MILLER ENERGY RESOURCES, INC.
Form 10-K
July 14, 2014

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

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FORM 10-K

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(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, 2014
OR
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________________ to __________________________

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

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Tennessee (State or Other Jurisdiction of Incorporation or Organization)	001-34732 (Commission File Number)	62-1028629 (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)

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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
10.75% Series C Cumulative Redeemable Preferred Stock, par value $0.0001 per share	New York Stock Exchange
10.5% Series D Fixed Rate/Floating Rate Cumulative Redeemable Preferred Stock,	New York Stock Exchange

par value $0.0001 per share

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.
o 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.
o 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.
þ Yes o 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 o 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.
o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company.

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). o 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, 2013 (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 $189,925,560. As of July 7, 2014, there were 46,076,707 shares of common stock of the registrant outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of registrant's proxy statement relating to registrant's 2014 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, 2014

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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 report, our Annual Report on Form 10-K for the year ended April 30, 2014, 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," "projects," "target," "goal," "plans," "objective," "should" or similar expressions or variations on such expressions. For these statements, we 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. Certain capitalized terms not defined immediately below are defined later in this Annual Report on Form 10-K.

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 us to experience additional operating losses;
- material weaknesses in our internal control over financial reporting and our need to enhance our systems, accounting, controls and reporting performance;
- potential limitations imposed by debt covenants under our senior credit facilities on our growth and our ability to meet our business objectives;
- debt costs under our existing senior credit facilities;
- the ability of our lenders to redetermine the borrowing base under our First Lien RBL;
- our ability to meet the financial and production covenants contained in the First Lien RBL and/or Second Lien Credit Facility;
- whether we are able to complete or commence our drilling projects within our expected time frame or expected budget;
- our ability to recover proved undeveloped reserves;
- our ability to successfully acquire, integrate and exploit new productive assets in the future;
- whether we can establish production on certain leases in a timely manner before expiration;
- our ability to complete the work commitments required as terms of our Susitna Basin Exploration Licenses;
- our experience with horizontal drilling;
- risks associated with the hedging of commodity prices;
- our dependence on third party transportation facilities;
- concentration risk in the market for the oil and natural gas we produce in Alaska;
- 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;
- uncertainties related to deficiencies identified by the SEC in our Form 10-K for 2011;
- the impact of natural disasters on our Cook Inlet Basin operations;
- the effect of global market conditions on our ability to obtain reasonable financing and on the prices of our common stock, 10.75% Series C Cumulative Redeemable Preferred Stock (the "Series C Preferred Stock") and 10.5% Series D Fixed Rate/Floating Rate Cumulative Redeemable Preferred Stock (the "Series D Preferred Stock");
- limitations placed on us with respect to the issuance and/or designation of additional preferred stock;
- litigation risks;
- the imprecise nature of our reserve estimates;
- risks related to drilling dry holes or wells without commercial quantities of hydrocarbons;
- fluctuating oil and gas prices and the impact on our results from operations;

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- 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;
- the potential for shortages or increases in costs of equipment, services and qualified personnel;
- strong industry competition;
- 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 potential to incur substantial penalties and fines if we fail to comply with all applicable FERC administered statutes, rules, regulations and orders;
- new regulation on derivative instruments used by us to manage our risk against fluctuating commodity prices;
- the impact that proposed federal, state, or local regulation regarding hydraulic fracturing could have on us;
- the effect that future environmental legislation could have on various costs;
- the impact of certain provisions included in the FY2015 U.S. federal budget on certain tax incentives and deductions we currently use;
- that no dividends may be paid on our common stock for some time;
- cashless exercise provisions of outstanding warrants;
- market overhang related to outstanding options, and warrants;
- the impact of non-cash gains and losses from derivative accounting on future financial results;
- risks to non-affiliate shareholders arising from the substantial ownership positions of affiliates;
- the effects of the change of control conversion features of our Series C and Series D Preferred Stock on a potential change of control;
- the junior ranking of our Series C and Series D Preferred Stock to our Series B Cumulative Redeemable Preferred Stock (the "Series B Preferred Stock") and all of our indebtedness;
- our ability to pay dividends on the Series C or Series D Preferred Stock;
- whether our Series C or Series D Preferred Stock is rated;
- the ability of our Series C or Series D Preferred Stockholders to exercise conversion rights upon a change of control;
- fluctuations in the market price of our Series C or Series D Preferred Stock;
- whether we issue additional shares of Series C or Series D Preferred Stock or additional series of preferred stock that rank on parity with the Series C and Series D Preferred Stock;
- the very limited voting rights held by our Series C and Series D Preferred Stockholders;
- the newness of the Series D Preferred Stock and the limited trading market of the Series C and Series D Preferred Stock; and
- risks related to our continued listing of the Series C and Series D Preferred Stock on the NYSE.

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-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

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and investor pages. On our website, you can access, free of charge, electronic copies of the charters of the committees of our Board of Directors, other documents related to our corporate governance, and documents we file with the SEC, including our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934. Included in our annual and quarterly reports are the certifications of our principal executive officer and our principal financial officer that are required by applicable laws and regulations. Access to these electronic filings is available as soon as reasonably practicable after we file such material with, or furnish it to, the SEC. You may also request printed copies of our committee charters or other governance documents free of charge by writing to our corporate secretary at the address on the cover of this report. Our reports filed with the SEC are made available to read and copy at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C., 20549. You may obtain information about the Public Reference Room by contacting the SEC at 1-800-SEC-0330. Reports filed with the SEC are also made available on its website at www.sec.gov. From time to time, we also post announcements, updates, and investor information on our website in addition to copies of all recent press releases. Information on our website or any other website is not incorporated by reference into, and does not constitute 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 Energy Colorado 2014-1, 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, 2014 is referred to as "fiscal 2014" or "2014," the year ended April 30, 2013 is referred to as "fiscal 2013" or "2013," the year ended April 30, 2012 is referred to as "fiscal 2012" or "2012" and the year ending April 30, 2015 is referred to as "fiscal 2015" or "2015."

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.

MBoe. One thousand barrels of oil equivalent.

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

Mcfd. One thousand cubic feet of natural gas per day.

MMBbls. Million barrels of oil.

MMcf. Million cubic feet of natural gas corrected 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.

Downstream. Refers to oil and gas infrastructure or operations relating to the refining, manufacturing, or sales of sales-quality crude oil or natural gas. This term is used in contrast to upstream (exploration and production) or midstream (transportation and ancillary services).

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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 or processing of sales-quality crude oil and gas production facilities to market. Used in contrast to upstream (exploration & production) or downstream (refining, 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 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 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 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.

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 in contrast to midstream (transportation and ancillary services) or downstream (refining, manufacturing and sales).

Working interest. An interest in an oil and gas property that is burdened with the costs of development and operation of the property.

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(Dollars in thousands, except per share data and per unit data)

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, development and operation of oil and gas wells in southcentral Alaska, including the Cook Inlet and Kenai Peninsula, and the Appalachian region of east Tennessee. During fiscal 2015, we expect to expand our operations into Alaska's North Slope (the "North Slope") through our acquisition of Savant Alaska, LLC ("Savant"). Occasionally we offer these services to third-party customers on a contract basis.
During fiscal 2014, 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. In addition to developing the Pacific Energy assets, we also acquired the North Fork Unit and associated assets located on the southern Kenai Peninsula in Alaska during fiscal 2014. These assets include six natural gas wells and related leases (consisting of approximately15,465 net acres), and production and processing equipment, along with twin natural gas transmission pipelines and a multi-year natural gas sales contract held by Anchor Point Energy, LLC, which we are to acquire upon the receipt of necessary regulatory approvals.
Subsequent to the end of fiscal 2014, we entered into an Agreement and Plan of Merger to acquire Savant (the "Merger Agreement"), a company with operations on the North Slope focused on the Badami Unit and its associated assets. Upon the closing of this transaction, Miller will own a 67.5% working interest in the Badami Unit through a subsidiary, along with a 100% working interest in nearby exploration leases, and ownership of midstream assets with a design capacity of 38,500 bopd and 50 miles of pipeline. ASRC Exploration, LLC owns the remaining 32.5% working interest in the Badami Unit. We expect this transaction to close by the end of December 2014, with an effective date of May 1, 2014.
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 increases 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 are focused 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 are increasing oil and gas production through the maintenance, repair, and optimization of wells located in the Cook Inlet region and development of wells in the Appalachian region of east Tennessee. Our operational team employs a combination of the latest available technologies along with tried and true technologies to restore as well as explore and develop our properties;
- Expand Our Revenue Stream. We intend to fully exploit 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, our capacity to process third party fluids and natural gas and, when available, to offer excess electrical power to net users in the Cook Inlet region; 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 continues to seek opportunities that meet our criteria for risk, reward, rate of return, and growth potential. We pursue value-creating acquisitions when the opportunities arise, subject to the availability of sufficient capital.

For a more in-depth discussion of our fiscal 2014 results and our 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

Proposed Settlement of Class Action Lawsuit

On July 3, 2014, we agreed upon a potential settlement with the Plaintiffs in the purported class action lawsuit styled In re Miller Energy Resources, Inc. Securities Litigation wherein the Plaintiffs would dismiss the lawsuit with prejudice in exchange for a settlement payment of $2,950, expected to be funded by our director and officer insurance policy. The proposed agreement, when and if it becomes effective, would not be an admission of wrongdoing or acceptance of fault by us or any of the individual defendants named in the complaint. We, along with those individual defendants, have agreed upon the terms of this proposed settlement to eliminate the uncertainties, risk, distraction and expense associated with protracted litigation. The proposed settlement

(Dollars in thousands, except per share data and per unit data)

remains subject to court approval and class notice administration before it will be effective. We expect to complete full documentation of the settlement and file a motion for preliminary approval of the class action settlement and approval of the class no later than August 31, 2014. The estimated potential loss and expected insurance recovery are accrued on our consolidated balance sheet as of April 30, 2014.

Intended Disposition of Tennessee Assets

On June 24, 2014, we announced our intent to divest our Tennessee assets in order to allocate our capital to our Alaskan operations and investment opportunities. We have engaged in strategic discussions, but until a definitive agreement is executed, we will continue to conduct our business as usual in Tennessee.

Acquisition of Savant Alaska, LLC

On May 8, 2014, we entered into the Merger Agreement to acquire Savant, subject to due diligence and regulatory approval, for $9,000. We have formed a wholly-owned subsidiary, Miller Energy Colorado 2014-1, LLC ("Miller Colorado"), which will merge with Savant to facilitate the acquisition. Savant currently owns, and, by acquiring Savant, we would indirectly acquire as a result of this merger, a 67.5% working interest in the Badami Unit and 100% ownership in certain nearby leases. ASRC Exploration, LLC owns the remaining 32.5% working interest in the Badami Unit. In addition to the working interest in the Badami Unit and the leases, we would acquire certain midstream assets located in the North Slope with a design capacity of 38,500 bopd, a 500,000 gallon diesel storage tank, 20 megawatts of power generation, a grind and inject solid waste disposal facility and Class 1 disposal well, a one mile airstrip, and two pipelines each running 25 miles in length from Badami to the Endicott Pipeline.

We expect the transaction to close by the end of December 2014, following regulatory approval with a May 1, 2014 effective date.

Entry into First Lien RBL

On June 2, 2014, we entered into a credit agreement (the "First Lien Loan Agreement"), among us, as borrower, KeyBank National Association ("KeyBank"), as administrative agent (in that capacity the “RBL Administrative Agent”), and the lenders from time to time party thereto (the “RBL Lenders”). In addition to KeyBank, the syndicate includes CIT Finance LLC, Mutual of Omaha Bank and OneWest Bank N.A.

The First Lien Loan Agreement provides for a $250,000 senior secured, reserve-based revolving credit facility (the "First Lien RBL"), $60,000 of which was made available to us on the closing date. Amounts outstanding under the First Lien RBL are priced on a sliding scale, based on LIBOR plus 300 to 400 basis points and an undrawn commitment fee, depending upon the level of borrowing (per the table below).

Borrowing Base Utilization Grid

Borrowing base utilization percentage	<25%	≥ 25%, but <50%	≥ 50%, but <75%	≥ 75%, but <90%	≥ 90%, but ≤100%
Spread above LIBOR	3.00%	3.25%	3.50%	3.75%	4.00%
Undrawn commitment fee rate	0.50%	0.50%	0.75%	0.75%	0.75%

The First Lien RBL will mature on the third anniversary of closing. The facility includes leverage, interest coverage, current ratio, minimum gross production, minimum liquidity, asset coverage and change of management control covenants as well as other covenants customary for a transaction of this type. Subject to certain conditions contained in the First Lien Loan Agreement, the First Lien RBL also allows us to implement a discretionary share repurchase plan on terms and conditions reasonably satisfactory to the RBL Administrative Agent and the RBL Lenders. The First Lien RBL contemplates up-front fees, arrangement fees, and ongoing commitment and other fees customary for transactions of this nature.

We drew $20,000 on the closing date under the First Lien RBL, which will be used to provide working capital for development drilling in Alaska. The amounts drawn were subject to an original issue discount equal to 1% of the initial borrowing base. On June 24, 2014, we drew an additional $10,000 under the First Lien RBL.

Also on June 2, 2014, in connection with the First Lien RBL, we, along with all of our consolidated subsidiaries (other than Miller Energy Income 2009-A, LP ("MEI"), Miller Colorado, and Miller Energy Drilling 2009-A, L.P.), entered into a First Lien Guarantee and Collateral Agreement (the "First Lien Guarantee") with KeyBank, for the benefit of the RBL Lenders from time to time party to the First Lien Loan Agreement. Under the terms of the First Lien Guarantee and related security documents each of our consolidated subsidiaries (other than MEI, Miller Colorado, and Miller Energy Drilling 2009-A, L.P.) have guaranteed

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our obligations under the First Lien RBL and we and those subsidiaries have granted a security interest in substantially all of our assets to secure the performance of the obligations arising under the First Lien RBL.

Amendment of Second Lien Credit Facility Documents

As previously disclosed, in February 2014 we entered into a Credit Agreement with Apollo Investment Corporation ("Apollo") and Highbridge Capital Strategies (the “New Apollo Loan Agreement”), under which a credit facility of up to $175,000 (the “Second Lien Credit Facility”) was made available to us. At closing, we drew $175,000 under the Second Lien Credit Facility.

On June 2, 2014, we entered into the Amendment No. 1 to Credit Agreement and Guarantee and Collateral Agreement to the Second Lien Credit Facility and the Second Lien Guarantee (as defined later in this Annual Report). This amendment conforms certain of the covenants, terms and conditions in the Second Lien Credit Facility to match those of the First Lien RBL, including the financial covenants. Under the amendment, the maturity date of the Second Lien Credit Facility was redefined, and will occur on February 3, 2018.

Drilling Activities

On June 7, 2014 we successfully brought online WMRU-2B with an initial seven-day average production rate of approximately 630 boe/d. WMRU-2B is an onshore oil well that was drilled using the Patterson 191 drilling rig. The well was a sidetrack of the unused WMRU-2A wellbore and targeted the Hemlock structure at approximately 14,500 feet. Following completion of WMRU-2B, we moved the Patterson 191 drilling rig to the West Foreland location adjacent to West McArthur River and we are currently drilling the West Foreland #3 well, which is a gas prospect.

On March 31, 2014, we entered into an option to purchase a land-based drilling rig from Baker Process, Inc., which we exercised on May 5, 2014 by entering into a definitive agreement to purchase the rig for $3,250. The 2400 HP rig, which we have named Rig 36, will require approximately $5,000 to $8,000 of improvements and will be used to drill our Sabre prospect.

On the Osprey platform, we are currently drilling RU-9 using Rig 35. The well has a target depth of 18,500 feet in the Hemlock structure, which is south of the Osprey platform. We are currently evaluating our drilling program following completion of the RU-9 well, but tentatively plan to drill the RU-12 grassroots oil well located in the Northern Fault.

Effective July 4, 2014, we entered into an option to purchase the Glacier Drilling Rig, a Mesa 1000 carrier-mounted land-drilling rig primarily for developing the North Fork Field; however, we may use the rig to support other fields. Prior to securing a drilling rig, we attempted to access a previously isolated gas zone in the North Fork 14-25 well which is in the process of being completed.

Subsequent to our fiscal year end we also completed WMRU-8 and are intermittently producing from that well. We are currently evaluating the well as it produces and may follow up with other well work to further increase production rates.

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. We recently acquired the North Fork Unit, located in the southern Kenai Peninsula and Cook Inlet sedimentary basin in Alaska.

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.

	2014 Production	Percentage of Total 2014 Production	2014 Oil and Gas Revenues	4/30/2014 Estimated Proved Reserves	Percentage of Total Estimated Proved Reserves
	(In Boe)			(In MBoe)	
Alaska region [1]	772,993	95%	$66,606	6,111	97%
Appalachian region	43,993	5%	2,863	187	3%
Total	816,986	100%	$69,469	6,298	100%

1 Cook Inlet production excludes 152,373 boe of natural gas produced and used as fuel gas.

Alaska Region

Overview

The Cook Inlet Basin contains large oil and gas deposits including multiple onshore and offshore fields. As of April 30, 2014, 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

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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 35 miles southwest of Anchorage in Nikiski, which is in 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. Our West McArthur River Unit ("WMRU") and its associated production facility are located on the opposite end of Cook Inlet roughly 14 miles northwest of Nikiski on a small peninsula known as the West Foreland. Also located on the West Foreland is the Kustatan Production Facility which is twelve miles west of Nikiski and four miles south of the West McArthur River Production Facility. The Osprey Platform is located two miles southeast from the tip of the West Foreland and nine miles west of Nikiski. The west side of Cook Inlet is generally accessible, but these assets are isolated from public utilities and infrastructure. Located roughly 60 miles to the northwest of Anchorage is the Susitna Basin, which is perhaps best known for its coal seams in the sedimentary basin underneath the basin and could become a new source of much-needed natural gas. The North Fork field is produced from two well pads located 65 miles south of Nikiski near the community of Nikolaevsk. In contrast to our Alaskan assets located on the west side of the Cook Inlet, these pads are located on the considerably more developed east side as they are on the federal highway system and have access to an electric utility.

Cook Inlet, Susitna Basins, and North Fork Unit

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 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.

As of April 30, 2014 and 2013, we owned approximately 340,810 and 100,099 gross (315,913 and 75,202 net) acres of leasehold interests, respectively, along with the exploration license rights to an additional 108,673 and 580,147 gross (108,673 and 580,147 net) acres, respectively, in Alaska. The increase in leased acreage from April 30, 2013 is a result of the conversion of a portion of our expired Susitna #2 License (defined below) to leases, as well as acreage acquired in the North Fork Unit and annual Cook Inlet areawide lease sale. The reduction in licensed acreage from April 30, 2013 is a result of the expiration of the Susitna #2 License (defined below). We also owned interests in twelve crude oil and eleven natural gas wells as of April 30, 2014, compared to ten crude oil and five natural gas wells as of April 30, 2013. The increase in these interests is a result of our drilling activities during fiscal 2014 and the acquisition of the North Fork Unit.

At the time we acquired the Alaskan operations, all of the wells were shut-in, with the exception of one gas well. When we acquired the North Fork Unit, we acquired six natural gas wells, four of which were producing. As of April 30, 2014, seven oil wells and seven gas wells are producing.

