins

The Cook Inlet is a vast estuary stretching 180 miles from the Gulf of Alaska to Anchorage in southcentral Alaska. The Inlet separates the Kenai Peninsula in the east from the Alaska Peninsula in the west. The Cook Inlet Basin underlying this region contains large oil and gas deposits including several offshore fields. There are also numerous oil and gas pipelines located in and under the Cook Inlet. The Cook Inlet Basin has produced approximately 1.3 billion barrels of oil and 7.8 trillion cubic feet ("tcf") of natural gas.

The Susitna Basin underlies the sprawling Susitna River valley to the north of Anchorage. The Susitna Basin lies directly north of the Cook Inlet Basin, separated by the Castle Mountain Fault, and has similar geology. While the Cook Inlet Basin is a historic region of oil and gas production, there is not currently commercial production of oil or gas from the Susitna Basin.

In its 2011 Assessment of Undiscovered Oil and Gas Resources of the Cook Inlet Region, the United States Geologic Survey ("USGS") estimated mean undiscovered technically recoverable reserves of 599 million bbls of oil and 19 tcf of natural gas. All of the undiscovered oil and 13.7 tcf of the undiscovered gas are conventional resources, 5.3 tcf of natural gas was estimated to be technically recoverable as coal bed methane. This report considered the full oil and gas potential of the Cook Inlet Basin, but only the coal-bed methane potential of the Susitna Basin. These numbers do not include oil and gas remaining to be produced in currently producing fields.

As of April 30, 2012 and 2011, we owned approximately 105,713 and 115,124 gross acres of leasehold interests, the exploration license rights to an additional 534,383 acres and interests in 10 crude oil and five natural gas wells. The reduction in leased acreage from April 30, 2011 is a result of our surrender of five leases nearing expiration and the

assignment of a portion of one lease to Union Oil Company of California ("Unocal"). The increase in license acreage resulted from the issuance of Susitna Basin Exploration License No. 5, consisting of 45,764 acres.
At the time we acquired the Alaskan operations, all ten oil wells, three of four gas wells and four injection wells were shut-in. By April 30, 2010, three oil wells and five gas wells had been returned to production. In addition, we own a 30% working interest in two gas wells operated by Aurora Gas, which have been operated continuously.

Oil wells drilled in this area range from 9,000 vertical feet to 10,000 feet in vertical depth while gas wells have a vertical depth of 8,000 feet to 9,000 feet. Wells that are deviated (continue on from the vertical depth either diagonally or horizontally) will have a longer measured depth of approximately 5,000 feet giving total measured depth of 14,000 feet to 15,000 feet. Well spacing is quite variable, as there are large parts of Cook Inlet which are completely undeveloped and others that are more mature. Our fields have approximately 60 to 80 acre spacing. The Cook Inlet Basin contains a thick section of terrestrial Tertiary rocks which includes shale, sandstone, and coal. The primary targets in the area are crude oil reserves, but prolific gas fields are increasingly attractive due to the rising price of gas in the Alaska market and liquefied natural gas ("LNG"). Cook Inlet natural gas is strategically situated to provide LNG to Asian markets where the LNG price is high and rising. The Nikiski LNG plant is the only LNG export facility in the United States, and has been shipping Cook Inlet LNG to Japan for over 40 years.

Osprey Platform and Redoubt Shoals Field

The Osprey platform is located in the Redoubt Unit approximately 1.8 miles southeast of the West Foreland in central Cook Inlet at a water depth of approximately 45 feet. The Osprey platform, which produces from the Redoubt Shoals Field is connected to our Kustatan Production Facility. It relies on our Kustatan Production Facility and our West McArthur River Unit Production Facility to provide all of its electricity and gas, and the Kustatan Production Facility to process all of Osprey's produced fluids. The platform has 21 slots, eight of which are currently used, and an attached 48 man camp. After a period of inactivity, we started work to re-commission Osprey in February 2011 and restored production in May 2011.

The Osprey platform was placed on site in June 2000 and initially used to conduct exploration drilling operations between January 2001 and July 2002. Eight wells were drilled, which in their present configuration consist of one water flood well, one Class I injection well, and six oil wells. The oil wells were equipped with electrical submersible pumps (“ESPs”) which were necessary to bring the oil to surface. In 2005, the third-party drilling rig was removed from the platform after a contract dispute. The removal of the rig delayed the ability to maintain and repair the platform's wells or to expand production, and the Osprey platform was shut-in in the spring of 2009.

In order to restore production from the Redoubt Unit, it was necessary to mobilize a drilling rig to the Osprey platform to repair the shut-in wells. Two of the wells required replacement of the ESPs, but the other four wells required re-drilling in sections. Due to significant drilling rig rental cost and delays associated with mobilization and availability of a drilling rig sufficient in size and power to repair the wells, we determined it was most effective to permanently locate a drilling rig on the Osprey platform. We estimated the total cost of restoring full production, including the purchase and construction of a drilling rig, to be approximately $45 million. In March 2011, we transitioned the Osprey platform out of lighthouse mode and successfully repaired the first of the two wells needing ESP replacement, of which one later failed in September 2011 as a result of successive pump failure. In June 2011, we contracted with Voorhees Equipment and Consulting, Inc. for the custom construction and purchase of Rig 35 for $17.9 million.

We successfully mobilized all components of the custom rig to the Osprey platform in late December 2011. Assembly of the rig began as parts were delivered to the platform. In January 2012, the region experienced prolonged, near-record cold weather, which caused us to temporarily delay rig assembly efforts due to safety concerns. The cold weather also led to significant generation of ice volume in the Cook Inlet and made shipping and the operation of work-boats impossible. As warmer temperatures moderated the region, we resumed work on the assembly of Rig 35, which in its present state is substantially completed and expected to be fully operational in July 2012.

Kustatan Production Facility

The Kustatan Production Facility was constructed in 2001-2002 by Forest Oil Corporation to process an estimated 25,000 bopd. Processing capabilities are expandable to 50,000 bopd. The facility provides power and processes hydrocarbons produced from our offshore Osprey platform.

West McArthur River Field and Production Facility

The West McArthur River Facility processes oil and gas from the West McArthur River Field and has the ability to process gas from the West Foreland Field. Currently, there are three producing wells in the field. The facility was built in 1990s to process approximately 5,000 bopd.

West Foreland Field and Production Facility

The West Foreland Field is produced through the West Foreland Facility but can be processed through the West McArthur River Facility. Currently, there are three wells in the field, one of which is off-line. The West Foreland Facility is tied into the gas pipeline network including sales gas pipelines.

Three Mile Creek Field

The three Mile Creek Field is operated by Aurora Gas. There are two gas wells in which we own a 30% working

Table of Contents

interest in this field.

Susitna Basin

Included in the Alaskan operations we acquired is a 100% interest in Susitna Basin Exploration License No. 2, granted by the State of Alaska in October 2005 covering approximately 471,474 acres in the Susitna basin area north of Anchorage. Under the terms of the Exploration License, the licensee was granted a seven-year exclusive license to explore for oil and gas on the specified lands, and upon fulfillment of the work commitment, the license for all or any part of the land could be converted into oil and gas leases. The original work commitment of approximately $3.0 million was fulfilled. In an effort to control the timing of the development of this acreage, in April 2010 we requested a three-year extension of the exploration license for a work commitment of $0.8 million. The State granted the extension in October 2010. We will have the right to convert all or any portion of the licensed acreage into oil and gas leases upon completion of the new work commitment.

On April 1, 2011, we were awarded Susitna Basin Exploration License No. 4, which consists of 62,909 acres. It granted us an exclusive ten-year license to explore for oil and gas on the specified lands. Upon fulfillment of a $2.3 million work commitment, we will gain the option to convert any part of the licensed area into oil and gas leases. We posted an initial performance bond of $0.2 million toward fulfilling its work commitment, and will need to post additional bonds annually if no work is carried out in the licensed area.

On April 1, 2012, we were awarded Susitna Basin Exploration License No. 5, which consists of 45,764 acres. It granted us an exclusive ten-year license to explore for oil and gas on the specified lands. Upon fulfillment of a $0.3 million work commitment, we will gain the option to convert any part of the licensed area into oil and gas leases. We posted an initial performance bond of $50,000 toward fulfilling its work commitment, and will need to post additional bonds annually if no work is carried out in the licensed area.

Assignment Oversight Agreement

On November 5, 2009, CIE entered into an Assignment Oversight Agreement with the Alaska Department of Natural Resources (“Alaska DNR”) which set out certain terms under which the Alaska DNR would approve the assignment of certain specified state oil and gas leases from Pacific Energy Resources to CIE. This agreement remains in place following our acquisition of CIE in December 2009. Generally, the agreement requires CIE to provide the Alaska DNR with additional information and oversight authority to ensure that CIE is acting diligently to develop the oil and gas reserves from the Redoubt Shoal, West McArthur River and West Foreland Fields. Under the terms of the agreement, until the Alaska DNR determines, in its sole discretion, that CIE has completed its development and operation obligations under the assigned leases CIE agreed to the following:

- file a monthly summary of expenditures by oil and gas field, tied to objectives in CIE's business plan and plan of development previously presented to the Alaska DNR,
- meet monthly with the Alaska DNR to provide an update on operations and progress towards meeting these objectives,
- notify the Alaska DNR 10 days prior to commitment when CIE is preparing to spend funds on a purchase, project or item of more than $0.1 million during the first 12 months, more than $1 million during the second 12 months and more than $5 million thereafter, and
- submit a new plan of development and plan of operations for the Alaska DNR's approval on or before December 15, 2009 and submit a plan of development annually thereafter on or before February 1, 2010. CIE timely met these deadlines.

The agreement required CIE to obtain financing in the minimum amount of $5.2 million to provide funds to be used for expenditures approved by the Alaska DNR as part of CIE's plan of development. We have provided these funds for the West McArthur River facility using a portion of the proceeds of our capital raising efforts described elsewhere herein.

The agreement required CIE to demonstrate funding commitments to support restoration of the base production at the Redoubt Unit, including bringing a number of the shut-in wells back on line, which was estimated at $31 million in the agreement, but which we have internally increased to $45 million primarily to accommodate the contractual purchase price of a drilling rig.

CIE is prohibited from using any of the proceeds from the operations under the assigned leases of the funding commitments for non-core oil and gas activities under the assigned leases, or any activities outside the assigned leases, without the prior written approval of the Alaska DNR until the parties mutually agree that the full dismantlement obligation under the assigned leases is funded.

On March 11, 2011, CIE entered into a Performance Bond Agreement with the Alaska DNR that applies to the offshore obligations under the Assignment Oversight Agreement. Under the Performance Bond Agreement, CIE is required to post a total bond of $18 million; however, the Performance Bond Agreement makes clear that approximately $6.8 million held by the state will apply to the total bond required. The first payment of $1.0 million toward the bonding requirement is due in July 2013.

The assigned leases will be subject to default and termination should CIE fail to submit the information required under the agreement and expenditure of funds for items or activities do not support core oil and gas activities, as reasonably determined by the Alaska DNR.

Membership in Cook Inlet Spill Prevention and Response, Inc.

CIE is a member of the CISPRI. CISPRI is a non-profit corporation formed in 1990 to provide oil spill prevention and response capabilities in Cook Inlet. CISPRI has been designated as a Class "E" Oil Spill Removal Organization by the U.S. Coast Guard, which is the highest level of designation based on spill containment and removal equipment requirements for offshore/ocean response. CISPRI's response zone includes the entire Cook Inlet region. At each annual meeting of CISPRI members adopt a budget for the coming year which includes funds for day to day operational activities of CISPRI, investments in capital equipment and materials to be used in connection with the cleanup activities and research and development and training. The budget is funded though payment of dues by the members and the amount of dues is calculated in accordance with a participation formula. We pay an annual fee of $10,000 together with additional fees based upon the amount of oil we transport.

If a spill of crude oil/synthetic crude oil or refined petroleum products is identified as originating from facilities owned or operations conducted by one or more of the members, CISPRI will act to control and clean up the spill without any further action by the members. Any member that utilizes or receives the benefit of these activities must reimburse CISPRI for all expenses of control and clean up, including costs of equipment, materials and personnel.

Each member is required to execute a response action contract providing terms and conditions under which response and cleanup activities will be undertaken. CIE is a party to such an agreement which, in part, requires CIE to maintain worker's compensation insurance, employers' liability insurance, comprehensive general and automotive liability insurance covering injury or death or persons and property damage of at least $10 million. CIE is in compliance with these insurance requirements. All members accept responsibility for spills which result from their operations or facilities and have indemnified CISPRI and all other members for all liabilities arising for a spill. This indemnification is not limited by the amount of insurance coverage.

CIE may resign its membership in CISPRI upon 30 days written notice. At the effective date of the resignation, CIE is obligated to pay all unpaid dues and assessments levied prior to the notice of resignation. CIE's membership may be terminated by the Board of Directors of CISPRI upon 60 days notice if it's determined CIE is no longer eligible for membership. CIE would not be entitled to a refund of any monies paid to CISPRI.

Appalachian Region

We are the largest owner/operator of oil and natural gas wells in Tennessee. As of April 30, 2012, we owned approximately 49,260 gross acres of leasehold interests with 183 producing oil wells and 181 producing gas wells in which we own an interest. Wells drilled within our acreage range from approximately 1,500 to 4,200 feet in depth with major targets in descending order being: the Mississippian age Monteagle Limestone and Fort Payne Limestone, and the Devonian age Chattanooga Shale, with the Fort Payne Limestone being the primary oil target.

The Appalachian region of Tennessee has produced oil from a number of fields. Some of those fields include the Indian Creek, Burrville, Low Gap, Lick Branch, Gum Branch, Skull Creek, and Bendix Spur. We have acreage in and around these previously producing fields and plan to utilize our expertise to enhance present production and extract additional oil from areas previously overlooked.

Historically, only 12 percent to 18 percent of the oil in place has been recovered by primary recovery methods in the Mississipian age formations of the Monteagle Limestone and Fort Payne Limestone in Tennessee. We believe that Horizontal drilling within our acreage holdings described above will unlock much of the oil still in place. Horizontal drilling is the process of drilling a well from the surface to a subsurface location just above the target formation called the "kickoff point," then deviating the well bore from the vertical plane around a curve to intersect the formation at the "entry point" with a near-horizontal inclination. At this point, the well-bore remains in the horizontal plane until the desired length is achieved. With the Monteagle and Fort Payne being stratigraphic oil producing zones, horizontal drilling will be a way to recover a much greater percentage of the remaining oil in place by placing the well bore within the stratigraphic zone and not drilling through the zone vertically. This drilling and production method along with gas pressure maintenance will enable us to maximize the oil potential in Tennessee.

Another focus for the Appalachian region is the potential extraction from the Devonian age Chattanooga Shale. Across the U.S., from the West Coast to the Northeast, some 19 geographic basins are recognized sources of shale gas. Although natural gas has been known for years to exist in these formations, the natural gas trapped in it was not considered commercially viable to produce because of shale's tendency to be so dense that the trapped natural gas could not be accessed. The

Table of Contents

introduction of Horizontal Drilling and Multiple Zone Hydraulic Fracturing has allowed for this untapped resource to become commercially viable. As is the case above with the horizontal drilling in the Mississippian limestone formations, along this horizontal lateral, multiple-zone hydraulic fracturing breaks open the shale to allow natural gas to flow freely to the well bore. This horizontal approach to accessing the hydrocarbons trapped within the shale formation has proven to be more cost effective than traditional vertical drilling while minimizing the number of wells necessary to monetize a formation. Currently, within the acreage controlled by us, there are numerous potential well locations that can be drilled and produced to be used as a pressure maintenance program or natural gas storage within the Mississippian age Fort Payne Limestone.

Principal Markets and Customers

The existing markets for natural gas production in southcentral Alaska are the Tesoro Nikiski Refinery, utility companies, petrochemical manufacturing, the production of LNG for export to Asian markets, and the production of synthetic crude oil (“syncrude”). Presently, our sole market for crude oil produced from our Alaskan operations is the Tesoro Nikiski Refinery. Crude oil is shipped by pipeline and tanker vessel to the Tesoro Nikiski Refinery, operated by Tesoro Alaska Petroleum Company ("Tesoro").

Under the terms of the Alaska crude oil sales contract, Tesoro has agreed to purchase all crude oil produced by us, subject to a minimum of 200 bbls/day and a maximum of 24,000 bbls/day. Should the quantity of oil produced by us fall below the minimum or rise above the maximum, the contract would be open for renegotiation.

The price for each delivery of oil shall be equal to the simple arithmetic average of the published daily NYMEX WTI for the applicable front month NYMEX Contract published each business day in the calendar month of delivery, subject to certain adjustments: (i) If the ANS Index Midpoint Price is at least $2.285/barrel greater than the WTI Index Price, then the price shall be equal to the ANS Index Midpoint Price less $4.00/bbl; (ii) If the ANS Index Midpoint Price is equal to or less than the sum of the WTI Index Price plus $2.285/barrel, then the price shall be equal to the WTI Index Price less $1.715; (iii) less a deduction for the CISPRI; (iv) less a deduction for transportation through the Kenai Pipeline; (v) less a deduction for transportation and shipping, and; (vi) less a deduction adjusting for Redoubt Shoal quality. Non-Redoubt Shoal oil will have an additional quality adjustment.

We are also responsible for paying taxes on the sale or on production or handling of the oil prior to delivery. The contract may be opened for renegotiation if the quality of the oil changes, certain volume reductions or increases, changes to the CISPRI charges, or closure of the company's Alaska Refinery. In fiscal 2012, 2011 and 2010, purchases by Tesoro accounted for 100%, 99%, and 100%, respectively, of our total Alaska oil and gas production revenues.

Currently, all natural gas produced by our Alaskan operations is used to generate heat and power at our production facilities. At such time as gas production exceeds our internal needs, we can sell the excess production as all of our gas wells are connected to the Southcentral Alaska Railbelt pipeline network through the Cook Inlet Gas Gathering System and/or the Beluga Pipeline, both of which are operated by Marathon Pipelines.

The principal markets for our crude oil and natural gas produced in the Appalachian region are refining companies, utility companies and private industry end users. Crude oil is stored in tanks at the well site until the purchaser retrieves it by tank truck. Direct purchases of our crude oil are made statewide at our well sites by Barrett Oil Purchasing Company. Our natural gas has multiple markets throughout the eastern United States through gas transmission lines. Access to these markets is presently provided by three companies in northeastern Tennessee, Cumberland Valley Resources, NAMI Resources Company, and Tengasco. Local markets in Tennessee are served by Citizens Gas Utility District and the Powell Clinch Utility District. Natural gas is delivered to the purchaser via gathering lines into the main gas transmission line. Surplus gas is placed in storage facilities or transported to East Tennessee Natural Gas which serves Tennessee and Virginia. In fiscal 2012, 2011 and 2010, sales to Barrett Oil Purchasing and Sunoco, collectively, represented approximately 35%, 2%, and 9%, respectively, of our total Tennessee revenues.

Drilling Statistics

Historically, our drilling activities have generally concentrated on the recompletion of wells in the Cook Inlet region and the exploitation and extension of existing producing fields in the Appalachian region. In fiscal 2012, we transitioned our efforts to the construction of a custom rig for the Osprey platform, Rig 35, with the anticipation that it will restore all previously producing wells on the platform. We also made significant improvements and modifications to one of our rigs, Rig 34, to enable onshore drilling in winter conditions while complying with Alaska regulations. Upon certification from the AOGCC in March 2012, we mobilized Rig 34 to the Kustatan gas field to workover the KF-1 well, a previously producing gas well, and to the Otter Prospect in April 2012 to begin drilling the Otter 1 well. In addition to rig construction and modification activities, we successfully brought on-line two previously producing wells on the Osprey platform, RU-1 and RU-7. After a short period of production, RU-1 ceased production as a result of an ESP failure. Our objective for the coming year is to utilize Rig 35 on the Osprey platform to repair all non-producing wells and

Table of Contents

restore production to anticipated capacity.

We incurred dry hole costs on one well in Alaska and two wells in Tennessee. In Alaska, we explored two new zones in our KF-1 that were unproductive. The cost of exploring the two new zones was expensed in 2012. In Tennessee, we drilled two new development wells that were unproductive. The development cost of these wells was capitalized in 2012.

The following table shows the results of the oil and gas wells drilled and completed for each of the last three fiscal years:

	Drilling Activities					
	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Producing						
Cook Inlet	—	—	—	—	—	—
Appalachian region	—	—	—	—	—	—
Total producing	—	—	—	—	—	—
Non-Producing						
Cook Inlet	—	—	—	—	—	—
Appalachian region	—	—	—	—	—	—
Total non-producing	—	—	—	—	—	—
Injection						
Cook Inlet	—	—	—	—	—	—
Appalachian region	—	—	—	—	—	—
Total injection	—	—	—	—	—	—
Dry						
Cook Inlet	—	—	—	—	—	—
Appalachian region	2	2	—	—	—	—
Total dry	2	2	—	—	—	—
Total development	2	2	—	—	—	—
Exploratory:						
Productive						
Cook Inlet	—	—	—	—	—	—
Appalachian region	—	—	3	3	—	—
Total productive	—	—	3	3	—	—
Dry						
Cook Inlet	1	1	—	—	—	—
Appalachian region	—	—	—	—	—	—
Total dry	1	1	—	—	—	—
Pending determination	—	—	—	—	—	—
Total exploratory	1	1	3	3	—	—
Total drilling activity	3	3	3	3	—	—

8

Table of Contents

Productive Oil and Gas Wells

The number of productive oil and gas wells, operated and non-operated, in which we had an interest as of April 30, 2012 is set forth below:

	Producing Wells					
	Gross [(a)]			Net [(b)]		
	Oil	Gas	Total	Oil	Gas	Total
Cook Inlet	4	8	12	4	6	10
Appalachian region	183	181	364	114	117	231
Total	187	189	376	118	123	241

(a) The number of gross wells is the total number of wells in which an interest is owned.

(b) The number of net wells is the sum of fractional interests we own in gross wells expressed as whole numbers and fractions thereof.

Production, Pricing, and Lease Operating Cost Data

The following table describes, for each of the last three fiscal years, oil and gas production volumes, average sales prices, and average production cost per boe after deducting royalties and interests of others, with respect to oil and gas production attributable to our interest. Average production cost presented within the table are costs incurred to operate, maintain the wells and equipment and to pay the production costs, which does not include transportation, ad valorem and severance taxes per unit of production, and is exclusive of work-over costs.

	For the Year Ended April 30,		
	2012	2011	2010
Production - boe[1]	405,799	327,712	88,030
Average oil price - per bbl	$93.10	$75.75	$70.90
Average natural gas price - per mcf	$3.47	$4.77	$4.99
Average lease operating expenses - per boe	$27.86	$24.93	$26.58

1 Total production for fiscal 2012, 2011 and 2010 includes 33,956, 34,987 and 11,695 boe of fuel gas, respectively, which is considered in the calculation of average production cost but excluded from the calculation of average sales prices.

Gross and Net Undeveloped and Developed Acreage

Our staff of professional geologists utilize results from logs, seismic data and other tools to evaluate existing wells and to predict the location of economically attractive new natural gas and oil reserves. To further this process, we have collected and continue to collect logs, core data, production information and other raw data available from state and private agencies and other companies and individuals actively drilling in the regions being evaluated. From this information, the geologists develop models of the subsurface structures and formations that are used to predict areas for prospective economic development.

On the basis of these models, we obtain available natural gas and oil leaseholds, farm-outs and other development rights in these prospective areas. In most cases, to secure a lease, we pay a lease bonus and an annual rental payment, converting to a royalty upon initial production. In addition, overriding royalty payments may be granted to third parties in conjunction with the acquisition of drilling rights initially leased by others.

We believe that we hold good and defensible title to our developed properties, in accordance with standards generally accepted in the industry. As is customary in the industry, a preliminary title examination is conducted at the time the undeveloped properties are acquired. Prior to the commencement of drilling operations, a title examination is conducted and remedial work is performed with respect to discovered defects which we deem to be significant. Title examinations have been performed with respect to substantially all of our producing properties.

Certain of the properties we own are subject to royalty, overriding royalty and other outstanding interests customary to the industry. The properties may also be subject to additional burdens, liens or encumbrances customary to the industry, including items such as operating agreements, current taxes, development obligations under natural gas and oil leases, farm-out agreements and other restrictions. We do not believe that any of these burdens will materially interfere with the use of the properties.

Table of Contents

The following table presents our gross and net acreage position in each region where we have operations as of April 30, 2012:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Cook Inlet	34,997	32,801	639,470	621,621	674,467	654,422
Appalachian region	9,261	6,385	39,999	31,987	49,260	38,372
Total acreage	44,258	39,186	679,469	653,608	723,727	692,794

The following table presents the net undeveloped acres that we control under fee leases and exploration licenses and the period the leases and exploration license are scheduled to expire, absent pre-expiration drilling and production which extends the term of the lease(s) or the fulfillment of the exploration license terms which permits us to convert all or any portion of the exploration license into oil and gas leases. The expiration dates of the leases are subject to one year automatic renewals so long as we are producing oil and/or gas on the lease. During fiscal 2012, the terms of the two Olsen Creek leases were extended to the Susitna Basin #5 Exploration License, a segment of ADL 17597 containing 1,000 net acres was assigned to Unocal, and five Cook Inlet leases near expiration were surrendered.

Table of Contents

Lease/Exploration License	Net Undeveloped Acres Year of Expiration	Total Acres
Cook Inlet		
MHT 9300062 - Olsen Creek	2013	5,483
MHT 9300063 - Olsen Creek	2013	3,906
ADL 391613 - Olsen Creek	2018	107
ADL 391614 - Olsen Creek	2018	35
ADL 391615 - Olsen Creek	2018	570
ADL 391623 - N Alexander	2018	5,513
ADL 390571 - Pretty Creek	2012	1,160
ADL 390749 - Otter	2013	2,522
ADL 390579 - Otter	2012	5,760
ADL 391621 - Otter	2018	2,528
ADL 391624 - Otter	2018	2,514
ADL 390078 - Susitna Basin #2 Exploration License	2013	471,474
ADL 391628 - Susitna Basin #4 Exploration License	2021	62,909
ADL 391794 - Susitna Basin #5 Exploration License	2017	45,764
ADL 390735 - Stingray	2013	2,047
ADL 391608 - Tazlina	2018	5,760
ADL 17602 - Sabre	1967, Held by Unit	896
ADL 18758 - Sabre	1967, Held by Unit	280
ADL 17594	1967, Held by Unit	80
ADL 17597	1967, Held by Unit	1,280
ADL 18730	1967, Held by Unit	480
ADL 18777	1967, Held by Unit	553
Total		621,621
Appalachian region		
Lindsay	Held by production	1,439
Edwards-Fowler, Gann	Held by production	70
Gunsight	Held by production	1,501
Phillips et al from Gunsight acreage	Held by production	1,031
KTO acreage	Held by production	24,586
Baker-Senior lease farm out	Held by production	1,590
Other Undeveloped, net	2012 to 2013	1,770
Total		31,987
Total acreage		653,608

Oil and Natural Gas Reserves

"Proved reserves" are the quantities of oil and gas that, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible. We provide information on two types of proved reserves - developed and undeveloped. "Proved developed reserves" are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods and "proved undeveloped reserves" are reasonably certain reserves in drilling units immediately adjacent to the drilling unit containing a producing well as well as areas beyond one offsetting drilling unit from a producing well.

"Unproved reserves" are based on geological and/or engineering data similar to that used in estimates of proved reserves, but technical, contractual, or regulatory uncertainties preclude such reserves being classified as proved. They are sub-

Table of Contents

classified as probable and possible. Probable reserves are attributed to known accumulations and usually claim a 50% confidence level of recovery. Possible reserves are attributed to known accumulations that have a less likely chance of being recovered than probable reserves. This term is often used for reserves which are claimed to have at least a 10% certainty of being produced. Reasons for classifying reserves as possible include varying interpretations of geology, reserves not producible at commercial rates, uncertainty due to reserve infill (see page from adjacent areas) and projected reserves based on future recovery methods.

The following table shows proved oil and gas reserves as of April 30, 2012, based on average commodity prices in effect on the first day of each month in fiscal 2012, held flat for the life of the production, except where future oil and gas sales are covered by physical contract terms. This table shows reserves on a boe basis in which natural gas is converted to an equivalent barrel of oil based on a 6:1 energy equivalent ratio. This ratio is not reflective of the current price ratio between the two products. All of our proved reserves are located in the United States.

	Net Reserves at April 30, 2012			
Reserves category:	Oil (MBbls)	Natural Gas (MMcf)	MBoe	Reserve %
PROVED				
Developed				
Cook Inlet	2,234	2,329	2,622	28%
Appalachian region	91	272	137	1
Undeveloped				
Cook Inlet	6,209	1,956	6,535	71
Appalachian region	—	—	—	—
Total Proved	8,534	4,557	9,294	100%

Our estimates of proved reserves, proved developed reserves and PUD reserves as of April 30, 2012, 2011 and 2010, changes in estimated proved reserves during the last three years, and estimates of future net cash flows from proved reserves are contained in Supplemental Oil and Gas Disclosures (Unaudited) set forth in Part IV, Item 15 of this Form 10-K. Estimated future net cash flows were calculated using a discount rate of 10% per annum, end of period costs, and an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months, held flat for the life of the production, except where prices are defined by contractual arrangements.

In fiscal 2012, we did not develop any PUDs. We anticipate developing three of our offshore PUDs in Alaska's Redoubt Unit during fiscal 2013, including Redoubt 4A, 2A and 5A. Additionally, we expect to develop the Redoubt 9 PUD in fiscal 2014. Depending on the availability of an onshore drilling rig, we also plan on developing two PUDs in Alaska's West MacArthur River Field in fiscal 2013 including WMRU 8 and 9.

Preparation of Oil and Gas Reserve Information

Our reserve estimates for oil and natural gas at April 30, 2012 for our Cook Inlet and Appalachian region assets were prepared by Ralph E. Davis Associates, Inc., an independent engineering firm. Our reserve reports, which are filed as exhibits to this annual report, were prepared using engineering and geological methods widely accepted in the industry. All reserve definitions comply with the applicable definitions of the rules of the SEC. The accuracy of the reserve estimates is dependent upon the quality of available data and upon independent geological and engineering interpretation of that data. For the proved developed producing reserves, the estimates were made when considered to be definitive, using performance methods that utilize extrapolations of various historical data including, but not limited to, oil, gas and water production and pressure history. For the other proved producing, proved behind pipe reserves, proved undeveloped reserves, and probable and possible reserves estimates were made using volumetric methods.

Our reserve estimate for oil and natural gas at April 30, 2011 and 2010 for our Cook Inlet assets was prepared by Ralph E. Davis Associates, Inc. Our reserve estimates for oil and gas at April 30, 2011 and 2010 for our Appalachian region assets were prepared by Lee Keeling and Associates, Inc., an independent engineering firms.

Internal Controls over Reserves Estimate

Our policies regarding internal controls over reserve estimates require reserves to be in compliance with the SEC definitions and guidance and for reserves to be prepared by an independent engineering firm. Our Acting Chief Financial Officer and the Chief Executive Officer of CIE are primarily responsible for the engagement and oversight of our independent engineering firms. We provide the engineering firms with estimate preparation material such as property interests, production, current operation costs, current production prices and other information. This information is reviewed by the Chief Executive

Officer of CIE and our Acting Chief Financial Officer prior to submission to our third party engineering firm. A letter which identifies the professional qualifications of each of the independent engineering firms who prepared the reserve reports are included in those reserve reports which are filed as exhibits to this annual report. There was no conversion of unproved reserves to proved reserves during the fiscal year ended April 30, 2012.

Other Ancillary Services

We also generate ancillary revenue from drilling activities. While the equipment and personnel on hand are for the benefit of drilling on our own properties, from time to time we optimize unused capacity to perform drilling and related services on behalf of third parties. In fiscal 2012 and 2011, 29% and 35%, respectively, of our other revenue related to a plugging project for the U.S. Department of Interior. Drilling wells for Atlas Energy Resources, LLC accounted for approximately 43% of our other revenue for fiscal 2010.

Competitive Conditions

Our oil and gas exploration activities in Alaska and Tennessee are undertaken in a highly competitive and speculative business environment. In seeking any other suitable oil and gas properties for acquisition, we compete with a number of other companies doing business in Alaska, Tennessee and elsewhere, including large oil and gas companies and other independent operators, many with greater financial resources than we have.

At the local level, as we seek to expand our lease holdings, we compete with several companies who are also seeking to acquire leases in the areas of the acreage which we have under lease. In Alaska, we have nine significant competitors consisting of Apache Corporation, Aurora Gas, Buccaneer Alaska, Hilcorp, ConocoPhillips, Furie, XTO, Linc Energy, and Marathon. However, we believe we have a competitive edge because we already have existing oil and gas production, facilities, infrastructure, and pipelines that connect us to the oil and gas markets as well as some of the lowest operating cost in the area. We believe that our existing Alaska oil and gas reserves and current leases with large acreage positions enhance our competitive position within the area and will enable us to compete effectively for additional lease acreage with our competitors. In the Appalachian region, we have six significant competitors consisting of Atlas Energy Resources, LLC, Consol Energy, Inc., Can Argo Energy Corporation, Champ Oil, and Tengasco, Inc. These companies are in competition with us for oil and gas leases in known producing areas in which we currently operate, as well as other potential areas of interest. We believe we can effectively compete for leases, however, as in the Appalachian region we have name recognition of over 40 years, we are the largest operator of oil and gas wells in Tennessee and we have a staff of experienced, proven petroleum geologists and engineers that allows us to exploit the potential the Appalachian region provides.

Government Regulation

While the prices of oil and natural gas are set by the market, other aspects of our business and the industry in general are heavily regulated. The availability of a ready market for oil production and natural gas depends on several factors beyond our control. These factors include regulation of production, federal and state regulations governing environmental quality and pollution control, the amount of oil and natural gas available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. State and federal regulations generally are intended to protect consumers from unfair treatment and oppressive control, to reduce the risk to the public and workers from the drilling, completion, production and transportation of oil and natural gas, to prevent waste of oil and natural gas, to protect rights among owners in a common reservoir and to control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies. Our exploration and production business is subject to various federal, state and local laws and regulations on the taxation of natural gas and oil, the development, production and marketing of natural gas and oil and environmental and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, water discharge, prevention of waste and other matters. Prior to commencing drilling activities for a well, we must procure permits and/or approvals for the various stages of the drilling process from the applicable state and local agencies in the state in which the area to be drilled is located. The permits and approvals include those for the drilling of wells. Additionally, other regulated matters include the following:

- bond requirements in order to drill or operate wells;
- the location of wells;
- the method of drilling and casing wells;
- the surface use and restoration of well properties;
- the plugging and abandoning of wells; and
- the disposal of fluids.

Table of Contents

The Regulatory Commission of Alaska regulates the intrastate pipeline tariffs and encompasses all pipelines CIE ships through including the CIPL, CIGGS, and Beluga lines. The Regulatory Commission of Alaska must also review and approve most major long-term gas sales contracts to public utilities, and through this mechanism plays the dominant role in determining gas pricing, since Alaska has no spot market for gas. Southcentral Alaska gas is typically sold under long or short term contracts as opposed to a spot market. For the purposes of reasonably valuing gas reserves, therefore, future gas production is assumed to be sold at contract terms comparable to similarly situated producers.

CIE has posted $0.8 million in Alaska and federal bonds. The Alaska DNR requires $0.6 million in bonding to operate oil and gas leases on state lands, and the Alaska Oil and Gas Conservation Commission (“AOGCC”) requires a $0.2 million bond to drill wells in the state. These bonds are fully funded and are held by the First National Bank of Alaska in certificates of deposit for benefit of the various beneficiaries.

CIE has a total of $0.9 million in designated accounts to satisfy future abandonment obligations. A $0.3 million letter of credit is established for two Class 1 non-hazardous injection wells for benefit of the United States Environmental Protection Agency (“EPA”). This letter of credit is backed by an account which must maintain a minimum value of $0.3 million. Under the terms of the bankruptcy sale of the Pacific Energy assets, CIE was obligated to establish accounts to cover abandonment obligations to Cook Inlet Region, Inc. (“CIRI”), Salamatof Native Association (“Salamatof”), and the State of Alaska; $0.6 million was required to cover future abandonment expenses related to the three West Foreland gas wells for benefit of CIRI, all of which has been funded. An additional $0.8 million is for future abandonment expenses associated with surface facilities and pipelines for benefit of CIRI and Salamatof, none of which has yet been funded.

In March 2011, CIE entered into a Performance Bond Agreement that set the bond for the Osprey platform at an inflation-adjusted $18 million. The agreement sets a payment schedule totaling $12 million in annual payments between July 2013 and July 2019. An existing interest bearing account containing approximately $7.0 million as of April 30, 2012 is to be credited against the inflation-adjusted $18 million liability. Annual payments will be made after 2019 as necessary to the degree that inflation has caused the liability to increase over the amount contained in the funded accounts.

Under the Oil Pollution Act of 1990, CIE is required to fund a citizens advisory group, the Cook Inlet Regional Citizen’s Advisory Council, under which its commitment is approximately $60,000 per year.

Tennessee law requires that we obtain state permits for the drilling of oil and gas wells and to post a bond with the Tennessee Gas and Oil Board to ensure that each well is reclaimed and properly plugged when it is abandoned. The reclamation bonds cost $1,500 per well. The cost for the plugging bonds range from $2,000 to $3,000 per well depending on depth or $0.02 million for ten wells. Currently, we have several old $10,000 blanket plugging bonds. For most of the reclamation bonds, we have deposited a $1,500 certificate of deposit with the Tennessee Gas and Oil Board.

Sales of natural gas in Tennessee are affected by intrastate and interstate gas transportation regulation. Beginning in 1985, the Federal Energy Regulatory Commission ("FERC"), which sets the rates and charges for transportation and sale of natural gas, adopted regulatory changes that have significantly altered the transportation and marketing of natural gas. The stated purpose of FERC's changes is to promote competition among the various sectors of the natural gas industry. In 1995, FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. These regulations may tend to increase the cost of transporting oil and natural gas by pipeline. Every five years, FERC will examine the relationship between the change in the applicable index and the actual cost changes experienced by the industry. We are not able to predict with certainty what effect, if any, these regulations will have on us.

The state and regulatory burden on the oil and natural gas industry generally increases our cost of doing business and affects our profitability. While we believe we are presently in compliance with all applicable federal, state and local laws, rules and regulations, continued compliance (or failure to comply) and future legislation may have an adverse impact on our present and contemplated business operations. Because such federal and state regulation are amended or reinterpreted frequently, we are unable to predict with certainty the future cost or impact of complying with these laws.

We are subject to various federal, state and local laws and regulations governing the protection of the environment, such as the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended ("CERCLA"), the Resource Conservation and Recovery Act ("RCRA"), the Clean Air Act and the Federal Water Pollution Control Act of 1972 (the "Clean Water Act"), which affect our operations and costs. In particular, our exploration, development and production operations, our activities in connection with storage and transportation of oil and other hydrocarbons and our use of facilities for treating, processing or otherwise handling hydrocarbons and related wastes may be subject to regulation under these and similar state legislation. These laws and regulations:

- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;

Table of Contents

- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- impose substantial liabilities for pollution resulting from our operations.

CERCLA, also known as "Superfund," imposes liability for response costs and damages to natural resources, without regard to fault or the legality of the original act, on some classes of persons that contributed to the release of a "hazardous substance" into the environment. These persons include the "owner" or "operator" of a disposal site and entities that disposed or arranged for the disposal of the hazardous substances found at the site. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. 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. In the course of our ordinary operations, we may generate waste that may fall within CERCLA's definition of a "hazardous substance." We may be jointly and severally liable under CERCLA or comparable state statutes for all or part of the costs required to clean up sites at which these wastes have been disposed.

We currently lease properties that for many years have been used for the exploration and production of oil and natural gas. Although we have used operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed or released on, under or from the properties owned or leased by us or on, under or from other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose actions with respect to the treatment and disposal or release of hydrocarbons or other wastes were not under our control. These properties and wastes disposed on these properties may be subject to CERCLA and analogous state laws. Under these laws, we could be required to do the following:

- remove or remediate previously disposed wastes, including wastes disposed or released by prior owners or operators,
- clean up contaminated property, including contaminated groundwater; or to perform remedial operations to prevent future contamination, and/or
- clean up contaminated property, including contaminated groundwater; or to perform remedial operations to prevent future contamination.

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

The RCRA is the principal federal statute governing the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating requirements and liability for failure to meet such requirements on a person who is either a "generator" or "transporter" of hazardous waste or an "owner" or "operator" of a hazardous waste treatment, storage or disposal facility. At present, RCRA includes a statutory exemption that allows most oil and natural gas exploration and production waste to be classified as nonhazardous waste. A similar exemption is contained in many of the state counterparts to RCRA. As a result, we are not required to comply with a substantial portion of RCRA's requirements because our operations generate minimal quantities of hazardous wastes. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes oil and natural gas exploration and production wastes from regulation as hazardous waste. Repeal or modification of the exemption by administrative, legislative or judicial process, or modification of similar exemptions in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us to incur increased operating expenses.

The Clean Water Act imposes restrictions and controls on the discharge of produced waters and other wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. The Clean Water Act requires us to construct a fresh water containment barrier between the surface of each drilling site and the underlying water table. This involves the insertion of a seven-inch diameter steel casing into each well, with cement on the outside of the casing. The cost of compliance with this environmental regulation is approximately $10,000 per well. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into certain coastal and offshore waters. Further, the EPA has adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans.

The Clean Water Act and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges for oil and other pollutants and impose liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

Our operations are also subject to laws and regulations requiring removal and cleanup of environmental damages under certain circumstances. Laws and regulations protecting the environment have generally become more stringent in recent years, and may in certain circumstances impose "strict liability," rendering a corporation liable for environmental damages without regard to negligence or fault on the part of such corporation. Such laws and regulations may expose us to liability for the conduct of operations or conditions caused by others, or for acts which may have been in compliance with all applicable laws at the time such acts were performed. The modification of existing laws or regulations or the adoption of new laws or regulations relating to environmental matters could have a material adverse effect on our operations.

In addition, our existing and proposed operations could result in liability for fires, blowouts, oil spills, discharge of hazardous materials into surface and subsurface aquifers and other environmental damage, any one of which could result in personal injury, loss of life, property damage or destruction or suspension of operations. We have an Emergency Action and Environmental Response Policy Program in place. This program details the appropriate response to any emergency that management believes to be possible in our area of operations. We believe we are presently in compliance with all applicable federal and state environmental laws, rules and regulations; however, continued compliance (or failure to comply) and future legislation may have an adverse impact on our present and contemplated business operations.

Employees

On April 30, 2012, we had 70 employees.

Offices

Our principal executive offices are located at 9721 Cogdill Road, Suite 302, Knoxville, TN. At April 30, 2012, we maintained regional exploration and/or production offices in Huntsville and Sunbright, Tennessee and Anchorage, Alaska. We lease all of our primary administrative offices in Knoxville, Tennessee and Anchorage, Alaska. The current lease on our principal executive office runs through 2016. For more information regarding our obligations under office leases, please see Management's Discussion and Analysis of Financial Condition and Results of Operations under the caption "Contractual Obligations" set forth in Part II, Item 7 of this Form 10-K.

Our History

We were formed in Delaware in November 1985. In January 1997, we acquired Miller Petroleum, Inc., a privately-held company controlled by Mr. Deloy Miller, our Chairman, in a reverse merger in which Miller Petroleum, Inc. was the accounting survivor. In conjunction with this transaction, we changed our name to Miller Petroleum, Inc. and re-domesticated to the State of Tennessee.

From 1997 to 2008, we focused our operations on our existing acreage in the State of Tennessee. During this time, we participated in a joint venture with Wind City Oil & Gas, LLC (“Wind City”), which resulted in the drilling of ten successful natural gas wells on our Koppers, Lindsay, and Harriman acreage. However, a dispute arose between Wind City and us as to the winding up of the joint venture, and it was ultimately resolved after we were able to sell some of the acreage to Atlas Energy Resources, LLC (“Atlas”), in 2008. The Atlas transaction was subject to unwinding pursuant to a pending litigation between our company and CNX Gas Company, LLC as disclosed in Item 3. Legal Proceedings.

In August 2008, we hired Scott M. Boruff as our Chief Executive Officer, and began to look for opportunities to expand our acreage and operations by acquiring other businesses and forming strategic partnerships with other exploration and production companies. During Mr. Boruff's tenure as CEO, we have acquired the assets of one company, and acquired sole ownership of three companies.

The first acquisition under Mr. Boruff's leadership was the KTO transaction in which we acquired certain oil and gas properties in exchange for 1,000,000 shares of our common stock valued at $0.3 million.

Shortly thereafter, we acquired ETC, in exchange for an aggregate of 1,000,000 shares of our common stock valued at $0.3 million. In March 2009, we formed Miller Energy GP and in April 2009 we formed Miller Energy Income 2009-A, LP ("MEI"). MEI was organized to provide the capital required to invest in various types of oil and gas ventures including the acquisition of oil and gas leases, royalty interests, overriding royalty interests, working interests, mineral interests, real estate, producing and non-producing wells, reserves, oil and gas related equipment including transportation lines and potential investments in entities that invest in such assets (except for other investment partnerships sponsored by affiliates of MEI). Through a subsidiary we own 1% of MEI, however due to the shared management of our company and MEI, we consolidate this entity.

Table of Contents

The third acquisition significantly expanded our operations, assets, and reserves, and took us into a new geographic area. On December 10, 2009, we acquired 100% of the membership interests in CIE in exchange for four year stock warrants to purchase 3,500,000 shares of our common stock at exercise prices ranging from $0.01 to $2.00 per share and $0.3 million in cash to satisfy certain expenses as well as reimbursement for reasonable out of pocket expenses. Following the transaction, Mr. Hall was appointed as a member of our Board of Directors and as Chief Executive Officer of CIE.

Immediately prior to our acquisition of CIE, CIE acquired, through a Delaware Chapter 11 bankruptcy proceeding, the former Alaskan operations of Pacific Energy. The purchased operations included the West McArthur River oil field, the West Foreland natural gas field, the Redoubt field and related Osprey offshore platform and Kustatan Production Facility. All of these assets are located along the west side of the Cook Inlet. We also acquired 602,000 acres of oil and gas leases, including 471,474 acres under the Susitna Basin Exploration License as well as completed 3D seismic geology and other production facilities. At closing we paid Pacific Energy $2.3 million and provided $2.2 million for bonds, contract cure payments and other federal and State of Alaska requirements to operate the facilities.

On June 24, 2011, we acquired a 48% minority interest in each of two limited liability companies, Pellissippi Pointe, LLC and Pellissippi Pointe II, LLC for total cash consideration of $0.4 million. We have also agreed to indemnify the sellers of the membership interests with respect to their guaranties of the construction loans held by the Pellissippi Pointe entities, but have not become direct guarantors of the loans ourselves. As of April 30, 2012, the gross outstanding amount under the loans is $5.7 million. The Pellissippi Pointe entities own two office buildings in West Knoxville, Tennessee. In November, 2011, we moved our corporate headquarters into one of these buildings, located at 9721 Cogdill Road, Knoxville, TN. We executed a five-year lease for the space, and with the addition of us, the building is fully occupied by tenants.

In April 2011 we changed our name to Miller Energy Resources, Inc. Additional information regarding the acquisitions of the KTO assets, ETC, and CIE can be found in Note 2 - Acquisitions in the Notes to Consolidated Financial Statements set forth in Part VI, Item 15, of this Form 10-K.

Table of Contents

ITEM 1A. RISK FACTORS.

In addition to the other information set forth elsewhere in the Form 10-K, you should carefully consider the following material risk factors associated with our business and the oil and gas industry in which we operate. If any of the events described below occur, our business, financial condition, results of operations, liquidity or access to the capital markets could be materially adversely affected. There may be additional risks that are not presently material or known, or may be included in the prospectuses for securities we issue in the future.

An investment in Miller is subject to risks inherent in our business. The trading price of our common shares will be affected by the performance of our business relative to, among other things, competition, market conditions and general economic and industry conditions. The value of an investment in Miller may decrease, resulting in a loss.

Risks Related to Our Business

We have a history of operating losses; we incurred a net loss in both fiscal 2011 and fiscal 2012 and our net income in fiscal 2010 was the result of one-time acquisition gains. Our revenues are not currently sufficient to fund our operating expenses and there are no assurances we will develop profitable operations.

We reported an operating loss of approximately $25.1 million in fiscal 2012, $14.6 million in fiscal 2011 and $11.3 million in 2010. Our net loss of approximately $18.7 million in 2012 is primarily attributable to the operating loss, plus $4.6 million in other expense, partially offset by an approximate $11.0 million benefit from income taxes. Our net loss of approximately $3.9 million in 2011 is primarily attributable to the operating loss, partially offset by an approximate $4.4 million in other income and a $6.3 million benefit from income taxes. Our net income of approximately $250.9 million in fiscal 2010 is attributable to $461.1 million in gains on the acquisition of the Alaska and Tennessee businesses. As a result of the continued expansion of our business during fiscal 2012, our operating expenses presently exceed our revenues. We anticipate that our operating expenses will continue to increase as we fully develop our operations following the acquisition of the Alaskan assets. Although we expect an increase in our revenues to come from these development activities, we will continue depleting our cash resources to fund operating expenses until such time as we are able to significantly increase our revenues. We may have to reduce our expansion efforts if we have not seen an increase in revenues in the next few months. While we believe that our revenue will increase and exceed our operating expenses, there are no assurances that we will develop profitable operations.

We will be subject to new debt costs under the terms of our Credit Facility with Apollo Investment Corporation. Monies borrowed are subject to an interest rate of 18% per annum.

As described later in this report, in June 2012 we entered into a Loan Agreement with Apollo Investment Corporation, under which a credit facility of up to $100 million (the “Apollo Credit Facility”) was made available to us. At closing, we drew $40 million under the Apollo Credit Facility. That amount and any other monies borrowed by us will bear interest at mezzanine rates and will be subject to a make whole premium and prepayment penalties if any prepayments are made prior to June 29, 2016. These debt costs may be substantial, and will adversely impact our results until such time as the facility has been repaid. We are also subject to restrictions on our ability to pay for general and administrative expenses. This could mean that we would need to make reductions in general and administrative expenses in future periods, which could impact our ability to operate our business and achieve our aggressive plan for development. The Apollo Credit Facility further establishes priorities among the projects we may choose to fund using either loan proceeds or our ordinary collections. This may constrain management's ability to pursue projects in their optimal order, or require us to obtain consents from our lenders in order to deviate from the established list of priorities.

Restrictive debt covenants could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

The Apollo Credit Facility contains a number of significant covenants that, among other things, restrict our ability to:

- dispose of assets;
- incur or guarantee additional indebtedness and issue certain types of preferred stock;
- pay dividends on our capital stock;
- create liens on our assets;

- enter into sale or leaseback transactions;
- enter into specified investments or acquisitions;
- repurchase, redeem or retire our capital stock or subordinated debt;

Table of Contents

- merge or consolidate, or transfer all or substantially all of our assets and the assets of our subsidiaries;
- engage in specified transactions with subsidiaries and affiliates; or
- pursue other corporate activities.

We may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants under the Apollo Credit Facility. Also, the Apollo Credit Facility will require us to maintain compliance with specified financial ratios and satisfy certain financial condition and oil and gas production-level tests. Our ability to comply with these ratios and financial condition and production-level tests may be affected by events beyond our control and, as a result, we may be unable to meet these ratios and financial condition and production-level tests. These financial ratio restrictions and financial condition and production-level tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary corporate activities. A decline in oil and natural gas prices, a prolonged period of oil and natural gas prices as lower levels, or any event with limits our ability to meet oil and gas production requirements specified in the Apollo Credit Facility could eventually result in our failing to meet one or more of the financial and production-level covenants required by the Apollo Credit Facility, which could require us to raise additional capital at an inopportune time or on terms not favorable to us.

A breach of any of these covenants or our inability to comply with the required financial ratios or financial condition or production-level tests could result in a default under the Apollo Credit Facility. A default under that facility, if not cured or waived, could result in acceleration of all indebtedness outstanding under our credit agreement. The accelerated debt would become immediately due and payable. If that should occur, we may be unable to pay all such debt or to borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms that are acceptable to us.

Our business and stock price could be adversely affected if we are not successful in enhancing our management, systems, accounting, controls and reporting performance.

We have experienced, and may continue to experience, difficulties in implementing the management, operations and accounting systems, controls and procedures necessary to support our growth and expanded operations, as well as difficulties in complying with the accounting and reporting requirements related to our growth, acquisitions and status as an accelerated filer. With respect to enhancing our management and operations team, we may experience difficulties in finding and retaining additional qualified personnel, and if such personnel are not available locally, we may incur higher recruiting, relocation, and compensation expense. In an effort to meet the demands of our planned activities in fiscal 2013 and thereafter, we may be required to supplement our staff with contract and consultant personnel until we are able to hire new employees. We further may not be successful in our efforts to enhance our systems, accounting, controls and reporting performance. All of this may have a material adverse effect on our business, results of operations, cash flows and growth plans, on our regulatory and listing status, and on our stock price.

The staff of the SEC has determined that certain of our Forms 8-K related to acquisitions we made in fiscal year 2010 are materially deficient which will adversely impact our ability to raise additional capital.

In connection with a review of our Annual Report on Form 10-K for the year ended April 30, 2010, the staff of the SEC has concluded that we omitted required audited financial statements of three acquired businesses, including ETC, KTO and CIE, from our Forms 8-K reporting these acquisitions. Until such time as we file audited financial statements, the staff has advised us it considers those Forms 8-K to be materially deficient and that it will not waive these financial statement requirements. As a result, we are unable to utilize a “short-form” registration statement on SEC Form S-3. In addition, until such time as the audited financial statements of the acquired businesses are filed, the staff of the SEC has advised us it will not declare effective any registration statements or post-effective registration statements.

It is currently expected that we will not be able to rectify the deficient filings until the filing of this fiscal 2012 Annual Report on Form 10-K, at which time we will ask the staff of the SEC to waive the financial statement requirements of Form 8-K for these acquisitions. There are no assurances we will be successful in our efforts to obtain a waiver.

We are party to several lawsuits seeking millions of dollars in damages against us. An adverse decision in any of these lawsuits could result in our being forced to pay the prevailing plaintiff substantial amounts of money that would adversely impact our ability to continue with our development plans and/or operate our business.

As described later in this annual report on Form 10-K, we are subject to lawsuits seeking millions of dollars in damages against us. While we believe these suits to be of an essentially frivolous nature, litigation is inherently unpredictable, and any damages that could ultimately be paid by us in relation to any of these lawsuits are subject to significant uncertainty. The timing and progression of each case is also unpredictable; it may take years for the case to make its way to trial and through various appeals. The total amounts that will ultimately be paid by us in relation to all obligations relating to these lawsuits are subject to significant uncertainty and the ultimate exposure and cost to us will be dependent on many factors, including the time spent litigating each case and the attorneys' fees incurred by us in defending the cases. Our financial statements contained herein do not contain any reserves for any potential damages associated with this pending litigation. If we should not be successful in our defense of this pending litigation, our results of operations in future periods could be materially adversely impacted.

CIE's operations are subject to oversight by the Alaska DNR. CIE's oil and gas leases could be terminated if it fails to uphold the terms of the Assignment Oversight Agreement. If the leases were terminated, we would be unable to continue our operations as they are presently conducted. The Assignment Oversight Agreement, along with the Performance Bond Agreement for the Redoubt Unit and Redoubt Shoal Field, also impose significant bonding requirements on us, which could adversely impact our ability to increase our revenues in future periods.

As a condition of the assignment of certain leases, CIE entered into the Assignment Oversight Agreement with the Alaska DNR effective November 5, 2009. The terms of the agreement require CIE to meet certain funding thresholds and report to the Alaska DNR regularly, until the Alaska DNR determines that CIE has completed its development and operation obligations under the leases. Should CIE fail to submit the information required under the agreement, or spend funds for items or activities that do not support core oil and gas activity as set out in the Plan of Operations or Plan of Development for the leases, the Alaska DNR could choose to terminate the leases.

Additionally, on March 11, 2011, CIE entered into a Performance Bond Agreement with the DNR concerning certain bonding requirements initially established by the Assignment Oversight Agreement. The performance bond, which is set at $18 million, is intended to ensure that CIE has sufficient funds to meet its dismantlement, removal and restoration obligations pertaining to the Redoubt Unit and Redoubt Shoal Field. The Agreement includes a funding schedule, which requires payments annually on July 1, beginning in 2013, of amounts ranging from $1 million to $2.5 million per year, and totaling $12 million, as approximately $6.8 million was funded by the previous owner. If CIE is more than 10 days late with a payment to the State Trust Account or more than 10 days late providing proof of a payment into a private account, the State will assess a late payment fee of $50,000. Our obligation to fund the bond beginning in July 2013 will adversely impact our cash resources available to devote to the expansion of our operations. If we must pay one or more late payment fees, it will further reduce the cash resources we have available to devote to the expansion of our operations and could adversely impact our ability to increase our revenues in future periods.

We may be subject to regulatory actions surrounding the filing of the 2011 Form 10-K

On July 30, 2011, the Audit Committee of our Board of Directors determined that our consolidated balance sheet at April 30, 2011, and our consolidated statements of operations, stockholders' equity and cash flows for the year then ended (collectively, the “2011 Financial Statements”), as well as the report of KPMG LLP dated July 29, 2011 on such statements, all as included in our 2011 Form 10-K, should not be relied upon. The 2011 Form 10-K was filed with the SEC on July 29, 2011 prior to KPMG LLP completing its audit of the 2011 consolidated financial statements and issuing their independent accountants' report thereon, or issuing its consent to the use of their report. We have received a request from the SEC for a more detailed explanation regarding the specific circumstances that lead to the filing of the 2011 Form 10-K that included the audit report and consent from KPMG LLP prior to the completion of their audit. In September 2011, we provided the requested explanation to the SEC and are fully cooperating with the staff. We have not received and cannot predict the nature of any regulatory responses or actions that may be required of us surrounding the filing of the 2011 Form 10-K. Such responses could divert management's time and attention from the operation of our business and could result in increased legal fees and fines.

We will be subject to risks in connection with acquisitions, and the integration of significant acquisitions may be difficult.

Our business plan contemplates significant acquisitions of reserves, properties, prospects, and leaseholds and other strategic transactions that appear to fit within our overall business strategy, which may include the acquisition of asset packages of producing properties or existing companies or businesses operating in our industry. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their appropriate differentials;
- development and operating costs; and

- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspection s may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We are not entitled to

Table of Contents

contractual indemnification for environmental liabilities and acquired properties on an "as is" basis.

Significant acquisitions of existing companies or businesses and other strategic transactions may involve additional risks, including:

- diversion of our management's attention to evaluating, negotiating, and integrating significant acquisitions and strategic transactions;
- the challenge and cost of integrating acquired operations, information management, and other technology systems, and business cultures with our own while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate organizations; and
- the challenge of attracting and retaining personnel associated with acquired operations.

The process of integrating operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to manage the integration process effectively, or if any significant business activities are interrupted as a result of the integration process, our business could be materially and adversely affected.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on the acreage.

A sizeable portion of our acreage is currently undeveloped. Unless production is established on these leases during their terms, the leases will expire. If our leases expire, we will lose our right to develop the related properties. Our drilling plans for these areas are subject to change based upon various factors, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling, and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals.

Our Susitna Basin Exploration Licenses require us to fulfill certain work commitments and convert acreage to leases in order to retain the acreage after the term of the license.

Over 580,000 acres of our total acreage consists of the three Susitna Basin Exploration Licenses in Cook Inlet, Alaska. These three licenses require us to spend $3.3 million in work commitments before we may convert the licenses into leases. We may not be able to complete our work commitments in a timely manner, or if we do complete them, we may not identify any acreage that we would convert to leases. This could result in a substantial decrease in our total acreage in the Cook Inlet Basin.

Approximately 71% of our total estimated proved reserves at April 30, 2012 were proved undeveloped reserves. In addition, there are no assurances that probable and possible reserves will be converted to proved reserves.

Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve engineer reports assumes that substantial capital expenditures are required to develop such reserves. Although cost and reserve estimates attributable to our natural gas and crude oil reserves have been prepared in accordance with industry standards, we cannot be sure that the estimated costs are accurate, that development will occur as scheduled or that the results of such development will be as estimated. We also have a significant amount of unproved reserves at April 30, 2012. There is significant uncertainty attached to unproved reserve estimates, which include probable and possible reserves. Proved reserves are more likely to be produced than probable reserves and probable reserves are more likely to be produced than possible reserves. There are no assurances that we can develop probable or possible reserves into proved reserves, or that if developed, probable reserves will become producing reserves to the level of the estimates.

Our commodity price risk management and trading activities may prevent us from benefitting fully from price increases and may expose us to other risks.

To the extent that we engage in price risk management activities to protect ourselves from commodity price declines, we may be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production falls short of the hedged volumes;
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- there is a widening of price-basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;
- the counterparties to our hedging or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Table of Contents

Our business depends on oil and natural gas transportation facilities, most of which are owned by others.

The marketability of our oil and natural gas production depends in large part on the availability, proximity and capacity of pipeline systems owned by third parties. The lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of drilling plans for properties. The lack of availability of these facilities for an extended period of time could negatively affect our revenues. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas.

The majority of our oil production is dedicated to one customer and as a result, our credit exposure to this customer is significant.

We have entered into an oil marketing agreement with Tesoro Refining and Marketing Company under which Tesoro purchases all of our net oil production in Alaska. We generally do not require letters of credit or collateral to support these trade receivables. Accordingly, a material adverse change in their financial condition could adversely impact our ability to collect the applicable receivables, and thereby affect our financial condition.