Oil wells drilled in this area range from 9,000 feet to 15,500 feet in vertical depth while gas wells have a vertical depth of 3,000 feet to 9,000 feet. Wells that are deviated (continue on from the vertical depth either diagonally or horizontally) will have an increased measured depth of approximately 5,000 feet to 9,000 feet or more giving measured depth of up to 19,000 feet or more. Well spacing is quite variable, as there are large parts of Cook Inlet which are completely undeveloped and others that are more mature. The Cook Inlet Basin contains a thick section of terrestrial tertiary rocks which includes shale, sandstone, and coal.

Osprey Platform and Redoubt Shoals Field

The Osprey platform is located in the Redoubt Unit approximately 1.8 miles southeast of 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 on the Kustatan Production Facility to process all of Osprey's produced fluids. The platform has 21 available 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 conducted exploration drilling operations between January 2001 and July 2002. The oil wells were equipped with electrical submersible pumps (“ESPs”) which were necessary to bring the oil to the 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 six existing shut-in wells. Two of the wells required replacement of the ESPs, and the other four wells required re-

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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. In March 2011, we transitioned the Osprey platform out of lighthouse mode and successfully repaired the first of the two wells needing ESP replacement, though RU-1 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 $17,900.

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 very limited. As warmer temperatures moderated the region and rig contractor and supplies were in order, we resumed work on the assembly of Rig 35, which was brought online in August 2012. Rig 35 has since replaced pumps in oil wells RU-1 and RU-7, sidetracked oil wells RU-2A, RU-1A and RU-5B, and completed the reworking of RU-3 and RU-4 as gas wells. Rig 35 has also performed maintenance on RU-D1, our platform disposal well. As we were unable to optimize the performance of RU-1 due to obstructions which were stuck in the lower part of the well bore during the second ESP replacement, we eventually performed a side track on this well bore. We are currently in the process of drilling RU-9, our first grassroots well on the Osprey platform.

Kustatan Production Facility

The Kustatan Production Facility was constructed in 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 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 two wells in the field. WF 1 is not currently producing. There is one producing well in the field which has two separately treated zones, WF 2U and WF 2L. 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 this field in which we own a 30% working interest. Production from this field has been intermittent.

Susitna Basin

Included in the Alaskan operations we acquired was a 100% interest in Susitna Basin Exploration License No. 2 ("Susitna #2 License"), 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 Susitna #2 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 $3,000 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 Susitna #2 License for a work commitment of $750. The State granted the extension in October 2010. We had the right to convert all or any portion of the licensed acreage into oil and gas leases upon completion of the new work commitment. The Susitna #2 License expired on October 31, 2013. We converted 167,900 acres to 36 leases, at a cost of $504, which represents the payment of the first year's $3.00 per acre annual rental fee.

On April 1, 2011, we were awarded Susitna Basin Exploration License No. 4 ("Susitna #4 License"), 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 $2,250 work commitment, we will gain the option to convert any part of the licensed area into oil and gas leases. We currently have a performance bond of $321 toward the fulfillment of its work commitment, and will need to post additional bonds annually if no work is carried out in the licensed area. In addition to bonding, we need to spend 50% of the total work commitment amount, or $1,125, by the fourth anniversary of the license, April 1, 2015, or we will forfeit 25% of the license area. If we do not spend at least 25% of the total work commitment amount, or

$563, by April 1, 2015, we will forfeit the entire license.

On April 1, 2012, we were awarded Susitna Basin Exploration License No. 5 ("Susitna #5 License"), 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 $250 work commitment, we will gain the option to convert any part of the licensed area into oil and gas leases. We currently have a performance bond of $83 toward the fulfillment of its work commitment, and will need to post additional bonds annually if no work is carried out in the licensed area. In addition to bonding, we need to spend 50% of the total work commitment amount, or $125, by the fourth anniversary of the license, April 1, 2016, or we will forfeit 25% of the license area. If we do not spend at least 25% of the total work commitment amount, or $63, by April 1, 2016, we will forfeit the entire license.

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Assignment Oversight Agreement

On November 5, 2009, CIE entered into an Assignment Oversight Agreement ("AOA") with the Alaska Department of Natural Resources ("Alaska DNR") which set out certain terms under which the Alaska DNR would approve the transfer of oil and gas leases owned by the State of Alaska 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 the Redoubt Unit and West McArthur River Unit. Under the terms of the AOA, until the Alaska DNR determines that CIE has completed certain development and operational commitments relating to the WMRU and Redoubt Units, CIE must do the following, in addition to the normal requirements under the terms of the leases:

- file a quarterly 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 quarterly 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 relating to the WMRU or Redoubt Unit Leases of more than $5,000,
- annually submit a new plan of development for the Alaska DNR's approval.

The AOA required CIE to demonstrate funding commitments of $5,150 to support the redevelopment of the WMRU and an estimated $31,000 to support the development of the Redoubt Unit. We believe CIE has adequately fulfilled these commitments.

The AOA prohibited CIE from using proceeds from operations at the WMRU or Redoubt Unit for non-core oil and gas activities, or activities unrelated to the WMRU or Redoubt Unit, without the prior written approval of the Alaska DNR until the parties mutually agreed that the full dismantlement obligation under the assigned leases was funded.

On March 11, 2011, CIE entered into a Performance Bond Agreement under its AOA with the State of Alaska. Under the Performance Bond Agreement, CIE is required to post a total bond of $18,000 for the dismantling and abandonment of the properties. As agreed with the State of Alaska, the Performance Bond Agreement fulfills our commitment under the AOA to fund the full dismantlement costs with respect to our onshore and offshore assets. The Performance Bond Agreement also stipulated that funds held by the state in an escrow account will be credited towards the $18,000.

Failure to submit the information required by the AOA would constitute a default under the AOA. If the default could not be cured within 30 days, the leases would be subject to termination by the Alaska DNR.

North Fork Properties

On November 22, 2013, CIE entered into a purchase and sale agreement by and among Armstrong Cook Inlet, LLC, GMT Exploration Company, LLC, Dale Resources Alaska, LLC, Jonah Gas Company, LLC and Nerd Gas Company, LLC (together, the "North Fork Sellers") and CIE (the "North Fork Purchase Agreement"). In this transaction, CIE (i) acquired a 100% working interest in six natural gas wells and related leases (consisting of approximately 15,465 net acres) referred to as the "North Fork Unit" in the Cook Inlet region of the State of Alaska, together with other associated rights, interests and assets for $59,975, subject to certain adjustments and (ii) subject to regulatory approval, has the right to acquire all the issued and outstanding membership interests of Anchor Point Energy, LLC (the "Anchor Point Equity"), a limited liability company owning certain pipeline facilities and related assets which service the North Fork properties, for 213,586 shares (valued at approximately $5,000) of the Company's Series D Preferred Stock. Collectively, we refer to the assets as the "North Fork Properties."

The acquisition of the North Fork Properties closed on February 4, 2014 and the proposed acquisition of the Anchor Point Equity will close upon receiving approval from the Regulatory Commission of Alaska, subject to customary closing conditions. Upon the closing of the acquisition, the portion of consideration consisting of Series D Preferred Stock and an assignment of Anchor Point Equity were deposited into an escrow account. These will be disbursed upon the closure of the Anchor Point Equity acquisition pursuant to the terms of the North Fork Purchase Agreement.

The North Fork Unit and gas field is located on the southern Kenai Peninsula, east of the community of Anchor Point. Production at the time of acquisition was approximately 7.0 MMcfd (1,167 boe/d). Current production is approximately 9.9 MMcfd (1,706 boe/d), and is expected to increase as CIE performs well optimizations and commences full field development of up to 24 additional wells. Anchor Point Energy, LLC ("Anchor Point") owns and operates nine miles of twin 4-inch natural gas transmission pipelines and is party to a multi-year natural gas sales contract with an affiliate of ENSTAR for use by ENSTAR (the "ENSTAR Gas Sales Agreement"), the largest natural gas utility in Alaska. There is approximately 2.9 BCF remaining of a 10.0 BCF commitment to ENSTAR at a price of approximately $7.00 per Mcf. Our acquisition of Anchor Point and the Anchor Point Equity is currently pending and awaiting regulatory approval; however, under the terms of the acquisition agreement with the North Fork Sellers, the acquisition will be effective as of May 1, 2014. Currently, under a separate agreement between CIE and

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Anchor Point mirroring the ENSTAR Gas Sales Agreement ("APE Gas Sales Agreement"), CIE is selling natural gas from the North Fork Unit to Anchor Point (for sale by Anchor Point to ENSTAR). The price paid to CIE by Anchor Point for that natural gas is equal to the amount paid to Anchor Point for such gas (by the third party acquiring it), minus a tariff amount established by the Regulatory Commission of Alaska for transportation on the North Fork Pipeline which is currently equal to $1.95 per Mcf. In addition, CIE is also selling and delivering natural gas from the North Fork Unit to other purchasers.

Membership in Cook Inlet Spill Prevention and Response, Inc. ("CISPRI")

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 through 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 $50 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 $10,000. 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 is 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 own and operate a total of 379 gross (261 net) oil and gas wells in which we own an interest in the State of Tennessee. As of April 30, 2014, we owned approximately 46,864 gross (37,999 net) acres of leasehold interests with 200 gross (144 net) producing oil wells and 179 gross (117 net) producing gas wells in which we own an interest. This is a decline of 3,396 gross (1,878 net) acres from April 30, 2013. The decline in gross and net acreage is attributable to undeveloped acreage leases being allowed to lapse. 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.

During fiscal 2014, Miller focused its operations on continuing to improve our horizontal drilling results and on the acquisition of additional working interests in wells in which we already have a working interest. These working interest acquisitions increase our net production.

In October 2013, we drilled and completed our third horizontal oil well in the Fort Payne Limestone in Tennessee, the Brimstone et. al H-1, which is located in the Low Gap Field. We are producing this well and have begun a reservoir study to present to the State to unitize the Low Gap Field in order to allow maximum oil recovery, conserve associated gas, and pave the way for a gas pressure maintenance program that will further enhance production.

In addition to the horizontal well program, we continued to acquire working interest in wells we operate and also purchased ten wells and associated infrastructure in March of 2014. We also received the permits needed from the State of Tennessee to begin construction of a portable gas processing plant in the Burrville area, enabling us to recover and sell liquids from high BTU gas from our gas wells and other operators' wells in the area and sell the required lower BTU gas to the local utility.

Principal Markets and Customers

The existing markets for natural gas production in southcentral Alaska are the Tesoro Nikiski Refinery, utility companies such as ENSTAR, 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

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Refinery. Crude oil is shipped by pipeline and tanker vessel to the Tesoro Nikiski Refinery, operated by Tesoro Alaska Petroleum Company.

Under the terms of the Alaska crude oil sales contract, Tesoro Refining and Marketing Company ("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/bbl 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/bbl, then the price shall be equal to the WTI Index Price less $1.715/bbl; (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 and 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 Tesoro's Alaska Refinery. In fiscal 2014, 2013 and 2012, purchases by Tesoro accounted for 93%, 100%, and 100%, respectively, of our total Alaska oil and gas production revenues.

Currently, approximately 1.5 MMcfd to 3.0 MMcfd of natural gas produced by our Alaskan operations is used to generate heat and power at our production facilities. Gas production in excess of our internal needs is sold to third parties.

In addition, as described above, CIE currently sells gas to Anchor Point under the APE Gas Sales Agreement. Anchor Point is further obligated to make sales to ENSTAR’s affiliate under the ENSTAR Gas Sales Agreement. Under this arrangement, CIE receives a price for its natural gas sold to Anchor Point equal to the price paid to Anchor Point under the ENSTAR Gas Sales Agreement of approximately $7.00 per Mcf minus a tariff amount established by the Regulatory Commission of Alaska of $1.95 per Mcf.

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 by Barrett Oil Purchasing Company, Sunoco, and Kentucky Oil and Refining 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 Swan Creek Partners, LLC, formerly Tengasco, Inc. 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 2014, 2013 and 2012, sales to Barrett Oil Purchasing and Sunoco, collectively, represented approximately 70%, 81%, and 35%, respectively, of our total Tennessee oil and gas 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. During fiscal 2013 and fiscal 2014, we have used Rig 35 to restore or commence production from oil wells RU-1, RU-7, RU-1A, RU-2A and RU-5B and gas wells RU-3 and RU-4. Rig 35 has also performed maintenance on our platform disposal well, RU-D1, and is drilling our first Redoubt grassroots well, RU-9.

During fiscal 2014, we leased the Patterson-191 rig in order to drill our first well in the Sword prospect. Sword #1 came online on November 18, 2013 with an initial gross production rate of 883 boe/d from one of three productive zones. Since bringing the well online, we have tested the two other productive zones and received two permits to commingle production from the different zones. In addition to the Sword #1 well, the Patterson-191 rig has also drilled the WMRU-8 and WMRU-2B oil wells, and is currently drilling the WF-3 gas well.

On March 31, 2014, we entered into an option to purchase a land-based drilling rig from Baker Process, Inc. for $1,500, which we exercised on May 6, 2014 by making additional payments of $1,750 and entering into a definitive agreement to purchase the rig for a total of $3,250. The 2400 HP rig, which we have named Rig 36, will require approximately $5,000 to $8,000 of improvements in order to drill our Sabre prospect.

While we have plans to drill up to 24 additional wells in our newly-acquired North Fork Unit, because this acquisition occurred in the fourth quarter of fiscal 2014, we did not commence any drilling in this field during this fiscal year.

In Tennessee, we drilled one producing development well, Brimstone et. al H-1, during fiscal 2014.

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In fiscal 2013, we incurred dry hole costs on one well in Tennessee, and we drilled two new development wells; one well that is producing and one well that is classified non-producing.
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					
	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Producing						
Cook Inlet	3	3	—	—	—	—
Appalachian region	1	1	1	1	—	—
Total producing	4	4	1	1	—	—
Non-Producing						
Cook Inlet	—	—	—	—	—	—
Appalachian region	—	—	1	1	—	—
Total non-producing	—	—	1	1	—	—
Injection						
Cook Inlet	—	—	—	—	—	—
Appalachian region	—	—	—	—	—	—
Total injection	—	—	—	—	—	—
Dry						
Cook Inlet	—	—	—	—	—	—
Appalachian region	—	—	—	—	2	2
Total dry	—	—	—	—	2	2
Total development	4	4	2	2	2	2
Exploratory:						
Productive						
Cook Inlet	1	1	—	—	—	—
Appalachian region	—	—	—	—	—	—
Total productive	1	1	—	—	—	—
Dry						
Cook Inlet	—	—	—	—	1	1
Appalachian region	—	—	1	1	—	—
Total dry	—	—	1	1	1	1
Pending determination	—	—	—	—	—	—
Total exploratory	1	1	1	1	1	1
Total drilling activity	5	5	3	3	3	3

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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, 2014 is set forth below:

	Producing Wells					
	Gross [(a)]			Net [(b)]		
	Oil	Gas	Total	Oil	Gas	Total
Cook Inlet	11	12	23	7	7	14
Appalachian region	200	179	379	144	117	261
Total	211	191	402	151	124	275

(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, net 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, to 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.

	For the Year Ended April 30,		
	2014	2013	2012
Net production - boe[1]	816,986	317,606	371,843
Average oil price - per bbl	$100.85	$101.53	$93.10
Average natural gas price - per mcf	$6.26	$3.52	$3.47
Average lease operating expenses - per boe[2]	$24.71	$70.17	$30.40

1 Net production for fiscal 2014, 2013 and 2012 excludes 152,373, 57,123 and 33,956 boe of fuel gas, respectively, which is considered in the calculation of average production cost but excluded from the calculation of average sales prices.

2 Fiscal 2013 average lease operating expenses per boe includes $7,462 in workover expenses.

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The following table describes, for each of the last three fiscal years, net oil and gas production volumes, average sales price per bbl, and average production cost per boe after deducting royalties and interests of others, with respect to oil and gas production attributable to our interest in the West McArthur River, North Fork and Redoubt Shoals fields, which comprise at least 15% of our total proved reserves.

	For the Year Ended April 30,		
	2014	2013	2012
Net production - boe			
West McArthur River[1]	245,718	200,123	234,301
Redoubt Shoal[2]	413,471	75,535	91,455
North Fork	98,725	—	—
Average oil price - per bbl			
West McArthur River	$102.84	$103.74	$95.33
Redoubt Shoal	$101.50	$100.03	$89.98
Average natural gas price - per mcf			
Redoubt Shoal	$7.02	$—	$—
North Fork	$6.96	$—	$—
Average lease operating expenses - per boe			
West McArthur River	$31.23	$28.76	$18.08
Redoubt Shoal[3]	$21.16	$190.16	$57.30
Average lease operating expenses - per mcf			
North Fork	$0.24	$—	$—

1 Net production for West McArthur River for fiscal 2014, 2013 and 2012 excludes 15,198, 11,350 and 12,669 boe of fuel gas, respectively, which is considered in the calculation of average production cost but excluded from the calculation of average sales prices.

2 Net production for Redoubt Shoal for fiscal 2014, 2013 and 2012 excludes 123,423, 25,301 and 3,796 boe of fuel gas, respectively, which is considered in the calculation of average production cost but excluded from the calculation of average sales prices.

3 Fiscal 2013 average lease operating expenses per boe for Redoubt Shoal includes $7,462 in workover expenses.

Gross and Net Undeveloped and Developed Acreage

Our staff of professional geologists utilizes 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.

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The following table presents our gross and net acreage position in each region where we have operations as of April 30, 2014:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Cook Inlet	25,596	25,164	408,935	399,420	434,531	424,584
Appalachian region	11,160	7,560	35,704	30,439	46,864	37,999
Total acreage	36,756	32,724	444,639	429,859	481,395	462,583

During fiscal 2014, 477,521 gross (477,521 net) undeveloped acres expired in Alaska. A significant portion of this acreage was encompassed by our Susitna #2 License, which consisted of 471,474 acres and expired in accordance with its terms as of October 31, 2013. We were able to convert 167,900 acres from this license to 36 leases, which now represents 41% of our gross (42% net) total undeveloped acreage as of April 30, 2014. During fiscal 2014, 2,148 gross (1,678 net) undeveloped acres expired in Tennessee.

The substantial majority of our undeveloped acreage is located in the State of Alaska. As of April 30, 2014, we had 15,132 gross (15,132 net) undeveloped acres set to expire in Alaska by April 30, 2015 if production is not established or we take no other action to extend the terms of the applicable leases. The remainder of our Alaskan undeveloped acreage is not scheduled to expire until at least April 30, 2018, with the notable exception of our Susitna #5 License consisting of 45,764 gross (and net) acres which is scheduled to expire prior to April 30, 2017. Should we fulfill the terms of the Susitna #5 License, we will be able to convert all or any portion of the license into oil and gas leases. No material amount of acreage is scheduled to expire in Tennessee by April 30, 2015. We strive to extend the terms of many of these leases and licenses through operational or administrative actions, but cannot assure that such extensions can be achieved on an economic basis or otherwise on terms agreeable to both the Company and third parties including governments.