Future economic conditions in the U.S. and key international markets may materially adversely impact our operating results.

The U.S. and other world economies are slowly recovering from a global financial crisis and recession that began in 2008. Growth has resumed but is modest and at an unsteady rate. There are likely to be significant long-term effects resulting from the recession and credit market crisis, including a future global economic growth rate that is slower than in the years leading up to the crisis, and more volatility may occur before a sustainable, yet lower, growth rate is achieved. Global economic growth drives demand for energy from all sources, including fossil fuels. A lower future economic growth rate could result in decreased demand growth for our crude oil and natural gas production as well as lower commodity prices, which would reduce our cash flows from operation and our profitability.

The majority of our reserves and assets, including our Cook Inlet Basin leases and our Osprey Platform, are located in a region of active volcanoes and we could be subject to the adverse impacts of natural disasters or other regional events.

The Cook Inlet region contains active volcanoes, including Augustine Volcano, Mount Spurr and Mount Redoubt, and volcanic eruptions in this region have been associated with earthquakes and tsunamis and debris avalanches have also resulted in tsunamis. In 2009 the Cook Inlet Pipeline Co. suspended operations on several occasions as a result of the spring 2009 major eruption of Mount Redoubt which also resulted in a shutdown of the Drift River Oil Terminal. Our operations in this area are subject to all of the inherent risks associated with operations in a geographical region which is subject to natural disasters and we are susceptible to the risk of damage to our operations and assets located in the Cook Inlet Basin. While our facilities are engineered to withstand seismic activity, and the current tight line configuration should allow us to continue shipments through an active volcanic period without much interruption, we do not maintain business interruption insurance which could adversely impact our results of operations as the result of lost revenues in future periods.

The majority of our oil and gas reserves are located in the Cook Inlet Basin. Any regional events, including price fluctuations, the natural disasters mentioned above, restrictive laws or regulations that increase costs, reduce availability of equipment or supplies, reduce demand or limit our production may impact our operations more than if our reserves were more geographically diversified.

Risks Related to the Oil and Natural Gas Industry

Estimates of oil and natural gas reserves are inherently imprecise. Any material inaccuracies in these reserve estimates or underlying assumptions will affect materially the quantities and present value of our reserves.

Estimates of proved oil and natural gas reserves and the future net cash flows attributable to those reserves are prepared by independent petroleum engineers and geologists. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and cash flows attributable to such reserves, including factors beyond our control and that of our engineers. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. Different reserve engineers may make different estimates of reserves and cash flows based on the same available data. The accuracy of an estimate of quantities of reserves, or of cash flows attributable to such reserves, is a function of the available data, assumptions regarding future oil and natural gas prices and expenditures for future development drilling and exploration activities, and of engineering and geological interpretation and judgment. Additionally, reserves and future cash flows may be subject to material downward or upward revisions, based upon production history, development drilling and exploration activities and prices of oil and natural gas. Actual future production, revenue, taxes, development drilling expenditures, operating expenses, underlying information, quantities of recoverable reserves and the value of cash flows from such reserves may vary significantly from the assumptions and underlying information set forth herein.

We may not realize an adequate return on wells that we drill.

Drilling for oil and gas involves numerous risks, including the risk that we will not encounter commercially productive oil or gas reservoirs. The wells we drill or participate in may not be productive, and we may not recover all or any portion of our investment in those wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that crude oil or natural gas is present or may be produced economically. The costs of drilling, completing, and operating wells are often uncertain, and drilling operations may be curtailed, delayed, or canceled as a result of a variety of factors including, without limitation:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- fires, explosions, blowouts, and surface cratering;
- marine risks such as capsizing, collisions, or adverse weather conditions; and
- increase in the cost of, or shortages or delays in the availability of, drilling rigs and equipment.

Future drilling activities may not be successful, and, if unsuccessful, this failure could have an adverse effect on our future results of operations and financial condition. While all drilling, whether developmental or exploratory, involves these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons.

Oil and gas prices fluctuate due to a number of uncontrollable factors, creating a component of uncertainty in our development plans and overall operations. Declines in prices adversely affect our financial results and rate of growth in proved reserves and production.

Oil and gas markets are very volatile, and we cannot predict future oil and natural gas prices. The prices we receive for our oil and natural gas production heavily influence our revenue, profitability, access to capital and future rate of growth. The prices we receive for our production depend on numerous factors beyond our control. These factors include, but are not limited to, changes in global supply and demand for oil and gas, the actions of the Organization of Petroleum Exporting Countries, the level of global oil and gas exploration and production activity, weather conditions, technological advances affecting energy consumption, domestic and foreign governmental regulations and tax policies, proximity and capacity of oil and gas pipelines and other transportation facilities.

Additionally, a decline in future oil and natural gas prices and the related reduction in revenues could precipitate a breach in the interest coverage ratio covenant contained in our Loan Agreement with Apollo.

Discoveries or acquisitions of additional reserves are needed to avoid a material decline in reserves and production.

The production rate from oil and gas properties generally declines as reserves are depleted, while related per-unit production costs generally increase as a result of decreasing reservoir pressures and other factors. Therefore, unless we add reserves through exploration and development activities or, through engineering studies, identify additional behind-pipe zones, secondary recovery reserves, or tertiary recovery reserves, or acquire additional properties containing proved reserves, our estimated proved reserves will decline materially as reserves are produced. Future oil and gas production is, therefore, highly dependent upon our level of success in acquiring or finding additional reserves on an economic basis. Furthermore, if oil or gas prices increase, our cost for additional reserves could also increase.

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

You should not assume that the present value of future net revenues from our proved reserves referred to in this annual report is the current market value of our estimated natural gas, crude oil and natural gas liquids reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from our proved reserves are based on prices and costs on the date of the estimate, held constant for the life of the properties. Actual future prices and costs may differ materially from those used in the present value estimate. Actual future net cash flows will also be affected by increases or decreases in consumption by oil and gas purchasers and changes in governmental regulations or taxation. The timing of both the production and the incurrence of expenses in connection with the development and production of oil and gas properties affects the timing of actual future net cash flows from proved reserves. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily an appropriate discount factor for determining a market valuation. The effective interest rate at various times and the risks associated with our business or the oil and gas industry in general will affect the relevance of the 10% discount factor.

Table of Contents

Our business involves many operating risks that may result in substantial losses for which insurance may be unavailable or inadequate.

Our operations are subject to hazards and risks inherent in drilling for oil and gas, such as fires, natural disasters, explosions, formations with abnormal pressures, casing collapses, uncontrollable flows of underground gas, blowouts, surface cratering, pipeline ruptures or cement failures, and environmental hazards such as natural gas leaks, oil spills and discharges of toxic gases. Any of these risks can cause substantial losses resulting from injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution and other environmental damages, regulatory investigations and penalties, suspension of our operations and repair and remediation costs. In addition, our liability for environmental hazards may include conditions created by the previous owners of properties that we purchase or lease. We maintain insurance coverage against some, but not all, potential losses. We do not believe that insurance coverage for all environmental damages that could occur is available at a reasonable cost. Losses could occur for uninsurable or uninsured risks, or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could harm our financial condition and results of operation.

Our industry is subject to extensive environmental regulation that may limit our operations and negatively impact our production. As a result of increased enforcement of existing regulations and potential new regulations following the Gulf of Mexico oil spill, the costs for complying with government regulation could increase.

Extensive federal, state, and local environmental laws and regulations in the United States affect all of our operations. Environmental laws to which we are subject in the U.S. include, but are not limited to, the Clean Air Act and comparable state laws that impose obligations related to air emissions, the Resource Conservation and Recovery Act of 1976 ("RCRA"), and comparable state laws that impose requirements for the handling, storage, treatment or disposal of solid and hazardous waste from our facilities, the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or at locations to which our hazardous substances have been transported for disposal, and the Clean Water Act, and comparable state laws that regulate discharges of wastewater from our facilities to state and federal waters. Failure to comply with these laws and regulations or newly adopted laws or regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations or imposing additional compliance requirements on such operations. Certain environmental laws, including CERCLA and analogous state laws, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances or hydrocarbons have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Environmental legislation may require that we do the following:

- acquire permits before commencing drilling;
- restrict spills, releases or emissions of various substances produced in association with our operations;
- limit or prohibit drilling activities on protected areas such as wetlands or wilderness areas;
- take reclamation measures to prevent pollution from former operations;
- take remedial measures to mitigate pollution from former operations, such as plugging abandoned wells and remedying contaminated soil and groundwater; and
- take remedial measures with respect to property designated as a contaminated site.

There is inherent risk of incurring environmental costs and liabilities in connection with our operations due to our handling of natural gas and other petroleum products, air emissions and water discharges related to our operations, and historical industry operations and waste disposal practices. The costs of any of these liabilities are presently unknown but could be significant. We may not be able to recover all or any of these costs from insurance. In addition, we are unable to predict what impact the Gulf oil spill will have on independent oil and gas companies such as our company. For instance, companies such as ours currently pay an $0.08 per barrel tax on all oil produced in the U.S. which is contributed to the Oil Spill Liability Trust Fund. There are pending proposals to raise this tax to $0.18 to $0.25 per barrel. It is also probable that there will be increased enforcement of existing regulations and adoption of new regulations which will also increase our cost of doing business which would reduce our operating profits in future periods.

The effects of future environmental legislation on our business are unknown but could be substantial.

Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. Changes in, or enforcement of, environmental laws may result in a curtailment of our production activities, or a material increase in the costs of production, development drilling or exploration, any of which could have a material adverse effect on our financial condition and results of operations or prospects. In addition, many countries, as well as several states in the United States have agreed to regulate emissions of “greenhouse gases.” Methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning natural gas, are greenhouse gases. Regulation of greenhouse gases could adversely impact some of our operations and demand for products in the future.

Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the Energy Policy Act of 2005, the Federal Energy Regulatory Commission, or FERC, has authority to impose penalties for violations of the Natural Gas Act, up to $1 million per day for each violation and disgorgement of profits associated with any violation. FERC has recently proposed and adopted regulations that may subject our facilities to reporting and posting requirements. Additional rules and legislation pertaining to these and other matters may be considered or adopted by FERC from time to time. Failure to comply with FERC regulations could subject us to civil penalties.

Proposed federal, state, or local regulation regarding hydraulic fracturing could increase our operating and capital costs.

Several proposals are before the U.S. Congress that, if implemented, would either prohibit or restrict the practice of hydraulic fracturing or subject the process to regulation under the Safe Drinking Water Act. Several states are considering legislation to regulate hydraulic fracturing practices that could impose more stringent permitting, transparency, and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. In addition, some municipalities have significantly limited or prohibited drilling activities and/or hydraulic fracturing, or are considering doing so. We routinely use fracturing techniques in the U.S. and other regions to expand the available space for natural gas and oil to migrate toward the wellbore. It is typically done at substantial depths in very tight formations.

Although it is not possible at this time to predict the final outcome of the legislation regarding hydraulic fracturing, any new federal, state, or local restrictions on hydraulic fracturing that may be imposed in areas in which we conduct business could result in increased compliance costs or additional operating restrictions in the U.S.

The proposed U.S. federal budget for fiscal year 2013 includes certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations, and cash flows.

On February 13, 2012, the Office of Management and Budget released a summary of the proposed U.S. federal budget for fiscal year 2013. The proposed budget repeals many tax incentives and deductions that are currently used by U.S. oil and gas companies and imposes new taxes. The provisions include elimination of the ability to fully deduct intangible drilling costs in the year incurred; repeal of the manufacturing tax deduction for oil and natural gas companies; and an increase in the geological and geophysical amortization period for independent producers. Should some or all of these provisions become law, our taxes will increase, potentially significantly, which would have a negative impact on our net income and cash flows. This could also cause us to reduce our drilling activities. As none of these proposals have yet to be voted on or become law, we do not know the ultimate impact these proposed changes may have on our business.

Risks Related to the Ownership of Our Securities

We do not currently pay dividends on our common stock and do not anticipate doing so in the future.

We intend to retain any future earning to fund our operations; therefore, we do not anticipate paying any cash dividends on our common stock in the foreseeable future. Also, our credit agreement does not permit us to pay dividends on our common stock. We are prohibited by Tennessee law from paying dividends, if after the payment of the dividend we are unable to pay our debts as they come due in the ordinary course of business, or if our total assets would be less than the sum of our total liabilities plus the amount that would be needed, if we were to be dissolved at the time of the dividend, to satisfy any preferential liquidation rights to those of our common stock.

Certain of our outstanding warrants contain cashless exercise provisions which means we will not receive any cash proceeds upon their exercise.

At April 30, 2012 we have common stock warrants outstanding to purchase an aggregate of 1,385,400 shares of our common stock with an average exercise price of $5.11 per share which are exercisable on a cashless basis. This means that the holders, rather than paying the exercise price in cash, may surrender a number of warrants equal to the exercise price of the warrants being exercised. It is possible that the warrant holders will utilize the cashless exercise feature which will deprive us of additional capital which might otherwise be obtained if the warrants did not contain a cashless feature.

A large portion of our outstanding common shares are “restricted securities” and we have outstanding options, warrants and purchase rights to purchase approximately 37% of our currently outstanding common stock. The exercise of these options, warrants and purchase rights would be dilutive to our current shareholders, and could adversely effect our stock price.

Table of Contents

We may in the future issue our previously authorized and unissued securities, resulting in the dilution of the ownership interests of our present shareholders. We are currently authorized to issue 500,000,000 shares of common stock and 150,000 shares of preferred stock with such designations, preferences and rights as determined by our Board of Directors. At July 06, 2012 we had 41,945,393 shares of common stock outstanding together with outstanding options and warrants to purchase an aggregate of 15,450,955 shares of common stock at exercise prices of between $0.01 and $6.94 per share. Of our outstanding shares of common stock at July 06, 2012, approximately 8,953,411 shares are "restricted securities." Future sales of restricted common stock under Rule 144 or otherwise could negatively impact the market price of our common stock. In addition, in the event of the exercise of the warrants and options, the number of our outstanding common stock will increase by approximately 15,450,955, which will have a dilutive effect on our existing shareholders.

The impacts of non-cash gains and losses from derivative accounting in future periods could materially impact our financial results.

As of April 30, 2012, we have warrants with “full-ratchet” or reset provisions, which means that the exercise or conversion price adjusts to pricing as described within the respective agreements. These instruments require liability classification and mark-to-market accounting with changes in the estimated fair value recorded to our consolidated statement of operations. In addition, to manage variability in cash flows resulting from fluctuation in oil prices, we occasionally enter into commodity derivatives to hedge a portion of our crude oil production. These instruments are marked-to-market on a periodic basis with changes in the estimated fair value recorded to our consolidated statement of operations. As of April 30, 2012, we have a derivative liability of $10.5 million. We recognized a non-cash loss on derivatives of $3.4 million in fiscal 2012, $1.0 million in fiscal 2011 and $13.3 million in fiscal 2010. Beginning in the first quarter of fiscal 2013, we expect to record either a gain or loss based upon the market price of oil and our common stock. The amount of quarterly non-cash gains or losses we will record in future periods is unknown at this time as the measurement is based upon the fair market value of oil and our common stock on the measurement date. It is likely, however, that these non-cash gains or losses will continue to have a material impact on our financial results in future periods.

Substantial stock ownership by our affiliates may limit the ability of our non-affiliate stockholders to influence the outcome of director elections and other matters requiring shareholder approval.

As of April 30, 2012, management and members of the Board of Directors own approximately 23% of our outstanding common stock. Accordingly, they have significant influence in the election of our directors and, therefore, our policies and direction. This concentration of voting power could have the effect of delaying or preventing a change in control or discouraging a potential acquirer from attempting to obtain control of us, which in turn could have a material adverse effect on the market price of our common stock or prevent our shareholders from realizing a premium over the market price for their shares of common stock.

Table of Contents

ITEM 1B. UNRESOLVED STAFF COMMENTS.

The staff of the Securities and Exchange Commission (the “Staff”) conducted a review of our Annual Reports on Form 10-K for the years ended April 30, 2011 and April 30, 2010, and issued a letter commenting on certain aspects of these reports. We believe that all matters addressed in the comment letters, and in our subsequent responses to these letters to and discussions with the Staff, have been resolved with the exception of certain comments which remain under review. The Staff has indicated that it is still reviewing our responses but could have additional comments regarding (1) production costs used in our third party reserve reports, (2) support for our inclusion of RU 17 as a proved undeveloped reserve, (3) revisions to a third party engineering report (included as an exhibit to a prior filing) reducing probable and possible reserve estimates and (4) the correction of certain immaterial errors in our previous financial statements. We believe that we have adequately responded to these comments by the Staff, but the Staff may choose to issue additional comments related to these matters in the future.

ITEM 3. LEGAL PROCEEDINGS.

The information set forth in Note 10 - Litigation in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K is incorporated herein by reference.

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable to our operations.

Table of Contents

PART II

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

During fiscal 2012, our common stock, par value $0.0001 per share, was listed on the New York Stock Exchange under the symbol "MILL." From May 6, 2010 to April 11, 2011 our common stock was listed on the NASDAQ Global Market. Previously, our common stock was quoted on the OTC Bulletin Board and in the over the counter market on the Pink Sheets. The table below provides certain information regarding our common stock for fiscal 2012 and 2011. Prices were obtained from The New York Stock Exchange, Inc. Composite Transactions Reporting System. The quotations reflect inter-dealer prices, without retail mark-up, markdown or commission, and may not represent actual transactions. Per-share prices shown below have been rounded to the indicated decimal place.

	2011		2012	
	High	Low	High	Low
First quarter	$7.48	$4.40	$8.02	$4.41
Second quarter	6.31	4.05	3.95	2.16
Third quarter	5.69	4.20	4.04	2.63
Fourth quarter	6.11	4.80	5.47	3.90

The closing price of our common stock, as reported on the New York Stock Exchange for July 06, 2012, was $5.10 per share. As of July 06, 2012, there were 41,945,393 shares of our common stock outstanding held by approximately 348 stockholders of record and approximately 5,243 beneficial owners.

We have never paid cash dividends on our common stock and we do not anticipate that we will declare or pay dividends in the foreseeable future. Payment of dividends, if any, is within the sole discretion of our Board of Directors and will depend, among other factors, upon our earnings, capital requirements and our operating and financial condition. In addition under Tennessee law, we may not pay a dividend if, after giving effect, we would be unable to pay our debts as they become due in the usual course of business or if our total assets would be less than the sum of our total liabilities plus the amount that would be needed if we were to be dissolved at the time of the payment of the dividend to satisfy the preferential rights upon dissolution of shareholders whose preferential rights were superior to those receiving the dividend. In addition, our credit facility with Apollo does not permit us to pay dividends on our common stock.

Information concerning securities authorized for issuance under equity compensation plans is set forth in the proxy statement relating to our fiscal 2012 annual meeting of stockholders, which is incorporated herein by reference.

Stockholder Return Performance Presentation

The following stock price performance graph is intended to allow review of stockholder returns, expressed in terms of the appreciation of our common stock relative to two broad-based stock performance indices. The information is included for historical comparative purposes only and should not be considered indicative of future stock performance. The graph compares the yearly percentage change in the cumulative total stockholder return on the Company's common stock with the cumulative total return of the Standard & Poor's Composite 500 Stock Index and of the Dow Jones U.S. Exploration & Production Index (formerly Dow Jones Secondary Oil Stock Index) from April 30, 2008, through April 30, 2012. The stock performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

Table of Contents

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*
Among Miller Energy Resources, Inc., S&P 500 Index
and the Dow Jones US Exploration & Production Index

	2008	2009	2010	2011	2012
Miller Energy Resources, Inc.	$100	$330	$5,780	$5,770	$5,430
S&P's Composite 500 Stock Index	100	63	86	99	101
Dow Jones US Exploration & Production Index	100	52	75	100	87

Table of Contents

ITEM 6. SELECTED FINANCIAL DATA.

The following table sets forth selected financial data of our company over the five-year period ended April 30, 2012, which information has been derived from our audited financial statements. This information should be read in connection with, and is qualified in its entirety by, the more detailed information in the Company's financial statements set forth in Part IV, Item 15 of this Form 10-K. As discussed in more detail under Item 15, the fiscal 2010 data in the following table reflect a $461 million non-cash gain resulting from our acquisition of CIE. For a discussion of significant acquisitions, please see Note 2 - Acquisitions in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

	As of or for the Year Ended April 30,				
	2012	2011	2010	2009	2008
	(In thousands, except share and per share amounts)				
Income Statement Data:					
Total revenues	$35,402	$22,842	$5,867	$1,567	$829
Net income (loss) attributable to common stockholders	(19,537)	(3,880)	250,941	8,356	(2,436)
Net income (loss) per common share:					
Basic	(0.48)	(0.11)	11.65	0.56	(0.17)
Diluted	(0.48)	(0.11)	8.34	0.56	(0.17)
Balance Sheet Data:					
Total assets	$536,389	$509,081	$500,342	$9,942	$2,934
Total debt	24,130	2,000	1,239	1,959	646
Weighted average common shares outstanding:					
Basic	40,811,308	36,112,286	21,537,677	14,827,877	14,454,288
Diluted	40,811,308	36,112,286	30,092,017	14,827,877	14,454,288

Table of Contents

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

We are an independent exploration and production company that utilizes seismic data and other technologies for geophysical exploration and development of oil and gas wells in the Appalachian region of East Tennessee and in southcentral Alaska. Occasionally, during times of excess capacity, we offer these services, on a contract basis, to third-party customers primarily engaged in our core competency - natural gas exploration and production.

Executive Overview

Strategy

Our mission is to grow a profitable exploration and production company for the long-term benefit of our shareholders by focusing on the development of our reserves, continued expansion of our oil and natural gas properties and increase in our production and related cash flow. We intend to accomplish these objectives through the execution of our core strategies, which include:

- Develop Acquired Acreage. We will focus on organically growing production through drilling for our own benefit on existing leases and acreage in the exploration licenses with a view towards retaining the majority of working interest in the new wells. This strategy will allow us to maintain operational control, which we believe will translate to long-term benefits;
- Increase Production. We plan on increasing oil and gas production through the maintenance, repair and optimization of wells located in the Cook Inlet Basin and development of wells in the Appalachian region of East Tennessee. Our management team will employ the latest available technologies to restore as well as explore and develop our properties;
- Expand Our Revenue Stream. We intend on fully exploiting our mid-stream facilities, such as our injection wells and the Kustatan Production Facility, our ability to engage in the commercial disposal of waste generated by oil and gas operations, and our capacity to process third party fluids and natural gas and to offer excess electrical power to net users in the Cook Inlet area; and
- Pursue Strategic Acquisitions. We have significantly increased our oil and gas properties through strategic low-cost / high-value acquisitions. Under the same strategy, our management team will continually seek for opportunities that meet our criteria for risk, reward, rate of return, and growth potential. We plan to leverage our management team's expertise to pursue value-creating acquisitions when the opportunities arise, subject to the availability of sufficient capital.

Our management team is focused on obtaining the financial flexibility required to successfully execute these core strategies. During fiscal 2012, through the use of funds provided under our credit facility, we completed the modification and improvements to Rig 34 and are on our way to completing the construction of Rig 35. These accomplishments, although marked with challenges, have bolstered our ability to carry out our onshore and offshore drilling plans. Our ability to deliver successful results and continue enhancing shareholder value have been strengthened as a result of these recent accomplishments.

However, our future oil and natural gas reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing current reserves and economically finding, developing and acquiring additional recoverable reserves. We may not be able to find, develop or acquire additional reserves to replace our current and future production at acceptable costs, which could materially adversely affect our business, financial condition and results of operations. We will focus on adding reserves through drilling and well recompletions, as well as the corresponding costs necessary to produce such reserves and will seek to grow our production and our asset base by pursuing both organic growth opportunities and acquisitions of producing oil and natural gas reserves that are suitable for us.

Financial and Operating Results

We continued to utilize funds under our prior credit facility along with other financing sources and operational cash flow to support our capital expenditures for fiscal 2012. For the 12-month period ended April 30, 2012, we reported notable achievements in several key areas. Highlights for the year include:

- We completed significant modifications and improvements to Rig 34, allowing the rig to drill in winter conditions while complying with Alaska regulations. The AOGCC inspected and issued final approvals to operate the rig in March 2012. The rig was mobilized to our Kustatan Gas Field to workover the KF-1 well and, at completion of the KF-1 well, mobilized to the Otter Prospect to begin drilling Otter 1.
- We successfully mobilized all components of Rig 35 to the Osprey platform. In January 2012 the region

Table of Contents

experienced prolonged near-record cold weather, which caused us to temporarily delay rig assembly efforts on the Osprey platform due to concerns of safety. The cold weather also led to significant generation of ice volume in the Cook Inlet and made shipping and the operation of work-boats impossible. As warmer temperatures moderated the region, we resumed work on the assembly of Rig 35, which in its present state is substantially completed and expected to be fully operational in July 2012.

- On April 6, 2012, we issued a new class of Series A Cumulative Preferred Stock to 20 accredited and institutional investors in a private offering exempt from registration under the Securities Act of 1933, as amended. We received gross proceeds of $10 million. These funds were used primarily to workover the KF-1 well and drill the Otter 1 well.
- On April 1, 2012, we were awarded Susitna Basin Exploration License No. 5, which consists of 45,764 acres. It granted us an exclusive five-year license to explore for oil and gas on the specified lands. Upon fulfillment of a $0.3 million work commitment, we will gain the option to convert any part of the licensed area into oil and gas leases.

2013 Outlook

As we head into 2013, with the expected completion of Rig 35, we believe our inventory of recompletion as well as exploration and development projects offers numerous growth opportunities. Our current 2013 capital budget is $50 to 100 million. Nearly all of our budget is expected to be spent on projects in Alaska, with the remaining amount allocated to our Appalachian region. Due to the uncertainty associated with changes in commodity prices, we closely monitor our cost levels and revise our capital budgets based on changes in forecasted cash flows. This means our plan for capital expenditures may change as a result of anticipated changes in the market place. Further, our ability to fully utilize the budget will be dependent on a number of factors including, but not limited to, access to capital, Rig 35 being operational in a timely manner, weather and regulatory approval.

We expect to fund our 2013 capital budget with funds borrowed under the Apollo Credit Facility, proceeds received from anticipated preferred stock offerings, cash flows from operations and proceeds from potential asset dispositions. We may also access the capital markets as necessary to fund specific drilling programs and continue developing our assets. In the event we are unable to raise additional capital on acceptable terms, we may reduce our capital spending.

Results of Operations

Revenues

	For the Year Ended April 30,				
	2012		2011		2010
	$ Value	Increase (Decrease)	$ Value	Increase (Decrease)	$ Value
	(In thousands, except percentages)				
Oil revenues:					
Cook Inlet	$30,566	57%	$19,459	437%	$3,622
Appalachian region	1,314	46	901	12	808
Total	$31,880	57%	$20,360	360%	$4,430
Natural gas revenues:					
Cook Inlet	$134	(53)%	$286	100%	$—
Appalachian region	479	9	440	18	372
Total	$613	(16)%	$726	95%	$372
Other revenues:					
Cook Inlet	$1,212	61%	$753	107%	$363
Appalachian region	1,697	69	1,003	43	702
Total	2,909	66	1,756	65	1,065
Total revenues	$35,402	55%	$22,842	289%	$5,867

Table of Contents

Production

	For the Year Ended April 30,				
	2012	Increase (Decrease)	2011	Increase (Decrease)	2010
Oil volume - bbls:					
Cook Inlet	325,756	28%	254,504	410%	49,901
Appalachian region	16,655	17	14,292	14	12,580
Total	342,411	27	268,796	330	62,481
Natural gas volume[1]- mcf:					
Cook Inlet	45,985	8	42,480	100	—
Appalachian region	130,609	19	109,683	47	74,532
Total	176,594	16	152,163	104	74,532
Total production[2] - boe					
Cook Inlet	333,420	27	261,584	424	49,901
Appalachian region	38,423	18	32,573	30	25,002
Total	371,843	26	294,157	293	74,903

1 Cook Inlet natural gas volume excludes natural produced and used as fuel gas.

2 These figures show production on a boe basis in which natural gas is converted to an equivalent barrel of oil based on a 6:1 energy equivalent ratio. This ratio is not reflective of the current price ratio between the two products.

Pricing

	For the Year Ended April 30,				
	2012	Increase (Decrease)	2011	Increase (Decrease)	2010
Average oil sales price - per barrel:					
Cook Inlet	$93.83	23%	$76.46	5%	$72.58
Appalachian region	78.89	25	63.04	(2)	64.25
Total	93.10	23	75.75	7	70.90
Average natural gas sales price - per mcf:					
Cook Inlet	2.92	(57)	6.73	100	—
Appalachian region	3.66	(9)	4.01	(20)	4.99
Total	3.47	(27)	4.77	(4)	4.99

Crude Oil Prices

All of our crude oil production is sold at prevailing market prices, which are subject to fluctuations driven by market factors outside of our control. As volatility increases in response to the rise in global demand for oil combined with economic uncertainty, prices will continue to experience volatility at unpredictable levels. Prices received for crude oil in 2012 were 23% above 2011. Crude oil prices realized in 2012 averaged $93.10 per barrel, compared with $75.75 per barrel in 2011.

Natural Gas Prices

Natural gas is subject to price variances based on local supply and demand conditions. The majority of our natural gas sales contracts are indexed to prevailing local market prices. Average realized prices decreased 27% in 2012 compared to 2011.

Crude Oil Revenues

2012 vs. 2011. During 2012, crude oil revenues totaled $31.9 million, 57% higher than 2011, driven by a 23% increase in average realized prices and a 27% increase in production. Crude oil represented 98% of our 2012 oil and gas revenues and 92% of our equivalent production, compared to 97% and 91%, respectively, in the prior year. Higher realized prices contributed $5.3 million to the increase in full-year oil revenues, while higher production volumes added another $6.2 million.

Table of Contents

Production increased 73,615 bbls, driven by a 71,252 bbls increase in the Cook Inlet region, with the Appalachian region contributing 2,363 bbls to total production for the year. The significant production increase in the Cook Inlet region resulted from bringing wells at our Redoubt Unit online.

2011 vs. 2010. During 2011, crude oil revenues increased $15.9 million to $20.4 million, driven by a 330% increase in production and a 7% increase in average realized prices. Production increased 206,315 bbls with approximately 99% of the increase contributed by increased production in the Cook Inlet region. Higher realized prices contributed $0.2 million to the increase in full-year oil revenues, while higher production volumes added another $15.7 million. The significant production increase in the Cook Inlet region resulted from a full year of production in fiscal 2011 subsequent to the mid-year fiscal 2010 acquisition of CIE.

Natural Gas Revenues

2012 vs. 2011. Natural gas revenues totaled $0.6 million, $0.1 million lower than the 2011 total of $0.7 million, driven by a 27% decrease in average realized prices, offset by a 16% increase in production. Natural gas represented 2% of our 2012 oil and gas revenues and 8% of our equivalent production, compared to 3% and 9%, respectively, in the prior year.

2011 vs. 2010. Natural gas revenues totaled $0.7 million, reflecting a $0.3 million increase from the 2010 total of $0.4 million. Production increased 77,631 Mcf to 152,163 Mcf with approximately 45% of the increase contributed by increased production in the Appalachian region and 55% in the Cook Inlet region. Higher production volume contributed $0.4 million to the increase in full-year natural gas revenues, offset by $0.1 million due to lower realized prices.

Other Revenues

2012 vs. 2011. Other revenues primarily represent revenues generated from contracts for plugging, drilling, maintenance and repair of third party wells as well as rental income we received for use of facilities in the Cook Inlet region. During 2012, other revenues totaled $2.9 million, driven by a 69% increase in plugging activities in the Appalachian region and a 61% increase in facility rentals and other miscellaneous income in the Cook Inlet region.

2011 vs. 2010. Other revenues increased 65% to $1.8 million during 2011, reflecting a 107% increase in facility rentals in the Cook Inlet region combined with a 43% increase in plugging and drilling activities in the Appalachian region.

Cost and Expenses

The table below presents a comparison of our expenses on an absolute dollar basis and an equivalent unit of production (boe) basis where meaningful.

	For the Year Ended April 30,			For the Year Ended April 30,		
	2012	2011	2010	2012	2011	2010
	(In thousands)			(Per boe)		
				405,799	327,712	88,030
Oil and gas operating	$14,861	$9,703	$2,738	$36.62	$29.61	$31.10
Cost of other revenues	926	808	755	NM	NM	NM
General and administrative	29,718	14,555	10,263	NM	NM	NM
Exploration expenses	1,241	—	—	NM	—	—
Depreciation, depletion and amortization	13,310	10,961	3,110	32.80	33.45	35.33
Accretion of asset retirement obligation	1,072	1,407	315	NM	NM	NM
Other operating expense (income), net	(641)	—	—	NM	NM	NM
Total costs and expenses	$60,487	$37,434	$17,181	$149.06	$114.23	$195.17

NM - Not Meaningful

Oil and Gas Operating Costs

2012 vs. 2011 Oil and gas operating costs increased $5.2 million from 2011, or 53%. On a per-unit cost basis, oil and gas operating costs increased $7.01 per unit due to higher costs associated with returning the Osprey platform and Kustatan production facility to operational status.

2011 vs. 2010 Oil and gas operating costs increased $7 million from 2010, or 254%, as a result of increased activities in the Cook Inlet region. Costs associated with the work to restore nonproductive wells to producing status increased significantly, driven primarily by a 293% increase in total production with direct labor and contract services contributing an additional $3.03 per unit of production.

Cost of Other Revenues

Our business is primarily focused on exploration and production activities. The cost of other revenues represent costs of services to third parties as a result of excess capacity, and are derived from the direct labor costs of employees associated with these services, as well as costs associated with equipment, parts and repairs.

	For the Year Ended April 30,				
	2012	Increase (Decrease)	2011	Increase (Decrease)	2010
	(In thousands, except percentages)				
Direct labor	$677	57%	$430	(18)%	$527
Equipments	—	(100)	41	(61)	104
Repairs	89	31	68	(45)	124
Others	160	(41)	269	100	—
Total	$926	15%	$808	7%	$755

2012 vs. 2011 During 2012, cost of other revenues increased 15% to $0.9 million. A substantial portion of this increase is related to labor costs associated with services provided under the U.S. Department of Interior contract for plugging abandoned wells located in the Big South Fork area in Tennessee and Kentucky.

2011 vs. 2010 During 2011, cost of other revenues increased 7% to $0.8 million. We drilled three wells in 2011 and also entered into the contract with the U.S. Department of Interior for plugging abandoned wells located in the Big South Fork area in Tennessee and Kentucky. During 2010, we drilled 10 wells for Atlas Energy, and in preparation for the Atlas Energy drilling contract we spent significant time and expense maintaining and repairing our drilling equipment in fiscal 2010 which contributed to the costs for that year.

General and Administrative Expenses

General and administrative ("G&A") expenses include the costs of our employees, related benefits, professional fees, travel and other miscellaneous general and administrative expenses.

	For the Year Ended April 30,				
	2012	Increase (Decrease)	2011	Increase (Decrease)	2010
	(In thousands, except percentages)				
Salaries	$3,330	29%	$2,580	96%	$1,317
Professional fees	4,561	36	3,347	11	3,023
Travel	1,693	115	786	192	269
Employee benefits	3,824	115	1,780	21	1,471
Stock-based compensation	14,072	175	5,126	52	3,375
Other	2,238	139	936	16	808
Total	$29,718	104%	$14,555	42%	$10,263

2012 vs. 2011 G&A expenses increased $15.2 million from 2011, or 104%. As we continue to recruit and retain quality employees and build our professional staff, salaries and related employee benefits rose 29% and 115% respectively over the prior year. Professional fees increased 36% from 2011 due to an increase in legal fees and fees related to Sarbanes-Oxley implementation, internal audit and tax services. Our increase in travel expenses is related to evaluating financing alternatives, securing our new credit facility, raising equity and investor relations. In 2012, we granted equity awards for an additional 4,345,000 shares our common stock in exchange for certain employee and non-employee services provided to the Company resulting in a 171% increase in non-cash compensation expense. The

159% increase in other expenses primarily relates to increased cost of our new corporate office space, trade shows and exhibits and general liability insurance.

Table of Contents

2011 vs. 2010 During 2011, G&A expenses increased $4.3 million from 2010, or 42%. A substantial portion of the increase is related to non-cash compensation where we incurred expenses of $5.2 million. We also incurred an additional $2.1 million in salaries, travel and employee benefits.

Exploration expense

2012 vs. 2011 Exploration expense consists of abandonments of drilling locations, dry hole costs, delay rentals, geological and geophysical costs, and the impairment, amortization, and abandonment associated with leases on unproved properties. During 2012, we incurred $0.3 million related to the impairment of certain unproved properties and $0.9 million in seismic and dry hole costs incurred in the Cook Inlet region. These expenses were not incurred in previous periods.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization (“DD&A”) expenses include the depreciation, depletion and amortization of acquisition costs and equipment costs. Depletion is calculated on a unit-of-production basis.

	For the Year Ended April 30,					
	2012	2011	2010	2012	2011	2010
	(In thousands)			(Per boe)		
Depletion:						
Cook Inlet region	$11,790	$9,703	$2,113	$29.42	$29.86	$22.12
Appalachian region	747	773	506	19.45	23.73	20.24
	12,537	10,476	2,619	28.55	29.31	21.73
Depreciation:						
Cook Inlet region	169	2	—	NM	NM	NM
Appalachian region	604	483	491	NM	NM	NM
	773	485	491	1.76	1.36	4.07
Total DD&A	$13,310	$10,961	$3,110	$30.31	$30.66	$25.80

NM - Not Meaningful

2012 vs. 2011 Recurring successful-efforts depletion expense increased $2.1 million on an absolute dollar basis: $2.2 million from additional production, offset by $0.1 million on lower rates. Our successful-efforts depletion rate decreased 3% to $28.55 per boe as our historical cost basis remained relatively constant year over year. The decline in the West MacArthur River Unit rate per boe is due to a positive adjustment in the reserve base resulting from our April 30, 2011 reserve engineering report estimate. Other asset depreciation increased $0.3 million over 2011 primarily on slightly higher asset balances.

2011 vs. 2010 Recurring successful-efforts depletion expense increased $7.9 million on an absolute dollar basis: $7.6 million from additional production and $0.2 million on higher rates. Our successful-efforts depletion rate increased 35% to $29.31 per boe due to significant increases in production resulting from a full year of operations in the Cook Inlet region.

Other Income and Expense

The following table shows the components of other income and expense for the fiscal years indicated.

	For the Year Ended April 30,				
	2012	Increase (Decrease)	2011	Increase (Decrease)	2010
	(In thousands, except percentages)				
Interest expense, net of interest income	$(1,837)	97%	$(934)	618%	$(130)
Loss on derivative, net	(2,832)	181	(1,008)	(92)	(13,299)
Gain on acquisitions	—	NM	6,910	(99)	461,112
Other income (expense), net	58	NM	(537)	NM	(751)
Total	$(4,611)		$4,431		$446,932

NM - Not Meaningful

Interest Expense

2012 vs. 2011 Interest expense, net of interest income increased $0.9 million from 2011, or 97%, driven primarily by a $0.6 million increase in amortization of deferred financing costs. The Company capitalized $3.7 million of interest in equipment and oil and gas properties as of April 30, 2012.

2011 vs. 2010 During 2011, net interest expense increased $0.8 million from 2010, or 618%, reflecting a $0.5 million increase in amortization charges from deferred financing costs and a $0.3 million increase in interest expense associated with our 6% convertible note program.

Loss on Derivatives, Net

We experience earnings volatility as a result of not using hedge accounting to account for changes in commodity prices. As the positions of future oil production are marked-to-market, both realized and unrealized gains or losses are included on our consolidated statements of operations. We do not engage in speculative trading and utilize commodity derivatives only as a mechanism to lock in future prices for a portion of our expected crude oil production.

Changes in commodity prices typically account for a significant portion of our net gain (loss) on derivative transactions.

2012 vs. 2011 During 2012, unrealized loss on derivatives totaled $3.4 million, offset by a net realized gain of $0.6 million. Our overall net loss position increased 181% from 2011, primarily as a result of changes in commodity prices. Unrealized net loss on commodity derivatives accounted for $3 million of the total net loss on derivatives, with the remaining portion related to changes in the fair value of warrants.

2011 vs. 2010 Net loss on derivatives decreased $12.3 million, or 92% from 2010. During 2010, we recorded a non-cash loss of $13.3 million as a result of changes to certain warrant agreements that forfeited the option to purchase an aggregate amount of 3,300,000 shares of our common stock. The removal of these warrants resulted in our recognition of the $13.3 million year over year loss. As of April 30, 2011, we had one warrant agreement outstanding with the option to purchase 817,055 shares of our common stock.

Gain on Acquisitions

During 2011, we recorded a gain of $6.9 million related to restricted cash held by the State of Alaska that was not previously accounted for as part of the Alaska acquisition in 2010. This amount could not be verified until our entry into the Performance Bond Agreement with the State of Alaska on March 11, 2011. Under the agreement, we are required to post a bond for an aggregate amount of $18 million with $6.8 million restricted cash held by the State to be applied to the total bond requirement. We recorded this event as a gain on acquisition for our Alaska subsidiary.

Liquidity and Capital Resources

Our cash flows, both in the short-term and long-term, are impacted by highly volatile oil and natural gas prices. Significant deterioration in commodity prices negatively impacts revenues, earnings and cash flows, capital spending, and potentially our liquidity. Sales volumes and costs also impact cash flows; however, these historically have not been as volatile or as impactful as commodity prices in the short-term.

Our long-term cash flows are highly dependent on our success in efficiently developing current reserves and economically finding, developing and acquiring additional recoverable reserves. Cash investments are required continuously to fund exploration and development projects and acquisitions, which are necessary to offset the inherent declines in production and proven reserves. We may not be able to find, develop or acquire additional reserves to replace our current and future production at acceptable costs, which could materially adversely affect our future liquidity. For a discussion of risk factors related to our business and operations, please see Part I, Item 1A – Risk Factors, of this Form 10-K.

We may elect to utilize excess borrowing capacity, access to both debt and equity capital markets, or proceeds from the occasional sale of nonstrategic assets to supplement our liquidity and capital resource needs.

In fiscal 2012, we experienced operating losses and had a working capital deficit as of April 30, 2012. We anticipate that our operating expenses will continue to increase as we fully develop our assets in the Cook Inlet and Appalachian regions. Although we expect an increase in our revenues to come from these development activities, we will continue depleting our cash resources to fund operating expenses until such time as we are able to significantly increase our

revenues above costs.
We believe that the liquidity and capital resource alternatives available to us, combined with internally generated cash flows and other potential sources of funds, will be adequate to fund our short-term and long-term operations, including our capital budget, repayment of debt maturities, and any amount that may ultimately be paid in connection with contingencies; however, we are restricted under our new Apollo Investment Corporation credit facility to commit to certain financial requirements and provisions as described in Note 16 - Subsequent Events in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Sources and Uses of Cash

The following table presents the sources and uses of our cash and cash equivalents for the years presented:

	For the Year Ended April 30,		
	2012	2011	2010
	(In thousands)		
Sources of cash and cash equivalents:			
Net cash provided (used) by operating activities	$6,901	$7,734	$(730)
Proceeds from borrowings, net of debt acquisition costs	28,754	5,500	4,957
Proceeds from preferred stock issuance	10,000	—	—
Proceeds from common stock activities	1,383	1,266	9,928
Release of restricted cash	—	—	1,796
	47,038	14,500	15,951
Uses of cash and cash equivalents:			
Capital expenditures	(33,967)	(11,315)	(4,903)
Payments on credit facilities	(8,764)	(3,500)	(3,763)
Acquisition of Alaska business	—	—	(4,337)
Restricted cash	(1,895)	(1,121)	—
	(44,626)	(15,936)	(13,003)
Increase (decrease) in cash and cash equivalents	$2,412	$(1,436)	$2,948

Net Cash Provided by Operating Activities

Our sources of capital and liquidity are partially supplemented by cash flows from operations, both in the short-term and long-term. These cash flows, however, are highly impacted by volatility in oil and natural gas prices. The factors in determining operating cash flows are largely the same as those that affect net earnings, with the exception of non-cash expenses such as DD&A, asset retirement obligation ("ARO") accretion, non-cash compensation and deferred income tax expense, which affect earnings but do not affect cash flows.

Net cash provided by operating activities for 2012 totaled $6.9 million, down $0.8 million from 2011. Despite the $12.6 million increase in revenues, driven by a combination of increases in oil prices and increases in volumes sold, operating expenses continued to rise at a higher rate than cash flows from operations. During 2012, oil and gas operating costs increased $5.2 million, with transportation, labor and contract services contributing all of the rise in cost. G&A expenses, excluding non-cash items, contributed another $6.2 million to the reduction in operating cash flows.

For a detailed discussion of commodity prices, production and expenses, please see “Results of Operations” in this Item 7. For additional detail on the changes in operating assets and liabilities and the non-cash expenses which do not impact net cash provided by operating activities, please see the Statement of Consolidated Cash Flows in the Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Proceeds from Credit Facilities and Stock Related Issuances

During 2012, borrowings under the credit facilities totaled $28.8 million, net of $2.1 million in financing costs. The proceeds were used to finance all of our capital projects on-going in the Cook Inlet region.

On April 6, 2012, we issued 100,000 shares of Series A Cumulative Preferred Stock for total proceeds of $10 million, before expenses. The proceeds were used to supplement our projects in the Cook Inlet region. For additional information on the preferred stock offering, please see Note 3 - Derivative Instruments and Note 8 - Capital Stock in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

During 2012, we also received $1.4 million in proceeds from the exercise of equity rights.

Repayment of Debt

We made payments in an aggregate amount of $8.8 million to our lenders during fiscal 2012, including the termination of the Plains Capital line of credit. For information on this line of credit, please see Note 4 - Debt in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K. In May 2012, we paid another $2.2 million in mandatory payments, drawn by the lenders as part of our monthly requirement to make payment on the outstanding obligations equal to

Table of Contents

90% of our consolidated net revenues. On June 29, 2012, the Guggenheim credit facility was paid in full. For additional information on the repayment, please see Note 16 - Subsequent Events in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Capital Expenditures

We use a combination of operating cash flows, borrowings under credit facilities and, from time to time, issues of debt or common stock to fund significant capital projects. Due to the volatility in oil and natural gas prices, our capital expenditure budgets, both in the short-term and long-term, are adjusted on a frequent basis to reflect changes in forecasted operating cash flows, market trends in drilling and acquisition costs, and production projections.

During 2012, we placed significant emphasis on rig construction and modification activities. Total spending on capital projects was up 200% from 2011, primarily on the construction of Rig 35 and modification to Rig 34. We spent a portion of the budget on recompletion activities and brought RU-1 and RU-7 on-line during the first quarter of the year. Some of the costs were spent on exploratory projects, which were proved unsuccessful in both the Cook Inlet and Appalachian regions.

Liquidity

Cash and Cash Equivalents

As of April 30, 2012, we had $6 million in cash and cash equivalents.

Debt

Outstanding debt consisted of $24.1 million in borrowings under the Guggenheim credit facility, which is classified as current on the accompanying consolidated balance sheet of April 30, 2012. The Guggenheim credit facility was paid in full on June 29, 2012.

Available Credit Facilities

We had $10.9 million in borrowing capacity under our Guggenheim credit facility as of April 30, 2012.

On June 29, 2012, we closed a new credit facility with Apollo Investment Corporation and the Guggenheim credit facility was repaid in full. For a full description of terms of the Apollo Investment Corporation credit facility, see Note 16 - Subsequent Events in the Notes to Consolidated Statements set forth in Part IV, Item 15 of this Form 10-K.

Contractual Obligations

The following table summarizes our contractual obligations as of April 30, 2012. For additional information regarding these obligations, please see Note 4 - Debt and Note 6 - Commitments and Contingencies in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

	Note Reference	Total (In thousands)	2013	2014-2015	2016-2017	and after
Contractual obligations:[(a)]						
Debt, at face value	Note 4	$24,130	$24,130	$—	$—	$—
Interest payments	Note 4	3,163	2,292	871	—	—
Dismantlement, removal and restoration (Osprey)[(b)]	Note 6	12,000	—	2,500	4,500	5,000
Rights of way and easements:[(c)]	Note 6					
Osprey to shore pipeline	Note 6	275	13	26	26	210
Osprey to shore optic cable	Note 6	7	—	1	1	5
CIRI Kustatan pipeline easement	Note 6	307	28	56	56	167
West Foreland CIRI/Salamatof agreement	Note 6	191	17	35	35	104
Salamatof surface use agreement	Note 6	500	50	100	100	250
Office and related equipment[(d)]	Note 6	858	278	360	220	—
Total contractual obligations		$41,431	$26,808	$3,949	$4,938	$5,736

a. This table does not include the Company's liability for dismantlement, abandonment, and restoration costs of oil and gas properties,

Table of Contents

derivative liabilities, or tax reserves. For additional information regarding these liabilities, please see Notes 3 - Derivative Instruments, Note 5 - Asset Retirement Obligations and Note 6 - Commitment and Contingencies, respectively, in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K. This table includes contractual obligations related to the Guggenheim credit facility which was extinguished on June 29, 2012. See Note 16 - Subsequent Events in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

b. This represents the Performance Bond Agreement with the State of Alaska for dismantlement, removal and restoration of the Redoubt Field offshore assets.

c. Obligations to landowners for use of surface and subsurface rights for West McArthur River Unit and Redoubt Unit facilities including processing facilities, pipelines, roads, etc.

d. Other operating lease obligations relating to office and related equipments.

We also subject to various contingent obligations that become payable only if certain events or rulings were to occur. The inherent uncertainty surrounding the timing of and monetary impact associated with these events or rulings prevents any meaningful accurate measurement, which is necessary to assess settlements resulting from litigation. For a detailed discussion of our legal contingencies, please see Note 10 - Litigation in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

Off Balance Sheet Arrangements

We enter into customary agreements in the oil and gas industry for drilling commitments, firm transportation agreements, and other obligations as described herein under Contractual Obligations in this Item 7. Other than the off-balance sheet arrangements described, we do not have any off-balance sheet arrangements with unconsolidated entities that are reasonably likely to materially affect our liquidity or capital resource positions.

Non-GAAP Measures

Adjusted Earnings

Adjusted EBITDA is a significant performance metric used as a quantitative standard by our management and by external users of our financial statements such as investors, research analysts and others to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness; and
- our operating performance and return on capital as compared to those of other companies in our industry, without regard to financing or capital structure.

We define Adjusted EBITDA as net income (loss) before taxes adjusted by:

- depreciation, depletion and amortization;
- write-off of deferred financing fees;
- asset impairments;
- (gain) loss on sale of assets;
- accretion expense;
- exploration costs;
- (gain) loss from equity investment;
- stock-based compensation expense;
- (gain) loss from mark-to-market activities;
- interest expense and interest (income)

Our Adjusted EBITDA should not be considered as a substitute for net income (loss), operating income, cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Our Adjusted EBITDA excludes some, but not all, items that affect net income and operating income and these measures may vary among other companies. Therefore, our Adjusted EBITDA may not be comparable to similarly titled measures of other companies.

The following table presents a reconciliation of net income (loss) before taxes to Adjusted EBITDA, our most directly comparable GAAP performance measure, for each of the periods presented:

Table of Contents

	For the Year Ended April 30,		
	2012	2011	2010
	(In thousands)		
Income (loss) before income taxes	$(29,696)	$(10,161)	$435,618
Adjusted by:			
Interest expense, net	1,837	934	130
Depreciation, depletion and amortization	13,310	10,961	3,110
Accretion of asset retirement obligation	1,072	1,407	315
Exploration expense	1,241	—	—
Stock-based compensation	14,072	5,126	4,514
Unrealized loss on derivatives	3,436	1,008	13,299
Adjusted EBITDA	$5,272	$9,275	$456,986

Critical Accounting Policies and Estimates

General

The preparation of financial statements requires us to utilize estimates and make judgments that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. These estimates are based on historical experience and on various other assumptions that we believe to be reasonable under the circumstances. The estimates are evaluated by management on an ongoing basis, and the results of these evaluations form a basis for making decisions about the carrying value of assets and liabilities that are not readily apparent from other sources. Although actual results may differ from these estimates under different assumptions or conditions, we believe that the estimates used in the preparation of our financial statements are reasonable. The following is a discussion of our most critical accounting policies.

Estimates of Proved Reserves and Future Net Cash Flows

Proved oil and gas reserves are the estimated quantities of natural gas and crude oil that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing conditions, operating conditions, and government regulations.

Proved undeveloped reserves include those reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Undeveloped reserves may be classified as proved reserves on undrilled acreage directly offsetting development areas that are reasonably certain of production when drilled, or where reliable technology provides reasonable certainty of economic producibility. Undrilled locations may 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 specific circumstances justify a longer time.

Despite the inherent imprecision in these engineering estimates, our reserves are used throughout our financial statements. For example, since we use the units-of-production method to amortize our oil and gas properties, the quantity of reserves could significantly impact our DD&A expense. Further, these reserves are the basis for our unaudited supplemental oil and gas disclosures.

Reserves as of April 30, 2012, 2011, and 2010, were calculated using an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months, held flat for the life of the production, except where prices are defined by contractual arrangements.

We elected not to disclose probable and possible reserves or reserve estimates in this filing. Our unaudited supplemental oil and gas disclosures for fiscal years 2011 and 2010 have been revised to reflect revisions to the reserve classification of certain reserves related to our Redoubt field.

Asset Retirement Obligation

We have significant obligations to remove tangible equipment and restore land or seabed at the end of oil and gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells and removing and disposing of offshore oil and gas platforms. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments.

Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety, and public relations considerations. ARO associated with retiring tangible long-lived assets is recognized as a liability in the period

Table of Contents

in which the legal obligation is incurred and becomes determinable. The liability is offset by a corresponding increase in the underlying asset. The ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with our oil and gas properties. We utilize current retirement costs to estimate the expected cash outflows for retirement obligations. Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental, and political environments. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance.
Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

Fair Value of Financial Instruments
We measure fair value of our financial and non-financial assets and liabilities on a recurring basis. Accounting standards define fair value, establish a framework for measuring fair value and require certain disclosures about fair value measurements for assets and liabilities measured on a recurring basis. All of our derivative instruments are recorded at fair value in our financial statements. Fair value is the exit price that we would receive to sell an asset or pay to transfer a liability in an orderly transaction between market participants at the measurement date.

The following hierarchy prioritizes the inputs used to measure fair value:

- Level 1-Quoted prices in active markets that are unadjusted and accessible at the measurement date for identical, unrestricted assets or liabilities;
- Level 2-Quoted prices for identical assets and liabilities in markets that are inactive; quoted prices for similar assets and liabilities in active markets or financial instruments for which significant inputs are observable, either directly or indirectly; or
- Level 3-Prices or valuations that require inputs that are both unobservable and significant to the fair value measurement.

We consider an active market to be one in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis, and view an inactive market as one in which there are few transactions for the asset or liability, prices are not current, or price quotations vary substantially either over time or among market makers. Where appropriate, we consider non-performance risk in determining the fair values of the assets and liabilities.

Stock-Based Compensation
The computation of stock-based compensation requires the use of a valuation model. ASC 718, "Compensation - Stock Compensation," requires significant judgment and the use of estimates, particularly surrounding model assumptions such as stock price volatility, expected terms, and expected forfeiture rates, to value equity-based compensation. We use various pricing models to determine the fair value of our stock options and warrants. Changes in the underlying assumptions could result in a material change to the fair value of the stock-based awards. Although every effort is made to ensure the accuracy of our estimates and assumptions, significant unanticipated changes in those estimates, interpretations and assumptions may result in recording expenses that could have a significant effect on results of operations in the future.

Purchase Price Allocation
Accounting for the acquisition of a business requires the allocation of the purchase price to the various assets and liabilities of the acquired business and recording deferred taxes for any differences between the allocated values and tax basis of assets and liabilities.
The purchase price allocation is accomplished by recording each asset and liability at its estimated fair value. Estimated deferred taxes are based on available information concerning the tax basis of the acquired company’s assets and liabilities and tax-related carryforwards at the merger date, although such estimates may change in the future as additional information becomes known.

In estimating the fair values of assets acquired and liabilities assumed, we made various assumptions. The most significant assumptions related to the estimated fair values assigned to proved and unproved crude oil and natural gas properties. To estimate the fair values of these properties, we prepared estimates of crude oil and natural gas reserves as described above under Estimates of Proved Reserves and Future Net Cash Flows of this Item 7. Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future.

Recent Accounting Pronouncements

In May 2011, the FASB issued ASU 2011-04, "Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs," which amends ASC 820, “Fair Value Measurements and Disclosures.”

Table of Contents

The amended guidance clarifies many requirements in GAAP for measuring fair value and for disclosing information about fair value measurements. Additionally, the amendments clarify the FASB's intent about the application of existing fair value measurement requirements. The guidance provided in ASU 2011-04 is effective for interim and annual periods beginning after December 15, 2011. The Company does not expect the adoption of this amendment to have a material impact on its consolidated financial statements.

In June 2011, the FASB issued ASU No. 2011-05, "Presentation of Comprehensive Income." ASU 2011-05 eliminates the option to report other comprehensive income and its components in the statement of changes in stockholders' equity and requires an entity to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement or in two separate but consecutive statements. This update is effective for fiscal years, and interim periods within those years beginning after December 15, 2011. In December 2011, the FASB issued ASU No. 2011-12, which becomes effective at the same time as ASU 2011-05, to defer the effective date of provisions of ASU 2011-05 that relate to the presentation of reclassification adjustments. We expect adoption of ASU 2011-05 or ASU 2011-12 will not have an impact on our financial position or results of operations.
In December 2011, the FASB issued ASU No. 2011-11, "Disclosures about Offsetting Assets and Liabilities," which will enhance disclosures by requiring an entity to disclose information about netting arrangements, including rights of offset, to enable users of its financial statements to understand the effect of those arrangements on its financial position. This pronouncement was issued to facilitate comparison between financial statements prepared on the basis of U.S. GAAP and IFRS. This update is effective for annual and interim reporting periods beginning on or after January 1, 2013 and is to be applied retroactively for all comparative periods presented. The adoption of ASU 2011-11 is not expected to have a significant impact on our financial position or results of operations.
We determined that all other issued, but not yet effective accounting pronouncements are inapplicable or insignificant to us and once adopted are not expected to have a material impact on our financial position.

Supplemental Quarterly Financial Information (Unaudited)

The following table sets forth selected unaudited quarterly results for the eight quarters ended April 30, 2012. The comparability of our results between quarters is impacted by (1) the $461 million gain we recorded in the third quarter ended January 31, 2010 in connection with the December 2009 acquisition of our Alaska properties, (2) quarterly increases in production that have resulted from bringing online Alaskan wells acquired, and (3) the $6.9 million gain on acquisition recorded in the fourth quarter ended April 30, 2011 (see Note 2 - Acquisitions in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K).

	April 30, 2012	Jan. 31, 2012	Oct. 31, 2011	July 31, 2011
	(In thousands, except per share data)			
Total revenues	$8,898	$8,443	$9,205	$8,856
Loss from operations	(7,354)	(6,096)	(7,726)	(3,909)
Net loss attributable to common stockholders	(8,360)	(6,510)	(4,484)	(183)
Diluted loss per share	(0.20)	(0.16)	(0.11)	—

	April 30, 2011	Jan. 31, 2011	Oct. 31, 2010	July 31, 2010
	(In thousands, except per share data)			
Total revenues	$6,442	$6,386	$5,639	$4,376
Loss from operations	(5,390)	(979)	(4,647)	(3,888)
Net income (loss) attributable to common stockholders	1,442	(87)	(4,086)	(1,149)

Diluted earnings (loss) per share	0.05	—	(0.12)	(0.04)

43

Table of Contents

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

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our exposure to market risk. The term market risk relates to the risk of loss arising from adverse changes in oil, gas, and interest rates, or adverse governmental actions. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. The forward-looking information provides indicators of how we view and manage our ongoing market risk exposures.

Commodity Risk

Our revenues, earnings, cash flow, capital investments, and, ultimately, future rate of growth are highly dependent on the prices we receive for our crude oil and natural gas, which have historically been very volatile due to unpredictable events such as economic growth or retraction, weather, and political climate.

We periodically enter into hedging activities on a portion of our projected oil production through financial arrangements intended to support oil prices at targeted levels and to manage our overall exposure to oil price fluctuations. In 2012 and 2011, approximately 60% to 80% of our crude oil production was subject to financial derivative hedges. Realized gains or losses from the our price-risk management activities are recognized in other income and expense when the associated production occurs. We do not hold or issue derivative instruments for trading purposes.

On April 30, 2012, we had open oil derivative hedges in a liability position with a fair value of $5.4 million. A 10% increase in oil prices would increase the fair value by approximately $5.9 million, while a 10% decrease in prices would decrease the fair value by approximately $4.9 million. These fair value changes assume volatility based on prevailing market parameters at April 30, 2012. For notional volumes and terms associated with our derivative contracts, please see Note 3 - Derivative Instruments in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

We conduct our risk management activities for commodities under the controls and governance of our risk management policy. The Audit Committee of our Board of Directors approves and oversees these controls, which have been implemented by designated members of the management team. The treasury and accounting departments also provide separate checks and reviews on the results of hedging activities. Controls for our commodity risk management activities include limits on volume, segregation of duties, delegation of authority and a number of other policy and procedural controls.

Interest Rate Risk

We consider our interest rate risk exposure to be minimal as a result of fixing interest rates on 100% of our debt. At April 30, 2012, there were no float-rate debt that would expose us to market fluctuations in interest rates.