As of April 30, 2014, 8% of our gross (6% net) Alaskan undeveloped acreage was held by production, and 100% of our gross (100% net) Tennessee undeveloped acreage was held by production.

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-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, and projected reserves based on future recovery methods.

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The following table shows proved oil and gas reserves as of April 30, 2014, based on average commodity prices in effect on the first day of each month in fiscal 2014, 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, 2014			
Reserves category:	Oil (MBbls)	Natural Gas (MMcf)	MBoe	Reserve %
PROVED				
Developed				
Cook Inlet	4,129	11,891	6,111	57%
Appalachian region	135	311	187	2
Undeveloped				
Cook Inlet	1,832	15,439	4,405	41
Appalachian region	—	—	—	—
Total proved	6,096	27,641	10,703	100%

Our estimates of proved reserves, proved developed reserves and proved undeveloped ("PUD") reserves as of April 30, 2014, 2013 and 2012, 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.

The following table details the changes in MBoe of our PUD reserves.

	MBoe
PUD as of April 30, 2013	6,828
Conversion to proved developed reserves	(1,880)
Acquisition of reserves in place	2,212
Extensions, discoveries and other additions	948
Revisions of previous estimates	(3,703)
Sales of minerals in place	—
PUD as of April 30, 2014	4,405

During fiscal 2014, we converted 1,880 MBoe of PUD reserves to proved developed reserves by drilling the RU-2A, RU-5B, and WMRU-8 wells. As part of our capital budget , among other wells planned for fiscal 2015, we expect to drill RU-3, RU-4, and WF-3, converting them from PUD reserves to proved developed reserves. Further, we believe that we will develop our PUD reserves and convert them to proved developed reserves within five years from the time each well was initially booked as a PUD.

Also during fiscal 2014, we acquired 2,212 MBoe in the North Fork Properties acquisition which closed in February 2014. As a result of ongoing drilling and completion activities during fiscal 2014, we reported extensions, discoveries, and other additions of 948 MBoe which are attributable to the offsetting PUD location from bringing the Sword #1 well online within the West McArthur River area. The downward revisions were primarily driven by a decrease in PUD volumes. During the fiscal 2014 year we made a change in our independent reserve engineer from Ralph E. Davis Associates, Inc. to Ryder Scott Company, L.P. for our Alaska properties. The decrease in PUD volumes resulted primarily from changes in the professional judgment of our independent petroleum engineer, additional production history leading to lower projected recovery estimates and to a lesser extent, changes in price and cost.

Preparation of Oil and Gas Reserve Information

Our reserve estimates for oil and natural gas as of April 30, 2014 for our Cook Inlet and Appalachian region assets were prepared by Ryder Scott Company, L.P. and Ralph E. Davis Associates, Inc., respectively, both of which are independent engineering firms. The report prepared by Ryder Scott Company, L.P. covered 98% of our reserves and the report prepared by Ralph E. Davis,

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Inc. covered 2% of our reserves. Our reserve reports, which are filed as exhibits to this annual report, were prepared using engineering and geological methods widely accepted in the industry. A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are decline curve analysis, advance production type curve matching, petro physics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields. 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.

Our reserve estimates for oil and natural gas as of April 30, 2013 and 2012 for our Cook Inlet and Appalachian region assets were prepared by Ralph E. Davis Associates, Inc.

Internal Controls over Reserves Estimate

Our reserve estimates are in compliance with the SEC definitions and guidance and were prepared by an independent engineering firm. Mr. David M. Hall, our Chief Operating Officer (and Chief Executive Officer of CIE), is the technical person primarily responsible for overseeing the preparation of our proved reserve estimates by independent petroleum engineers. Mr. Hall has over 20 years of experience in oil and gas operations, development and reservoir engineering, including over 20 years of experience with many of our Alaska oil and gas assets, as a result of former positions held with our predecessors in title, Forest Oil and Pacific Energy. Mr. Hall's experience includes: (i) managing our geological, geophysical, production, and drilling groups, including setting directives for these groups; (ii) estimating reserves and forecasting for property evaluations and development planning; (iii) predicting reserves and performance for well proposals; (iv) supervising and working with third party reserve engineering firms; (v) developing and applying reservoir optimization techniques; (vi) overseeing the development of reservoir monitoring and surveillance programs, and overseeing performance of reservoir characterization studies; and (vii) coordinating geological and petrophysical studies.

We provide the engineering firms with estimate preparation materials such as property interests, production, current operation costs, current production prices and other information. This information is reviewed by the Chief Operating Officer prior to submission to our third party engineering firm. Letters which identify 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.

Other Ancillary Services

We also generate ancillary revenues from facility rentals, services and drilling activities. While the facilities, equipment and personnel on hand are for the benefit of servicing and drilling our own properties, from time to time we optimize unused capacity by renting space and performing services and drilling on behalf of third parties. During 2014 and 2013, other revenues totaled $1,089, or 2%, and $4,886, or 14%, respectively, of our consolidated total revenues. The decrease in other revenues primarily resulted from the completion of the road and pad building project in the Cook Inlet region which contributed 51% of our other revenue in 2013.

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 NordAq. However, we believe we can effectively compete 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 both oil and gas sales contracts in place. 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 five significant competitors consisting of Atlas Energy Resources, LLC, Consol Energy, Inc., Champ Oil, ENREMA, LLC, and Swan Creek Partners, LLC, formerly 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 have more than 40 years of experience in the Appalachian region.

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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.

The Regulatory Commission of Alaska regulates the intrastate pipeline tariffs and encompasses all pipelines CIE ships through, including the Cook Inlet Pipeline Company ("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, future gas production is assumed to be sold at contract terms similar to both our existing contract prices and comparable to similarly situated producers.

CIE has posted $800 in Alaska and federal bonds. The Alaska DNR requires $600 in bonding to operate oil and gas leases on state lands, and the AOGCC requires a $200 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 $1,909 in designated accounts to satisfy future abandonment obligations. A $324 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 $324. 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; $585 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. In March 2011, CIE entered into a Performance Bond Agreement that set the bond for the Osprey platform at an inflation-adjusted $18,000. The agreement sets a payment schedule totaling $12,000 in annual payments between July 2013 and July 2019. As of April 30, 2014, we have funded $1,000 of this amount. An existing interest bearing account containing approximately $7,026 as of April 30, 2014 is to be credited against the inflation-adjusted $18,000 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. We do not anticipate any additional bonding requirements for the North Fork Unit.

CIE has a work commitment bond for Otter in the amount of $1,200. In order to satisfy the work commitment, the Otter well has to be finished to a depth sufficient to test the Beluga formation by March 31, 2016. Additionally, we have a work commitment bond for Olson Creek in the amount of $250. We must commence drilling by September 1, 2014 in order to satisfy the work commitment under this bond.

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 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 Oil and Gas Board to ensure that each well is reclaimed and properly plugged when it is abandoned. The reclamation

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bonds cost $2 per well. The cost for the plugging bonds range from $2 to $3 per well depending on depth or $20 for ten wells. For most of the reclamation bonds, we have deposited a $2 certificate of deposit with the Tennessee Oil and Gas 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 regulations 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;
- 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 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, and/or
- clean 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

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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 constructing pit(s) and inserting heavy gauge plastic in the pit(s) in order to keep any drilling fluids and/or oil from escaping the drill site and contaminating the ground water and/or any navigable waters. 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 the corporation. These 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, 2014, we had 84 employees.

Offices

Our principal executive offices are located at 9721 Cogdill Road, Suite 302, Knoxville, Tennessee. At April 30, 2014, we maintained regional exploration and/or production offices in Huntsville and Sunbright, Tennessee and Anchorage, Alaska, and had entered into a lease establishing our Houston, Texas administrative office with a commencement date of May 15, 2014. We lease 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.

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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 resulted in litigation which was settled during fiscal 2014 for $1,250.

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 completed five acquisitions, including the North Fork Unit assets, and are in the process of completing a merger to acquire Savant.

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 $320.

Shortly thereafter, we acquired ETC, in exchange for an aggregate of 1,000,000 shares of our common stock valued at $250. In March 2009, we formed Miller Energy GP and in April 2009 we formed 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 owned 1% of MEI, however due to the shared management of our company and MEI, we have consolidated this entity.

On February 3, 2014, we repaid all obligations under and terminated the First Secured Promissory Note dated as of November 1, 2009, a Second Secured Promissory Note dated as of December 15, 2009, a Third Secured Promissory Note dated as of May 15, 2010, and a Loan and Security Agreement dated as of March 19, 2010 (as amended, supplemented or otherwise modified prior to the date hereof, the "MEI Loan Documents"). Once paid, in accordance with the governing documents of MEI, the interests of the limited partners in MEI were effectively redeemed and ceased to exist. As a result, under Delaware law, MEI ceased to be a "limited partnership" when no new limited partners were admitted within the statutorily prescribed time limit. As the Company was the sole general partner and sole remaining holder of any equity interest in MEI, MEI has therefore been legally consolidated into the Company. We are in the process of preparing a certificate of cancellation for filing with the State of Delaware with respect to MEI.

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 $250 in cash to satisfy certain expenses as well as reimbursement for reasonable out of pocket expenses. Following the transaction, Mr. David Hall was appointed 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 #2 License as well as completed 3D seismic geology and other production facilities. At closing we paid Pacific Energy $2,250 and provided $2,220 for bonds, contract cure payments and other federal and State of Alaska requirements to operate the facilities.

In April 2011, we changed our name to Miller Energy Resources, Inc.

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 $400. 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, Tennessee. We executed a five-year lease for the space, and with the addition of us, the building is fully occupied by tenants.

On February 4, 2014, we acquired the North Fork Unit and its associated assets. As part of that transaction, subject to the receipt of regulatory approval, we will also acquire 100% of the membership interests in Anchor Point. We paid a total of approximately $64,557, after customary adjustments, in a combination of $59,557 and 213,586 shares (valued at approximately $5,000) of our Series D Preferred Stock for these assets, including the Anchor Point Equity. The assets acquired included six natural gas wells, approximately15,465 net acres, and production and processing equipment. Anchor Point is the owner and operator of nine miles of twin 4-inch natural gas transmission pipelines and a party to the ENSTAR Gas Sales Agreement.

ITEM 1A. RISK FACTORS.

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In addition to the other information set forth elsewhere in the Form 10-K, you should carefully consider the following known, material risk factors associated with our business, the oil and gas industry in which we operate, and the ownership of our securities. 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, and holders or purchasers of our securities could lose part or all of their investments. There may be additional risks that are not presently material or known. We may include additional risk factors in the prospectuses for securities we issue in the future.

Risks Related to Our Business
We have a history of operating losses and incurred a net loss in fiscal years 2014, 2013 and 2012. Our revenues are not currently sufficient to fund our operating expenses and there are no assurances we will develop profitable operations.
We reported operating losses of $10,693 in fiscal 2014, $32,349 in fiscal 2013 and $25,085 in fiscal 2012. As a result of the continued expansion of our business during fiscal 2014, our operating expenses presently exceed our revenues. We anticipate that our operating expenses will continue to increase as we continue to develop our operations in Alaska, and as we continue to make acquisitions. We will continue depleting our cash resources to fund operating expenses until such time as we are able to significantly increase our revenues. We have had to borrow and raise capital through issuances of equity in order to fund our operations in the past, resulting in debt costs, interest, and dilution of our existing shareholders' equity. We may have to reduce our expansion efforts if we do not see an increase in revenues in the next fiscal year, which could also lead to a loss of properties or reserves. There are no assurances that we will be able to significantly increase our revenues or develop profitable operations.
In preparing our consolidated financial statements for the fiscal years 2014, 2013, and 2012, we and our independent public accounting firm identified material weaknesses in our internal control over financial reporting. If we fail to achieve or maintain effective internal control over financial reporting, we may be unable to accurately and timely report our financial results or prevent fraud, and our business, investor confidence and the market price of our shares may be adversely impacted.
In the course of the preparation and audit of our consolidated financial statements for the fiscal years 2014, 2013, and 2012 we and our independent registered public accounting firm identified a number of deficiencies in our internal control over financial reporting, including a “material weakness” as defined in the standards established by the Public Company Accounting Oversight Board Standard (United States). 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, and a significant deficiency is a deficiency, or a combination of deficiencies, in internal control over financial reporting that is less severe than a material weakness, but important enough to merit attention by those responsible for oversight of the company's financial reporting.
The material weaknesses identified for the fiscal years 2014, 2013 and 2012 related to an insufficient complement of corporate accounting and finance personnel necessary to consistently operate management review controls. In remediating the material weakness, we may experience difficulties in integrating new personnel into the accounting department and may identify areas where additional personnel may be required. In an effort to meet the demands of our planned activities in fiscal 2015 and thereafter, we may be required to supplement our staff with more expensive contract and consultant personnel until we are able to hire new employees. Further, we 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.
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 First Lien RBL and Second Lien Credit Facility contain a number of significant covenants that, among other things, restrict our ability to:
- pay for general and administrative expenses;

- make capital expenditures on new wells without lender consent;
- 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 leaseback transactions;
- enter into specified investments or acquisitions;
- repurchase, redeem or retire our capital stock or subordinated debt;
- merge or consolidate, or transfer all or substantially all of our assets and the assets of our subsidiaries;

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- engage in specified transactions with subsidiaries and affiliates; or
- pursue other corporate activities.

Because we are limited in the total amount we may spend on general and administrative expenses, we may 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.

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 First Lien RBL or Second Lien Credit Facility.

We are subject to substantial debt costs under the terms of our Second Lien Credit Facility with Apollo Investment Corporation and Highbridge Capital Strategies. Monies borrowed are subject to an interest rate of LIBOR + 9.75% per annum, with a 2.00% LIBOR floor.

As described above in this Annual Report, in February 2014 we entered into the New Apollo Loan Agreement with Apollo and Highbridge Capital Strategies, under which the Second Lien Credit Facility was made available to us. Our total indebtedness under our Second Lien Credit Facility is $175,000. That amount bears interest at a rate of LIBOR plus 9.75% (subject to a 2.00% LIBOR floor) and are subject to a make whole premium and repayment premiums payable on certain repayments of the loans. These debt costs may be substantial, and will adversely impact our results until the facility has been repaid.

We are subject to redeterminations of the Borrowing Base under our First Lien RBL. If our reserves decrease, or if other events occur which cause our lenders to decrease the Borrowing Base to an amount lower than our current outstanding borrowings, any excess borrowings would become immediately due and payable.

Our First Lien RBL provides for redeterminations of our Borrowing Base on both a regularly scheduled basis and an interim basis. Our lenders rely on certain engineering reports, including reserve reports, as well as our swaps and hedges to determine our Borrowing Base. Should we experience a decline in our reserves, sell a certain amount of our oil and gas properties, cancel a certain amount of our hedges or swaps, or experience other events which negatively impact the status of our oil and gas properties with respect to our lenders' normal oil and gas lending criteria, our lenders may determine to lower our Borrowing Base. Should we have an outstanding balance in excess of a lower redetermined Borrowing Base, the amount in excess of the new Borrowing Base would become immediately due and payable, and we would need to come up with sufficient cash to repay such amounts. This could require us to raise additional capital at an inopportune time, or on terms not favorable to us.

Our inability to timely repay the amount in excess of the new Borrowing Base could result in a default under the First Lien RBL and our Second Lien Credit Facility. A default, if not cured or waived, could result in acceleration of all indebtedness outstanding under our First Lien Loan Agreement and New Apollo Loan 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.

If we fail to meet financial and production covenants contained in the First Lien RBL and Second Lien Credit Facility, we may be limited in our ability to make additional borrowings, obtain additional funds on favorable terms, make capital expenditures, withstand a downturn in our business or the economy, or pay dividends on our Series B, Series C, or Series D Preferred Stock. If the failure to meet these covenants results in a default, we could face the acceleration of our indebtedness under the First Lien RBL or Second Lien Credit Facility which would become immediately due and payable.

Both our First Lien RBL and Second Lien Credit Facility 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 at lower levels, or any event which limits our ability to meet oil and gas production requirements specified in the First Lien RBL or Second Lien Credit Facility could eventually result in our failing to meet one or more of the financial and production-level covenants, 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 First Lien RBL or Second Lien Credit Facility. A default under either facility, if not cured or waived, could result in acceleration of all indebtedness outstanding under both facilities. 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.

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Material differences between the estimated and actual timing of critical events may affect the completion and commencement of production from our projects. In addition, unexpected problems or delays in our drilling operations may cause us to spend additional amounts over those budgeted for our projects.

We have identified and budgeted for numerous drilling locations, but we may not be able to drill those locations within our expected time frame or at all. Our projects may be delayed by the availability of rigs, project approvals from joint venture partners, timely issuances of permits and licenses by governmental agencies, weather conditions, manufacturing and delivery schedules of critical equipment, equipment repairs, the availability of sufficient capital resources, and other unforeseen events including problems with drilling. Delays and differences between estimated and actual timing of critical events may adversely affect our production and our projected cash flows from operations, and could cause us to spend additional amounts over those budgeted for our projects which could be substantial.

The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Approximately 41% of our total estimated proved reserves at April 30, 2014 were proved undeveloped reserves.

Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in our reserve engineer reports assumes that substantial capital expenditures are required to develop such reserves, and we typically hold most or all of the working interests in our wells, so we must bear most or all of the costs of development ourselves. 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 may fail to fully identify potential problems related to acquired businesses or assets, or obtain protection from the sellers, 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. Inspections 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 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;
- our ability to meet the reporting requirements under federal securities laws due to the condition or availability of the target's financial records;
- the challenge and cost of integrating acquired operations, accounting, internal controls, human resources, information management, administrative and other technology systems, and business cultures with our own while carrying on our ongoing business;
- the adjustment to operating a larger combined organization once integrations are complete;

- failure to realize expected synergies and cost savings;
- difficulty associated with coordinating geographically separate organizations; and
- the challenge of attracting and retaining personnel associated with acquired operations.

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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 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, all of which could result in our making decisions to delay drilling on certain leases notwithstanding the resulting expiration of those leases that could occur.

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.

Approximately 108,673 acres of our total acreage consists of the two Susitna Basin Exploration Licenses in Cook Inlet, Alaska. These two licenses require us to spend a total of $2,500 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.

The results of our use of horizontal drilling in Tennessee using long laterals and modern completion techniques are subject to more uncertainties than our vertical drilling programs and may not meet our expectations for reserves or production.

During fiscal 2013, we believe we became the first company to drill horizontal oil wells in the Fort Payne formation in Tennessee. Part of our drilling strategy in formations where we have drilled horizontal wells involves the drilling of long horizontal laterals and the use of modern completion techniques of multi-stage fracture stimulations that have been used in other basins by other operators. Our experience with horizontal drilling and multi-stage fracture stimulations of these formations to date is relatively limited and there is no way at this time to determine whether the use of these techniques will prove to be commercially successful in the formations of interest in Tennessee.

Our commodity price risk management and trading activities may prevent us from benefiting fully from price increases and may expose us to the risk of financial loss.

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;
- 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.

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 under which Tesoro purchases all of our 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.

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

Anchor Point has entered into the ENSTAR Gas Sales Agreement with ENSTAR's affiliate under which a majority of our natural gas produced in Alaska is ultimately sold to ENSTAR. We generally do not require letters of credit or collateral to support these trade receivables. Accordingly, a material adverse change in the financial condition if ENSTAR and its affiliates could adversely impact our ability to collect the applicable receivables, and thereby affect our financial condition.