Table of Contents

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The financial statements and supplementary financial information required to be filed under this Item 8 are presented in Part IV, Item 15 of this Form 10-K and are incorporated herein by reference.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures
a) Disclosure Controls and Procedures.
Under the supervision and with the participation of our management, including our principal executive officer and our principal financial officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) under the Securities Exchange Act of 1934, as amended, at the end of the period covered by this report (the “Evaluation Date”).
In conducting our evaluation, we concluded there is a material weakness in the operating effectiveness of our internal control over financial reporting, as described below.
As a result of the foregoing, we have concluded that as of the Evaluation Date we did not maintain disclosure controls and procedures that were effective in providing reasonable assurance that information required to be disclosed in our reports filed under the Securities Exchange Act of 1934 was recorded, processed, summarized and reported within the time periods prescribed by SEC rules and regulations, and that such information was accumulated and communicated to our management to allow timely decisions regarding required disclosure.
Our management does not expect that our disclosure controls and procedures will prevent all errors and all fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the control system's objectives will be met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. The design of any system of controls is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions.
b) Management's Report on Internal Control over Financial Reporting
The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended.
Management, including our principal executive officer and principal financial officer, conducted an evaluation of the effectiveness of such controls as of April 30, 2012. This assessment was based on criteria established for effective internal control over financial reporting in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”).
A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis.
Management identified the following material weakness in the Company's internal control over financial reporting as of April 30, 2012:

We did not maintain a sufficient complement of corporate accounting and finance personnel necessary to consistently operate management review controls. As a result of this material weakness, we made a number of adjustments in connection with our financial statement audit in order to prepare the consolidated financial statements and footnotes included in this Form 10-K. Additionally, there is a reasonable possibility that a material misstatement of the Company's annual or interim consolidated financial statements would not be prevented or detected on a timely basis.

As a result of this material weakness, the Company's management has concluded that, as of April 30, 2012, its internal control over financial reporting was not effective based on criteria established in Internal Control - Integrated Framework issued by the COSO.

Table of Contents

KPMG LLP, an independent registered public accounting firm, has issued audit reports on its assessment of internal control over financial reporting and our consolidated financial statements that are included in Item 15 of this Annual Report on Form 10-K.

/s/ Scott M. Boruff	/s/ David J. Voyticky
Chief Executive Officer and Director	President, Chief Financial Officer and Director
(principal executive officer)	(principal financial officer)

c) Changes in Internal Control over Financial Reporting and Remediation

During fiscal 2011, we were unable to complete our assessment of the effectiveness of the Company's internal control over financial reporting in accordance with SEC rules and regulations. Notwithstanding our inability to complete this assessment, we identified material weaknesses in our internal control over financial reporting as of April 30, 2011. At such time we did not maintain: i) a sufficient complement of personnel with an appropriate level of accounting knowledge, experience and training in the selection and application of U.S. GAAP and SEC reporting requirements commensurate with our financial reporting requirements, ii) sufficient policies, procedures and controls to prevent and/or detect material misstatements in our consolidated financial statements, or iii) adequate controls to ensure that the Company maintains compliance with various SEC rules and regulations regarding reporting.

During fiscal 2012, we hired experienced personnel and engaged independent consultants to evaluate, design, implement and document appropriate internal control over financial reporting. These actions enabled us to complete our assessment of the Company's internal control over financial reporting in accordance with SEC rules and regulations as of April 30, 2012. During fiscal 2012 we also provided training to key corporate accounting and finance personnel in U.S. GAAP and SEC reporting requirements.

During the fourth quarter of fiscal 2012, we continued to remediate deficiencies identified in our internal control over financial reporting. Other than those activities, there were no changes that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting. Notwithstanding these efforts, we concluded that a material weakness in the operating effectiveness of management review controls exists as of April 30, 2012.

To remediate this material weakness, during fiscal year 2013, we will:

- Determine the appropriate complement of corporate accounting and finance personnel required to consistently operate management review controls.
- Hire the requisite additional personnel and/or contractors with public company accounting and reporting experience.

We can give no assurance that the measures we take will remediate the material weakness that we identified or that any additional material weaknesses will not arise in the future. We will continue to monitor the effectiveness of these and other processes, procedures and controls and will make any further changes management determines appropriate.

ITEM 9B. OTHER INFORMATION

None.

Table of Contents

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

The information required by this item will be contained in our proxy statement for our 2013 Annual Meeting of Shareholders to be filed on or prior to August 28, 2012 (the "Proxy Statement") and is incorporated herein by this reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item will be contained in our Proxy Statement and is incorporated herein by this reference.

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

The information required by this Item will be contained in our Proxy Statement and is incorporated herein by this reference.

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

The information required by this Item will be contained in our Proxy Statement and is incorporated herein by this reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The following table shows the fees that were billed for audit services provided by KPMG LLP for fiscal 2012 and 2011. There were no audit-related, tax or other services provided.

	2012	2011
Audit Fees (In thousands)	$578	451

Audit Fees — This category includes the integrated audit of our annual financial statements and internal control over financial reporting, review of financial statements included in our Quarterly Reports on Form 10-Q and services that are normally provided by the independent registered public accounting firm in connection with engagements for those fiscal years.

Our Board of Directors has adopted a procedure for pre-approval of all fees charged by our independent registered public accounting firm. Under the procedure, the Audit Committee approves the engagement letter with respect to audit, tax and review services. Other fees are subject to pre-approval by the Audit Committee, or, in the period between meetings, by the Chairman of the Audit Committee. Any such approval by the designated member is disclosed to the entire Board at the next meeting. The audit fees paid to the auditors with respect to fiscal 2012 and 2011 were pre-approved by the Audit Committee.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

a. Documents included in this report:

1. Financial Statements

Report of Independent Registered Public Accounting Firm	F-1
Report of Independent Registered Public Accounting Firm	F-2
Report of Independent Registered Public Accounting Firm	F-3
Consolidated Balance Sheets	F-4
Consolidated Statements of Operations	F-5
Consolidated Statements of Stockholders' Equity	F-6
Consolidated Statements of Cash Flows	F-7
Notes to the Consolidated Financial Statements	F-8

2. Financial Statement Schedules

Financial statement schedules have been omitted because they are either not required, not applicable or the information required to be presented is included in our financial statements and related notes.

3. Exhibits

The following documents are filed as a part of this annual report on Form 10-K or are incorporated by reference to previous filings, if so indicated:

EXHIBIT NO.		DESCRIPTION
2.1	–	Agreement and Plan of Reorganization dated December 20, 1996 between Triple Chip Systems, Inc. and Miller Petroleum, Inc. (incorporated by reference to Registrant's Current Report on Form 8-K dated January 15, 1997).
3.1	–	Certificate of Incorporation (incorporated by reference to Registrant's Annual Report on Form 10-KSB for the year ended December 31, 1995).
3.2	–	Certificate of Amendment of Certificate of Incorporation (incorporated by reference to Registrant's Annual Report on Form 10-KSB for the year ended December 31, 1995).
3.3	–	Certificate of Amendment of Certificate of Incorporation (incorporated by reference to Registrant's Annual Report on Form 10-KSB for the year ended December 31, 1995).
3.4	–	Certificate of Ownership and Merger and Articles of Merger between Triple Chip Systems, Inc. and Miller Petroleum, Inc. (incorporated by reference to Registrant's exhibits filed with the registration statement on Form SB-2, SEC File No. 333-53856, as amended).
3.5	–	Amended and Restated Charter of Miller Petroleum, Inc. (incorporated by reference to Registrant's Current Report on Form 8-K filed on April 29, 2010).
3.6	–	Amended and Restated Bylaws of Miller Petroleum, Inc. (incorporated by reference to Registrant's Current Report on Form 8-K filed on April 29, 2010).
3.7	–	Articles of Amendment to the Bylaws of Miller Petroleum, Inc. (incorporated by reference to Registrant's Current Report on Form 8-K filed on March 17, 2011).

3.8	–	Articles of Amendment to the Charter of Miller Petroleum, Inc. (incorporated by reference to Registrant's Current Report on Form 8-K filed on April 15, 2011).
3.9	–	Articles of Amendment to the Charter of Miller Energy Resources, Inc. (incorporated by reference to Registrant's Current Report on Form 8-K filed on April 2, 2012).

Table of Contents

4.1	–	Form of Stock Purchase Warrant issued May 4, 2005 to Prospect Energy Corporation (incorporated by reference to Registrant's Current Report on Form 8-K dated May 9, 2005).
4.2	–	Form of Stock Purchase Warrant issued May 4, 2005 to Petro Capital III, L.P. (incorporated by reference to Registrant's Current Report on Form 8-K dated May 9, 2005).
4.3	–	Form of Stock Purchase Warrant issued May 4, 2005 to Petrol Capital Advisors, LLC (incorporated by reference to Registrant's Current Report on Form 8-K dated May 9, 2005).
4.4	–	Form of Stock Purchase Warrant issued December 31, 2005 to Petro Capital III, L.P. (incorporated by reference to Registrant's Quarterly Report on Form 10-QSB for the period ended January 31, 2006).
4.5	–	Form of Stock Purchase Warrant issued December 31, 2005 to Prospect Energy Corporation (incorporated by reference to Registrant's Quarterly Report on Form 10-QSB for the period ended January 31, 2006).
4.6	–	Form of Stock Purchase Warrant issued December 31, 2005 to Petro Capital Advisors, LLC (incorporated by reference to Registrant's Quarterly Report on Form 10-QSB for the period ended January 31, 2006).
4.7	–	Form of warrant issued to Cresta Capital Corporation (incorporated by reference to Registrant's Annual Report on Form 10-K for the year ended April 30, 2009).
4.8	–	Form of option granted to Paul W. Boyd (incorporated by reference to Registrant's Annual Report on Form 10-K for the year ended April 30, 2009).
4.9	–	Form of warrant issued to David M. Hall, Walter J. Wilcox, II and Troy Stafford (incorporated by reference to Registrant's Current Report on Form 8-K filed on December 23, 2009).
4.10	–	Miller Petroleum, Inc. Stock Plan (incorporated by reference to Registrant's Current Report on Form 8-K filed on April 29, 2010).
4.11	–	Form of common stock purchase warrant for March 2010 private placement (incorporated by reference to Registrant's Annual Report on Form 10-K for the year ended April 30, 2010).
4.12	–	Form of common stock purchase warrant issued to purchasers in the Miller Energy Income Fund 2009-A, LP offering (incorporated by reference to Registrant's Annual Report on Form 10-K for the year ended April 30, 2010).
4.13	–	Form of common stock purchase warrant issued to Sutter Securities Incorporated (incorporated by reference to Registrant's Annual Report on Form 10-K for the year ended April 30, 2010).
4.14	–	2011 Equity Compensation Plan (incorporated by reference to Registrant's Current Report on Form 8-K filed on March 17, 2011).

4.15	–	Form of Series PPA Warrant (incorporated by reference to Registrant's Current Report on Form 8-K filed on April 12, 2012).
10.1	–	Purchase and Sale Agreement dated December 16, 1997 between AKS Energy Corporation and Miller Petroleum, Inc. (incorporated by reference to Registrant's Current Report on Form 8-K dated March 17, 1998).
10.2	–	Termination Agreement, General Release and Covenant No To Sue Dated June 13, 2008 with Cresta Capital Strategies, LLC (incorporated by reference to Registrant's Annual Report on Form 10-K for the year ended April 30, 2009).

Table of Contents

10.3	–	Agreement dated June 8, 2009 between Ky-Tenn Oil, Inc. and Miller Petroleum, Inc. (incorporated by reference to Registrant's Current Report on Form 8-K filed on June 12, 2009).
10.4	–	Agreement dated June 18, 2009 for Sale of Capital Stock of East Tennessee Consultants, Inc. and Sale of Membership Interests of East Tennessee Consultants II, LLC (incorporated by reference to Registrant's Current Report on Form 8-K filed on June 24, 2009).
10.5	–	Agreement for Sale of Membership Interest in Cook Inlet Energy, LLC (incorporated by reference to Registrant's Current Report on Form 8-K filed on December 23, 2009).
10.6	–	Form of Securities Purchase Agreement for December 2009 private placement (incorporated by reference to Registrant's Current Report on Form 8-K filed on January 4, 2010).
10.7	–	First Secured Promissory Note from Miller Petroleum, Inc. to Miller Energy Income 2009-A, LP (incorporated by reference to Registrant's Quarterly Report on Form 10-Q for the period ended January 31, 2010).
10.8	–	Second Secured Promissory Note from Miller Petroleum, Inc. to Miller Energy Income 2009-A, LP (incorporated by reference to Registrant's Quarterly Report on Form 10-Q for the period ended January 31, 2010).
10.9	–	Loan and Security Agreement between Miller Petroleum, Inc and Miller Energy Income 2009-A, LP (incorporated by reference to Registrant's Quarterly Report on Form 10-Q for the period ended January 31, 2010).
10.10	–	Escrow Agreement (incorporated by reference to Registrant's Quarterly Report on Form 10-Q for the period ended January 31, 2010).
10.11	–	Form of Securities Purchase Agreement for March 2010 private placement (incorporated by reference to Registrant's Annual Report on Form 10-K for the year ended April 30, 2010).
10.12	–	Form of Registration Rights Agreement for March 2010 private placement (incorporated by reference to Registrant's Annual Report on Form 10-K for the year ended April 30, 2010).
10.13	–	Consulting Agreement dated March 12, 2010 with Bristol Capital, LLC (incorporated by reference to Registrant's Annual Report on Form 10-K for the year ended April 30, 2010).
10.14	–	

		Marketing Agreement dated August 1, 2009 with The Dimirak Companies (incorporated by reference to Registrant's Annual Report on Form 10-K for the year ended April 30, 2010).
10.15	–	Assignment Oversight Agreement dated November 5, 2009 between Cook Inlet Energy, LLC and The State of Alaska Department of Natural Resources (incorporated by reference to Registrant's Annual Report on Form 10-K for the year ended April 30, 2010).
10.16	–	Cook Inlet Energy, LLC Master Services Agreement with Fairweather E&P Services, Inc. dated January 1, 2010 (incorporated by reference to Registrant's Annual Report on Form 10-K for the year ended April 30, 2010).
10.17	–	Purchase and Sale Agreement by and between Cook Inlet Energy, LLC and Pacific Energy Alaska Operating LLC and Pacific Energy Alaska Holdings, LLC dated as of November 24, 2009 (incorporated by reference to Registrant's Current Report on Form 8-K/A filed on July 27, 2010).
10.18	–	Cook Inlet Spill Prevention and Response, Inc. Bylaws and Response Action Contract (incorporated by reference to Registrant's Annual Report on Form 10-K for the year ended April 30, 2010).
10.19	–	Third Secured Promissory Note from Miller Petroleum, Inc. to Miller Energy Income 2009-A, LP (incorporated by reference to Registrant's Registration Statement on Form S-1 filed on August 13, 2010, SEC File No. 333-53856).

Table of Contents

10.20	–	Letter from the State of Alaska to Cook Inlet Energy, LLC announcing acceptance of terms for the extension of Susitna Exploration License #2 (incorporated by reference to Registrant's Current Report on Form 8-K filed on November 2, 2010).
10.21	–	Settlement Agreement between Petro Capital III, LP, Petro Capital Advisors, LLC, and Miller Petroleum, Inc. (incorporated by reference to Registrant's Current Report on Form 8-K filed on November 4, 2010).
10.22	–	Settlement Agreement between Cook Inlet Pipe Line Company and Cook Inlet Energy, LLC (incorporated by reference to Registrant's Current Report on Form 8-K filed on November 26, 2010).
10.23	–	Settlement Agreement between Prospect Capital Corporation and Miller Petroleum, Inc. (incorporated by reference to Registrant's Current Report on Form 8-K filed on December 9, 2010).
10.24	–	Amended and Restated Employment Agreement with Scott M. Boruff (incorporated by reference to Registrant's Current Report on Form 8-K filed on December 29, 2010).
10.25	–	Performance Bond Agreement between the State of Alaska and Cook Inlet Energy, LLC (incorporated by reference to Registrant's Current Report on Form 8-K filed on March 17, 2011).
10.26	–	Employment Agreement with Paul W. Boyd (incorporated by reference to Registrant's Current Report on Form 8-K filed on March 17, 2011).
10.27	–	Employment Agreement with David J. Voyticky (incorporated by reference to Registrant's Current Report on Form 8-K filed on June 14, 2011).
10.28	–	Contract of Construction and Sale between Miller Energy Resources, Inc. and Voorhees Equipment and Consulting, Inc. (incorporated by reference to Registrant's Current Report on Form 8-K filed on June 16, 2011).
10.29	–	Collateral Assignment of Rig Contract between Miller Energy Resources, Inc. and Guggenheim Corporate Funding, LLC (incorporated by reference to Registrant's Current Report on Form 8-K filed on June 16, 2011).
10.30	–	Loan Agreement between Miller Energy Resources, Inc. and Guggenheim Corporate Funding, LLC, Citibank, N.A. and Bristol Investment Fund, Ltd. (incorporated by reference to Registrant's

		Current Report on Form 8-K filed on June 17, 2011).
10.31	–	Shareholders' Agreement between Deloy Miller, Scott M. Boruff, David J. Voyticky, David M. Hall, Paul W. Boyd and Miller Energy Resources, Inc. (incorporated by reference to Registrant's Current Report on Form 8-K filed on June 17, 2011).
10.32	–	Guarantee and Collateral Agreement between Miller Energy Resources, Inc. and its subsidiaries, and Guggenheim Corporate Funding, LLC (incorporated by reference to Registrant's Current Report on Form 8-K filed on June 17, 2011).
10.33	–	First Amendment to Consulting Agreement between Miller Energy Resources, Inc. and Bristol Capital, LLC (incorporated by reference to Registrant's Current Report on Form 8-K filed on June 17, 2011).
10.34	–	Lease between Miller Energy Resources, Inc. and Pellissippi Pointe II, LLC (incorporated by reference to Registrant's Annual Report on Form 10-K for the year ended April 30, 2011).
10.35	–	Form of Assignment of Membership Interest in Pellissippi Pointe, LLC (incorporated by reference to Registrant's Annual Report on Form 10-K for the year ended April 30, 2011).
10.36	–	Form of Assignment of Membership Interest in Pellissippi Pointe II, LLC (incorporated by reference to Registrant's Annual Report on Form 10-K for the year ended April 30, 2011).
10.37	–	First Amendment and to Loan Agreement and Limited Waiver (incorporated by reference to Registrant's Current Report on Form 8-K filed on August 29, 2011).

Table of Contents

10.38	–	Limited Consent and Extension (incorporated by reference to Registrant's Quarterly Report on Form 10-Q filed on December 12, 2011).
10.39	–	Indemnification Agreement (incorporated by reference to Registrant's Quarterly Report on Form 10-Q filed on December 12, 2011).
10.40	–	Sales Agreement with Tesoro Refining and Marketing Company (incorporated by reference to Registrant's Current Report on Form 8-K filed on March 15, 2012, and amended on April 24, 2012).
10.41	–	Employment Agreement with Kurt C. Yost (incorporated by reference to Registrant's Current Report on Form 8-K filed on May 24, 2012).
10.42	–	Loan Agreement, dated as of June 29, 2012 between Miller Energy Resources, Inc. and Apollo Investment Corporation (incorporated by reference to Registrant's Current Report on Form 8-K filed on July 5, 2012).
10.43	–	Guarantee and Collateral Agreement, dated as of June 29, 2012, among Miller Energy Resources, Inc., each of its consolidated subsidiaries (excluding Miller Energy Income 2009-A, LP), as guarantors and grantors, and Apollo Investment Corporation, as secured party (incorporated by reference to Registrant's Current Report on Form 8-K filed on July 5, 2012).
10.44	–	First Amendment to Promissory Notes and Related Documents, dated as of June 29, 2012 between Miller Energy Resources, Inc. and Miller Energy Income 2009-A, LP (incorporated by reference to Registrant's Current Report on Form 8-K filed on July 5, 2012).
14.1	–	Amended and Restated Code of Business Conduct and Ethics (incorporated by reference to Registrant's Annual Report on Form 10-K for the year ended April 30, 2011).
21.1	–	Subsidiaries of the registrant *
23.1	–	Consent of Ralph E. Davis Associates, Inc. *
23.2	–	Consent of KPMG LLP*
23.3	–	Consent of Sherb & Co., LLP*
31.1	–	Rule 13a-14(a)/15d-14(a) certification of Chief Executive Officer *
31.2	–	Rule 13a-14(a)/15d-14(a) certification of Chief Financial Officer *

32.1	–	Section 1350 certification of Chief Executive Officer *
32.2	–	Section 1350 certification of Chief Financial Officer *
99.1	–	Reserve Report of Ralph E. Davis Associates, Inc. at April 30, 2012 on Cook Inlet assets *
99.2	–	Reserve Report of Ralph E. Davis Associates, Inc. at April 30, 2012 on Appalachian region assets *
99.3	–	Reserve Report of Ralph E. Davis Associates, Inc. at April 30, 2011 on Cook Inlet assets *
99.4	–	Reserve Report of Ralph E. Davis Associates, Inc. at April 30, 2010 on Cook Inlet assets *
101.INS	–	XBRL Instance Document *
101.SCH	–	XBRL Taxonomy Extension Schema Document *
101.CAL	–	XBRL Taxonomy Extension Calculation Linkbase Document *

Table of Contents

101.DEF	–	XBRL Taxonomy Extension Definition Document *
101.LAB	–	XBRL Taxonomy Extension Label Linkbase Document *
101.PRE	–	XBRL Taxonomy Extension Presentation Linkbase Document *
*	Filed herewith	

Table of Contents

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.
Date: July 16, 2012

MILLER ENERGY RESOURCES, INC.

By: /s/ SCOTT BORUFF
Chief Executive Officer

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 and on the dates indicated.

Signature	Title	Date
/s/ DELOY MILLER Deloy Miller	Chairman of the Board, Chief Operating Officer	July 16, 2012
/s/ SCOTT M. BORUFF Scott M. Boruff	Chief Executive Officer, Director, Principal Executive Officer	July 16, 2012
/s/ DAVID J. VOYTICKY David J. Voyticky	President, Chief Financial Officer, Director, Principal Financial Officer	July 16, 2012
/s/ HERMAN GETTELFINGER Herman Gettelfinger	Director	July 16, 2012
/s/ JONATHAN S. GROSS Jonathan S. Gross	Director	July 16, 2012
/s/ DAVID M. HALL David M. Hall	Director	July 16, 2012
/s/ MERRILL A. MCPEAK Merrill A. McPeak	Director	July 16, 2012
/s/ CHARLES STIVERS Charles Stivers	Director	July 16, 2012
/s/ DON A. TURKLESON Don A. Turkleson	Director	July 16, 2012

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Miller Energy Resources, Inc.:

We have audited Miller Energy Resources, Inc.'s and subsidiaries (the Company) internal control over financial reporting as of April 30, 2012, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). 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 (Item 9A(b)). 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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the company's annual or interim financial statements will not be prevented or detected on a timely basis. A material weakness related to an insufficient complement of corporate accounting and finance personnel to consistently operate management review controls has been identified and included in management's assessment.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Miller Energy Resources, Inc. and subsidiaries as of April 30, 2012 and 2011, and the related consolidated statements of operations, stockholders' equity, and cash flows for the years then ended. This material weakness was considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2012 consolidated financial statements, and this report does not affect our report dated July 16, 2012, which expressed an unqualified opinion on those consolidated financial statements.

In our opinion, because of the effect of the aforementioned material weakness on the achievement of the objectives of the control criteria, the Company has not maintained effective internal control over financial reporting as of April 30, 2012, based on the criteria established in Internal Control - Integrated Framework issued by the COSO.

/s/ KPMG LLP
Knoxville, Tennessee
July 16, 2012

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Miller Energy Resources, Inc.:

We have audited the accompanying consolidated balance sheets of Miller Energy Resources, Inc. and subsidiaries (the Company) as of April 30, 2012 and 2011, and the related consolidated statements of operations, stockholders' equity, and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated 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 Miller Energy Resources, Inc. and subsidiaries as of April 30, 2012 and 2011, and the results of their operations and their cash flows for the years then ended, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Miller Energy Resources, Inc.'s internal control over financial reporting as of April 30, 2012, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organization of the Treadway Commission (COSO), and our report dated July 16, 2012 expressed an adverse opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP
Knoxville, Tennessee
July 16, 2012

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of Miller Energy Resources, Inc. a/k/a Miller Petroleum, Inc.:
We have audited the accompanying consolidated balance sheet of Miller Energy Resources, Inc. as of April 30, 2010 and the related consolidated statements of operations, stockholders' equity (deficit), and cash flows for the year ended April 30, 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our 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 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 principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Company as of April 30, 2010, and the results of its operations and cash flows for the year ended April 30, 2010, in conformity with generally accepted accounting principles in the United States.

/s/ Sherb & Co., LLP
SHERB & CO, LLP
Certified Public Accountants

New York, New York
July 25, 2010

Table of Contents

MILLER ENERGY RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS

	April 30, 2012	2011
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$3,971	$1,559
Restricted cash	2,250	203
Accounts receivable	3,107	1,620
State production credits receivable	2,958	3,620
Inventory	1,835	1,043
Prepaid expenses and other	482	259
	14,603	8,304
OIL AND GAS PROPERTIES, NET	475,802	482,052
EQUIPMENT, NET	33,728	8,107
OTHER ASSETS:		
Land	542	527
Restricted cash, non-current	9,875	10,027
Other assets	1,839	64
	$536,389	$509,081
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$9,504	$7,496
Accrued expenses	6,744	4,185
Short-term portion of derivative instruments	2,803	2,305
Current debt	24,130	2,000
	43,181	15,986
OTHER LIABILITIES:		
Deferred income taxes	167,319	178,326
Asset retirement obligation	18,366	17,294
Long-term portion of derivative instruments	7,700	2,733
	236,566	214,339
COMMITMENTS AND CONTINGENCIES (Notes 6, 8 and 10)		
MEZZANINE EQUITY:		
Series A cumulative preferred stock, redemption amount of $11.2 million	8,818	—
STOCKHOLDERS' EQUITY:		
Common stock, $0.0001 par, 500,000,000 shares authorized, 41,086,751 and 39,880,251 shares issued and outstanding, respectively	4	4
Paid-in capital	64,813	49,013
Retained earnings	226,188	245,725
	291,005	294,742
	$536,389	$509,081

See accompanying notes to consolidated financial statements.

Table of Contents

MILLER ENERGY RESOURCES, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Year Ended April 30,		
	2012	2011	2010
	(In thousands, except share and per share data)		
REVENUES:			
Oil sales	$31,880	$20,360	$4,430
Natural gas sales	613	726	372
Other	2,909	1,756	1,065
	35,402	22,842	5,867
OPERATING EXPENSES:			
Oil and gas operating	14,861	9,703	2,738
Cost of other revenue	926	808	755
General and administrative	29,718	14,555	10,263
Exploration expense	1,241	—	—
Depreciation, depletion and amortization	13,310	10,961	3,110
Accretion of asset retirement obligation	1,072	1,407	315
Other operating expense (income), net	(641)	—	—
	60,487	37,434	17,181
OPERATING LOSS	(25,085)	(14,592)	(11,314)
OTHER INCOME (EXPENSE):			
Interest income	10	546	27
Interest expense	(1,847)	(1,480)	(157)
Loss on derivatives, net	(2,832)	(1,008)	(13,299)
Gain on acquisitions	—	6,910	461,112
Other income (expense), net	58	(537)	(751)
	(4,611)	4,431	446,932
INCOME (LOSS) BEFORE INCOME TAXES	(29,696)	(10,161)	435,618
Income tax provision (benefit)	(11,006)	(6,281)	184,677
NET INCOME (LOSS)	(18,690)	(3,880)	250,941
Accretion of preferred stock	847	—	—
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCKHOLDERS	$(19,537)	$(3,880)	$250,941
NET INCOME (LOSS) PER COMMON SHARE:			
Basic	$(0.48)	$(0.11)	$11.65
Diluted	$(0.48)	$(0.11)	$8.34
WEIGHTED AVERAGE NUMBER OF COMMON SHARES:			
Basic	40,811,308	36,112,286	21,537,677
Diluted	40,811,308	36,112,286	30,092,017

See accompanying notes to consolidated financial statements.

Table of Contents

MILLER ENERGY RESOURCES, INC.
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock		Additional Paid-in Capital	Retained Earnings (Deficit)	Total
	Shares	Amount			
BALANCE AT APRIL 30, 2009	15,974,356	$2	$8,555	$(1,336)	$7,221
Net income	—	—	—	250,941	250,941
Issuance of equity for cash	7,893,432	1	7,800	—	7,801
Issuance of equity for acquisitions	2,000,000	—	2,641	—	2,641
Issuance of equity for compensation	100,000	—	1,662	—	1,662
Issuance of equity for financing	1,679,250	—	2,962	—	2,962
Issuance of equity for services	469,100	—	1,736	—	1,736
Exercise of equity rights	2,017,847	—	282	—	282
Beneficial conversion features	—	—	809	—	809
Conversion of notes	2,090,909	—	1,150	—	1,150
BALANCE AT APRIL 30, 2010	32,224,894	3	27,597	249,605	277,205
Net loss	—	—	—	(3,880)	(3,880)
Issuance of equity for services	30,000	—	1,881	—	1,881
Issuance of equity for equipment	100,000	—	453	—	453
Issuance of equity for compensation	162,500	—	4,516	—	4,516
Exercise of equity rights	4,262,858	1	12,861	—	12,862
Conversion of notes	3,099,999	—	1,705	—	1,705
BALANCE AT APRIL 30, 2011	39,880,251	4	49,013	245,725	294,742
Net loss	—	—	—	(18,690)	(18,690)
Accretion of preferred stock	—	—	—	(847)	(847)
Issuance of equity for services	130,000	—	1,501	—	1,501
Issuance of equity for compensation	107,500	—	12,916	—	12,916
Exercise of equity rights	969,000	—	1,383	—	1,383
BALANCE AT APRIL 30, 2012	41,086,751	$4	$64,813	$226,188	$291,005

See accompanying notes to consolidated financial statements.

F-6

Table of Contents

MILLER ENERGY RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Year Ended April 30,		
	2012	2011	2010
	(In thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$(18,690)	$(3,880)	$250,941
Adjustments to reconcile net income (loss) to net cash provided (used) by operating activities:			
Depreciation, depletion and amortization	13,310	10,961	3,110
Amortization of deferred financing costs	1,123	491	—
Accretion expense	1,072	1,407	315
Gain on acquisitions	—	(6,910)	(461,112)
Loss on sale of equipment	—	626	—
Write off of prepaid offering cost	—	—	666
Expense from issuance of equity	14,072	5,126	4,514
Dry hole costs and leasehold impairments	1,061	—	—
Deferred income taxes	(11,006)	(6,281)	184,677
Unrealized loss on derivative instruments, net	3,436	1,008	13,299
Changes in operating assets and liabilities, net of effects of acquisitions:			
Receivables, net	(808)	(2,669)	(2,429)
Inventory	(235)	(768)	(222)
Prepaid expenses and other assets	(654)	1,448	1,564
Accounts payable and accrued expenses	4,220	7,306	3,676
Asset retirement obligation	—	(131)	271
NET CASH PROVIDED (USED) BY OPERATING ACTIVITIES	6,901	7,734	(730)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Purchase of equipment and improvements	(26,409)	(825)	(750)
Capital expenditures for oil and gas properties	(7,558)	(10,490)	(4,153)
Acquisition of Cook Inlet Energy, LLC	—	—	(4,541)
NET CASH USED IN INVESTING ACTIVITIES	(33,967)	(11,315)	(9,444)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Payments on debt	(8,764)	(3,500)	(3,763)
Debt acquisition costs	(2,140)	—	(619)
Proceeds from borrowings	30,894	5,500	5,576
Proceeds from sale of shares	10,000	—	9,646
Cash acquired through acquisition	—	—	204
Exercise of equity rights	1,383	1,266	282
Restricted cash	(1,895)	(1,121)	1,796
NET CASH PROVIDED BY FINANCING ACTIVITIES	29,478	2,145	13,122
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	2,412	(1,436)	2,948
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	1,559	2,995	47
CASH AND CASH EQUIVALENTS AT END OF YEAR	$3,971	$1,559	$2,995
SUPPLEMENTARY CASH FLOW DATA:			
Cash paid for interest	$1,986	$824	$603

See accompanying notes to consolidated financial statements.

F-7

MILLER ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

We are an independent exploration and production company that utilizes seismic data and other technologies for the geophysical exploration, development and production of oil and natural gas wells in the Cook Inlet Basin of southcentral Alaska and the Appalachian region of eastern Tennessee. The accounting policies used by us and our subsidiaries reflect industry practices and conform to accounting principles generally accepted in the U.S. ("GAAP"). Certain reclassifications have been made to prior periods to conform to current-year presentation. Significant policies are discussed below.

Principles of Consolidation

The accompanying consolidated financial statements include our consolidated accounts, including the accounts of our wholly-owned subsidiaries (collectively, the "Company"), after elimination of intercompany balances and transactions. The consolidated financial statements also include the accounts of all investments in which we, either through direct or indirect ownership, have more than a 50% interest or significant influence over the management of those entities.

Risks and Uncertainties

Factors that could affect our future operating results and cause actual results to vary materially from management's expectation include, but are not limited to: the capital intensive nature of our business and our ability to maintain and secure adequate capital to fully develop our operations and assets; our ability to perform under the terms of the Alaska Oversight Agreement with the Alaska Department of Natural Resources ("DNR"), including meeting the funding requirements of that agreement; the imprecise nature of our reserve estimates; our ability to recover proved undeveloped reserves and convert probable and possible reserves to proved reserves; fluctuating oil and natural gas prices; changes in environmental or regulatory requirements; our ability to control expenses; and the impact of changes in accounting principles. Negative developments in these or other risk factors could have a significant adverse effect on our financial position, results of operations and cash flows.

Use of Estimates

The preparation of consolidated financial statements in conformity with U.S. generally accepted accounting principles requires us to make a number of estimates and assumptions relating to the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about carrying values of assets and liabilities that are not readily apparent from other sources. We evaluate our estimates and assumptions on a regular basis. Actual results may differ from these estimates and assumptions used in preparation of its financial statements and changes in these estimates are recorded when known. Significant estimates made in preparing these financial statements include the fair value determination of acquired assets and liabilities (see Note 2 - Acquisitions), the estimate of proved oil and gas reserves and related present value estimates of future net cash flows therefrom (see Supplemental Oil and Gas Disclosures (Unaudited)), assessing asset retirement obligations (see Note 5 - Asset Retirement Obligations) and the estimate of income taxes (see Note 7 - Income Taxes).

Cash Equivalents

We consider all highly liquid short-term investments with a maturity of three months or less at the time of purchase to be cash equivalents. These investments are carried at cost, which approximates fair value due to their short-term nature.

Restricted Cash
Current restricted cash balances include amounts held in escrow to secure company related credit cards. As of April 30, 2012, current restricted cash also includes $2.0 million of cash temporarily held in an account that is controlled by our lender. Non-current restricted cash balances include amounts held in escrow to provide for the future plugging and abandonment of wells, including the possible dismantling of our off-shore platform, and general liability bonds.

Accounts Receivable and Allowance for Doubtful Accounts
Accounts receivable are stated at the historical carrying amount net of write-offs and allowance for uncollectible

accounts. We routinely assess the recoverability of all material customer and other receivables to determine their collectability and record a reserve when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of the reserve may be reasonably estimated. When collection is no longer pursued, we charge uncollectible accounts receivable against the reserve. As of April 30, 2012 and 2011, all of our accounts receivable were considered fully collectible and, therefore, no reserve was established.

Inventory

Inventory consists of crude oil produced but not sold stated at the lower of cost or market.

Oil and Gas Properties

We follow the successful efforts method of accounting for oil and gas properties. Under this method, exploration costs such as exploratory geological and geophysical costs, delay rentals and exploration overhead are charged against earnings as incurred. Acquisition costs and costs of drilling exploratory wells are capitalized pending determination of whether proved reserves can be attributed to the area as a result of drilling the well. If management determines that commercial quantities of hydrocarbons have not been discovered, capitalized costs associated with exploratory wells are charged to exploration expense.

Costs of drilling and equipping successful wells, costs to construct or acquire facilities and associated asset retirement costs are depreciated using the unit-of-production method based on estimated total proved reserves. Costs of acquiring proved properties, including leasehold acquisition costs transferred from unproved properties and costs to construct or acquire offshore platforms and associated asset retirement costs, are depleted using the unit-of-production method based on estimated total proved reserves.

Acquisition costs of unproved properties are assessed for impairment during the holding period and transferred to proved oil and gas properties to the extent the costs are associated with successful exploration activities. Significant undeveloped leases are assessed individually for impairment, based on our current exploration plans, and a valuation allowance is provided if impairment is indicated. Costs of expired or abandoned leases are charged to expense, while costs of productive leases are transferred to proved oil and gas properties. Costs of maintaining and retaining unproved properties and impairment of unsuccessful leases are included in oil and gas operating expense. In fiscal 2012, our consolidated statement of operations include $0.3 million related to impairment of certain unproved properties and $0.9 million in seismic and dry hole costs incurred in the Cook Inlet region.

Equipment

Equipment includes drilling rigs, automobiles, trucks, an airplane, office furniture, computer equipment and buildings. These items are recorded at cost and are depreciated on the straight-line method based on expected lives of the individual assets or group of assets, which range from five to forty years.

Equipment is reviewed for impairment when facts and circumstances indicate that book values may not be recoverable. In performing this review, an undiscounted cash flow test is performed on the impairment unit. If the sum of the undiscounted estimated future net cash flows is less than the net book value of the property, an impairment loss is recognized for the excess, if any, of the property's net book value over its estimated fair value.

Investments

The Company accounts for its investments in non-consolidated entities using the equity method of accounting and has recorded the investments within other assets in its consolidated balance sheets. The Company records equity in earnings and losses of these entities accounted for following the equity method of accounting in its consolidated statements of operations. The Company reviews investments in non-consolidated subsidiaries accounted for under the equity method for impairment whenever events or changes in circumstances indicate that the carrying amount of the investment may not be fully recoverable.

As of April 30, 2012, the Company holds a 48% interest in Pellissippi Pointe I, LLC and Pellissippi Pointe II, LLC. We lease our corporate offices from this affiliate under a five-year operating lease that was initiated in October 2011.

The Company also agreed to indemnify the sellers of the membership interests with respect to their guaranties of certain debt held by the investee, but did not become direct guarantors of the loans. As of April 30, 2012, the gross outstanding debt balance of the investee is $5.7 million. As of April 30, 2012, our equity investment was $0.4 million. We recorded a loss on this investment of less than $0.1 million during fiscal 2012.

Table of Contents

Capitalized Interest
Interest is capitalized as part of the historical cost of developing and constructing assets for significant projects. Significant investments in unproved oil and gas properties, significant exploration and development projects for which depreciation, depletion and amortization ("DD&A") is not currently recognized, and exploration or development activities that are in progress qualify for interest capitalization. Interest is capitalized until the asset is ready for service. Capitalized interest is determined based upon our weighted-average borrowing cost on debt for the average amount of qualifying costs incurred. The Company incurred $5.5 million of interest expense in fiscal 2012, of which $3.7 million was capitalized in equipment and oil and gas properties on the balance sheet. Once an asset subject to interest capitalization is completed and placed in service, the associated capitalized interest is expensed through depreciation or impairment, along with other capitalized costs related to that asset.

Asset Retirement Obligations
Asset retirement obligations ("ARO") liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with our oil and gas properties. We utilize current retirement costs to estimate the expected cash outflows for retirement obligations. We estimate the ultimate productive life of the properties, a risk-adjusted discount rate, and an inflation factor in order to determine the current present value of this obligation.
The initial estimated ARO is recorded as a liability, with an offsetting asset retirement cost recorded as an increase to the associated property and equipment on the consolidated balance sheet. If the fair value of the recorded ARO changes, a revision is recorded to both the asset retirement obligation and the asset retirement cost. Revisions in estimated liabilities can result from changes in estimated inflation rates, changes in service and equipment costs and changes in the estimated timing of an asset's retirement. Asset retirement costs are depreciated using a systematic and rational method similar to that used for the associated property and equipment. Accretion expense on the liability is recognized over the estimated productive life of the related assets.

Loss Contingencies
Accruals for loss contingencies arising from claims, assessments, litigation, environmental and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. These accruals are adjusted as additional information becomes available or circumstances change.

Revenue Recognition
Oil and natural gas sales revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Cash received relating to future revenues is deferred and recognized when all revenue recognition criteria are met.

Derivative Instruments and Hedging Activities
We periodically enter into commodity derivative contracts to hedge future production and minimize the Company's exposure to commodity price risk. These derivative contracts typically take the form of a swap contract. The oil reference prices, upon which the commodity derivative contracts are based, reflect market indices that have a high degree of historical correlation with actual prices received by us for our oil production.
We account for our derivative instruments in accordance with Accounting Standards Codification ("ASC") 815, "Derivatives and Hedging," which requires that all derivative instruments, other than those that meet the normal purchases and sales exception, be recorded on the balance sheet at fair value as either a current or non-current asset or liability, depending on the derivative position and the expected timing of settlement. Where we have a contractual right and intend to net settle, derivative assets and liabilities are reported on a net basis. Changes in fair value are recognized currently in earnings.

Stock-Based Compensation

We grant various types of stock-based awards including stock options, restricted stock units, and performance-based awards. Stock-based compensation awards granted are valued on the date of grant and are expensed, net of estimated forfeitures, over the requisite service period.

Income Taxes
Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.
We routinely assess the realizability of our deferred tax assets. If we conclude that it is more likely than not that some or all of the deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and gas prices) and changing tax laws.

Earnings Per Share
We determine "basic" earnings (loss) per share and "diluted" earnings (loss) per share in accordance with the provisions of ASC 260, "Earnings Per Share." Basic earnings (loss) per share is calculated by dividing net income (loss) attributable to common stockholders by the weighted average number of common shares outstanding during each period. The calculation of diluted earnings (loss) per share is similar to that of basic earnings per share, except that the denominator is increased, if net income is positive, to include the number of additional common shares that would have been outstanding if all potentially dilutive common shares, such as those issuable upon the exercise of stock options and warrants, had been exercised. There were no dilutive shares for the fiscal years ended April 30, 2012 and 2011 due to our net loss.

Business Combinations
We account for business combinations under the acquisition method of accounting. The acquisition method requires that the acquired assets and liabilities, including contingencies, be recorded at fair value determined on the acquisition date and that changes thereafter be reflected in income (loss). The estimation of the fair values of the assets acquired and liabilities assumed involves a number of estimates and assumptions that could differ materially from the actual amounts recorded. The results of the acquired businesses are included in our results from operations beginning from the day of acquisition.

Statement of Comprehensive Income
No statement of comprehensive income is presented since net income (loss) and comprehensive income (loss) would be the same for all periods reported.

Changes in Accounting Principles
Effective July 1, 2010, we adopted U.S. Securities and Exchange Commission ("SEC") Release 33-8995 and the amendments to ASC 932, “Extractive Industries - Oil and Gas” (the "Modernization Rules"). Under the Modernization Rules, estimated future net cash flows are calculated using end-of-period costs and an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months, held flat for the life of the production, except where prices are defined by contractual arrangements. Prior to July 1, 2010, estimated after-tax future net cash flows were calculated using commodity prices in effect at the end of each quarter.

Recently Issued Accounting Standards Not Yet Adopted
In May 2011, the FASB issued ASU 2011-04, "Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs," which amends ASC 820, “Fair Value Measurements and Disclosures.” The amended guidance clarifies many requirements in GAAP for measuring fair value and for disclosing

information about fair value measurements. Additionally, the amendments clarify the FASB's intent about the application of existing fair value measurement requirements. The guidance provided in ASU 2011-04 is effective for interim and annual periods beginning after December 15, 2011. The Company does not expect the adoption of this amendment to have a material impact on its consolidated financial statements.

In June 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2011-05, "Presentation of Comprehensive Income." ASU 2011-05 eliminates the option to report other comprehensive income and its components in the statement of changes in stockholders' equity and requires an entity to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement or in two separate but consecutive statements. This update is effective for fiscal years, and interim periods within those years beginning after December 15, 2011. In December 2011, the FASB issued ASU 2011-12, which becomes effective at the same time as ASU 2011-05, to defer the effective date of provisions of ASU 2011-05 that relate to the presentation of reclassification adjustments. We expect adoption of ASU 2011-05 or ASU 2011-12 will not have an impact on our financial position or results of operations.

In December 2011, the FASB issued ASU 2011-11, "Disclosures about Offsetting Assets and Liabilities," which increases disclosures about offsetting assets and liabilities. New disclosures are required to enable users of financial statements to understand significant quantitative differences in balance sheets prepared under GAAP and International Financial Reporting Standards ("IFRS") related to the offsetting of financial instruments. The existing GAAP guidance allowing balance sheet offsetting, including industry-specific guidance, remains unchanged. The guidance in ASU 2011-11 is effective for annual and interim reporting periods beginning on or after January 1, 2013. The disclosures should be applied retrospectively for all prior periods presented. We do not expect the adoption of this amendment to have a material impact on its consolidated financial statements.

2. ACQUISITIONS

Ky-Tenn Oil, Inc.

On June 8, 2009, we completed an acquisition of oil and gas assets from Ky-Tenn Oil, Inc. ("KTO"), a privately-held company with approximately 35,325 leased acres located on the Chattanooga Shale and 153 natural gas and oil producing wells in the Appalachian region of Tennessee. We also received $0.2 million in restricted bond certificates for well reclamation with a related liability. The transaction was funded with 1,000,000 shares of the Company's common stock, which was valued at $0.3 million at the date of acquisition.

A third-party expert was engaged to perform a valuation to estimate the fair value of the business acquired. The valuation was prepared utilizing methods and procedures regularly used by petroleum engineers to estimate oil and gas reserves for properties of this type and character. In accordance with ASC 810, “Business Combinations”, the $1.0 million pre-tax difference between the estimated fair value of the acquired business less the fair value of our common stock consideration was recorded as “gain on acquisitions” in our consolidated statement of operations.

We determined that pro-forma information related to this acquisition was not required (or useful to investors) due to the fact that this business combination was not material in relation to our consolidated financial statements. As 92 of the 153 wells acquired were shut in, and approximately 81% of the value of the well interests acquired were for undeveloped locations, pro-forma results would not have differed materially from actual results.

East Tennessee Consultants, Inc.

On June 18, 2009, we acquired East Tennessee Consultants, Inc., a Tennessee corporation, and East Tennessee Consultants II, LLC, a Tennessee limited liability company (together, "ETC"). The acquisition included 221 producing oil and gas wells and approximately 4,442 leased acres. The transaction was funded by 1,000,000 shares of our common stock, which was valued at $0.3 million at the date of acquisition. In accordance with ASC 810, the $1.4 million pre-tax difference between the estimated fair value of the acquired business less the fair value of our common stock consideration was recorded as “gain on acquisitions” in our consolidated statement of operations.

The following table summarizes the fair value estimates of assets acquired and liabilities assumed in the acquisition as well as the bargain purchase gain determined in accordance with the provisions of ASC 810:

Table of Contents
MILLER ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	(In thousands)
Cash	$204
Receivables	25
Fixed assets	313
Oil and gas properties	1,319
Other assets	1
Total assets acquired	1,862
Accounts payable	(202)
Net assets acquired	1,660
Fair value of equity issued	(250)
Pre-tax gain on acquisition	$1,410

The acquisition of ETC increased our revenues by $0.8 million and costs of revenues by $0.4 million for fiscal 2010. The impact of this business combination on all other line items within our consolidated statement of operations was insignificant.

Cook Inlet Energy, LLC and Pacific Energy Resources
On December 10, 2009, we acquired Cook Inlet Energy, LLC ("CIE"), an independent exploration and production company headquartered in Anchorage, Alaska in exchange for warrants to purchase 3,500,000 shares of the Company's common stock. The warrants were issued in three tranches with vesting features ranging from immediate to four years and with exercise prices ranging from $0.01 to $2.00 per share. The fair value of the warrants was determined to be $2.1 million. In addition, the Company was obligated to deliver $0.3 million in cash by March 10, 2010 to satisfy certain expenses as well as reimbursement for reasonable out of pocket expenses.
Simultaneously, CIE acquired a business from Pacific Energy Resources (“Pacific Energy”) through a Delaware Chapter 11 Bankruptcy proceeding. The acquisition included the West McArthur River oil field, the West Foreland natural gas field, the Redoubt unit with the Osprey offshore platform, 602,000 acres of oil and gas leases and licenses, completed 3D seismic geology and other production facilities, and proven reserves. At closing, the Company paid Pacific Energy $2.3 million in cash and provided $2.2 million for bonds, contract cure payments and other federal and state of Alaska requirements to operate the facilities.
The following table summarizes the fair values of assets acquired and liabilities assumed in the acquisition as well as the bargain purchase gain determined in accordance with the provisions of ASC 810.

	(In thousands)
Restricted cash	$1,790
Inventory	212
Fixed assets	2,517
Oil and gas properties	476,035
Total assets acquired	480,554
Accounts payable	(2,230)
Asset retirement obligation	(15,290)
Total liabilities assumed	(17,520)
Net assets acquired	463,034
Cash paid at closing	(2,250)
Fair value of equity issued	(2,072)
Pre-tax gain on acquisition	458,712
Deferred income taxes	(184,703)
After-tax gain on acquisition	$274,009

Due to the lack of accounting records and related financial data maintained prior to the acquisition, we were unable to prepare pro-forma information for disclosure. However, we believe the usefulness of such information would have been limited since a significant portion of the assets were not operational at the date of acquisition.

3. DERIVATIVE INSTRUMENTS

We are exposed to fluctuations in crude oil prices on the majority of our production. As a result, our management believes it is prudent to manage the variability in cash flows by occasionally entering into hedges on a portion of our crude oil production. We primarily utilize swap contracts to manage fluctuations in cash flows resulting from changes in commodity prices and account for these instruments as derivative assets or liabilities measured at fair value on a recurring basis in accordance with the provisions of ASC 815, "Derivatives and Hedging."
From time to time we issue warrants in connection with certain of our equity transactions. Certain warrants contain exercise reset provisions which are considered freestanding derivatives and are accounted for as liabilities measured at fair value in accordance with ASC 815.

Derivative Instruments
Commodity Derivatives
As of April 30, 2012, we had the following open crude oil derivative positions:

	Fixed-Price Swaps	
Production Period:	Bbls	Weighted Average Fixed Price
2013	243,500	$94.65
2014	219,000	92.82
2015	147,000	92.50

Warrant Derivatives
Series A Cumulative Preferred Stock In April 2012, purchasers of our Series A preferred stock were issued warrants to purchase an aggregate amount of 1,000,000 shares of our common stock at an exercise price of $5.28 per share. These warrants are subject to a reset provision requiring adjustment of the exercise price, from $5.28 to $3.00, if the preferred stock is not redeemed within 30 days of our refinancing and repayment of the Guggenheim credit facility (see Note 8 - Capital Stock).
Warrants Issued in Connection with Other Equity Transactions On March 26, 2010, purchasers of our common stock and certain third party consultants were issued warrants to purchase an aggregate amount of 817,055 shares of our common stock at an exercise price of $5.28 per share. Under the terms of the respective agreements, an adjustment to the exercise price is required if, at any time after issuance, we issue warrants at an exercise price lower than $5.28. As of April 30, 2012, 767,055 warrants remained outstanding.

At April 30, 2010, the Company had additional warrants with reset provisions outstanding for the purchase of 2,930,000 shares of the Company's common stock. During the year ended April 30, 2011, 2,650,000 of the warrants were forfeited in connection with a settlement agreement and the reset provision for the remaining 300,000 was removed (see Note 8 - Capital Stock).

Fair Value Measurements
As of April 30, 2012 and 2011, the fair market value of our derivative liabilities is as follows:

	As of April 30, 2012	2011
	(In thousands)	
Current liabilities:		
Commodity derivatives	$2,803	$2,305
Warrant derivatives	—	—
Current portion of derivative instruments	2,803	2,305
Long-term liabilities:		
Commodity derivatives	2,551	—
Warrant derivatives	5,149	2,733
Long-term portion of derivative instruments	7,700	2,733
Total derivative liability	$10,503	$5,038

Commodity Derivatives

Our commodity derivatives consist of variable-to-fixed price commodity swaps. The fair values of our commodity derivatives are not actively quoted in the open market, thus we use an income approach to estimate fair value. The use of commodity derivative instruments also exposes us to counterparty credit risk, or the risk that a counterparty will be unable to meet its commitments. Thus, to minimize this exposure, we utilize an investment-grade rated counterparty. In measuring fair value, we also take into account the impact of counterparty risk on our derivative instruments and use observable market data for credit default swaps to assess the impact of non-performance credit risk when evaluating our net assets from the counterparty. We use the cumulative S&P default rating for small, independent exploration and production companies to assess the impact of non-performance credit risk when evaluating our net obligations to the counterparty. As of April 30, 2012 and 2011, the effect of non-performance risk on our commodity derivatives was negligible.

Warrant Derivatives

Due to their reset provisions, our warrants are considered freestanding derivative instruments and are given liability treatment with fair value measured on a recurring basis in accordance with the provisions of ASC 820, "Fair Value Measurements."

Series A Cumulative Preferred Stock We utilized a binomial, or lattice model, to value the warrants. In selecting a binomial tree model, we evaluated the model's capability to incorporate certain provisions present in these financial instruments and believe it is consistent with the fair value measurement objectives and requirements under ASC 820. A binomial tree valuation model uses a "discrete-time" (lattice based) model of the varying price over the term of the underlying financial instrument. Each node in the lattice represents a possible price of the underlying (stock price) at a given point in time. Valuation is performed iteratively, starting at each of the final nodes (those that may be reached at the time of expiration), and then working backwards through the tree towards the first node (valuation date). When valuing the warrant instruments, a lattice representing all possible paths the stock price could take during the life of the conversion and a lattice representing variations in the strike price if certain conditions are met are developed and used in concert.

The following weighted average assumptions were used to determine fair value at April 30, 2012: risk-free rate of 0.4%, expected volatility of 83% and an expected term of 3 years. As of April 30, 2012, the warrants had an aggregate fair value of $2.9 million.

Warrants Issued in Connection with Other Equity Transactions As of April 30, 2012, warrants issued on March 26, 2010 had an aggregate fair value of $2.4 million. To determine fair value, we utilized the Black-Scholes model with the following weighted average assumptions: risk-free rate of 0.4%, expected volatility of 83% and an expected term of 2.9 years. As of April 30, 2011, warrants issued on March 26, 2010 had an aggregate fair value of $2.7 million. To determine fair value, we utilized the Black-Scholes model with the following weighted average assumptions: risk-free rate of 1.4%, expected volatility of 77% and an expected term of 3.9 years.

Fair Value Hierarchy

ASC 820 provides a hierarchy that prioritizes and defines the types of inputs used to measure fair value. The fair value hierarchy gives the highest priority to Level 1 inputs, which consist of unadjusted quoted prices for identical instruments in active markets. Level 2 inputs consist of quoted prices for similar instruments. Level 3 valuations are derived from inputs that are significant and unobservable; hence, these valuations have the lowest priority.

The valuation techniques that may be used to measure fair value include a market approach, an income approach, and a cost approach. A market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. An income approach uses valuation techniques to convert future amounts to a single present amount based on current market expectations, including present value techniques, option-pricing models, and excess earnings method. The cost approach is based on the amount that currently would be required to replace the service capacity of an asset (replacement cost).
As of April 30, 2012 and 2011, all of our derivatives were classified as Level 2 instruments due to the lack of quoted prices readily available in an active market. The following table presents the hierarchy classification of our derivative instruments:

	Fair Value Measurements		
	Level 1	Level 2	Level 3
	(In thousands)		
At April 30, 2012			
Commodity derivatives	$—	$5,354	$—
Warrant derivatives	—	5,149	—
Total	$—	$10,503	$—
At April 30, 2011			
Commodity derivatives	$—	$2,305	$—
Warrant derivatives	—	2,733	—
Total	$—	$5,038	$—

Derivative Activities Reflected on Consolidated Statements of Operations

Changes in the fair value of our derivative liabilities are recorded in loss of derivatives, net on our consolidated statement of operations:

	For the Year Ended April 30,		
	2012	2011	2010
	(In thousands)		
Realized gain recognized in earnings	$604	$—	$—
Unrealized loss recognized in earnings	(3,436)	(1,008)	(13,299)
Loss on derivatives, net	$(2,832)	$(1,008)	$(13,299)

On June 6, 2012, the Company terminated the commodity derivative contracts in place of April 30, 2012 (see Note 16 - Subsequent Events).

4. DEBT

As of April 30, 2012 and 2011, we had the following debt obligations reflected at their respective carrying values on our consolidated balance sheets:

	As of April 30	
	2012	2011
	(In thousands)	
Guggenheim senior secured credit facility	$24,130	$—
PlainsCapital Bank line of credit	—	2,000
Total debt obligations	$24,130	$2,000

Guggenheim Senior Secured Credit Facility

On June 13, 2011, we closed a senior secured credit facility, maturing on June 13, 2013, with a syndicate of lenders and Guggenheim Corporate Funding, LLC as administrative agent ("Guggenheim"). As of April 30, 2012, we had $24.1 million in outstanding loans under the facility and an additional borrowing capacity of $10.9 million. The total borrowing capacity is determined in accordance with a borrowing base calculated based on the assets of the Company, to a maximum facility amount of $100 million. The lenders have a first priority security interest in substantially all of our assets, including all of the oil and natural gas properties that we and our subsidiaries own. We are required to make monthly payments in an amount equal to 90% (or 100%, following an event of default) of our consolidated net revenues, excluding certain operating costs such as royalty interests, lease operating costs and permissible general and monthly administrative expenses up to $0.8 million. The credit facility is used to support the development our Alaska assets, with a smaller amount of the facility dedicated to certain Tennessee projects.

Unamortized debt issue costs related to this credit facility were $1.4 million as of April 30, 2012. These costs were amortized over the life of the credit facility through June 13, 2013.

The applicable interest rate used to determine our monthly interest payment was the higher of (i) the U.S. Prime Rate or (ii) 5%, plus an applicable margin of 4.5% per annum. Upon repayment of the facility, the aggregate amount of borrowings under the facility was subject to a make-whole premium, which was determined by deriving at an internal rate of return to the lenders equal to (i) 25% per annum if the facility was repaid prior to June 30, 2012, (ii) 30% per annum if the facility was repaid between July 1, 2012 and December 1, 2012, and (iii) 35% per annum if the facility was repaid after January 1, 2013.

This credit facility with Guggenheim was repaid in full and terminated on June 29, 2012, in connection with the closing of the new credit facility (see Note 16 - Subsequent Events).

In connection with the credit facility, we also entered into a shareholder's agreement, effective June 13, 2011, with Scott M. Boruff, Paul W. Boyd, David Hall, Deloy Miller and David J. Voyticky (the “Shareholders”). The shareholders agreement provided that the Shareholders may not transfer their shares of common stock while the loans under the facility are outstanding, subject to certain exceptions for Messrs. Miller and Boyd. Specifically, Mr. Miller was permitted to transfer a number of shares of our common stock beneficially owned by him which does not exceed the lesser of (a) 2,500,000 shares of common stock, and (b) a number of shares necessary for him to receive net proceeds equal to $10 million, provided that simultaneous with such transfer, we received net proceeds from a new issuance of its securities equal to two times the net proceeds received by Mr. Miller and Mr. Miller transfers the shares at the same price and for the same consideration as received by us from the new issuance. Mr. Boyd was permitted to exercise outstanding options to purchase 250,000 shares of the Company's common stock and to transfer the shares of common stock obtained upon the exercise. There were no permitted exceptions for the transfer of shares by Messrs. Boruff, Hall or Voyticky. This shareholders' agreement was terminated automatically upon the repayment of the credit facility with Guggenheim (see Note 16 - Subsequent Events).

On August 26, 2011, due to certain events of default, an amendment was executed between us and the lenders under the Guggenheim credit facility to revise, among other things, specific reporting requirements due by us under the relevant documentation, the effective date of the repayment schedule from January 2012, accelerating it to October 2011, and the determination of the make-whole premium allowing an exclusion of certain penalties, including waiver fees and interest resulting from an event of default. The amendment also required delivery of a Sarbanes-Oxley compliance report on April 30, 2012, which was delivered by us on a timely basis. In connection with the amendment, we paid a waiver fee of $0.1 million and the lenders waived the events of default.

On October 11, 2011, the lenders granted us an extension of 180 days to pay certain registration rights penalties incurred by us in connection with the March 26, 2010 private placement and required registration statement related thereto. Under section 6.19(c) of the credit facility, we were required to pay these penalties within 120 days of closing. A further extension of this payment, until October 3, 2012, was granted to us by the lenders on April 6, 2012.

The amendment and the waiver discussed above ceased to be effective and were terminated upon repayment of the Guggenheim credit facility (see Note 16 - Subsequent Events).

At the time we filed our Quarterly Report on Form 10-Q for the fiscal third quarter ended January 31, 2012, our preliminary assessment indicated that we were in compliance with the financial covenant ratios and all other compliance requirements contained in our credit facility as of January 31, 2012. After delivery of the compliance report to our lenders, the administrative agent informed us that they elected to disallow certain expenses that we categorized as extraordinary or one-time expenses and had accordingly revised our compliance calculations. These changes caused us to fail to meet our financial covenant ratios for the third fiscal quarter of 2012.

As of April 30, 2012 and for the quarter then ended, we were required to maintain (i) an Interest Coverage Ratio at minimum of 5.00 to 1.00, (ii) an Asset Coverage Ratio at minimum of 3.00 to 1.00 and (iii) minimum gross production of an average of 1,250 barrels of oil (or the equivalent, where six McF of natural gas is deemed equivalent to one barrel of oil) per day from the Alaska operations. Although the repayment and termination of the Guggenheim credit facility renders any specific anticipated default not to be meaningful, we concluded that we were not in compliance with the financial covenant ratios and all other compliance requirements contained in our credit facility as of April 30, 2012.