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 $18,000, 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 $1,000 to $2,500 per year, and totaling $12,000, as approximately $6,800 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. 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 received a request from the SEC for a more detailed explanation regarding the specific circumstances that led 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 cannot predict the nature of any additional 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.

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. Debris avalanches have also resulted in tsunamis. In 2009, the CIPL 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.

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Disruptions in the financial markets could affect our ability to obtain financing on reasonable terms and have other adverse effects on us and the market price of our publicly traded securities, including our common stock, Series C Preferred Stock, and Series D Preferred Stock.

Over the last several years, the United States stock and credit markets have experienced significant price volatility, dislocations and liquidity disruptions, which have caused market prices of many stocks and debt securities to fluctuate substantially and the spreads on prospective debt financings to widen considerably. More recently, the financial crises in Europe (related primarily to concerns that certain European countries may be unable to pay their national debt) had similar, although less pronounced, effects. These circumstances have materially impacted liquidity in the financial markets, making terms for certain financings less attractive and in certain cases have resulted in the unavailability of certain types of financing. Unrest in certain Middle Eastern countries and the resultant increase in petroleum prices have added to the uncertainty in the capital markets. Such uncertainty will lead to continued volatility in the stock and credit markets and may negatively impact our ability to access additional financing at reasonable terms. A prolonged downturn in the stock or credit markets may cause us to seek alternative sources of potentially less attractive financing. These types of events in the stock and credit markets may make it more difficult or costly for us to raise capital through the issuance of our common stock, preferred stock or debt securities. These disruptions may have a material adverse effect on the market value of our common stock and preferred stock, including the Series C and Series D Preferred Stock, the return we receive on our investments, as well as other unknown adverse effects on us or the economy in general.

Covenants preventing the issuance and/or designation of additional preferred stock may limit our ability to raise funds on advantageous terms or through additional preferred stock offerings.

Our First Lien RBL contains certain negative covenants that may prohibit us from issuing more than approximately $15,000 in shares of Series B, Series C, or Series D Preferred Stock after the closing of the First Lien RBL. The First Lien Loan Agreement also prohibits us from designating new classes of preferred stock with terms that are more onerous to us than those contained in either the Series C or Series D Preferred Stock designations. These limitations could result in a loss of flexibility in our ability to raise funds quickly through our at-the-market agreements, or should we reach the $15,000 additional limit, at all.

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, 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, and whether our insurance provides coverage for the claims asserted in each case. Our consolidated financial statements contained herein may not contain any reserves, or the reserves contained in our consolidated financial statements may be insufficient, 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.

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.

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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 First Lien RBL and our Second Lien Credit Facility.

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.

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Our business involves a high degree of operational risk, particularly risk of personal injury, damage, or loss of equipment, and environmental accidents 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 operations.

Shortages or increases in costs of equipment, services, and qualified personnel could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

The demand for qualified and experienced personnel to conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Additionally, higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. Shortages of field personnel and equipment or price increases could significantly affect our ability to execute our exploration and development plans as projected.

We face strong industry competition that may have a significant negative impact on our results of operations.

Strong competition exists in all sectors of the oil and gas exploration and production industry. We compete with major integrated and other independent oil and gas companies for acquisition of oil and gas leases, properties, and reserves, equipment, and labor required to explore, develop, and operate those properties, and marketing of oil and natural gas production. Crude oil and natural gas prices impact the costs of properties available for acquisition and the number of companies with the financial resources to pursue acquisition opportunities. Many of our competitors have financial and other resources substantially larger than we possess and have established strategic long-term positions and maintain strong governmental relationships in countries in which we may seek new entry. As a consequence, we may be at a competitive disadvantage in bidding for drilling rights. In addition, many of our larger competitors may have a competitive advantage when responding to factors that affect demand for oil and natural gas production, such as fluctuating worldwide commodity prices and levels of production, the cost and availability of alternative fuels, and the application of government regulations. We also compete in attracting and retaining personnel, including geologists, geophysicists, engineers, and other specialists. These competitive pressures may have a significant negative impact on our results of operations.

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 RCRA, and comparable state laws that impose requirements for the handling, storage, treatment or disposal of solid and hazardous waste from our facilities, the 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;

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- 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.

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, FERC has authority to impose penalties for violations of the Natural Gas Act, up to $1 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.

Derivatives regulation included in current or proposed financial legislation and rulemaking could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices.

The Dodd-Frank Act, which was signed into law in July 2010, contains significant derivatives regulation, including a requirement that certain transactions be cleared on exchanges and a requirement to post collateral (commonly referred to as “margin”) for such transactions. The Dodd-Frank Act provides for a potential exception from these clearing and collateral requirements for commercial end-users and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and the parties to those transactions. We expect to qualify as a commercial end-user. As required by the Dodd-Frank Act, the Commodities Futures and Trading Commission ("CFTC") has promulgated numerous rules to define these terms. In addition, it is possible that the CFTC, in conjunction with prudential regulators, may mandate that financial counterparties entering into swap transactions with end-users must do so with credit support agreements in place, which could result in negotiated credit thresholds above which an end-user must post collateral.

We use derivative instruments with respect to a portion of our expected crude oil and natural gas production in order to reduce the impact of commodity price fluctuations and enhance the stability of cash flows to support our capital investment programs and acquisitions.

Depending on the rules and definitions adopted by the CFTC and prudential regulators, we could be required to post significant amounts of collateral with our dealer counterparties for derivative transactions. Requirements to post cash collateral could result in negative impacts on our liquidity and financial flexibility and also cause us to incur additional debt and/or reduce capital investment. In addition, the final CFTC rules may also require the counterparties to our derivative instruments to move some of their derivative activities to a separate entity, which may not be as creditworthy as the current counterparty.

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.

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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.
The proposed U.S. federal budget for fiscal year 2015 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 March 4, 2014, the President unveiled his $3.9 trillion U.S. federal budget proposals for fiscal year 2015. 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 eliminate the ability to fully deduct intangible drilling costs in the year incurred, repeal percentage depletion for oil and natural gas wells, repeal the domestic manufacturing deduction for oil and natural gas companies, increase the geological and geophysical amortization period for independent producers to seven years, repeal the exception to passive loss limitations for working interests in oil and natural gas properties, repeal the enhanced oil recovery credit, and repeal the credit for oil and gas produced from marginal wells. 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 no budget has been passed at this time, 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 earnings to fund our operations; therefore, we do not anticipate paying any cash dividends on our common stock in the foreseeable future. Also, our First Lien RBL and Second Lien Credit Facility do 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, 2014, we have common stock warrants outstanding to purchase an aggregate of 1,109,150 shares of our common stock with an average exercise price of $4.98 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.
We have outstanding options and warrants, if exercised, would increase our currently outstanding common stock by approximately 32%. The exercise of these options and warrants and purchase rights would be dilutive to our current shareholders, and could adversely affect our stock price.
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 100,000,000 shares of preferred stock with such designations, preferences and rights as determined by our Board of Directors. At July 7, 2014 we had 46,076,707 shares of common stock outstanding together with outstanding options and warrants to purchase an aggregate of 14,811,847 shares of common stock at exercise prices of between

$0.01 and $6.95 per share. Future sales of common stock under effective registration statements, 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 shares of our outstanding common stock will increase by approximately 14,811,847, 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.

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, 2014, we have a derivative liability of $7,207. We recognized a non-cash loss on derivatives of $6,365 in fiscal 2014, a non-cash gain of $5,235 in fiscal 2013, and a non-cash loss of $3,436 in fiscal 2012. The amount of quarterly non-cash gains or losses we will record in future periods is

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unknown at this time as the measurement is based upon the fair market value of oil 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, 2014, management and members of the Board of Directors own approximately 30% 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.

The Change of Control conversion features of our Series C and Series D Preferred Stock may prevent a change in control, or discourage a third party from acquiring us.

The Change of Control conversion features of the Series C and Series D Preferred Stock may have the effect of discouraging a third party from making an acquisition proposal for us or of delaying, deferring or preventing certain of our change of control transactions under circumstances that otherwise could provide the holders of our common stock, Series C, and Series D Preferred Stock with the opportunity to realize a premium over the then-current market price of such stock, or that shareholders may otherwise believe is in their best interests.

Risks Related to the Ownership of our Series C and Series D Preferred Stock

The Series C and Series D Preferred Stock rank junior to our Series B Preferred Stock and to all of our indebtedness and other liabilities and are effectively junior to all indebtedness and other liabilities of our subsidiaries.

In the event of our bankruptcy, liquidation, dissolution or winding-up of our affairs, our assets will be available to pay obligations on the Series C and Series D Preferred Stock only after all of our indebtedness and other liabilities have been paid. The rights of holders of the Series C and Series D Preferred Stock to participate in the distribution of our assets will rank junior to the prior claims of our current and future creditors, to our Series B Preferred Stock and any future series or class of preferred stock we may issue that ranks senior to the Series C and/or Series D Preferred Stock. As of the date hereof, 25,750 shares of Series B Preferred Stock, having a liquidation value of $2,575, are outstanding. In addition, the Series C and Series D Preferred Stock effectively rank junior to all existing and future indebtedness and other liabilities of (as well as any preferred equity interests held by others in) our existing subsidiaries and any future subsidiaries. Our existing subsidiaries are and any future subsidiaries would be separate legal entities and have no legal obligation to pay any amounts to us in respect of dividends due on the Series C and Series D Preferred Stock.

If we are forced to liquidate our assets to pay our creditors, we may not have sufficient assets to pay amounts due on any or all of the Series C or Series D Preferred Stock then outstanding. We and our subsidiaries have incurred and may in the future incur substantial amounts of debt and other obligations that will rank senior to the Series C and Series D Preferred Stock. At April 30, 2014, we had $184,202 of indebtedness, on a consolidated basis (including obligations arising under our Series B Preferred Stock), ranking senior to the Series C and Series D Preferred Stock. Our First Lien RBL and Second Lien Credit Facility prohibits payments of dividends on the Series C and Series D Preferred Stock if we fail to comply with certain financial covenants or, at certain times, if a default or event of default has occurred. Certain of our other existing or future debt instruments may restrict the authorization, payment or setting apart of dividends on the Series C and Series D Preferred Stock.

Future offerings of debt or senior equity securities may adversely affect the market price of the Series C or Series D Preferred Stock. If we decide to issue debt or senior equity securities in the future, it is possible that these securities will be governed by an indenture or other instruments containing covenants restricting our operating flexibility. Additionally, any convertible or exchangeable securities that we issue in the future may have rights, preferences and privileges more favorable than those of the Series C or Series D Preferred Stock and may result in dilution to owners of the Series C and Series D Preferred Stock. We and, indirectly, our shareholders, will bear the cost of issuing and servicing such securities. Because our decision to issue debt or equity securities in any future offering will depend on market conditions and other factors beyond our control, we cannot predict or estimate the amount, timing or nature of our future offerings. The holders of the Series C and Series D Preferred Stock will bear the risk of our future offerings, reducing the market price of the Series C and Series D Preferred Stock and diluting the value of their holdings in us.

We may not be able to pay dividends in cash on the Series C or Series D Preferred Stock.

Under Tennessee law, cash dividends may be paid from net earnings only if (1) we would still be able to pay our debts as they become due in the usual course of business after giving effect to the dividend payment, and (2) our total assets are not 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 distribution to satisfy the preferential rights upon dissolution of shareholders whose preferential rights on dissolution are superior to those receiving the distribution. Our ability to pay cash dividends on the Series C and Series D Preferred Stock will require us to have

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access to enough cash and to have positive net assets (total assets less total liabilities) over our capital. Further, notwithstanding these factors, we may not have sufficient cash to pay dividends on the Series C and Series D Preferred Stock. Our ability to pay dividends may be impaired if any of the risks described in this Annual Report, were to occur. In addition, payment of our dividends depends upon our financial condition and other factors as our Board of Directors may deem relevant from time to time. We cannot make assurances that our business will generate sufficient cash flow from operations or that future borrowings will be available to us in an amount sufficient to enable us to make distributions on our common stock and preferred stock, including the Series C and Series D Preferred Stock, or to pay our indebtedness or to fund our other liquidity needs.

The Series C and Series D Preferred Stock have not been rated.

We have not sought to obtain a rating for the Series C or Series D Preferred Stock. No assurance can be given, however, that one or more rating agencies might not independently determine to issue such a rating or that such a rating, if issued, would not adversely affect the market price of the Series C or Series D Preferred Stock. In addition, we may elect in the future to obtain a rating for the Series C or Series D Preferred Stock, which could adversely affect the market price of the Series C or Series D Preferred Stock. Ratings only reflect the views of the rating agency or agencies issuing the ratings and such ratings could be revised downward, placed on a watch list or withdrawn entirely at the discretion of the issuing rating agency if, in its judgment, circumstances so warrant. Any such downward revision, placing on a watch list, or withdrawal of a rating could have an adverse effect on the market price of the Series C or Series D Preferred Stock.

Series C or Series D Preferred Stock holders may not be able to exercise conversion rights upon a Change of Control, and, if exercisable, these conversion rights may not adequately compensate you.

Upon the occurrence of a Change of Control, each holder of the Series C or Series D Preferred Stock will have the right (unless, prior to the Change of Control Conversion Date, we have provided notice of our election to redeem some or all of the shares of Series C or Series D Preferred Stock held by such holder, in which case such holder will have the right only with respect to shares of Series C or Series D Preferred Stock that are not called for redemption) to convert some or all of such holder's Series C or Series D Preferred Stock into shares of our common stock (or under specified circumstances involving certain alternative consideration).

Although we generally may not redeem the Series C or Series D Preferred Stock prior to November 1, 2017 (and we are subject to a general prohibition on redemptions under the terms of our First Lien RBL and Second Lien Credit Facility prior to the date which is 30 days after all of our obligations and the lender commitments under those credit facilities have been satisfied), we have a special optional redemption right to redeem the Series C or Series D Preferred Stock in the event of a Change of Control, and holders of the Series C or Series D Preferred Stock will not have the right to convert any shares that we have elected to redeem prior to the Change of Control Conversion Date. If we do not elect to redeem or are prohibited from redeeming the Series C or Series D Preferred Stock prior to the Change of Control Conversion Date, then, upon an exercise of the applicable conversion rights, the number of shares of our common stock or other applicable consideration that the holders of Series C or Series D Preferred Stock will be entitled to receive will be limited to a maximum of 9.51 multiplied by the number of shares of Series C Preferred Stock to be converted and 7.1225 multiplied by the number of Series D Preferred Stock to be converted, respectively.

The market price of the Series C or Series D Preferred Stock could be substantially affected by various factors.

The market price of the Series C or Series D Preferred Stock will depend on many factors, which may change from time to time, including:

- prevailing interest rates, increases in which may have an adverse effect on the market price of the Series C or Series D Preferred Stock;
- trading prices of common and preferred equity securities issued by other energy companies;
- the annual yield from distributions on the Series C or Series D Preferred Stock as compared to yields on other financial instruments;
- general economic and financial market conditions;
- government action or regulation;
- the financial condition, performance and prospects of us and our competitors;

- changes in financial estimates or recommendations by securities analysts with respect to us, or competitors in our industry;
- our issuance of additional preferred equity or debt securities; and
- actual or anticipated variations in quarterly operating results of us and our competitors.

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As a result of these and other factors, investors who purchase the Series C or Series D Preferred Stock may experience a decrease, which could be substantial and rapid, in the market price of the Series C or Series D Preferred Stock, including decreases unrelated to our operating performance or prospects.

We may issue additional shares of Series C or Series D Preferred Stock and additional series of preferred stock that rank on parity with the Series C and Series D Preferred Stock as to dividend rights, rights upon liquidation, or voting rights.

We are allowed to issue additional shares of Series C or Series D Preferred Stock and additional series of preferred stock that would rank equally to the Series C and Series D Preferred Stock as to dividend payments and rights upon our liquidation, dissolution or winding up of our affairs pursuant to our amended and restated charter, as amended, and the articles of amendment for the Series C and Series D Preferred Stock without any vote of the holders of the Series C or Series D Preferred Stock. The issuance of additional shares of Series C or Series D Preferred Stock and preferred stock that would rank on parity with the Series C and Series D Preferred Stock could have the effect of reducing the amounts available to the current holders of our Series C and Series D Preferred Stock upon our liquidation or dissolution or the winding up of our affairs. It also may reduce dividend payments to the current holders of the Series C and Series D Preferred Stock if we do not have sufficient funds to pay dividends on all Series C and Series D Preferred Stock outstanding and other classes of stock with equal priority with respect to dividends.

In addition, although holders of Series C and Series D Preferred Stock are entitled to limited voting rights with respect to such matters, the Series C and Series D Preferred Stock will vote separately as a class along with the holders of all other classes or series of our equity securities we may issue upon which similar voting rights have been conferred and are exercisable and which are entitled to vote as a class with the Series C and Series D Preferred Stock. As a result, the voting rights of holders of Series C and Series D Preferred Stock may be significantly diluted, and the holders of such other series of preferred stock that we may issue may be able to control or significantly influence the outcome of any vote.

Future issuances and sales of preferred stock ranking on parity with the Series C and Series D Preferred Stock, or the perception that such issuances and sales could occur, may cause prevailing market prices for the Series C or Series D Preferred Stock and our common stock to decline and may adversely affect our ability to raise additional capital in the financial markets at times and prices favorable to us.

Holders of Series C and Series D Preferred Stock have extremely limited voting rights.

Voting rights as a holder of Series C or Series D Preferred Stock are limited. Our shares of common stock are the only class of our securities that carry full voting rights. Voting rights for holders of Series C and Series D Preferred Stock exist primarily with respect to the ability to elect, voting together with the holders of any other classes or series of our equity securities we may issue upon which similar voting rights have been conferred and are exercisable and which are entitled to vote as a class with the Series C and Series D Preferred Stock, two additional directors to our board of directors, subject to certain limitations, in the event that a “Listing Event” (defined below) occurs or four quarterly dividends (whether or not consecutive) payable on the Series C or Series D Preferred Stock are in arrears (as applicable), and with respect to voting on amendments to our amended and restated charter, as amended, or articles of amendment relating to the Series C or Series D Preferred Stock that materially and adversely affect the rights of the holders of Series C or Series D Preferred Stock or authorize, increase or create additional classes or series of our shares that are senior to the Series C and Series D Preferred Stock. A “Listing Event” means, with respect to the Series C or Series D Preferred Stock, respectively, if that class of stock is not listed on certain specified national stock exchanges (including the New York Stock Exchange or NASDAQ) for 180 or more consecutive days. Other than the limited circumstances described in this Annual Report, holders of Series C and Series D Preferred Stock do not have any voting rights.

The Series D Preferred Stock is a relatively new issue of securities and both the Series C and Series D Preferred Stock have only a limited trading market, which may negatively affect their value and the ability to transfer and sell shares.

The Series D Preferred Stock is a relatively new issue of securities with only a limited trading market. The volume of trades of shares of both the Series C and Series D Preferred Stock on the New York Stock Exchange ("NYSE") is often low, and an active trading market on the NYSE for the Series C and Series D Preferred Stock may not be maintained in the future and may not provide adequate liquidity. The liquidity of any market for the Series C and Series D Preferred Stock that may exist now or in the future will depend on a number of factors, including prevailing interest rates, the dividend rate on our common stock, our financial condition and operating results, the number of holders of the Series C and Series D Preferred Stock, the market for similar securities and the interest of securities dealers in making a market in the Series C and Series D Preferred Stock. As a result, the ability to transfer or sell the Series C and Series D Preferred Stock could be adversely affected.

If the Series C or Series D Preferred Stock or our common stock is delisted, the ability to transfer or sell shares of the Series C or Series D Preferred Stock may be limited, and the market value of the Series C or Series D Preferred Stock will likely be materially adversely affected.

Other than in connection with a Change of Control, the Series C and Series D Preferred Stock do not contain provisions that are intended to protect stockholders if our common stock is delisted from the NYSE. Since the Series C and Series D Preferred Stock have no stated maturity date, stockholders may be forced to hold their shares of the Series C or Series D Preferred Stock

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and receive stated dividends on the Series C or Series D Preferred Stock when, and if authorized by our board of directors and paid by us with no assurance as to ever receiving the liquidation value thereof. In addition, if our common stock is delisted from the NYSE, it is likely that the Series C and Series D Preferred Stock will be delisted from the NYSE as well. Accordingly, if the Series C or Series D Preferred Stock or our common stock is delisted from the NYSE, the ability to transfer or sell shares of the Series C or Series D Preferred Stock may be limited and the market value of the Series C or Series D Preferred Stock will likely be materially adversely affected.

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ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 3. LEGAL PROCEEDINGS.

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. As previously reported, 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 that 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.

This action was revived on August 4, 2011, when 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, arose from the same allegations as the previous action in the state court. The federal case sought money damages from us for breach of contract; however, unlike the previous action, it did not seek specific performance of the assignments at issue. The Plaintiff claimed that the other defendants tortiously interfered with, or induced the breach of, the letter of intent between us and the Plaintiff. We reached a settlement with the Plaintiff on January 24, 2014, wherein we would pay the Plaintiff $1,250 in exchange for their agreement to dismiss the case with prejudice. The Company recorded a loss of $1,250 in other operating (income) expense, net in its consolidated statement of operations for the year ended April 30, 2014 in connection with this settlement.

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 CIE. 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 warrants and violated a duty of good faith and fair dealing. The suit sought damages in excess of $3,000, which includes $2,687 of damages for loss of vested warrants. We believe that all of the asserted claims were 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 filed our Answer and conducted discovery. On January 21, 2013, Mr. Stafford's attorney filed a motion to withdraw as counsel, and on April 2, 2013, Mr. Stafford filed a motion to proceed pro se. On February 24, 2014, we filed a Motion to Dismiss with Prejudice based on Plaintiff’s failure to prosecute his case since April 2, 2013, Plaintiff’s having missed filing deadlines, and his having failed to appear to give his deposition both times we have noticed it. On February 26, 2014, the Court entered an Order to Show Cause, requiring the plaintiff to demonstrate why his case should not be dismissed. On March 14, 2014, the plaintiff filed a Motion for Voluntary Dismissal, Without Prejudice through his new attorney. On June 3, 2014, the court granted plaintiff’s motion to dismiss without prejudice, but did so with the condition that plaintiff must reimburse us for costs incurred by us as a result of his failure to cooperate in discovery in this case in the amount of $9 prior to his being allowed to refile the case. As such, this case has been dismissed and there is no further action currently required.

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) unjust 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 filed a Motion to Dismiss for lack of personal jurisdiction, but this motion was not granted by the court. We filed an Answer to the complaint in this case on October 10, 2012, and we have conducted discovery. Trial was previously set for November 4, 2013. On October 21, 2013, the trial was postponed with no new trial date having been set. On October 31, 2013, the judge ruled on our outstanding Motion for Summary Judgment, granting it as to the unjust enrichment claim and breach of the implied covenant of good faith and fair dealing claim, and denying it as to the breach of contract claim. We expect to proceed to trial on the breach of contract claim once a new trial date is set. In February 2014, we received notice from a third party seeking to intervene in the case in order to secure payment of a debt allegedly owed by the Plaintiff to the third party. On June 5, 2014, the court entered an order denying the motion to intervene. On May 29, 2014, the court put down a new scheduling order setting forth certain pre-trial deadlines with the final pre-trial conference being set for October 30, 2014. We expect the court to set a trial date that will be shortly after the final pre-trial conference. 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 lawsuits 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 us and the other defendants, and payment of the Plaintiffs' attorney's fees. We have filed a Motion to Dismiss the case, which was denied on February 4, 2014 as to all defendants save Ford Graham. On July 3, 2014, we agreed upon a potential settlement with the Plaintiffs would dismiss the lawsuit with prejudice in exchange for a settlement payment of $2,950, which is within the remaining policy limits of our director and officer insurance policy. The proposed settlement remains subject to court approval and class notice administration before it will be effective. We expect to complete full documentation of the settlement and file a motion for preliminary approval of the class action settlement and approval of the class no later than August 31, 2014.

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 alleged 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 sought 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. The Plaintiff agreed to stay this case awaiting a ruling on the plaintiff's appeal in the federal derivatives case in Lukas v. Miller Energy Resources, Inc., et al, as described in the next paragraph. The Plaintiff also agreed to voluntarily dismiss the case in the event the plaintiff's appeal in Lukas was denied. Following the dismissal of Lukas, on October 1, 2013, the Court entered an Order dismissing the case without prejudice on the motion of the Plaintiff. On October 24, 2013, we filed a Motion to Amend the Order of Dismissal as the agreement with the Plaintiff was that the case would be dismissed with prejudice if the Sixth Circuit Court of Appeals affirmed the dismissal of the Lukas case, which it has. On June 3, 2014, after reaching an agreement with the Plaintiff, we filed an amended agreed final order of dismissal with prejudice in this case.

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. As noted below, this case had been dismissed by the trial court, and that dismissal was unsuccessfully appealed by the plaintiffs. It contained substantially similar claims as Valdez. The suit alleged 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 sought unspecified money damages from the individual defendants, to have us take certain actions with respect to our management, restitution to us, and the Plaintiffs' attorney fees and costs. We filed a Motion to Dismiss, which was granted on September 21, 2012. On October 16, 2012, a notice of appeal of this dismissal was filed by the Plaintiffs with the Sixth Circuit Court of Appeals. On September 19, 2013, the Court of Appeals affirmed the judgment of the District Court dismissing the case. On October 3, 2013, the Plaintiff filed a Motion for Rehearing En Banc. The Court denied the motion on January 8, 2014. The Plaintiffs had three months to

file a petition to the Supreme Court of the United States, but did not do so. Therefore, these cases have ended.
On August 31, 2012, we terminated an agreement with Voorhees Equipment and Consulting, Inc. (“Voorhees”) for the construction and sale of the rig currently being used on the Osprey Platform, Rig 35, (the “Rig 35 Agreement”). We terminated the agreement based on our belief that Voorhees was in breach of its obligations thereunder. Voorhees later indicated its desire to arbitrate claims it believes it has under invoices arising between May 29, 2012 and August 31, 2012. We believed we had grounds to dispute liability with respect to some or all of those invoices, in addition to having certain counterclaims we expected to assert. The parties elected to engage a private arbitrator to settle this dispute (the “Voorhees Matter”) and conducted discovery. On September 18, 2013, we received a third-party complaint from Voorhees in connection with a lawsuit by Carlile Transportation Systems, Inc., in the Superior Court for the State of Alaska. The case is styled Carlile Transportation Systems, Inc. v. Voorhees Rig International, Inc. v. Cook Inlet Energy, LLC (the “Carlile Matter”). The dispute in the Carlile Matter related solely to unpaid transportation fees arising from the transportation of equipment for Rig 35. These fees were already the subject of the planned arbitration with Voorhees over the Voorhees Matter. As all disputes under the Rig 35 Agreement are subject to mandatory arbitration, we filed a motion to compel arbitration in the Carlile Matter, which the Court granted, along with an award of our legal costs

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incurred in connection with the Carlile Matter. On February 20, 2014, we reached an agreement in principle to settle the Voorhees Matter (including the transportation fees at issue in the Carlile Matter), and we entered into a settlement agreement which was effective as of May 12, 2014. We agreed to return to Voorhees the following equipment previously delivered to us under the Rig 35 Agreement, but which we subsequently replaced on that rig:

- An iron roughneck that we had to replace on Rig 35 due to mechanical unreliability; and
- A BOP stack originally included on Rig 35, but later removed and replaced with a better functioning replacement;

We also agreed to return to Voorhees two moving containers, left-over electrical equipment and tools belonging to Voorhees but left with CIE when Voorhees ceased working on Rig 35. No costs of defense or other cash payment are expected to be required of us in connection with this settlement, although we will pay the transportation costs of the equipment being returned. Accordingly, we have accrued our best estimate, based on the terms in the settlement agreement, of the potential loss on our consolidated balance sheet.

On April 4, 2013, we filed suit against a former contractor of CIE and its parent company (collectively “Cudd”) in the United States District Court for the District of Alaska at Anchorage. This case is styled Cook Inlet Energy, LLC v. Cudd Pressure Control Inc. and RPC, Inc. In our suit we are seeking declaratory relief and damages for breach of contract, breach of implied warrant of merchantability, breach of implied covenant of fitness for a particular purpose and breach of the implied covenant of good faith and fair dealing arising out of a dispute regarding certain equipment and services provided by Cudd on the Osprey Platform that did not meet our needs or expectations as promised. We have not yet determined the full amount of damages claimed. On May 29, 2013, Cudd filed its Answer denying our claims and including a counterclaim for equipment and services, totaling approximately $1,889, plus the costs of defense. We have filed our counteranswer and denied that these amounts are owed, in whole or in part. We are presently conducting discovery. Given the current stage of the proceedings with respect to this case, we believe that any loss would be limited to $1,889 plus the cost of defense, related to this matter. Based on the information currently available, we have accrued our best estimate of the potential loss on our consolidated balance sheet.

On February 7, 2014, we were served with a lawsuit filed by Vulcan Capital Corporation in the District Court for the Southern District of New York styled Vulcan Capital Corp. v. Miller Energy Resources, Inc. and PlainsCapital Bank. The suit asserts various causes of action against PlainsCapital Bank, and appears to assert the following causes of action against us: (1) Breach of Fiduciary Duty and (2) Concert of Action. The case stems from an agreement Plaintiff had with PlainsCapital Bank wherein Plaintiff secured certain loans by pledging four warrants to purchase our common stock that were issued as part of the employment package of Ford F. Graham, our former President. Upon Plaintiff’s default of the loan agreement, PlainsCapital presented the warrants to us for transfer, and, after requesting certain tenders required under Tennessee law, we registered the transfer of the warrants. We have retained counsel and we have filed a Motion to Transfer as the warrants have a valid exclusive forum clause that requires the case be tried in Knox County, Tennessee. In addition, PlainsCapital Bank has agreed to indemnify us for our first $500 of expenses related to this dispute. Given the current state 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.

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable to our operations.

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PART II

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

During fiscal 2014, our common stock, par value $0.0001 per share, was listed on the NYSE 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 2014 and 2013. 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.

	2014		2013	
	High	Low	High	Low
First quarter	$5.28	$3.66	$5.29	$3.75
Second quarter	8.39	4.91	5.26	3.79
Third quarter	8.83	5.69	5.01	3.38
Fourth quarter	7.44	4.79	4.23	3.50

The closing price of our common stock, as reported on the New York Stock Exchange for July 7, 2014, was $6.07 per share. As of July 7, 2014, there were 46,076,707 shares of our common stock outstanding held by approximately 338 stockholders of record. The actual number of holders of our common stock is greater than the number of record holders and includes stockholders who are beneficial owners, but whose shares are held in street name by brokers and nominees.

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 First Lien RBL and Second Lien Credit Facility do not permit us to pay dividends on our common stock.

Information concerning securities authorized for issuance under equity compensation plans will be forth in the proxy statement relating to our fiscal 2014 annual meeting of stockholders, which is incorporated herein by reference.

Unregistered Sales of Equity Securities

In March 2014, we issued 50,000 shares of our common stock to a warrant holder upon exercise of a common stock purchase warrant to purchase 50,000 shares of our common stock with an exercise price of $1.00 per share in a private transaction exempt from registration under the Securities Act of 1933 in reliance on an exemption provided by Section 4(2) of that act. The recipient was an accredited or otherwise sophisticated investor who had such knowledge and experience in business matters and was capable of evaluating the merits and risks of the prospective investment in our securities. The recipient had access to business and financial information concerning our company.

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, 2009, through April 30, 2014. 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.

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

	2009	2010	2011	2012	2013	2014
Miller Energy Resources, Inc.	$100	$1,752	$1,748	$1,645	$1,152	$1,461
S&P's Composite 500 Stock Index	100	136	156	160	183	216
Dow Jones US Exploration & Production Index	100	144	186	159	177	226

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ITEM 6. SELECTED FINANCIAL DATA.

The following table sets forth selected financial data of our company over the five-year period ended April 30, 2014, 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 of or for the Year Ended April 30,				
	2014	2013	2012	2011	2010
Income Statement Data:					
Total revenues	$70,558	$34,801	$35,402	$22,842	$5,867
Net income (loss) attributable to common stockholders	(41,767)	(25,495)	(19,537)	(3,880)	250,941
Net income (loss) per common share:					
Basic	(0.94)	(0.60)	(0.48)	(0.11)	11.65
Diluted	(0.94)	(0.60)	(0.48)	(0.11)	8.34
Balance Sheet Data:					
Total assets	$766,822	$572,824	$536,389	$509,081	$500,342
Total debt	184,202	54,978	24,130	2,000	1,239
Weighted average common shares outstanding:					
Basic	44,445,556	42,682,685	40,811,308	36,112,286	21,537,677
Diluted	44,445,556	42,682,685	40,811,308	36,112,286	30,092,017

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

This discussion summarizes the significant factors affecting the consolidated financial statements, financial condition, liquidity, and cash flows of Miller Energy Resources, Inc., for the fiscal years ended April 30, 2014, 2013 and 2012. The following discussion and analysis should be read in conjunction with the consolidated financial statements and the notes included elsewhere in this Form 10-K.

Executive Overview

We are an independent exploration and production company that utilizes seismic data and other technologies for geophysical exploration, development and operation 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 - oil and natural gas exploration and production.

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 increasing 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 are focused 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 are increasing oil and gas production through the maintenance, repair, and optimization of wells located in the Cook Inlet region and development of wells in the Appalachian region of east Tennessee. Our operational team employs a combination of the latest available technologies along with tried and true technologies to restore as well as explore and develop our properties;
- Expand Our Revenue Stream. We intend to fully exploit 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, our capacity to process third party fluids and natural gas and, when available, to offer excess electrical power to net users in the Cook Inlet region; 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 continues to seek opportunities that meet our criteria for risk, reward, rate of return, and growth potential. We pursue value-creating acquisitions when the opportunities arise, subject to the availability of sufficient capital.

Our management team is focused on maintaining the financial flexibility, assembling the right complement of personnel, and procuring the equipment required to successfully execute these core strategies.

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 new drilling, well workovers and recompletions of our current wells. Additionally, we 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 operational cash flow along with funds from our credit facilities and funds raised from sales of our Series C Preferred Stock and Series D Preferred Stock, including "at-the-market" public offerings to support our capital expenditures during fiscal 2014. For the fiscal year ended April 30, 2014, we reported notable achievements in several key areas. Highlights for fiscal 2014 and early fiscal 2015 include:

- Starting May 1, 2013, and periodically during the fiscal year, we issued 924,968 shares of our Series C Preferred Stock in "at-the-market" offerings pursuant to the October 12, 2012 At Market Issuance Sales Agreement ("Series C ATM Agreement") with MLV and Co. LLC ("MLV") and a prospectus supplement dated October 12, 2012 (issued

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under our existing S-3 registration statement, filed with the SEC as file number 333-183750). These sales were made at an average price on the date of such sale ranging from $21.48 to $26.71 per share. We received net proceeds of $20,202 in connection with these sales.

- On May 10, 2013, we issued 500,000 shares of our Series C Preferred Stock in a "follow-on" best efforts public offering. The shares were registered in the prospectus supplement dated May 7, 2013 and we received net proceeds of $10,320.
- Effective May 15, 2013, we entered into a new commercial gas sales agreement in the Cook Inlet region with Chugach Electric Associations, Inc., Alaska's largest electric utility. Contractual gas sales commenced during the month of May and have continued throughout the period. We have primarily delivered gas on the new agreement with production from the RU-3 and RU-4A wells in the Redoubt Shoals field.
- On June 19, 2013, we began drilling our Sword #1 well from our West McArthur River Production Facility in the Cook Inlet region. The Sword #1 well was completed as an extended reach well drilled directionally to approximately 19,000 feet in an adjacent fault block to the West McArthur River Field. The 3D seismic data shows a faulted four-way closure and an estimated 240-acre structure with an estimated ultimate recovery ("EUR") of approximately 800,000 barrels of oil from the Sword #1 well.
- On June 20, 2013, we brought a new oil well, RU-2A, into production. This well is a sidetrack of a previously producing oil well, RU-2. After clearing the well of drilling fluids from the sidetrack, a subsequent well test showed an initial gross production of 1,281 barrels of oil per day with a water cut of 19%. The rate of production has averaged 926 barrels of oil per day through April 30, 2014.
- On July 2, 2013, we issued 335,000 shares of our Series C Preferred Stock in a "follow-on" best efforts public offering. The shares were registered in the prospectus supplement dated June 27, 2013 and we received net proceeds of $6,655.
- On July 22, 2013, we announced that our Board of Directors appointed David M. Hall to Chief Operating Officer ("COO"). Mr. Hall has been the Chief Executive Officer of our wholly-owned Alaskan operating subsidiary, CIE, since 2009 and will continue in that capacity. In his new role as COO, Mr. Hall will oversee our drilling operations in both Alaska and Tennessee.
- On July 25, 2013, we elected a new independent director, Marceau Schlumberger, to our board of Directors. Mr. Schlumberger has nearly twenty years of investment banking experience, including international and domestic mergers and acquisitions, restructuring, strategic analysis, and financial experience.
- On August 5, 2013, we entered into the Sixth Amendment to our credit facility with Apollo (the "Prior Credit Facility") which allowed us to borrow an additional $20,000 at a temporarily reduced interest rate of 9%. For additional information on the Sixth Amendment and the Prior Credit Facility, refer to Note 4 - Debt.
- On August 17, 2013, we successfully brought our RU-1A oil well online. The well is a sidetrack of a previously producing oil well, RU-1. The newly completed well displayed an initial gross production rate of 700 barrels of oil per day and an approximate water cut of 5%. The rate of production has averaged 476 barrels of oil per day through April 30, 2014.
- On September 30, 2013, we completed our initial public offering of our Series D Preferred Stock, issuing 1,000,000 shares at $25.00 per share with net proceeds of $23,125.
- On September 30, 2013, we completed negotiations for a multi-year gas sales agreement with Chugach Electric Association, Inc., which expanded upon the short-term contract signed in May. The contract was submitted to the Regulatory Commission of Alaska and was approved on November 25, 2013.
- On October 12, 2013, we brought our RU-5B oil well online. The rate of production has averaged 130 barrels of oil per day through April 30, 2014.
- On October 15, 2013, we brought our Brimstone H-1 well online in Tennessee. Similar to our other horizontal wells, this well requires additional testing. At April 30, 2014, the well had produced 2,503 net barrels of oil.
- On October 23, 2013, we reached total depth on our Sword #1 well. On November 20, 2013, we brought the well online. Its initial gross production rate was 883 barrels of oil per day. At April 30, 2014, the well was producing approximately 403 barrels of oil per day.