PlainsCapital Bank Line of Credit

On December 22, 2010, we entered into $5 million line of credit with PlainsCapital Bank as sole lender. Under the terms of the agreement, all obligations under this loan was personally guaranteed by our Chairman of the Board and CEO, including a personal pledge of a portion of their shares of our common stock. The line of credit matured on July 15, 2011 and was satisfied in full by us utilizing funds drawn under the Guggenheim credit facility.

5. ASSET RETIREMENT OBLIGATIONS

The following table describes changes to the Company's ARO liability for the years ended April 30, 2012 and 2011:

	2012	2011
	(in thousands)	
Asset retirement obligation, beginning of year	$17,294	$16,018
Accretion expense	1,072	1,407
Revisions	—	(131)
Asset retirement obligation, end of year	$18,366	$17,294

6. COMMITMENTS AND CONTINGENCIES

On November 5, 2009, CIE entered into an Assignment Oversight Agreement with the Alaska DNR which set out certain terms under which the Alaska DNR would approve the assignment of certain specified state oil and gas leases from Pacific Energy to CIE. This agreement remains in place following our acquisition of CIE in December 2009. Generally, the agreement requires CIE to provide the Alaska DNR with additional information and oversight authority to ensure that CIE is acting diligently to develop the oil and gas from Redoubt Shoal, West McArthur River Field and West Foreland Field. Under the terms of the agreement, until the Alaska DNR determines, in its sole discretion, that CIE has completed its development and operational obligations under the assigned leases, CIE agreed to the following:

- file a monthly summary of expenditures by oil and gas filed, tied to objectives in CIE's business plan and plan of development previously presented to the Alaska DNR,
- meet monthly with the Alaska DNR to provide an update on operations and progress towards meeting these objectives,
- notify the Alaska DNR 10 days prior to commitment when CIE is preparing to spend funds on a purchase, project or item of more than $0.1 million during the first 12 months, more than $1 million during the second 12 months and more than $5 million thereafter, and
- submit a new plan of development and plan of operations for the Alaska DNR's approval on or before December 15, 2009 and submit a plan of development annually thereafter on or before February 1, 2010.

The agreement required CIE to obtain financing in the minimum amount of $5.2 million to provide funds to be used for expenditures approved by the Alaska DNR as part of CIE's plan of development. The funds are to be used for workover and repair of the wells, repair of the physical infrastructure, construction of a grind and inject plant at the West McArthur River facility, normal operating expenses associated with the leases and infrastructure and other capital project which are to be pre-approved by the Alaska DNR. The agreement also required CIE to demonstrate funding commitments to support restoration of the base production at the Redoubt Unit, including bringing a number of the shut-in wells back on line, which was estimated at $31 million in the agreement but which we have internally increased to $35 million to accommodate the purchase of a drilling rig. We have subsequently provided these funds for the West McArthur River facility using a portion of the proceeds of our capital raising efforts described elsewhere herein, and intend to seek alternative sources of funding for the balance of the necessary capital.

CIE is prohibited from using any of the proceeds from the operations under the assigned leases of the funding commitments for non-core oil and gas activities under the assigned leases, or any activities outside the assigned leases, without the prior written approval of the Alaska DNR until the parties mutually agree that the full dismantlement obligation under the assigned leases is funded. The assigned leases will be subject to default and termination should CIE fail to submit the information required under the agreement and expenditure of funds for items or activities do not support core oil and gas activities, as reasonably determined by the Alaska DNR.

On March 11, 2011, the Company entered into a Performance Bond Agreement under its Assignment Oversight Agreement with the state of Alaska. Under the Performance Bond Agreement, the Company is required to post a total bond of $18 million for the dismantling and abandonment of the properties. The Performance Bond Agreement also stipulates that $6 million held by the state in an escrow account will be credited towards the $18 million. Until this point in time, the Company could not verify that they had legal rights to the escrow account. As a result, the Company recorded a $6.9 million (which includes $0.9 million of accrued interest) gain on acquisition during the year ended April 30, 2011.

The Company is obligated to pay the remaining $12 million (subject to annual inflation adjustments) through annual payments as follows (in thousands):

July 1, 2013	$1,000
July 1, 2014	1,500
July 1, 2015	2,000
July 1, 2016	2,500
July 1, 2017	2,000
July 1, 2018	1,500
July 1, 2019	1,500
	$12,000

Other Commitments

In August 2008, we engaged a related party broker-dealer and member of FINRA, The Dimirak Companies ("Dimirak"), to assist us in raising capital by means of a private placement of securities. As initial compensation for their services, we paid a $25,000 retainer and issued 250,000 shares of our common stock, valued at $0.1 million and agreed to pay a monthly consulting fee of $5,000. Upon the successful completion of the private offering we will be obligated to pay the firm certain cash compensation and issue them up to an additional 150,000 shares of our common stock in amounts to be determined based upon the gross proceeds received by us from the financing.

7. INCOME TAXES

The components of income tax expense (benefit) are as follows:

	For the Year Ended April 30,		
	2012	2011	2010
	(In thousands)		
Federal:			
Current	$—	$—	$—
Deferred	(10,168)	(1,992)	143,513
Total	(10,168)	(1,992)	143,513
State:			
Current	—	—	—

Deferred	(838)	(4,289)	41,164
Total	(838)	(4,289)	41,164
Total income tax expense (benefit)	$(11,006)	$(6,281)	$184,677

Table of Contents
MILLER ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

A reconciliation of the provision for income taxes as reported and the amount computed by multiplying income before taxes by the U.S. federal statutory rate of 35% is as follows:

	For the Year Ended April 30,		
	2012	2011	2010
Provision calculated at federal statutory rate	(35.0)%	(35.0)%	35.0%
State and local income taxes, net of federal benefit	(7.8)	(5.6)	6.2
Change in effective state tax rate	5.0	(22.1)	—
Other	0.7	0.9	1.2
Total income tax expense (benefit)	(37.1)%	(61.8)%	42.4%

Significant components of the Company's net deferred tax assets (liabilities) consist of the following:

	April 30,		
	2012	2011	2010
	(In thousands)		
Deferred tax assets:			
Unrealized derivative loss	$2,198	$890	$116
Asset retirement obligation	4,703	7,243	6,551
Net operating loss carryforwards	12,811	7,696	5,924
Stock options and warrants	7,308	2,555	763
Other	907	9	6
Gross deferred tax assets	27,927	18,393	13,360
Deferred tax liabilities:			
Oil and gas properties and equipment in excess of tax basis	(194,950)	(196,616)	(197,514)
Other	(296)	(103)	(453)
Gross deferred tax liabilities	(195,246)	(196,719)	(197,967)
Net deferred tax liability	$(167,319)	$(178,326)	$(184,607)

We have a significant deferred income tax liability related to the excess of the book carrying value of oil and gas properties over their collective income tax bases. This difference will reverse (through lower tax depletion deductions) over the remaining recoverable life of the properties, resulting in future taxable income in excess of income for financial reporting purposes. As an independent producer of domestic oil and gas, we take advantage of certain elective provisions presently in the Internal Revenue Code allowing for expensing of specified intangible drilling and development costs that are typically capitalized for book purposes. This temporary difference also reverses over the remaining life of the properties. Partly as a result of these elections, we presently have U.S. federal and state net operating loss carryovers that are expected to be fully utilized against future taxable income resulting solely from the reversal of the temporary differences between the book carrying value of oil and gas properties and their tax bases. At April 30, 2012, we had net operating loss carryforwards for federal income tax purposes of approximately $28.7 million with expiration through 2023.

In assessing the realizable value of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which these temporary differences become deductible. As management believes, based on assessment of both positive and negative evidence and objective and subjective evidence, that it is more likely than not that all of the deferred tax assets will be realized, we do not maintain a valuation allowance against deferred tax assets at April 30, 2012 or 2011. We are not relying on forecasts of taxable income from other sources in concluding that no valuation allowance is needed against any of our deferred tax assets. Additionally, we experienced a "section 382 ownership change" in our fiscal year ended April 30,

2010. However, we do not expect that this event will result in loss of availability of any tax attribute (such as our net operating loss carryover).

We conduct business solely in the United States and, as a result, file income tax returns in the U.S. federal jurisdiction and in Alaska and Tennessee. The taxable years ended April 30, 2012, 2011, 2010, and 2009 remain open to examination by the taxing jurisdictions to which we are subject. Additional years may be subject to examination to the extent that our net operating loss carry-forwards are utilized in an open tax year. Generally, for tax years which produce net operating losses, capital losses or tax credit carry-forwards ("tax attributes"), the statute of limitations does not close, to the extent of these tax attributes, until the expiration of the statute of limitations for the tax year in which they are fully utilized. We are not subject to any ongoing U.S. federal, state or local income tax examinations for any tax years.

In light of the adjustments to our consolidated financial statements during the year ended April 30, 2010, we have amended our U.S. federal and state income tax returns for that year, and reflected those changes as necessary in tax returns for April 30, 2011 which have now been filed. We do not expect significant cash taxes, interest, or penalties to result from these amended or delinquent filings and do not expect that the failure to timely amend or file our returns could reasonably be expected to result in a Material Adverse Change (as such term is defined under our loan agreement).

We have not identified any uncertain tax positions. No cash payments of income taxes were made during the year ended April 30, 2012, and no significant payments are expected during the succeeding 12 months.

8. CAPITAL STOCK

During the year ended April 30, 2012, we issued a total of 1,356,500 common shares, consisting of 969,000 shares issued from the exercise of equity rights, 257,500 shares issued as equity for compensation and 130,000 shares issued as equity to non-employees for services.

On April 6, 2012, we issued 100,000 shares of our Series A cumulative preferred stock (“Preferred Stock”) to 20 accredited and institutional investors in a private offering exempt from registration under the Securities Act of 1933, as amended. We received gross proceeds of $10 million and paid a finder's fee of $0.1 million to Dimirak. The Preferred Stock is non-convertible and redeemable by us, at our discretion. Holders of the Preferred Stock are entitled to dividends of 10% per annum, payable in cash or in kind, at our election, with any unpaid dividends accumulated and paid upon liquidation or redemption.

Purchasers of the Preferred Stock were also issued warrants to purchase an aggregate amount of 1,000,000 shares of our common stock, at an above-market exercise price of $5.28 per share. At issuance of the Preferred Stock, the attached warrants were treated as an embedded derivative and the fair value of the warrants was bifurcated and recorded as a derivative liability during the year ended April 30, 2012 (see Note 3 - Derivative Instruments). The remaining balance of the proceeds was allocated to the Preferred Stock. The Preferred Stock is being accreted to its redemption amount as an adjustment to net income (loss) attributable to common stockholders through June 29, 2012, the date the Preferred Stock was redeemed (see Note 16 - Subsequent Events).

On January 1, 2012, we issued 30,000 shares of common stock to a non-employee as compensation for services. The fair value of the shares issued was $0.1 million based in the closing price of our common stock on the transaction date.

On August 4, 2011, we issued 100,000 shares of common stock to Bristol Capital, LLC based on the existing consulting agreement as compensation for services rendered. The fair value of the shares issued was $0.3 million based in the closing price of our common stock on the transaction date.

On May 20, 2011, we issued 300,000 warrants to Bristol Capital, LLC as compensation for services. The warrants have an exercise price of $5.51 per share and an expiration date of May 20, 2016. The grant date fair value of $1.1 million was determined using the Black-Scholes model. Key assumptions used in the model included a risk-free rate of 1.8%, expected volatility of 86%, and an expected term of 5 years.

During the year ended April 30, 2011, we issued a total of 7,655,357 common shares, consisting of 4,262,858 shares issued from the exercise of equity rights, 3,099,999 shares issued from the conversion of $1.7 million of debt obligations, 162,500 shares issued for compensation, and 130,000 shares issued for equipment and services.

On April 29, 2011, the Company modified an existing warrant agreement to remove the exercise price reset provision. The warrant agreement is for 300,000 shares with an exercise price of $2.50 per share and an expiration date of March 12, 2015. The estimated fair value on April 29, 2011, immediately prior to the modification, was $1.3 million. Such amount was reclassified from liabilities to equity on the modification date. Key assumptions utilized in the Black-Scholes calculated fair value as of April 29, 2011, included a risk-free rate of 1.4%, expected volatility of 77%, and an expected term of 3.9 years.

On December 3, 2010, we entered into a settlement agreement with Prospect Capital Corporation (“Prospect”) whereby we issued 2,013,814 shares of our common stock in exchange for Prospect forfeiting warrants to purchase 2,148,050

shares of our common stock.
On November 17, 2010, we issued 100,000 shares of common stock to acquire a jet from three sellers, one of which is a consultant to the Company and another of which is affiliated with that consultant. The Company valued the transaction at $0.5 million based on the fair value of the shares.
On October 29, 2010, we entered into a settlement agreement with Petro Capital III, LP and Petro Capital Advisors, LLC (collectively, "Petro") and resolved litigation that had been pending in federal court in Texas. The settlement agreement resulted in the Company issuing a total of 518,510 shares of its common stock to Petro.
On October 1, 2010, we issued 100,000 warrants to an advisor as compensation for services. The warrants have an exercise price of $5.53 per share and an expiration date of October 1, 2020. The warrants had a grant date fair value of $0.4 million, which was determined using the Black-Scholes model. Key assumptions used in the model included a risk-free rate of 1.6%, expected volatility of 79%, and an expected term of 10 years.
On October 1, 2010, the Company issued 30,000 shares of our common stock to an advisor for services. The closing price of our common stock on that date was $5.53, resulting in non-cash expense of $0.2 million.
During the year ended April 30, 2010, we issued a total of 16,250,538 shares, consisting of sales of 7,893,432 shares of our common stock for net proceeds of $7.8 million, 2,090,909 shares issued from the conversion of $1.2 million in debt obligations, 2,017,847 shares issued from the exercise of equity rights, 2,000,000 shares issued as acquisition consideration, 1,679,250 shares issued for financing costs, 469,100 shares issued for services, and 100,000 shares issued for compensation.

In June 2009, the Company sold in a private transaction to accredited investors 350,000 shares of common stock, which resulted in gross proceeds to the Company of $0.1 million.

In December 2009 and January 2010, we sold 6,015,000 shares of common stock for $1.00 a share, and $0.3 million was incurred as costs to raise such equity, including the issuance of 332,500 warrants to consultants related to this sale of common stock.

In March 2010, we sold 1,433,432 shares of common stock and 716,716 warrants exercisable at $2.50 a share for $5.0 million. The warrants contained exercise reset provisions and were accounted for as a derivative liability. In addition the common stock sale agreement contained a registration requirement that the Company register the shares within 30 days or become subject to a monthly penalty of 2%. As of April 30, 2012, the shares have not been registered and the Company has accrued a penalty due of $0.6 million. The Company also incurred $0.4 million of direct costs and issued 100,339 warrants in connection with this transaction. As of April 30, 2012, 50,000 warrants have been exercised. The warrants are recorded as a derivative liability of $2.3 million and $2.7 million as of April 30, 2012 and 2011, respectively. The Company utilized the Black-Scholes model with the following weighted average assumptions as of April 30, 2012 and 2011: risk-free rate of 0.4% and 1.4%, expected volatility of 83% and 77% and expected life term of 2.9 and 3.9.

In March 2010, the Company sold 95,000 shares of common stock in a private transaction resulting in $0.3 million of gross proceeds to the Company.

Between August 2009 and April 2010, we issued a total of 1,329,250 shares of our common stock and 1,329,250 warrants to purchase additional shares of our common stock to Miller Energy Income, LP (see Note 15- Related Party Transactions).

On October 29, 2009, February 2, 2010, March 29, 2010, and April 5, 2010, we issued 469,100 shares of our common stock to third party service providers for services rendered. The shares were valued based on the closing price of our common stock on each respective grant date.

On November 3, 2009, the Company borrowed $0.4 million, with a term of sixty days. We also issued 350,000 shares of our common stock as an inducement for such loan. The fair value of the shares issued was $0.2 million based on the closing price of our common stock on the transaction date.

On December 10, 2009, we issued a warrant to purchase 1,000,000 fully vested common shares to our former President. The warrants were valued at $0.6 million using the Black-Scholes pricing model.

Table of Contents
MILLER ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

9. STOCK-BASED COMPENSATION

Our Miller Petroleum, Inc. Stock Plan and our Miller Petroleum 2011 Equity Compensation Plan (the "Plans") enable us to offer our employees, officers, directors and consultants an opportunity to acquire a proprietary interest in the Company. The Plans authorized 3,000,000 and 8,250,000 shares of common stock. The Plans allow for the issuance of incentive stock options, nonqualified stock options and shares of restricted common stock. Stock options may not be granted with an exercise price less than the fair market value on the grant date. For stockholders that own more than 10% of our common stock, incentive stock options granted must have an exercise price that is at least 10% higher than the fair market value on the grant date. Stock options granted under the Plans have a term of 10 years except for incentive stock options granted to stockholders that own more than 10% of our common stock. Such options have a term of 5 years. Vesting provisions are determined by the Compensation Committee of the Board of Directors ("Compensation Committee"). All awards issued under the Plans must be approved by the Compensation Committee. At April 30, 2012, there were 1,250,000 additional shares available for us to grant under the Plans.

We recorded $12.6 million, $3.6 million and $1.1 million of employee compensation expense related to stock options during the years ended April 30, 2012, 2011 and 2010, respectively. We also recorded $0.3 million, $0.9 million and $0.6 million related to shares of common stock issued as compensation, resulting in total employee stock-based compensation of $12.9 million, $4.5 million and $1.7 million for the years ended April 30, 2012, 2011 and 2010, respectively. The grant date fair value of employee stock options and warrants granted during the years ended April 30, 2012, 2011 and 2010 was $13.8 million, $7.4 million and $10.0 million, respectively. The weighted average grant date fair value of employee stock options and warrants granted during the 2012, 2011 and 2010 fiscal years was $3.40, $2.25 and $3.56, respectively. We estimated the grant date fair value of employee stock options and warrants using the Black-Scholes pricing model with the following weighted average assumptions:

	2012	2011	2010
Risk-free interest rate	1.4%	1.5%	2.8%
Term (in years)	4.7	3.9	5.6
Volatility	83%	63%	133%
Dividend yield	—%	—%	—%

Risk-free interest rate:

The risk-free rate for the expected term of the option is based on the U.S. Treasury yield curve at the date of grant.

Expected term:

We use the simplified method to estimate the expected term of stock options due to the fact we experienced significant structural changes to our business in connection with the December 2009 acquisition of our Alaska properties. Due to these significant structural changes we do not believe that our historical exercise data provides a reasonable basis for estimating the expected term for the current share options granted. The simplified method assumes that employees will exercise share options evenly between the period when the share options are vested and ending on the date when the share options would expire.

Expected volatility:

In addition to our own historical volatility, we also consider the historical volatility of our peer group to estimate our future volatility. This is due to the fact that we do not believe that our historical volatility is the best indicator of future volatility. Accordingly, we have weighted both our historical volatility and our peer group's historical volatility to estimate our future volatility. The weight we allocate to the historical volatility of our peer group will continue to decline over time as more of our own historical volatility information becomes available. The historical volatility of our peer group was considered for all grant dates subsequent to March 22, 2010, which is the date we filed our Form 10-Q for the third quarter ended January 31, 2010, which is the first filing that reported the financial impact of the Alaska business combination.

Expected dividend:

We have not estimated any dividend yield as we currently do not pay a dividend and do not anticipate paying a dividend over the expected term.

During the years ended April 30, 2012, 2011 and 2010, we also recorded $1.5 million, $0.6 million and $0.2 million of non-employee equity related expense for services. These expenses are included in general and administrative in our consolidated statements of operations. The grant date fair value of non-employee awards granted during 2012, 2011 and 2010 was $1.1 million, $0.4 million and $1.1 million, respectively. The weighted average grant date fair value of non-employee awards issued for services during the 2012, 2011 and 2010 fiscal years was $3.73, $4.44 and $3.78, respectively.

We estimated the grant date fair value of non-employee stock awards issued for services using the Black-Scholes pricing model with the following weighted average assumptions:

	2012	2011	2010
Risk-free interest rate	1.8%	1.6%	2.6%
Term (in years)	5.0	10.0	5.0
Volatility	86%	79%	64%
Dividend yield	—%	—%	—%

In addition, we issued 7,588,805 warrants in fiscal 2010 in connection with acquisitions, debt financings, and equity financings (see Note 8 - Capital Stock). Such warrants are included in the summarized stock option and warrant information below.

A summary of the stock options and warrants as of and for the years ended April 30, 2012, 2011 and 2010 is presented below:

	2012		2011		2010	
	Number of Options and Warrants	Weighted Average Exercise Price	Number of Options and Warrants	Weighted Average Exercise Price	Number of Options and Warrants	Weighted Average Exercise Price
Balance at beginning of year	11,079,955	$3.98	12,306,305	$2.44	4,090,000	$0.88
Granted	5,345,000	5.34	3,275,000	5.82	10,688,805	2.62
Exercised	969,000	1.43	4,360,534	0.58	2,397,500	0.03
Expired	—	—	—	—	75,000	5.67
Canceled	50,000	5.94	140,816	4.59	—	0.96
Balance at end of year	15,405,955	4.60	11,079,955	3.98	12,306,305	2.44
Options exercisable at April 30	8,268,459	3.78	5,146,625	2.67	6,843,805	1.50

The following table summarizes stock options and warrants outstanding and exercisable as of April 30, 2012:

Options and Warrants Outstanding				Options and Warrants Exercisable	
Range of Exercise Price	Number Outstanding	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$0.01 to $1.82	2,193,900	2.4	$0.73	2,131,400	$0.74
$2.00 to $4.98	2,020,000	4.4	2.78	1,553,332	2.42
$5.25 to $5.53	4,817,055	4.1	5.33	2,300,388	5.32
$5.89 to $5.94	3,750,000	8.4	5.92	1,583,338	5.94
$6.00 to $6.94	2,625,000	3.7	6.03	700,001	6.06
	15,405,955	4.9	4.60	8,268,459	3.78

The aggregate intrinsic value of stock options and warrants exercised during the years ended April 30, 2012, 2011 and 2010 was $3.8 million, $20.4 million and $3.8 million, respectively. The aggregate intrinsic value was calculated as the difference between the exercise price of the underlying awards and the quoted price of our common stock for those awards that had an exercise price below the quoted price on the exercise date. During the years ended April 30, 2012, 2011 and 2010, we received cash of $1.4 million, $1.3 million and $0.3 million for options exercised, respectively. As of April 30, 2012, we have unrecognized stock-based compensation expense of $14.3 million with a weighted average vesting term of 2.0 years, over which the expense will be recognized. The impact on our basic earnings (loss) per common share that resulted from employee stock-based non-cash compensation is $(0.31), $(0.13) and $(0.08) for the years ended April 30, 2012, 2011 and 2010.

10. LITIGATION

On October 8, 2009, we filed an action styled Miller Petroleum, Inc. v. Maynard, Civil Action No. 9992 in the Chancery Court for Scott County, Tennessee, seeking a declaratory judgment that there has been continuing commercial production of oil, and oil and gas lease owned by us is still in full force and effect. The defendant filed an Answer and Counterclaim, seeking in the Counterclaim a declaration that the oil and gas lease has expired. Although no compensatory monetary damages have been sought against us, the Counterclaim does seek attorney fees, expenses and costs. On October 27, 2010, a temporary injunction was granted allowing us access to the property at issue in this case. Since entry of the temporary injunction, production of oil from the property has resumed. Until this matter is resolved by the court, all proceeds from the new production will be subject to disposition pursuant to further orders of the court. As of this time a trial date has not yet been assigned. Given the current stage of the proceedings in this case, we currently cannot assess the probability of losses, or reasonably estimate the range of losses, related to this matter.

On May 11, 2011, the Court of Appeals of Tennessee at Knoxville returned its opinion in the case styled CNX Gas Company, LLC v. Miller Petroleum, Inc., et al. CNX Gas Company, LLC (“CNX”) commenced litigation on June 11, 2008 in the Chancery Court of Campbell County, State of Tennessee to enjoin us from assigning or conveying certain leases described in the Letter of Intent signed by CNX and our company on May 30, 2008, to compel us to specifically perform the assignments as described in the Letter of Intent, and for damages. After the trial court granted the motion for summary judgment of the company and other party defendants and dismissed the case, finding that there were no genuine issues of material fact and we were entitled to judgment as a matter of law, CNX appealed. All parties filed briefs and the Court of Appeals heard oral arguments on May 18, 2010. In its May 11, 2011 opinion, the Court of Appeals reversed the trial court's grant of summary judgment in favor of our company and the other party defendants, and remanded the case back to the trial court for further proceedings. On July 28, 2011, the case was dismissed without prejudice on the motion of CNX.

On August 4, 2011, a breach of contract case was filed against us in the United States District Court for the Eastern District of Tennessee. The case, styled CNX Gas Company, LLC v. Miller Energy Resources, Inc., Chevron Appalachia, LLC as successor in interest to Atlas America, LLC, Cresta Capital Strategies, LLC and Scott Boruff, arises from the same allegations as the previous action filed in state court and voluntarily dismissed on July 28, 2011. The federal case seeks money damages from us for breach of contract; however, unlike the previous action, it does not seek specific performance of the assignments at issue. The Plaintiff claims that the other defendants tortiously interfered with, or induced the breach of, the letter of intent between us and the Plaintiff. We have filed our Answer and intend to vigorously defend this suit. We are presently conducting discovery. Given the current stage of the proceedings in this case, we currently cannot assess the probability of losses, or reasonably estimate the range of losses, related to this matter.

On May 17, 2011, we were served with a lawsuit filed in the United States District Court for the Eastern District of Tennessee at Knoxville by Troy D. Stafford, the former Chief Financial Officer of our wholly owned subsidiary, Cook Inlet Energy, LLC. The suit, styled Troy D. Stafford v. Miller Petroleum, Inc., Civil Action No. 3-11CV-206, claims that we terminated Mr. Stafford's employment without cause in contravention of the terms of the Purchase and Sale Agreement between us and the sellers of CIE (“PSA”), failed or refused to pay his salary, severance, percentage of purchase price, expenses or stock warrant and violated a duty of good faith and fair dealing. The suit seeks damages in excess of $3,000,000, which includes $2,686,700 of damages for loss of vested warrants. We believe the all of the asserted claims are baseless, particularly in view of the fact that we issued the warrants in accordance with the terms of the PSA. We believe that we had appropriate cause to dismiss Mr. Stafford's employment after discovering that he had breached certain representations and warranties in the PSA, and had acted in violation of our Code of Conduct.

We have filed our Answer and are presently conducting discovery. Given the current stage of the proceedings in this case, we currently cannot assess the probability of losses, or reasonably estimate the range of losses, related to this matter.

On June 15, 2011, a breach of contract lawsuit was filed against us and CIE in the United States District Court for the Eastern District of Pennsylvania styled VAI, Inc. v. Miller Energy Resources, Inc., f/k/a Miller Petroleum, Inc. and Cook Inlet Energy, LLC. The Plaintiff alleges three causes of action: (1) breach of contract, (2) unfair enrichment, and (3) breach of the implied covenant of good faith and fair dealing. The case seeks damages in warrants to purchase our common stock and monetary damages for certain fees and expenses. The Sale Agreement with David Hall, Walter "JR" Wilcox, and Troy Stafford dated December 10, 2009 contains indemnification provisions relevant to this claim. We have filed a Motion to Dismiss for lack of personal jurisdiction, which is pending while limited discovery is conducted. Given the current stage of the proceedings in this case, we currently cannot assess the probability of losses, or reasonably estimate the range of losses, related to this matter.

In August 2011, several purported class action lawsuit were filed against us in the United States District Court for the Eastern District of Tennessee. The lawsuits made similar claims, and have been consolidated into one case, styled In re Miller Energy Resources, Inc. Securities Litigation. The suit names us, along with several of our current and former executive officers, Scott Boruff, Paul Boyd, Ford Graham, David Hall, and Deloy Miller, as defendants. The Plaintiffs allege two causes of action against the defendants: (1) violation of Section 10(b) and Rule 10b-5 of the Exchange Act, (2) violation of Section 20(a) of the Exchange Act. The case seeks money damages against the Company and the other defendants, and payment of the Plaintiffs' attorney's fees. We have filed a Motion to Dismiss the case. Given the current stage of the proceedings in this case, we currently cannot assess the probability of losses, or reasonably estimate the range of losses, related to this matter.

On August 23, 2011, a derivative action was filed against us in Knox County Chancery Court. The case is styled Marco Valdez, derivatively on behalf Miller Energy Resources, Inc. v. Deloy Miller, Scott M. Boruff, Jonathan S. Gross, Herman Gettelfinger, David Hall, Merrill A. McPeak, Charles M. Stivers, Don A. Turkleson, and David J. Voyticky, and Miller Energy Resources, Inc., nominal defendant. The suit alleges the following causes of action: (1) Breach of Fiduciary Duty for disseminating false and misleading information; (2) Breach of Fiduciary Duty for failure to maintain internal controls; (3) Breach of Fiduciary Duty for failing to properly oversee and manage the company; (4) Unjust Enrichment; (5) Abuse of Control; Gross Mismanagement, and; (6) Waste of Corporate Assets. The Plaintiff seeks unspecified money damages from the individual defendants, that the Company take certain actions with respect to its management, restitution to the Company, and the Plaintiff's attorney fees and costs. We have filed a Motion to Dismiss and, in the alternative, a Motion to Stay pending the outcome of the Class Action. Given the current stage of the proceedings in this case, we currently cannot assess the probability of losses, or reasonably estimate the range of losses, related to this matter.

On August 25, 2011, and August 31, 2011, two derivative actions were filed against us and our Board of Directors and former Chief Financial Officer in the United States District Court for the Eastern District of Tennessee. These cases were consolidated into Patrick P. Lukas, derivatively on behalf Miller Energy Resources, Inc. v. Merrill A. McPeak, Scott M. Boruff, Deloy Miller, Jonathan S. Gross, Herman Gettelfinger, David Hall, Charles M. Stivers, Don A., Turkleson, and David J. Voyticky, and Miller Energy Resources, Inc., nominal defendant. It contains substantially similar claims as Valdez. The suit alleges the following causes of action: (1) Breach of Fiduciary Duty for disseminating false and misleading information; (2) Breach of Fiduciary Duty for failing to properly oversee and manage the company; (3) Unjust Enrichment; (4) Abuse of Control; (5) Gross Mismanagement, and; (5) Waste of Corporate Assets. The Plaintiffs seek unspecified money damages from the individual defendants, that we take certain actions with respect to our management, restitution to us, and the Plaintiff's attorney fees and costs. We have filed a Motion to Dismiss. Given the current stage of the proceedings in this case, we currently cannot assess the probability of losses, or reasonably estimate the range of losses, related to this matter.

We are also party to various routine legal proceedings arising in the ordinary course of our business. Management believes that none of these actions, individually or in the aggregate, will have a material adverse effect on our financial condition or results of operations.