- On October 24, 2013, we received an Underground Injection Control ("UIC") permit from the EPA. We intend to re-inject gas into a vertical well adjacent to our CPP H-1 horizontal well in Tennessee to maintain reservoir pressure and hopefully increase production.
- On October 31, 2013, we completed our workover of the RU-D1 disposal well to prepare for additional drilling activity on the Osprey platform.

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- On October 31, 2013, the Susitna #2 License expired. Prior to expiration, we received confirmation from the State of Alaska that we had met our work commitment under the Susitna #2 License and were eligible to convert acreage under the license to leases. We applied for conversion and requested issuance of the proposed leases in three groups. The first group of leases consisting of a total of 47,000 acres were issued with an effective date of November 1, 2013. The second and third group of leases consisting of a total of 120,900 acres were issued with an effective date of January 1, 2014. Upon award, an annual rental fee of $3.00 per acre was paid to the State of Alaska. The annual rental fee for all three groups of leases totals $504.
- On November 22, 2013, we entered into an agreement to acquire the North Fork Properties in the Cook Inlet region and the Anchor Point Equity for $64,975, subject to customary adjustments, with approximately $5,000 to be paid in our Series D Preferred Stock (213,586 shares).
- Beginning November 26, 2013 and periodically thereafter, we issued 70,448 shares of our Series D Preferred Stock in "at-the-market" offerings pursuant to the October 17, 2013 At Market Issuance Sales Agreement ("Series D ATM Agreement") and a prospectus supplement dated October 17, 2013 (issued under our existing S-3 registration statement filed with the SEC as file number 333-183750). These sales were made at an average price ranging from $23.95 to $24.38 per share. We received net proceeds of $1,654 in connection with these sales.
- On November 28, 2013, we spudded our WMRU-8 oil well from our West McArthur River Production Facility. WMRU-8 was drilled as a directional well into a separate fault block to the main producing structure in the West McArthur River Field. The well reached a total depth of 15,536 feet on February 12, 2014 after successfully drilling and logging the Jurassic and West Forelands secondary targets.
- On February 3, 2014, we entered into a new loan agreement with Apollo, as administrative agent, which set forth the terms of the Second Lien Credit Facility. Proceeds from the new $175,000 term credit facility were used to repay the previously existing credit facility, repay all obligations to Miller Energy Income 2009-A, LP, acquire the North Fork Properties and provide working capital.
- On February 6, 2014, we entered into the Trans-Foreland Pipeline Development Agreement with Tesoro Alaska Company and Trans-Foreland Pipeline Company, LLC. This agreement allows for the construction of the Trans-Foreland Pipeline to connect our Kustatan Production Facility on the west side of the Cook Inlet to the Kenai Pipe Line Company tank farm on the east side. Completion of the pipeline would provide numerous advantages to us, including reduced transportation cost and delays.
- On February 12, 2014, our Board of Directors appointed John M. Brawley as our Chief Financial Officer. In addition, the Board of Directors approved a change in the title of David J. Voyticky to President, as he previously held the title of President and Acting Chief Financial Officer.
- On March 31, 2014, we purchased ten wells and associated infrastructure in Tennessee.
- On April 17, 2014, we held our annual meeting of shareholders at which Bob G. Gower, Joseph T. Leary and William B. Richardson were elected to our Board of Directors as three new independent directors. The Board now consists of eight directors, six of whom are independent.
- On April 17, 2014, we received a construction permit from the State of Tennessee for the construction of a gas processing facility. Once operational, the facility will allow us to process high BTU gas, strip the liquids, and produce the lower BTU gas into the sales line without blending. The operational target date is July 2014.
- On May 8, 2014, we entered into the Merger Agreement with Savant subject to due diligence and regulatory approval for $9,000. Savant currently owns, and we would acquire as a result of this merger, a 67.5% working interest in the Badami Unit and 100% ownership in certain nearby leases. ASRC Exploration, LLC owns the remaining 32.5% working interest in the Badami Unit. In additional to the working interest in the Badami Unit and the leases, we would acquire certain midstream assets located in the North Slope. We expect the transaction to close by December 2014, following regulatory approval.
- On June 2, 2014 we entered into a credit agreement, among the Company, as borrower, and KeyBank National Association, as administrative agent. In addition to KeyBank, the syndicate includes CIT Finance LLC, Mutual of Omaha Bank and OneWest Bank N.A. The First Lien Loan Agreement provides for a $250,000 senior secured,

reserve-based revolving credit facility $60,000 of which was made available to us on the closing date. Amounts outstanding under the First Lien RBL are priced on a sliding scale, based on LIBOR plus 300 to 400 basis points, depending upon the level of borrowing. We drew $20,000 on the closing date under the First Lien RBL to provide working capital for development drilling in Alaska.

- On June 24, 2014, we drew an additional $10,000 under the First Lien RBL to provide working capital for development drilling in Alaska.
- On June 24, 2014, we received the proceeds of Alaska production credits totaling $21,837 from the State of Alaska.

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• On July 4, 2014, we entered into a Purchase and Sale Agreement with Teras Oilfield Support Limited ("Teras") for the right to purchase the Glacier Drilling Rig #1, a Mesa 1000 carrier-mounted land drilling rig (the "Glacier Rig"), and related equipment (the "Glacier PSA"). The Glacier PSA is dated as of July 3, 2014, but was signed by Teras the following day. A payment of $700 was required in connection with the execution and delivery of the Glacier PSA. An additional payment of $6,300 will be due if the sale is finalized.

Fiscal 2015 Outlook

As we head into fiscal 2015, we believe our inventory of recompletion, workovers, and exploration and development projects offers numerous growth opportunities. Subsequent to April 30, 2014, we have continued our onshore and offshore drilling programs. Since the year end, we have brought the WMRU-2B oil well online and have begun drilling the West Foreland #3 gas well. We have also received the second commingling permit for our Sword-1 well, with all three zones currently producing. Following the West Foreland #3 well, we plan to drill the nearby Sabre prospect. The Sabre-1 well will be drilled in the fall, following completion of upgrades to the newly acquired Rig 36. On the Osprey platform we are continuing to drill the RU-9 South step-out well using Rig 35 and expect to complete the well during the summer of 2014. Following successful completion of the well, we will assess the next development activity on the Osprey platform and plan to drill our RU-12 grassroots oil well located in the Northern Fault.

On the east side of the Cook Inlet, we also have several development projects at North Fork, which we expect will also contribute to production in fiscal 2015.

Beyond our existing assets, on May 14, 2014 we announced our intent to acquire Savant, subject to due diligence and regulatory approval, for $9,000 in cash. Savant would become a wholly-owned subsidiary of Miller. Through Savant, Miller would own a 67.5% working interest in the Badami Unit, with ASRC Exploration, LLC remaining as a 32.5% working interest partner. Miller would also obtain a 100% working interest in nearby exploration leases. As of May 2014, these assets would add approximately 600 bopd net of current production and ownership of midstream assets located in the North Slope with a design capacity of 38,500 bopd and 50 miles of pipeline. We are currently evaluating development plans and opportunities for joint ventures in the Badami Unit.

No assurance can be made regarding the success of these development and recompletion efforts. Our current 2015 capital budget is approximately $200,000 and excludes potential development activities associated with the pending Savant acquisition. The majority of this budget is expected to be spent on projects in Cook Inlet, Alaska.

Due to the uncertainty associated with changes in commodity prices and production, 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 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, rig availability, access to capital, weather and regulatory approval.

On June 2, 2014, we entered into the First Lien RBL contemplated by the Second Lien Credit Facility, with an initial borrowing base of $60,000. At closing we drew $20,000 and on June 24, 2014 we drew an additional $10,000. The remaining availability under the First Lien RBL was $30,000 as of July 7, 2014. As reserves grow, the borrowing base may be adjusted to provide additional capital to fund our development program. We note that the borrowing base of our First Lien RBL is calculated at the discretion of the lenders based on our proved reserves, commodity prices, total debt and other factors at their sole discretion. As such, it is possible our borrowing base could be reduced in the future.

On June 24, 2014, we received proceeds of Alaska production credits totaling $21,837 from the State of Alaska. Additionally, following our year end, we entered into a capital lease for the newly purchased Rig 36, for a total of $3,250 which can be expanded up to $5,000, as we upgrade Rig 36.

Effective as of July 4, 2014, we entered into a Purchase and Sale Agreement with Teras which grants us the right to purchase the Glacier Rig and the Glacier PSA. The Glacier PSA is dated as of July 3, 2014, but was signed by Teras the following day. A payment of $700 was required in connection with the execution and delivery of the Glacier PSA, which we are entitled to have refunded if we fail to close by August 8, 2014, if it should be determined that Teras

lacks clear title to the Glacier Rig, there are liens or encumbrances (other than immaterial defects in title or liens to which we consented) or if the Glacier Rig is affected by a significant casualty prior to closing. An additional payment of $6,300 will be due if the sale is finalized.
We believe that we will be able 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 with State of Alaska production credits, potential joint ventures, and through the debt, equity and preferred equity capital markets.
Although we have the ability to sell our Series C and Series D Preferred Stock in additional “at-the-market” offerings during fiscal 2015, subject to certain limits under our First Lien RBL, we cannot guarantee that market conditions will continue

to permit such sales at prices we would find acceptable. If that occurred, cash generated from those offerings would cease. In the event we are unable to raise additional capital on acceptable terms, we may reduce our capital spending.

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Results of Operations

Revenues

	For the Year Ended April 30,				
	2014	% Variance	2013	% Variance	2012
Oil sales:					
Cook Inlet	$62,018	122 %	$27,891	(9)%	$30,566
Appalachian region	2,482	60	1,556	18	1,314
Total	$64,500	119	$29,447	(8)	$31,880
Natural gas sales:					
Cook Inlet	$4,588	11,090	$41	(69)	$134
Appalachian region	381	(11)	427	(11)	479
Total	$4,969	962	$468	(24)	$613
Other:					
Cook Inlet	$379	(90)	$3,950	226	$1,212
Appalachian region	710	(24)	936	(45)	1,697
Total	$1,089	(78)	$4,886	68	$2,909
Total revenues	$70,558	103 %	$34,801	(2)%	$35,402

Net Production

	For the Year Ended April 30,				
	2014	% Variance	2013	% Variance	2012
Oil volume - bbls:					
Cook Inlet	659,188	139 %	275,658	(15)%	325,756
Appalachian region	25,513	29	19,825	19	16,655
Total	684,701	132	295,483	(14)	342,411
Natural gas volume[1]- mcf:					
Cook Inlet	682,831	9,004	7,500	(84)	45,985
Appalachian region	110,876	(11)	125,238	(4)	130,609
Total	793,707	498	132,738	(25)	176,594
Total production[2] - boe:					
Cook Inlet	772,993	179	276,908	(17)	333,420
Appalachian region	43,993	8	40,698	6	38,423
Total	816,986	157 %	317,606	(15)%	371,843

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1 Cook Inlet natural gas volume excludes natural gas 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.

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Pricing

	For the Year Ended April 30,				
	2014	% Variance	2013	% Variance	2012
Average oil sales price - per barrel:					
Cook Inlet	$101.20	(1)%	$102.74	9%	$93.83
Appalachian region	92.73	10	83.92	6	78.89
Total	100.85	(1)	101.53	9	93.10
Average natural gas sales price - per mcf:					
Cook Inlet	6.72	68	3.99	37	2.92
Appalachian region	3.43	1	3.41	(7)	3.66
Total	6.26	78	3.52	1	3.47

Oil Prices

All of our oil production is sold at prevailing market prices, which are subject to fluctuations driven by market factors outside 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 fiscal 2014 were 1% below fiscal 2013, decreasing from an average of $101.53 per bbl in 2013 to $100.85 per bbl in 2014.

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. During fiscal 2014, realized natural gas prices averaged $6.26 per mcf, compared with $3.52 per mcf for the same period in the prior year. The increase in the average realized gas prices primarily resulted from natural gas sales at higher realized prices as a result of the acquisition of the North Fork Properties.

Oil Sales

2014 vs. 2013. During 2014, oil sales totaled $64,500, which is 119% higher than 2013. The increase resulted from a 132% increase in production partially offset by a 1% decrease in realized oil prices. Oil sales represented 91% of our consolidated total revenues in 2014 and 84% of our equivalent production.

Oil production increased 389,218 bbls, driven by a 383,530 bbl increase in the Cook Inlet region and a 5,688 bbl increase in the Appalachian region. The production increase in the Cook Inlet region resulted from RU-1A, RU-2A and RU-5B in our Redoubt Shoals field and our new Sword #1 being online during 2014.

The difference between net barrels sold and net barrels produced is approximately equal to the change in quantity of our crude oil inventory balance during the period. Although we attempt to minimize crude oil inventory balances, shipping schedules in the Cook Inlet region are beyond our control and occasionally require us to store crude oil. In addition, we are required to maintain certain inventory levels in third party pipelines and storage facilities. As noted in the following table, we experienced an above average increase in inventory levels during fiscal 2014, which significantly reduced the potential revenue that may have resulted from our increased oil production during the current period. The increase in our inventory balance primarily resulted from shipping schedules and a requirement to maintain increased inventory levels in third party facilities in the Cook Inlet region.

	April 30, 2014		
	Cook Inlet	Appalachian	Total
In barrels:			
Beginning inventory balance	30,130	12,148	42,278
Gross production	788,324	25,513	813,837
Gross sales	(732,939)	(26,766)	(759,705)
Pipeline adjustments	(3,020)	—	(3,020)
Ending inventory balance	82,495	10,895	93,390

Net change in inventory	52,365	(1,253)	51,112

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2013 vs. 2012. During 2013, oil sales totaled $29,447, 8% lower than 2012, driven by a 9% increase in average realized prices and a 14% decrease in production. Oil sales represented 85% of our consolidated total revenue and 93% of our equivalent production in 2013.
Oil production decreased 46,928 bbls, driven by a 50,098 bbls decrease in the Cook Inlet region, offset by a 3,170 bbls increase in the Appalachian region. The production decrease in the Cook Inlet region resulted from wells being offline during certain portions of the year, a normal decline curve, and fluctuations in shipping schedules.
Natural Gas Sales
2014 vs. 2013. During 2014, natural gas sales totaled $4,969, which is 962% higher than 2013. The increase resulted from the acquisition of the North Fork Properties and from selling natural gas in excess of our fuel gas needs from our RU-3 and RU-4A wells in the Cook Inlet region which increased production by 498%. The North Fork Properties acquisition contributed $4,124 to natural gas sales during 2014. Natural gas represented 7% of our consolidated total revenues in 2014 and 16% of our equivalent production.
2013 vs. 2012. During 2013, natural gas sales totaled $468, 24% lower than the 2012. The decrease resulted from a 25% decrease in production. Natural gas represented 1% of our consolidated total revenues in 2013 and 7% of our equivalent production.
Other
2014 vs. 2013. Other revenues primarily represent revenues generated from contracts for road building, plugging, drilling and maintenance and repair of third party wells as well as rental income we receive for services and use of facilities in the Cook Inlet region. During 2014 and 2013, other revenues totaled $1,089, or 2%, and $4,886, or 14%, respectively, of our consolidated total revenues. The decrease in other revenues primarily resulted from the completion of the road and pad building project in the Cook Inlet region which contributed to our revenue in 2013.
2013 vs. 2012. During 2013 and 2012, other revenues totaled $4,886, or 14%, and $2,909, or 8%, respectively, of our consolidated total revenues. The increase in other revenues primarily resulted from a road and pad building project in the Cook Inlet region.

Cost and Expenses
The table below presents a comparison of our expenses for the years ended April 30, 2014, 2013 and 2012:

	For the Year Ended April 30,				
	2014	% Variance	2013	% Variance	2012
Lease operating expense	$20,187	(9)%	$22,288	97%	$11,305
Transportation costs	5,599	132	2,410	(32)	3,556
Cost of other revenues	1,147	(73)	4,189	352	926
General and administrative	31,744	22	26,067	(12)	29,718
Alaska carried-forward annual loss credits, net	(16,342)	400	(3,268)	N/A	—
Exploration expense	2,009	38	1,458	17	1,241
Depreciation, depletion, and amortization	33,528	155	13,170	(1)	13,310
Accretion of asset retirement obligation	1,239	38	900	(16)	1,072
Other operating (income) expense, net	2,140	(3,444)	(64)	(90)	(641)
Total costs and expenses	$81,251	21%	$67,150	11%	$60,487

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Lease Operating Expense
The table below presents a comparison of our lease operating expense for the years ended April 30, 2014 and 2013:

	For the Year Ended April 30,			
	2014	2013	$ Variance	% Variance
Lease operating expense	$20,187	$22,288	$(2,101)	(9)%
Net production - boe[1]	816,986	317,606		
Lease operating expense per boe produced	$24.71	$70.17	$(45.46)	(65)%

1 Net production for fiscal 2014 and 2013 excludes 152,373 and 57,123 boe of fuel gas, respectively.

Lease operating expense decreased $2,101 from fiscal 2013, or 9%. The decreased lease operating expense is primarily attributable to decreases in workover cost related to our RU-1 and RU-7 wells in the Redoubt Shoals field in the Cook Inlet region slightly offset by increases in our production. The increased production creates marginal increases in labor and camp facility costs and well maintenance; however, the majority of our production costs are fixed. For the year ended April 30, 2014 our lease operating expense per boe produced was $24.71 as compared to $70.17 for the year ended April 30, 2013. We expect our lease operating expense per boe produced to continue to decline as production increases.
The table below presents a comparison of our lease operating expense for the years ended April 30, 2013 and 2012:

	For the Year Ended April 30,			
	2013	2012	$ Variance	% Variance
Lease operating expense	$22,288	$11,305	$10,983	97%
Net production - boe[1]	317,606	371,843		
Lease operating expense per boe produced	$70.17	$30.40	$39.77	131%

1 Net production for fiscal 2013 and 2012 excludes 57,123 and 33,956 boe of fuel gas, respectively.

Lease operating expense increased $10,983 from fiscal 2012, or 97%. The majority of the increase resulted from $7,462 in workover cost related to our RU-1 and RU-7 wells in the Redoubt Shoals field in the Cook Inlet region. As the majority of our operating costs are fixed, we did not experience a proportionate decrease in cost from the declines in production.
Transportation Costs
2014 vs. 2013. Transportation costs increased $3,189 from fiscal 2013, or 132%. Increased oil transportation costs were due to increased production, and increased gas transportation costs were primarily due to the acquisition of the North Fork Properties for which we incurred $1,403 in gas transportation costs.
2013 vs. 2012. Transportation costs decreased $1,146 from fiscal 2013, or 32%. The decrease is primarily due to decreased production and a decrease in contractual oil transportation charges.

(Dollars in thousands, except per share data and per unit data)

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. During 2014, we experienced decreases in cost of other revenues in the Cook Inlet region as we had fewer projects during the year.

	For the Year Ended April 30,				
	2014	% Variance	2013	% Variance	2012
Direct labor	$665	(75)%	$2,656	292%	$677
Equipment	121	(84)	775	100	—
Repairs	316	(47)	598	572	89
Insurance	—	(100)	91	100	—
Other	45	(35)	69	(57)	160
Total	$1,147	(73)%	$4,189	352%	$926

2014 vs. 2013. During 2014, cost of other revenues decreased 73% to $1,147. A substantial portion of this decrease is related to direct labor and equipment costs incurred as a result of a road and pad building contract that was completed in 2013.

2013 vs 2012. During 2013, cost of other revenues increased 352% to $4,189. A substantial portion of this increase was related to direct labor and equipment costs incurred as a result of a road and pad building contract that was completed in 2013.

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,				
	2014	% Variance	2013	% Variance	2012
Stock-based compensation	$8,684	(14)%	$10,132	(28)%	$14,072
Professional fees	10,955	75	6,248	37	4,561
Salaries	5,050	35	3,732	12	3,330
Employee benefits	1,759	(25)	2,357	(38)	3,824
Travel	2,001	15	1,744	3	1,693
Other	3,295	78	1,854	(17)	2,238
Total	$31,744	22%	$26,067	(12)%	$29,718

2014 vs 2013. G&A expenses increased $5,677 from fiscal 2013, or 22%. Stock-based compensation decreased 14% from the same period in the prior year, primarily due to fewer awards granted during our 2014 fiscal year as compared to the previous fiscal year. Salaries increased 35% from the same period in the prior fiscal year as we continue to expand our engineering and accounting staff. The increase in professional fees of 75% results from additional cost related to corporate governance, litigation matters and investor relations activities.

2013 vs. 2012. G&A expenses decreased $3,651 from fiscal 2012, or 12%. The decrease to stock-based compensation of 28% was primarily due to significantly fewer awards being granted during our 2013 fiscal year as compared to our 2012 fiscal year. Salaries increased 12% from fiscal 2012 to fiscal 2013 as we continue to expand our engineering, legal and accounting staff. The increase in professional fees of 37% resulted from additional cost related to corporate governance and investor relations activities.

Alaska Carried-Forward Annual Loss Credits, Net

2014 vs. 2013. During 2014, Alaska carried-forward annual loss credits, net increased $13,074, or 400%. Alaska carried-forward annual loss credits, net are generated when there is an annual loss per the State of Alaska tax statues. Increased expenses and increased drilling activity led to higher annual losses per the State of Alaska tax statutes for carried-forward annual loss credits.

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2013 vs. 2012. During 2013, Alaska carried-forward annual loss credits, net increased $3,268, or 100%. Increased expenses and increased drilling activity led to higher annual losses per the State of Alaska tax statutes for carried-forward annual loss credits.

Exploration Expense

Exploration expense consists of abandonments of drilling locations, exploration licenses, dry hole costs, delay rentals, geological and geophysical costs, and the impairment, amortization, and abandonment associated with leases on unproved properties.

2014 vs. 2013. Exploration expense increased 38% to $2,009 primarily due to an increase in delay rentals as compared to the same period in the prior year.

2013 vs. 2012. Exploration expense increased 17% to $1,458 primarily due to the timing of impairments of unproved properties.

Depreciation, Depletion and Amortization

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

	For the Year Ended April 30,					
	2014	2013	2012	2014 (Per boe)	2013	2012
Depletion:						
Cook Inlet region	$28,316	$8,460	$11,790	$36.63	$26.80	$29.42
Appalachian region	976	1,343	747	22.19	22.61	19.45
	29,292	9,803	12,537	35.85	26.16	28.55
Depreciation:						
Cook Inlet region	3,506	2,591	169	NM	NM	NM
Appalachian region	730	776	604	NM	NM	NM
	4,236	3,367	773	4.37	8.99	1.76
Total DD&A	$33,528	$13,170	$13,310	$40.22	$35.15	$30.31

NM = not meaningful

2014 vs. 2013. The increase in depletion in the Cook Inlet region is primarily a result of the additional depletion expense associated with the acquisition of the North Fork Properties and increased production from the Cook Inlet region. The increase in depreciation in the Cook Inlet region is primarily due to Rig-35 being in service during all of fiscal 2014.

2013 vs. 2012. During fiscal 2013, the decrease in depletion in the Cook Inlet region was primarily a result of decreased production. The increase in depreciation in the Cook Inlet region from fiscal 2012 to fiscal 2013 was primarily due to Rig 34 and Rig 35 being placed in service during the period.

Accretion of Asset Retirement Obligation

Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

2014 vs. 2013. Accretion of asset retirement obligations increased 38% to $1,239 primarily due to additions of asset retirement obligations during fiscal 2014.

2013 vs. 2012. Accretion of asset retirement obligations decreased 16% to $900 primarily due to revisions of assumptions.

Other Operating (Income) Expense, Net

2014 vs. 2013. During fiscal 2014, we recorded other operating expenses of $2,140 which is due to asset impairment charges of $890 and a charge of $1,250 in connection with the settlement the CNX lawsuit, for additional information please see Note 10 - Litigation.

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2013 vs. 2012. Other operating income decreased $577 from 2012 primarily due to income recognized in 2012 related to revised estimates of royalties due based on a 2012 commission ruling.

Other Income and Expense

The following table presents the components of other income and expense:

	For the Year Ended April 30,				
	2014	% Variance	2013	% Variance	2012
Interest expense, net	$(7,470)	75 %	$(4,276)	133 %	$(1,837)
Gain (loss) on derivatives, net	(10,179)	251	6,751	(338)	(2,832)
Other income (expense), net	34	(110)	(329)	667	58
Loss on debt extinguishment	(15,145)	100	—	—	—
Total	$(32,760)	1,627 %	$2,146	(147)%	$(4,611)

Interest Expense, Net

2014 vs. 2013. Interest expense, net of interest income increased $3,194 from fiscal 2013, or 75%, driven primarily by an increase in the average debt balance outstanding during fiscal 2014.

2013 vs. 2012. Interest expense, net, increased $2,439 from 2012, or 133%, driven primarily by an increase in amortization of deferred financing costs and an increase in the average debt balance outstanding during fiscal 2013.

Gain (Loss) on Derivatives, Net

We have not designated any of our commodity derivative instruments as accounting hedges. As a result, gains and losses on derivatives include both amounts realized from the cash settlements of our derivative positions and amounts from changes in the fair value of open derivative positions in the period of change. 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.

2014 vs. 2013. Gain (loss) on derivatives, net experienced an unfavorable change of $16,930 in fiscal 2014 as compared to fiscal 2013. Of the total change, $5,331 was due to an unfavorable change in realized cash settlements related to our derivative positions in fiscal 2014 compared to fiscal 2013. The remaining amount was due to changes in the fair value of our open derivative positions in each period.

2013 vs. 2012. Gain (loss) on derivatives, net experienced a favorable change of $9,583 in fiscal 2013 compared to fiscal 2012. Of the total change, $912 was due to a favorable change in realized cash settlements related to our derivative positions in fiscal 2013 compared to fiscal 2012. The remaining amount was due to changes in the fair value of our open derivative positions in each period.

Loss on Debt Extinguishment

In connection with the termination and repayment of the loans outstanding under the Prior Credit Facility, we determined that the Second Lien Credit Facility had substantially different terms from the Prior Credit Facility and recorded a loss on debt extinguishment of $15,145, consisting of a $9,223 prepayment and extension fee owed to Apollo payable in four equal installments of $2,306 on the last day of each calendar quarter, commencing June 30, 2014, and a charge of $5,185 to extinguish the debt discount, the unamortized deferred financing costs and prepaid administrative fee. Additionally, there was a charge of $737 in connection with the termination and repayment of all obligations under the MEI Loan Documents.

Income Tax Benefit

2014 vs. 2013. Income tax benefit increased $5,103 from fiscal 2013, or 52% due to an increase in loss before income taxes. Our effective income tax rate for 2014 was 34.3%. This rate differed from the statutory rate primarily due to the effect of our state valuation allowance.

2013 vs. 2012. Income tax benefit decreased $1,223 from fiscal 2012, or 11% primarily due to a revaluation of deferred tax items due to an increase in the blended effective state tax rate. Our effective income tax rate for 2013 was 32.4%. This rate differed from the statutory rate primarily due to changes in our effective state tax rate.

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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 and production. 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.

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 refer to the section entitled "Risk Factors" in this Annual Report.

In fiscal 2014, we experienced an operating loss. We anticipate that our operating expenses will continue to increase as we fully develop our assets in the Cook Inlet and Appalachian regions and make additional acquisitions. Although we expect an increase in revenues from these development activities, we will continue to utilize our cash to fund drilling and workover activities as well as other operating expenses until such time as we are able to significantly increase our revenues above our operating expenses and capital costs.

At our fiscal year end, our cash and cash equivalent balance was $5,749, excluding restricted cash balances of $12,754 held in escrow to secure corporate credit cards and provide for the future plugging and abandonment of wells, including the possible dismantling of our off-shore platform, and general liability bonds.

On February 3, 2014, we refinanced the Prior Credit Facility by entering into the New Apollo Loan Agreement which set forth the terms of the Second Lien Credit Facility. The New Apollo Loan Agreement provided for a $175,000 term credit facility, all of which was made available to and drawn by us on the closing date and was used to refinance the Prior Credit Facility, to close the North Fork Properties acquisition and for general corporate purposes. The amounts drawn were subject to a 2% original issue discount. Amounts outstanding under the Second Lien Credit Facility bear interest at a rate of LIBOR plus 9.75%, subject to a 2% LIBOR floor. The Second Lien Credit Facility carries a four year maturity and contains leverage ratio, interest coverage ratio, current ratio, asset coverage ratio, minimum gross production and change of management control covenants as well as other covenants customary for a transaction of this type. The Second Lien Credit Facility permitted us to enter into a reserve-based revolving credit facility in the nature of the First Lien RBL.

On June 2, 2014, we entered into the First Lien RBL contemplated by the Second Lien Credit Facility, with an initial borrowing base of $60,000. At closing, we drew $20,000, and on June 24, 2014, we drew an additional $10,000. The remaining availability under the First Lien RBL was $30,000 as of July 7, 2014. As reserves grow, the borrowing base may be adjusted to provide additional capital to fund our development program. The borrowing base of our First Lien RBL is calculated at the discretion of the lenders based on our proved reserves, commodity prices, total debt and other factors at their sole discretion. As such, it is possible our borrowing base could be reduced in the future.

On June 24, 2014, we received proceeds of Alaska production credits totaling $21,837 from the State of Alaska. Additionally, following our year end, we entered into a capital lease for the newly purchased Rig 36, for a total of $3,250, which can be expanded up to $5,000, as we upgrade Rig 36.

We believe that we will be able 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 with State of Alaska production credits, potential joint ventures, and through the debt, equity and preferred equity capital markets.

Although we have the ability to sell our Series C and Series D Preferred Stock in additional “at-the-market” offerings during fiscal 2015, subject to certain limits under our First Lien RBL, we cannot guarantee that market conditions will continue to permit such sales at prices we would find acceptable. If that occurred, cash generated from those offerings would cease. In the event we are unable to raise additional capital on acceptable terms, we may reduce our capital spending.

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(Dollars in thousands, except per share data and per unit data)

Sources and Uses of Cash
The following table presents the sources and uses of our cash and cash equivalents for the periods presented:

	For the Year Ended April 30,		
	2014	2013	2012
Sources of cash and cash equivalents:			
Net cash provided by operating activities	$15,322	$—	$6,901
Proceeds from borrowings, net of debt acquisition costs	189,173	51,147	28,754
Proceeds from sale of equipment	—	2,000	—
Proceeds from Alaska expenditure and exploration based credits	18,531	131	—
Exercise of equity rights	4,638	3,832	1,383
Issuance of preferred stock, net of issuance costs	58,844	33,200	10,000
Release of restricted cash	4,984	—	—
Other	3	—	—
	291,495	90,310	47,038
Uses of cash and cash equivalents:			
Net cash used in operating activities	—	(11,491)	—
Cash dividends	(8,552)	(1,231)	—
Capital expenditures for oil and gas properties	(136,320)	(26,492)	(7,558)
Purchase of equipment and improvements	(2,943)	(11,533)	(26,409)
Payments on debt	(75,306)	(24,130)	(8,764)
Redemption of preferred stock	—	(11,240)	—
Repayment of MEI loans	(3,071)	—	—
Prepayment of drilling costs	(1,692)	—	—
North Fork acquisition	(59,557)	—	—
Acquisition of land	(356)	—	—
Savant purchase deposit	(500)	—	—
Increase in restricted cash	—	(5,613)	(1,895)
	(288,297)	(91,730)	(44,626)
Increase (decrease) in cash and cash equivalents	$3,198	$(1,420)	$2,412

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, 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 of fiscal 2014 totaled $15,322, an increase of $26,813 from 2013. The increase resulted primarily from an increase in revenue and a favorable shift in the timing of cash receipts and payments to vendors in the ordinary course of business.
Proceeds from Credit Facilities and Other Items
During fiscal 2014, we borrowed $20,000 under our Prior Credit Facility and borrowed $175,000 under our Second Lien Facility. In connection with the borrowings, we incurred approximately $5,827 in debt acquisition costs. We also repaid $75,306 under our Prior Credit Facility during fiscal 2014. For additional information on the credit facilities, please see Note 4 - Debt.
Net cash flows provided by financing activities included $62,738 received from the issuance of our Series C and Series D Preferred Stock, partially offset by issuance costs of $3,894 during fiscal 2014, as compared to $35,867 received from the issuance of our Series C Preferred Stock, partially offset by issuance costs of $2,667 during fiscal

2013.

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Under the terms of the North Fork Purchase Agreement, we paid $59,557 in cash to the North Fork Sellers for the acquisition of the North Fork Properties.

During fiscal 2014 we paid $8,552 for quarterly dividends on our Series C Preferred Stock and Series D Preferred Stock. During fiscal 2013, we paid $1,231 for quarterly dividends on our Series C Preferred Stock.

Short-term restricted cash primarily relates to accounts controlled by the administrative agent under the New Apollo Loan Agreement, Tennessee oil revenue accounts for joint interest holders and a credit card collateral account. The lenders under the New Apollo Loan Agreement required revenues and certain other items to be deposited directly into depository accounts subject to a Deposit Account Control Agreement. As Apollo, in its capacity as administrative agent, exercised control of the depository accounts subject to a Deposit Account Control Agreement, Apollo had the ability to prevent disbursements from those restricted accounts to our unrestricted cash accounts. Amounts deposited into these accounts were generally released to us in a timely manner. Subsequent to our entry into the First Lien Loan Agreement, we are in the process of moving our depository accounts to KeyBank where we will be able to control disbursements from our accounts until such time as KeyBank exercises control under a new Deposit Account Control Agreement.

Long-term restricted cash balances include amounts held in escrow to provide for the future plugging and abandonment of wells, the possible dismantling of our off-shore platform, performance bonds and general liability bonds. Amounts released from our long-term restricted cash accounts, if any, would be the result of a release from escrow by the beneficiary. Amounts transferred to our long-term restricted cash accounts result from bonding requirements for new wells and additions to our current bonding requirements.

Capital Expenditures and Alaska Production Credits

We use a combination of operating cash flows, borrowings under credit facilities and, from time to time, issuances of debt or common stock to fund significant capital projects. Due to the volatility in oil and natural gas prices and production, 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.

Total spending on capital projects increased significantly from the same period last year. For the year ended April 30, 2014, we incurred total capital expenditures of $167,919 which is inclusive of the increase in our capital accrual account of $28,656. Cash paid for capital expenditures was $139,263 for the year ended April 30, 2014.

During the year ended April 30, 2014, we collected $21,775 related to our Alaska production credits. The amounts collected related to expenditure and exploration based credits and carried-forward annual loss credits.

Prepayment of Drilling Costs

We occasionally are required to pay in advance for certain equipment rental and services related to our drilling activities. The advance payments are recorded in prepaid expenses at the time of payment and amortized to capital expenditures as the costs are incurred. At April 30, 2014, we had $1,692 in prepaid drilling costs and other capital related items.

Liquidity

Cash and Cash Equivalents

As of April 30, 2014, we had $5,749 in cash and cash equivalents.

Debt and Available Credit Facilities

Outstanding debt consisted of $175,000 under our new Second Lien Credit Facility, and an Apollo prepayment and extension fee note payable for $9,223 which is classified as a current debt obligation on the accompanying consolidated balance sheet as of April 30, 2014. In accordance with the terms in our Second Lien Credit Facility, we are required to pay down our outstanding debt with the proceeds received from selling our airplane, which we believe is probable to occur within the next twelve months. Accordingly, a portion of the outstanding debt balance under the Second Lien Credit Facility is classified as a current debt obligation on the accompanying consolidated balance sheet as of April 30, 2014, with the remainder classified as long term debt. As of April 30, 2014 we had no additional borrowing capacity under our Second Lien Credit Facility.

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Contractual Obligations

The following table summarizes our contractual obligations as of April 30, 2014. 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	2015	2016-2017	2018-2019	and after
Contractual obligations:[a]						
Debt, at face value[b]	Note 4	$187,984	$9,459	$950	$177,575	$—
Interest obligations	Note 4	81,802	22,030	44,053	15,719	—
Dismantlement, removal and restoration (Osprey)[c]	Note 6	11,000	1,500	4,500	3,500	1,500
Work commitments[d]	Note 6	3,326	875	1,700	188	563
Rights of way and easements:[e]	Note 6					
Osprey to shore pipeline	Note 6	248	13	26	26	183
CIRI Kustatan pipeline easement	Note 6	251	28	56	56	111
West Foreland CIRI/Salamatof agreement	Note 6	166	18	38	40	70
Salamatof surface use agreement	Note 6	400	50	100	100	150
Office and related equipment[f]	Note 6	1,578	447	625	249	257
Total contractual obligations		$286,755	$34,420	$52,048	$197,453	$2,834

a. This table does not include the Company's liability for dismantlement, abandonment, and restoration costs of oil and gas properties, derivative liabilities, or tax reserves. For additional information regarding these liabilities, please see Note 2 - Derivative Instruments, Note 5 - Asset Retirement Obligations and Note 6 - Commitments and Contingencies, respectively, in the Notes to Consolidated Financial Statements set forth in Part IV, Item 15 of this Form 10-K.

b. Debt includes Series B Preferred Stock of $2,575 which matures September 24, 2017, and the debt related to the Second Lien Credit Facility of $175,000 which carries a four year maturity, and a prepayment and extension fee owed to Apollo in the amount of $9,223.

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

d. Work commitments relate to two Susitna Basin Exploration Licenses, Otter, and Olsen Creek.

e. 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.

f. Office and related equipment relate to leases for office space and equipment.

We are 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.