11. FAIR VALUE FINANCIAL INSTRUMENTS

Fair Value Measurements
Cash and equivalents, trade receivables, account payables and other short-term liabilities
The carrying amounts reported on our consolidated balance sheets approximate fair value because of the short-term nature or maturity of these instruments.

Credit facility

The carrying amounts reported on our consolidated balance sheets approximate fair value because the interest rates are variable and reflective of market rates.

Derivative contracts

We measure the fair value of our derivatives using multiple approaches depending on the nature of the underlying instrument (see Note 3 - Derivative Instruments).

12. FIXED ASSETS

Oil and gas properties are summarized as follows:

	April 30, 2012	2011
	(In thousands)	
Cost	$503,770	$496,926
Less accumulated depletion	(27,968)	(14,874)
Oil and gas properties, net	$475,802	$482,052

Equipment is summarized as follows:

	April 30, 2012	2011
	(In thousands)	
Machinery and equipment	$5,595	$5,455
Vehicles	1,689	1,618
Aircraft	460	453
Buildings	2,683	2,683
Leasehold improvements	423	—
Drilling rigs	3,714	—
Office equipment	533	84
Construction in progress	21,589	—
	36,686	10,293
Less accumulated depreciation	(2,958)	(2,186)
Equipment, net	$33,728	$8,107

13. MAJOR CUSTOMER AND CONCENTRATIONS OF CREDIT RISK

During the years ended April 30, 2012, 2011 and 2010, sales to Tesoro Corporation accounted for 100%, 99%, and 100%, respectively, of our total Alaska oil and gas production revenues, and accounted for 83% and 71% of our consolidated accounts receivable as of April 30, 2012 and 2011, respectively.

Credit is extended to customers based on an evaluation of their creditworthiness and collateral is generally not required. We experienced no credit losses of significance during the years ended April 30, 2012, 2011 and 2010.

We maintain our cash and cash equivalents, which at times may exceed federally insured amounts, in highly rated financial institutions. As of April 30, 2012, we held $5.2 million in excess of the $250,000 limit insured by the Federal Deposit Insurance Corporation.

14. ALASKA PRODUCTION CREDITS

During the years ended April 30, 2012 and 2011, the Company qualified for several credits under Alaska statute 43.55.023:

- 43.55.023(a)(1) Qualified capital expenditure credit on or before June 30, 2010 (20%)
- 43.55.023(1)(1) Qualified capital expenditure credit after June 30, 2010 (40%)
- 43.55.023(a)(2) Qualified capital exploration credit on or before June 30, 2010 (20%)
- 43.55.023(1)(2) Qualified capital exploration credit after June 30, 2010 (40%)
- 43.55.023(b) Carried-forward annual loss credit (25%)

The Company recognizes a receivable when the amount of the credit is reasonably estimable and receipt is probable of

occurrence (based on actual qualifying expenditures incurred). For expenditure and exploration based credits, the credit is recorded as a reduction to the related assets. For carried-forward annual loss credits, the credit is recorded as a reduction to the Alaska production tax. To the extend the credit amount exceeds the Alaska production tax, the credit is recorded as a reduction to general and administrative expenses.

During the years ended April 30, 2012 and 2011, the Company recorded $0 and $1.8 million related to the carried-forward annual loss credit, which was recorded in the consolidated statement of operations as a reduction to general and administrative expense. As of April 30, 2012 and 2011, the Company has reduced the basis of capitalized assets by $7.8 million and $3.6 million, respectively, for expenditure and exploration credits. Such reductions are recorded in our consolidated balance sheet in oil and gas properties. As of April 30, 2012 and 2011, the Company had an outstanding receivable balance from Alaska in the amount of $3.0 million and $3.6 million, respectively.

15. RELATED PARTY TRANSACTIONS

We use a number of contract labor companies to provide on-demand labor at our Alaska operations. H&H Industrial, Inc. is an entity contracted by CIE, a wholly-owned subsidiary of the Company, to provide services related to the exploration and production of oil and natural gas. The company is owned by the sister and father of David Hall, CEO of CIE and member of our Board of Directors. The Audit Committee of our Board of Directors determined that the amounts paid by us for the services performed were fair to and in the best interests of the Company. For fiscal 2012 and 2011, we paid H&H Industrial, Inc. a total of $0.6 million and $0.2 million, respectively.

On July 13, 2011, CIE entered into a consulting agreement with Jexco LLC, an entity owned by Jonathan S. Gross, a member of our Board of Directors. Under the terms of this agreement, Jexco LLC provided advice to us in areas related to seismic processing services with contractors located in Houston, Texas. As compensation for the services, we agreed to pay a flat fee of $15,000 for work performed in the Houston metropolitan area and a fee of $2,500 per day for work performed outside of the Houston metropolitan area. Further, we agreed to reimburse Jexco LLC for out of pocket expenses incurred in rendering the services to us. The agreement terminated on December 31, 2011.

On August 27, 2010, we entered into a consulting arrangement with Matrix Group, LLC (“Matrix”), an entity through which one of our directors at the time, David J. Voyticky, provided consulting services to us, including assisting us in locating strategic investments and business opportunities. During fiscal 2011, and prior to his appointment as our President (and later, Chief Financial Officer), we paid Matrix less than $0.1 million for consulting services rendered under this arrangement, together with a $0.3 million bonus for the successful closing of the credit facility on June 13, 2011. We also reimbursed Matrix less than $0.1 million for related expenses. Following Mr. Voyticky's appointment as our President, we have terminated the consulting arrangement.

Miller Energy GP, LLC, a wholly-owned subsidiary of Miller Energy Resources, Inc., owns a 1% interest in Miller Energy Income 2009-A, LP (“MEI”). MEI was organized to provide the capital required to invest in various types of oil and gas ventures including the acquisition of oil and gas leases, royalty interests, overriding royalty interests, working interests, mineral interests, real estate, producing and non-producing wells, reserves, oil and gas related equipment including transportation lines and potential investments in entities that invest in such assets except for other investment partnerships sponsored by affiliates of MEI.

Between August 2009 and April 2010, MEI sold 61.35 units of securities in a private placement resulting in gross proceeds of $3.1 million. Each unit consisted of a $50,000 limited partnership interest in MEI, together with 25,000 shares of our common stock and a five-year warrant to purchase an additional 25,000 shares with an exercise price of $1.00 per share. We issued a total of 1,329,250 shares of common stock and warrants to purchase an additional 1,329,250 shares.

On November 1, 2009, we executed a promissory note with MEI in the amount of $2.4 million payable under a four-year term with a simple interest rate of 12% per annum. A monthly interest-only payment of $23,652 was payable on the effective date of the agreement and continues each succeeding month until expiration of the note when both principal and any unpaid interests will be paid in full. On December 15, 2009, we executed a second promissory note with MEI under similar terms for $0.3 million. On May 15, 2010, we executed a third promissory note with MEI under similar terms for a final $0.4 million and granted MEI a first priority security interest in oil and gas drilling equipment owned by us. Pursuant to the terms of the agreement, a third-party escrow agent was retained to hold the certificates of title for the collateral to which title is evidenced by a certificate.

In 2009 we entered into a marketing agreement with The Dimirak Companies, an affiliate of Dimirak Financial Corp.

and Dimirak Securities Corporation, a broker-dealer and member of FINRA. Mr. Boruff, our CEO, is a director and 49% owner of Dimirak Securities Corporation. Under the terms of this agreement, we engaged The Dimirak Companies to serve as our exclusive marketing agent in a $20 million income fund and a $25.5 million drilling offering, which included the MEI offering. The term of the agreement will expire upon the termination of the offerings. We agreed to pay The Dimirak Companies a monthly consulting fee of $5,000, a marketing fee of 2% of the gross proceeds received in the offerings or within 24 months from the expiration of the term of the agreement, a wholesaling fee of 2% of the proceeds and a reimbursement of pre-approved expenses. The agreement contains customary indemnification, non-circumvention and confidentiality clauses. During fiscal 2012, 2011 and 2010 we paid The Dimirak Companies and their affiliates less than $0.1 million, $0.1 million and $0.1 million, respectively, under the terms of this agreement.

16. SUBSEQUENT EVENTS

On June 29, 2012 (the “Closing Date”), Miller Energy Resources, Inc. (“Miller”) entered into a Loan Agreement (the “Loan Agreement”) with Apollo Investment Corporation (“Apollo”), as administrative agent and sole initial lender.
The Loan Agreement provides for a $100 million credit facility (the “Apollo Credit Facility”) with an initial borrowing base of $55 million. Of that initial $55 million, $40 million was made available to, and was drawn by, Miller on the Closing Date. The remaining $15 million of the initial borrowing base will be made available following the satisfaction of certain conditions by the Company, most notably, the delivery of audited year end financials for fiscal year 2012 and the Company's demonstration (to Apollo's satisfaction) that it can raise at least $15 million in additional equity (the “Equity Requirement”). The Apollo Credit Facility matures on June 29, 2017 and is, pursuant to the Guarantee (discussed below) secured by substantially all the assets of Miller and its consolidated subsidiaries (other than MEI). Amounts outstanding under the Apollo Credit Facility bear interest at a rate of 18% per annum (unless we are in default, and the interest rate would increase by 2.5%), with interest payable on the last day of each of Miller's fiscal quarters. Miller will be required to pay the outstanding balance of the loan in full on the maturity date; however, beginning with the fiscal quarter ending on July 31, 2013, if requested by Apollo (at the direction of lenders holding a majority of the commitments under the Loan Agreement), Miller would be required to repay $1,500,000 in principal. Such payments of principal would be made, together with any interest due on such date, on the last day of Miller's fiscal quarter.
In the event Miller should be required to prepay the Apollo Credit Facility at any time prior to the second anniversary of the Closing Date, the Company would be required to pay to Apollo and the lenders a make-whole payment equal to (a) the present value of all interest that would have been become due (but for the event that required the prepayment) on or prior to that second anniversary plus (b) the outstanding principal amount of the loan multiplied by 109%. Miller has the right to voluntarily prepay the loans under the Apollo Credit Facility at any time following the second anniversary of the Closing Date. If Miller prepays principal, in whole or in part, after the second anniversary of the Closing Date, no make-whole payment would apply, but a prepayment penalty on the principal prepaid would be charged equal to (i) 109%, for any prepayment made after the second anniversary and through (and including) the third anniversary of the Closing Date and (ii) 104.5% after the third anniversary and through (and including) the fourth anniversary of the Closing Date. No prepayment penalty would be payable on principal repaid after the four-year anniversary of the Closing Date. Proceeds of certain asset sales and indebtedness and other proceeds received outside the ordinary course of business are required to be used to repay loans outstanding under the Apollo Credit Facility when received.
Draws under the Apollo Credit Facility may be made once per fiscal quarter (other than the draw of the remaining $15 million of the borrowing base not drawn on the Closing Date). Increases in the borrowing base are subject to the discretion of Apollo. The borrowing base may be redetermined up to once per calendar quarter, following a request by Miller, or at any time at the discretion of the Apollo.

The Loan Agreement contains interest coverage, asset coverage, minimum gross production and leverage covenants, as well as other affirmative and negative covenants. In connection with the Loan Agreement, Miller has granted Apollo a right of first refusal to provide debt financing for the acquisition, development, exploration or operation of any oil and gas related properties including wells during the term of the Apollo Credit Facility and one year thereafter. The Loan Agreement contains no restrictions on Miller's ability to issue new equity securities, though it does contain limitations on the payment of dividends in cash. Under the Loan Agreement, the Company must prioritize certain oil and gas development projects over others, and will be restricted from spending its cash on lower priority projects prior to the completion of those with a higher priority. A list of priorities was negotiated in connection with the closing of the Loan Agreement, and that list can only be changed with the consent of Apollo and the majority of the lenders (as measured by the relative portion of the commitments held under the Loan Agreement from time to time). This may constrain management's ability to pursue new opportunities that may present themselves from time to time, unless the Apollo and any other lenders agree to amend the existing list of priorities. Upon an event of default under the Loan Agreement, all amounts outstanding may become immediately due and payable, and the lenders may stop making advances under the Apollo Credit Facility and may terminate the agreement. An “event of default” includes, among other things, our failure to pay any amounts when due, our failure to perform under or observe any term, covenant or provision of the Loan Agreement, the occurrence of a Material Adverse Change (as that term is defined in the Loan Agreement), the seizure of or levy upon our assets or properties, our insolvency or bankruptcy, judgments against us in excess of certain amounts, defaults under certain other agreements, the limitation or termination of the any of the guarantors, which includes Miller and all of our consolidated subsidiaries (other than MEI), under the Guarantee and Collateral Agreement described below, the death or incapacitation of either Mr. David Voyticky or Mr. David Hall, or if either of them cease to be substantially involved in our operations.

On the Closing Date, we paid the Apollo a non-refundable structuring fee of $2,750,000, payable for the account of the lenders, and we have agreed to pay an addition 5% fee to Apollo for the benefit of the lenders on the amount of every additional borrowing over and above the $55 million amount of the borrowing base at closing. In addition, we paid Apollo a supplemental fee of $500,000 on the Closing Date, and have agreed to pay another $500,000 fee on each anniversary of the Closing Date so long as the Loan Agreement remains in effect.

Additional compensation was due to Bristol Capital, LLC, a consultant to us, in connection with the closing of the Loan Agreement. This fee shall be paid solely in 312,500 shares of the Company's restricted common stock.

The Company has used a portion of the initial $40 million loan made available under the Apollo Credit Facility to repay in full the amounts outstanding under the prior loan agreement, dated June 13, 2011 (the “Prior Loan Agreement”), between the Company, as borrower, Guggenheim Corporate Funding, LLC, as administrative agent and lender, and Citibank, N.A. and Bristol Investment Fund, as lenders. This payment amounted to approximately $26.2 million. The Prior Loan Agreement and all related documents and security interests arising under them were terminated immediately upon that repayment. The remaining $13.8 million of the initial $40 million loan drawn on the Closing Date was used to (i) redeem the Company's outstanding Series A preferred stock; (ii) pay certain outstanding payables of the Company; and (iii) pay transaction costs associated with the closing of the Apollo Credit Facility, such as attorneys' fees. The undrawn portion of the initial borrowing base as of the Closing Date is $15 million, the drawing of which will be subject to the Equity Requirement and the other relevant conditions discussed above.

We expect to use the remaining proceeds of the loans made under the Apollo Credit Facility to increase oil production both onshore and offshore in Alaska through the drilling of new wells and the reworking of previously producing oil wells there, as well as the reworking of existing wells in Tennessee.

On the Closing Date, in connection with the Apollo Credit Facility, we, along with all of our consolidated subsidiaries (other than MEI), entered into a Guarantee and Collateral Agreement (the “Guarantee”) with Apollo, for the benefit of the lenders from time to time party to the Loan Agreement. We granted a security interest in substantially all of our and our subsidiaries' assets to secure the performance of our obligations under the Loan Agreement and the Guarantee.

As part of the foregoing transaction, we were required to amend the existing loan documents between the Company, as borrower, and MEI, as lender, to extend their maturity to a date after the maturity of the Apollo Credit Facility, and to subordinate their security interest in favor of MEI to that of Apollo.

On June 6, 2012, the Company terminated the commodity derivative contracts in place as of April 30, 2012, which were settled against the NYMEX WTI Cushing Index. In consideration of such termination, the counterparty paid the Company settlement value of $4.3 million on June 11, 2012. On June 6, 2012, the Company entered into several new commodity derivative contracts for comparable volume, which will be settled against the Brent Crude Oil Index.

On May 31, 2012, the Company sold a generator from its Kustatan facility for $2.0 million, with $0.6 million paid to the Company upon signing and the remainder due upon delivery.

On May 20, 2012 and July 3, 2012, the Company granted 421,142 shares of common stock, 376,030 shares of restricted stock, and 270,000 stock options to employees, officers and directors.

SUPPLEMENTAL OIL AND GAS DISCLOSURES (UNAUDITED)

Table of Contents
MILLER ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The Company made revisions to its unaudited supplemental oil and gas disclosures for the fiscal years ended April 30, 2011 and 2010. The revisions primarily related to: a) one well in our Redoubt Field in the Cook Inlet Region which was previously reported as proved undeveloped reserves has now been reclassified as unproved reserves, and b) a change in the estimated income tax rate. In addition, we corrected other computational errors in our calculations of the April 30, 2011 and 2010 unaudited disclosures, which did not result in changes to the Company's standardized measure calculations.

The following tables show our capital and operational costs for fiscal years 2012, 2011 and 2010:

a. Capitalized Costs Relating to Oil and Gas Producing Activities at April 30, 2012, 2011 and 2010 are as follows:

	2012	2011	2010
	(In thousands)		
Natural gas and oil properties:			
Proved properties	$321,066	$314,706	$304,760
Unproved properties	182,704	182,220	181,165
	503,770	496,926	485,925
Accumulated depletion	(27,968)	(14,874)	(3,156)
Net capitalized costs	$475,802	$482,052	$482,769

The following summarizes the revisions for fiscal years 2011 and 2010. The revision to fiscal 2011 and 2010 capital cost tables primarily relates to the reclassification of the Redoutbt proved undeveloped reserves to unproven reserves.

	2011 As Reported	Revisions	2011 As Adjusted
	(In thousands)		
Natural gas and oil properties:			
Proved properties	$344,250	$(29,544)	$314,706
Unproved properties	152,058	30,162	182,220
	496,308	618	496,926
Accumulated depletion	(14,439)	(435)	(14,874)
Net capitalized costs	$481,869	$183	$482,052

	2010 As Reported	Revisions	2010 As Adjusted
	(In thousands)		
Natural gas and oil properties			
Proved properties	$333,666	$(28,906)	$304,760
Unproved properties	152,259	28,906	181,165
	485,925	—	485,925
Accumulated depletion	(3,156)	—	(3,156)
Net capitalized costs	$482,769	$—	$482,769

b. Costs Incurred in Oil and Gas Property Acquisition, Exploration, and Development Activities:

	2012	2011	2010
	(In thousands)		
Property acquisition costs			
Proved properties	$—	$—	$2,052
Unproved properties	785	1,009	1,611
Acquisition costs	785	1,009	3,663
Exploration costs	180	—	—
Development costs	6,773	10,265	4,153
Total	$7,738	$11,274	$7,816

c. Results of Operations for Producing Activities:

	2012	2011	2010
	(In thousands)		
Production revenues	$32,493	$21,086	$4,802
Oil and gas operating costs	(14,861)	(9,703)	(2,738)
Depletion	(13,094)	(11,002)	(1,741)
Results of operations for producing activities (excluding corporate overhead and interest costs)	$4,538	$381	$323

d. Reserve Quantity Information (Unaudited)

The following reserve quantity information was derived from reserve and engineering reports prepared for the Company by various third parties. The reserve and engineering reports for both Alaska and Tennessee properties were prepared by Ralph E. Davis Associates, Inc. for the year ended April 30, 2012. Ralph E. Davis Associates, Inc. also prepared the reserve and engineering reports for our Alaska properties for the years ended April 30, 2011 and 2010. Reserve and engineering reports for our Tennessee properties were prepared by Lee Keeling and Associates, Inc. for the years ended April 30, 2011 and 2010.

The following schedule estimates proved oil and natural gas reserves attributable to the Company. Proved reserves are estimated quantities of oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those which are expected to be recovered through existing wells with existing equipment and operating methods. Reserves are stated in barrels of oil (Bbls) and thousands of cubic feet of natural gas (Mcf). Geological and engineering estimates of proved oil and natural gas reserves at one point in time are highly interpretive, inherently imprecise and subject to ongoing revisions that may be substantial in amount. Although every reasonable effort is made to ensure that the reserve estimates reported represent the most accurate assessments possible, these estimates are by their nature generally less precise than other estimates presented in connection with financial statement disclosures.

Table of Contents
MILLER ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Oil (MBbls)	Gas (MMcf)
Proved reserves		
Balance, April 30, 2009	53	1,864
Discoveries and extensions	—	—
Revisions of previous estimates	65	(1,082)
Acquisitions	9,211	4,831
Production	(62)	(154)
Balance, April 30, 2010	9,267	5,459
Discoveries and extensions	—	1,309
Revisions of previous estimates	(46)	156
Sales of reserves in place	—	(3,342)
Production	(273)	(339)
Balance, April 30, 2011	8,948	3,243
Discoveries and extension	94	1,850
Revisions of previous estimates	(124)	(359)
Sales of reserves in place	—	—
Production	(384)	(177)
Balance, April 30, 2012	8,534	4,557
Proved developed reserves at April 30, 2012	2,325	2,601
Proved developed reserves at April 30, 2011	2,461	2,441
Proved developed reserves at April 30, 2010	2,666	1,737
Proved undeveloped reserves at April 30, 2012	6,209	1,956
Proved undeveloped reserves at April 30, 2011	6,487	802
Proved undeveloped reserves at April 30, 2010	6,601	3,722

The following summarizes the revisions for fiscal years 2011 and 2010:

	Oil (MBbls) As Reported	Revisions	Oil (MBbls) As Adjusted
Proved reserves			
Balance, April 30, 2009	53	—	53
Discoveries and extensions	—	—	—
Revisions of previous estimates	65	—	65
Acquisitions	10,288	(1,077)	9,211
Production	(62)	—	(62)
Balance, April 30, 2010	10,344	(1,077)	9,267
Discoveries and extensions	—	—	—
Revisions of previous estimates	(64)	18	(46)
Sales of reserves in place	—	—	—
Production	(273)	—	(273)
Balance, April 30, 2011	10,007	(1,059)	8,948
Proved developed reserves at April 30, 2011	2,471	(10)	2,461
Proved developed reserves at April 30, 2010	2,666	—	2,666
Proved undeveloped reserves at April 30, 2011	7,536	(1,049)	6,487
Proved undeveloped reserves at April 30, 2010	7,678	(1,077)	6,601

Table of Contents

MILLER ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Gas (MMcf) As Reported	Revisions	Gas (MMcf) As Adjusted
Proved reserves			
Balance, April 30, 2009	1,864	—	1,864
Discoveries and extensions	—	—	—
Revisions of previous estimates	(1,082)	—	(1,082)
Acquisitions	4,831	—	4,831
Production	(154)	—	(154)
Balance, April 30, 2010	5,459	—	5,459
Discoveries and extensions	1,309	—	1,309
Revisions of previous estimates	(15)	171	156
Sales of reserves in place	(3,342)	—	(3,342)
Production	(339)	—	(339)
Balance, April 30, 2011	3,072	171	3,243
Proved developed reserves at April 30, 2011	2,488	(47)	2,441
Proved developed reserves at April 30, 2010	1,737	—	1,737
Proved undeveloped reserves at April 30, 2011	584	218	802
Proved undeveloped reserves at April 30, 2010	3,722	—	3,722

Acquisitions, as noted above, were comprised of several entities. The acquisition of ("KTO") included approximately 35,325 leased acres located on the Chattanooga Shale and 153 natural gas and oil producing wells. On June 18, 2009 the Company acquired 100% of the stock of East Tennessee Consultants, Inc., a Tennessee corporation ("ETC") and 100% of the membership interests in East Tennessee Consultants II, LLC, a Tennessee limited liability company ("LLC") from the owners of these entities. The acquisition included 221 producing oil and gas wells and consisted of approximately 4,442 acres. On December 10, 2009, the Company acquired 100% of the membership interests in Cook Inlet Energy, LLC, an Alaska limited liability company from the owners of this entity and simultaneously acquired former Alaskan operations of Pacific Energy Resources ("Pacific Energy") through a Delaware Chapter 11 Bankruptcy proceeding. The purchased assets include the West McArthur River oil field, the West Foreland natural gas field, and the Redoubt unit with the Osprey offshore platform, all located along the west side of the Cook Inlet. Also included in the asset purchase are 602,000 acres of oil and gas leases, which includes 471,474 acres under the Susitna Basin Exploration License.

With the closing of these acquisitions, our management is now able to focus the majority of its efforts on growing our company. We are continuing to focus our short-term efforts on three distinct areas, including:

- Increase our overall oil and gas production through maintenance and repairs of nonperforming or underperforming wells,
- Organically growing production through drilling for our own benefit on existing leases and under license rights, leveraging our 100,000 plus well log database and approximately 700,000 acres which are either under lease or part of our Alaska Susitna Basin Exploration Licenses, with a view towards retaining the majority of working interest in the new wells, and
- Expanding our contract drilling and service capabilities and revenues, including drilling and service contracts with third parties.

We have budgeted for capital expenditures of $50 million to $100 million in fiscal 2013; $24 million of this amount is budgeted for restoring additional production from our offshore Redoubt field in Alaska and $51 million will be used for onshore exploratory oil and natural gas projects in Alaska and Tennessee. We anticipate we will draw on our new

Apollo Investment Corporation credit facility and raise additional equity as needed to provide the required capital. In addition, we will utilize the increased cash flow from increased production.

The following schedule presents the standardized measure of estimated discounted future net cash flows from the Company's proved developed reserves for the years ended April 30, 2012, 2011 and 2010. All estimates were prepared by third party reserve and engineering firms. Because the standardized measure of future net cash flows was prepared using the prevailing economic conditions existing at April 30, 2012, 2011 and 2010, it should be emphasized that such conditions continually change. Accordingly, such information should not serve as a basis in making any judgment on the potential value of the Company's recoverable reserves or in estimating future results of operations.

Each of the engineering reports also projected future cash flows from our net reserves and the present value, discounted at 10% per annum. Future cash flows are based upon gross income from future production, less direct operating expenses and taxes. Estimated future capital for development costs was also deducted from gross income at the time it will be expended. No allowance was made for depletion, depreciation, income taxes or administrative expense. In the following table, the price per barrel of oil was $102.30 and the price per MMcf of natural gas was $6.37 for the Cook Inlet reserves and $87.68 per barrel of oil and $2.22 per MMcf of natural gas for the Appalachian region reserves. In each instance these prices are computed in accordance with the SEC's rule and represent the average fiscal year prices.

Operating costs and production taxes are estimated based on current costs with respect to producing gas properties. Future development costs are based on the best estimate of such costs assuming current economic and operating conditions.

Income tax expense is computed based on applying the appropriate statutory tax rate to the excess of future cash inflows less future production and development costs over the current tax basis of the properties involved.

The future net revenue information assumes no escalation of costs or prices, except for gas sales made under terms of contracts which include fixed and determinable escalation. Future costs and prices could significantly vary from current amounts and, accordingly, revisions in the future could be significant.

Standardized measures of discounted future net cash flows at April 30, 2012, 2011 and 2010 are as follows:

	2012	2011	2010
	(In thousands)		
Future cash flows	$894,027	$657,564	$597,654
Future production costs and taxes	(158,938)	(119,653)	(120,934)
Future development costs	(75,332)	(79,007)	(45,632)
Future income tax expense	(217,312)	(149,388)	(143,430)
Future cash flows	442,445	309,516	287,658
Discount at 10% for timing of cash flows	(139,242)	(102,715)	(99,365)
Discounted future net cash flows from proved reserves	$303,203	$206,801	$188,293

The following summarizes the revisions for fiscal years 2011 and 2010:

	2011 As Reported	Revisions	2011 As Adjusted
	(In thousands)		
Future cash flows	$732,002	$(74,438)	$657,564
Future production costs and taxes	(126,060)	6,407	(119,653)
Future development costs	(93,249)	14,242	(79,007)
Future income tax expense	(88,079)	(61,309)	(149,388)
Future cash flows	424,614	(115,098)	309,516
Discount at 10% for timing of cash flows	(177,677)	74,962	(102,715)

Discounted future net cash flows from proved reserves	$246,937	$(40,136)	$206,801

	2010 As Reported	Revisions	2010 As Adjusted
	(In thousands)		
Future cash flows	$662,582	$(64,928)	$597,654
Future production costs and taxes	(123,879)	2,945	(120,934)
Future development costs	(50,225)	4,593	(45,632)
Future income tax expense	(96,926)	(46,504)	(143,430)
Future cash flows	391,552	(103,894)	287,658
Discount at 10% for timing of cash flows	(153,356)	53,991	(99,365)
Discounted future net cash flows from proved reserves	$238,196	$(49,903)	$188,293

Of the Company's total proved reserves as of April 30, 2012, 2011 and 2010, approximately 17%, 23% and 24%, respectively, were classified as proved developed producing, 21%, 17% and 6%, respectively, were classified as proved developed non-producing and 62%, 60% and 70%, respectively, were classified as proved undeveloped. All of the Company's reserves are located in the continental United States.

The following table sets forth the changes in the standardized measure of discounted future net cash flows from proved reserves for April 30, 2012, 2011 and 2010.

	April 30, 2012	2011	2010
	(In thousands)		
Balance, beginning of year	$206,801	$188,293	$1,535
Sales, net of production costs and taxes	(17,632)	(11,383)	(2,064)
Changes in prices and production costs	116,689	33,625	1,327
Extensions, discoveries and improved recovery, less related costs	58,906	4,592	—
Purchase of reserves in place	—	—	278,536
Changes in estimated future development costs	7,641	(26,032)	1,013
Development costs incurred	6,773	10,265	4,153
Revisions of previous quantity estimates	(42,857)	(555)	(530)
Net changes in income taxes	(48,571)	(5,397)	(92,139)
Sales of reserves in place	—	(1,470)	—
Accretion of discount	30,503	28,112	222
Changes in timing and other	(15,050)	(13,249)	(3,760)
Balance, end of year	$303,203	$206,801	$188,293

The following summarizes the revisions for fiscal years 2011 and 2010:

Table of Contents
MILLER ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	2011 As Reported (In thousands)	Revisions	2011 As Adjusted
Balance, beginning of year	$238,196	$(49,903)	$188,293
Sales, net of production costs and taxes	(10,823)	(560)	(11,383)
Changes in prices and production costs	26,423	7,202	33,625
Extensions, discoveries and improved recovery, less related costs	4,592	—	4,592
Changes in estimated future development costs	(41,745)	15,713	(26,032)
Development costs incurred	10,265	—	10,265
Revisions of previous quantity estimates	26,689	(27,244)	(555)
Net changes in income taxes	8,847	(14,244)	(5,397)
Sales of reserves in place	(1,470)	—	(1,470)
Accretion of discount	33,512	(5,400)	28,112
Changes in timing and other	(47,549)	34,300	(13,249)
Balance, end of year	$246,937	$(40,136)	$206,801

	2010 As Reported (In thousands)	Revisions	2010 As Adjusted
Balance, beginning of year	$1,535	$—	$1,535
Sales, net of production costs and taxes	(1,699)	(365)	(2,064)
Changes in prices and production costs	298,306	(296,979)	1,327
Purchase of reserves in place	314,652	(36,116)	278,536
Changes in estimated future development costs	(44,887)	45,900	1,013
Development costs incurred	4,153	—	4,153
Revisions of previous quantity estimates	(293,699)	293,169	(530)
Net changes in income taxes	(95,381)	3,242	(92,139)
Accretion of discount	308	(86)	222
Changes in timing and other	54,908	(58,668)	(3,760)
Balance, end of year	$238,196	$(49,903)	$188,293