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Non-GAAP Measures

Adjusted EBITDA
Adjusted earnings before interest, taxes, depreciation and amortization ("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;
- impairment and dry hole costs;
- (gain) loss from equity investment;
- stock-based compensation expense;
- unrealized (gain) loss from mark-to-market activities;
- interest expense and interest (income);
- non-recurring litigation settlements and related matters;
- non-recurring North Fork Properties gas transportation costs.

Our Adjusted EBITDA should not be considered as a substitute for net income (loss), operating income (loss), 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. Our Adjusted EBITDA may not be comparable to similarly titled measures of other companies.

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

	For the Year Ended April 30,		
	2014	2013	2012
Loss before income taxes	$(43,453)	$(30,203)	$(29,696)
Adjusted by:			
Interest expense, net	7,470	4,276	1,837
Depreciation, depletion and amortization	33,528	13,170	13,310
Asset impairments	890	—	—
Accretion of asset retirement obligation	1,239	900	1,072
Exploration expense	2,009	1,458	1,241
Loss on debt extinguishment	15,145	—	—
Stock-based compensation	9,034	10,459	14,072
Non-recurring litigation settlements and matters	4,215	—	—
Non-recurring North Fork Properties transportation costs	1,403	—	—
Derivative contracts:			
(Gain) loss on derivatives, net	10,179	(6,751)	2,832
Cash settlements	(3,815)	1,516	604
Adjusted EBITDA	$37,844	$(5,175)	$5,272

Critical Accounting Policies and Estimates

General
The preparation of consolidated financial statements requires us to utilize estimates and make judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the 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, 2014, 2013, and 2012, 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.

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Asset Retirement Obligations ("AROs")

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. AROs associated with retiring tangible long-lived assets are recognized as a liability in the period 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 Measurements

We measure the 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 - Measurements are based on quoted prices in active markets that are unadjusted and accessible at the measurement date for identical, unrestricted assets or liabilities;
- Level 2 - Measurements are based on significant observable pricing inputs other than quoted prices included in Level 1 that are either directly or indirectly observable as of measurement date; or
- Level 3 - Measurements are based on process or valuation models that use inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity). These inputs generally reflect management’s own assumptions about the assumptions a market participant would use in pricing the asset or liability.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. Reclassifications of fair value between level 1, level 2, and level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter.

Stock-Based Compensation

The computation of stock-based compensation requires the use of a valuation model. FASB Accounting Standard Codification ("ASC") 718, "Compensation - Stock Compensation," requires significant judgment and the use of estimates, particularly surrounding model assumptions such as stock price volatility, expected term, 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 differ from those estimates and assumptions.

Purchase Price Allocation

Accounting for the acquisition of a business requires the allocation of the purchase price to the various assets acquired and the liabilities assumed.

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 acquisition date, although such estimates may change in the future as additional information becomes known.

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In estimating the fair value of assets acquired and liabilities assumed, we made various assumptions. The most significant assumptions related to the estimated fair value assigned to proved and unproved crude oil and natural gas properties. To estimate the fair value 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. The estimated fair value assigned to assets acquired and liabilities assumed involve a number of judgments and estimates that could differ materially from the actual amount.

Recent Accounting Pronouncements

In July 2013, the FASB issued ASU 2013-11, "Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists." The amendments in ASU 2013-11 require an entity to present an unrecognized tax benefit in the financial statements as a reduction to a deferred tax asset for a net operating loss ("NOL") carryforward, a similar tax loss, or a tax credit carryforward except when: (1) a NOL carryforward, a similar tax loss, or a tax credit carryforward is not available as of the reporting date under the governing tax law to settle taxes that would result from the disallowance of the tax position; or (2) the entity does not intend to use the deferred tax asset for this purpose (provided that the tax law permits a choice). If either of these conditions exists, an entity should present an unrecognized tax benefit in the financial statements as a liability and should not net the unrecognized tax benefit with a deferred tax asset. The amendment does not affect the recognition or measurement of uncertain tax positions under ASC Topic 740, Income Taxes. The amendments in this ASU are effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The amendments should be applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application is permitted. We do not expect this ASU to have a material impact to our consolidated financial statements.

In May 2014, the FASB issued ASU 2014-09, “Revenue from Contracts with Customers (Topic 606)” (“ASU 2014-09”). ASU 2014-09 is intended to improve the financial reporting requirements for revenue from contracts with customers by providing a principle based approach. The core principal of the standard is that revenue should be recognized when the transfer of promised goods or services is made in an amount that the entity expects to be entitled to in exchange for the transfer of goods and services. ASU 2014-09 also requires disclosures enabling users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. This standard will be effective for financial statements issued by public companies for annual reporting periods beginning after December 15, 2016. Early adoption is not permitted. The Company is currently evaluating the potential impact of ASU 2014-09 on the consolidated financial statements.

There are no other recently issued accounting pronouncements that are expected to have a material impact on our financial condition, results of operations or cash flows.

Supplemental Quarterly Financial Information (Unaudited)

The following table sets forth selected unaudited quarterly results for the eight quarters ended April 30, 2014.

	Apr 30, 2014	Jan 31, 2014	Oct 31, 2013	Jul 31, 2013
Total revenues	$22,126	$16,628	$18,796	$13,008
Income (loss) from operations	6,351	(6,585)	(4,283)	(6,176)
Net loss attributable to common stockholders	(17,241)	(6,824)	(8,285)	(9,417)
Diluted loss per share	(0.38)	(0.15)	(0.19)	(0.22)

	Apr 30, 2013	Jan 31, 2013	Oct 31, 2012	Jul 31, 2012
Total revenues	$7,730	$7,999	$10,810	$8,262
Loss from operations	(14,757)	(6,500)	(6,089)	(5,003)
	(13,121)	(6,164)	(6,399)	189

Net income (loss) attributable to common stockholders				
Diluted loss per share	(0.31)	(0.14)	(0.15)	0.00

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.

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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 macro-economic conditions, 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 2014 and 2013, approximately 86% to 82% of our crude oil production was subject to financial derivative hedges. Realized gains or losses from our price-risk management activities are recognized in gain (loss) on derivatives, net when the associated production occurs. We do not hold or issue derivative instruments for trading purposes.
On April 30, 2014, we had open oil derivative instruments in a net liability position with a fair value of $7,207. A 10% increase in oil prices would result in a net liability position with an approximate fair value of $25,357, while a 10% decrease in prices would result in a net asset position with an approximate fair value of $10,944. For notional volumes and terms associated with our derivative contracts, please see Note 2 - 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 are subject to interest rate risk in connection with our First Lien RBL and our Second Lien Credit Facility. Our principal interest rate exposure relates to our First Lien RBL which is based on LIBOR plus 300 to 400 basis points. Our Second Lien Credit Facility is based on LIBOR plus 9.75%, subject to a 2.0% LIBOR floor. Given current LIBOR rates, we do not believe LIBOR is likely to exceed the 2.0% floor. Thus, we believe our interest rate risk is primarily associated with our First Lien RBL.

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

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 reflects 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

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evaluation of controls can provide absolute assurance that all control issues, 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 errors or mistakes. 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, 2014. This assessment was based on criteria established for effective internal control over financial reporting in Internal Control - Integrated Framework (1992) 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, 2014:

We did not maintain a sufficient complement of corporate accounting and finance personnel necessary to consistently operate management review controls. This material weakness resulted in numerous material adjustments to the preliminary financial statements that were corrected prior to their issuance.

As a result of this material weakness, the Company's management has concluded that, as of April 30, 2014, its internal control over financial reporting was not effective based on criteria established in Internal Control - Integrated Framework (1992) issued by the COSO.

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.

c) Changes in Internal Control over Financial Reporting and Remediation

The material weakness described above was originally identified during fiscal 2011. Over the last several years, we have taken a number of actions in an attempt to remediate the material weakness, including the hiring and training of additional personnel; however, as of April 30, 2014, we have not remediated the material weakness. During this time period we have experienced substantial turnover in the key accounting and finance personnel responsible for management review controls. Late in fiscal 2014, we hired a new Chief Financial Officer and a new Vice President and Director of Financial Reporting. In fiscal 2015, we intend to take the following actions in an attempt to remediate the material weakness:

- Hire one additional accounting and finance manager
- Enhance the business understanding and relevant knowledge possessed by those operating management review controls
- Implement new process level controls to supplement management review controls

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

On February 2, 2014, the Board of Directors entered into revised indemnification agreements in order to establish procedures under which directors, officers, and certain key employees could seek indemnification by the Company in accordance with the Company’s Bylaws and Tennessee law. The indemnification agreement does not grant any additional substantive rights to the indemnitees than previously existed under the Company’s Bylaws and Tennessee law. When submitting a request for indemnification, the indemnitee is required to affirm that he acted in good faith and in a manner he reasonably believed to be in, or not opposed to, the best interests of the Company. He must further agree to repay to the Company any funds advanced by the Company or the Company's insurance carrier to him or on his behalf in the event that it is ultimately determined by a final non-appealable adjudication by a court of competent jurisdiction that he is liable for a breach of the duty of loyalty to the company or its shareholders, for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law, or under Tennessee Code Annotated §48-18-304.

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The foregoing description is qualified in its entirely by reference to the form of Indemnification Agreement, which is filed as Exhibit 10.61 to this report.

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(Dollars in thousands, except per share data and per unit data)

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 2014 Annual Meeting of Shareholders to be filed on or prior to August 28, 2014 (the "Proxy Statement") and is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION
The information required by this Item will be contained in our Proxy Statement and is incorporated herein by 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 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 reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

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

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PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

a. Documents included in this report:

1. Financial Statements

1. 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.

2. 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 (Commission file number 033-02249-FW) dated January 15, 1997).
2.2	–	Purchase and Sale Agreement, dated November 22, 2013, by and among Armstrong Cook Inlet, LLC, GMT Exploration Company, LLC, Dale Resources Alaska, LLC, Jonah Gas Company, LLC and Nerd Gas Company, LLC as sellers and Cook Inlet Energy as buyer (incorporated by reference to Registrant’s Current Report on Form 8-K dated November 25, 2013).
3.1	–	Certificate of Incorporation (incorporated by reference to Registrant's Annual Report on Form 10-KSB (Commission file number 033-02249-FW) 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 (Commission file number 033-02249-FW) 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 (Commission file number 033-02249-FW) 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 filed on January 17, 2001, 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).

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3.10	–	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 August 17, 2012).
3.11	–	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 September 4, 2012).
3.12	–	Articles of Amendment to the Charter of Miller Energy Resources, Inc. (incorporated by reference to Exhibit 3.20 to Registrant's Registration Statement on Form 8A filed on September 28, 2012).
3.13	–	Articles of Amendment to the Charter of Miller Energy Resources, Inc. (incorporated by reference to Exhibit 3.21 to Registrant's Registration Statement on Form 8A filed on September 26, 2013).
4.1	–	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).
†4.2	–	Miller Petroleum, Inc. Stock Plan (incorporated by reference to Registrant's Current Report on Form 8-K filed on April 29, 2010).
4.3	–	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), as amended by the Special Warrant Exercise Agreement filed as an exhibit to Registrant's Form 8-K filed on September 21, 2012.
4.4	–	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).
4.5	–	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), as amended by the Special Warrant Exercise Agreement filed as an exhibit to Registrant's Form 8-K filed on September 21, 2012.
4.6	–	2011 Equity Compensation Plan (incorporated by reference to Registrant's Current Report on Form 8-K filed on March 17, 2011).
4.7	–	Form of Series PPA Warrant (incorporated by reference to Registrant's Current Report on Form 8-K filed on April 12, 2012).
4.8	–	Form of Common Stock Certificate (incorporated by reference to Registrant's Registration Statement on Form S-3 filed on September 6, 2012).
4.9	–	Form of Series PPB warrant (incorporated by reference to Registrant's Current Report on Form 8-K filed on September 24, 2012).
†4.10	–	Form of option issued to Martin Funderlic (incorporated by reference to Registrant's Registration Statement on Form S-3 filed on October 5, 2012).
*4.11	–	Form of Warrant issued to MZ Group
*4.12	–	Form of Warrant issued to Michelle Borromeo
*4.13	–	Form of Warrant issued to Investor Relations Consultant
*4.14	–	Form of Warrant issued to William Weakley
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 (Commission file number 033-02249-FW) filed on 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).
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).

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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	–	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).
10.8	–	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).
10.9	–	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).
10.10	–	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).
10.11	–	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).
10.12	–	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).
10.13	–	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).
10.14	–	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).
10.15	–	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).
10.16	–	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).
10.17	–	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).
10.18	–	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).
10.19	–	

		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).
10.20	–	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).
10.21	–	Indemnification Agreement (incorporated by reference to Registrant's Quarterly Report on Form 10-Q filed on December 12, 2011).
10.22	–	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).
10.23	–	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).
10.24	–	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).
†10.25	–	Employment Agreement with Catherine Rector (incorporated by reference to Registrant's Current Report on Form 8-K filed on July 31, 2012).

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10.26	–	Acknowledgment and Amendment Regarding Series B Preferred Stock, dated August 13, 2012 (incorporated by reference to Registrant's Current Report on Form 8-K filed on August 17, 2012).
10.27	–	Special Warrant Exercise Agreement (incorporated by reference to Registrant's Current Report on Form 8-K filed on September 21, 2012).
10.28	–	Bristol Warrant Exercise Agreement (incorporated by reference to Registrant's Current Report on Form 8-K filed on September 21, 2012).
10.29	–	Acknowledgment and Amendment No. 2 (Series C Preferred Stock, Covenant Compliance, PDC Acquisition and APOD Adjustment), dated September 24, 2012 (incorporated by reference to Registrant's Current Report on Form 8-K filed on September 26, 2012).
10.30	–	Acknowledgment and Amendment No. 3, dated November 14, 2012 (incorporated by reference to Registrant's Current Report on Form 8-K filed on November 16, 2012).
10.31	–	Waiver and Amendment No. 4, dated February 7, 2013 (incorporated by reference to Registrant's Current Report on Form 8-K filed on February 7, 2013).
10.32	–	Waiver and Amendment No. 5, dated July 11, 2013 (incorporated by reference to Registrant's Current Report on Form 8-K filed on July 12, 2013).
†10.33	–	Amended and Restated Employment Agreement with Catherine Rector dated July 22, 2013 (incorporated by reference to Registrant's Current Report on Form 8-K filed on July 26, 2013).
10.34	–	Amendment No. 6 (incorporated by reference to Registrant’s Current Report on Form 8-K filed on August 5, 2013).
†10.35	–	Employment Agreement with Scott M. Boruff, dated as of July 29, 2013 (incorporated by referenced to Exhibit 10.1 to Registrant’s Current Report on Form 8-K/A filed on August 28, 2013).
†10.36	–	Employment Agreement with David J. Voyticky, dated as of July 29, 2013 (incorporated by referenced to Exhibit 10.2 to Registrant’s Current Report on Form 8-K/A filed on August 28, 2013).
†10.37	–	Employment Agreement with Deloy Miller, dated as of July 29, 2013 (incorporated by referenced to Exhibit 10.3 to Registrant’s Current Report on Form 8-K/A filed on August 28, 2013).
†10.38	–	Employment Agreement with David M. Hall, dated as of July 29, 2013 (incorporated by referenced to Exhibit 10.4 to Registrant’s Current Report on Form 8-K/A filed on August 28, 2013).
†10.39	–	Employment Agreement with Kurt C. Yost, dated as of July 29, 2013 (incorporated by referenced to Exhibit 10.5 to Registrant’s Current Report on Form 8-K/A filed on August 28, 2013).
10.40	–	Revised and Restated Consent and Amendment No. 7, dated as of September 20, 2013 (incorporated by reference to Registrant’s Current Report on Form 8-K filed on September 26, 2013).
10.41	–	Waiver and Amendment No. 8 (incorporated by reference to Registrant’s Current Report on Form 8-K filed on December 9, 2013).
10.42	–	Settlement Agreement dated January 24, 2014 between Miller Energy Resources, Inc. and CNX Gas Company, LLC (incorporated by reference to Registrant’s Current Report on Form 8-K filed on January 30, 2014.
10.43	–	Extension of Date for Prepayment of Tranche B Loan without Prepayment Premium (incorporated by reference to Registrant’s Current Report on Form 8-K filed on January 31, 2014).
10.44	–	Amended and Restated Credit Agreement dated as of February 3, 2014 among Miller Energy Resources, Inc., as Borrower, and Apollo Investment Corporation, as Arranger and Administrative Agent (incorporated by reference to Exhibit 10.01 to Registrant’s Current Report on Form 8-K filed on February 6, 2014).
10.45	–	Amended and Restated Guarantee and Collateral Agreement in favor of Apollo Investment Corporation, as Administrative Agent (incorporated by reference to Exhibit 10.02 to Registrant’s Current Report on Form 8-K filed on February 6, 2014).

10.46	–	Trans-Foreland Pipeline Development Agreement dated February 6, 2014 between Cook Inlet Energy, LLC, Tesoro Alaska Company and Trans-Foreland Pipeline Company, LLC (incorporated by reference to Registrant's Current Report on Form 8-K filed on February 12, 2014).

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†10.47	–	Employment Agreement with John M. Brawley (incorporated by reference to Registrant's Current Report on Form 8-K filed on February 18, 2014).
†10.48	–	Amendment to Executive Employment Agreements dated March 10, 2014 (incorporated by reference to Registrant's Current Report on Form 8-K filed on March 13, 2014).
10.49	–	Settlement Agreement dated March 28, 2014 among Miller Energy Resources, Inc. and Bristol Investment Fund, Ltd., Bristol Capital, LLC, Bristol Capital Advisors, LLC and Mr. Paul Kessler (incorporated by reference to Registrant's Current Report on Form 8-K filed on March 31, 2014).
10.50	–	Purchase Option Agreement between the Company and Baker Process, Inc. dated as of March 31, 2014 (incorporated by reference to Registrant's Current Report on Form 8-K filed on April 2, 2014).
10.51	–	Rig Equipment Purchase Agreement by and between Miller Energy Resources, Inc., as Buyer and Baker Process, Inc., as Seller (incorporated by reference to Registrant's Current Report on Form 8-K filed on May 6, 2014).
10.52	–	Master Lease between Miller Energy Resources, Inc. and First National Capital, LLC (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on May 14, 2014).
10.53	–	Equipment Schedule No. 1 between Miller Energy Resources, Inc. and First National Capital, LLC (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on May 14, 2014).
10.54	–	Interim Term Lease Schedule between Miller Energy Resources, Inc. and First National Capital, LLC (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on May 14, 2014).
10.55	–	Credit Agreement dated as of June 2, 2014 among Miller Energy Resources, Inc. as Borrower, and KeyBank National Association, as Administrative Agent (incorporated by reference to Exhibit 10.1 to Registrant's Current Report on Form 8-K filed on June 6, 2014).
10.56	–	Guarantee and Collateral Agreement in favor of KeyBank National Association, as Administrative Agent (incorporated by reference to Exhibit 10.2 to Registrant's Current Report on Form 8-K filed on June 6, 2014).
10.57	–	Amendment No. 1 to Credit Agreement and Guarantee and Collateral Agreement dated as of June 2, 2014 (incorporated by reference to Exhibit 10.3 to Registrant's Current Report on Form 8-K filed on June 6, 2014).
†10.58	–	Extension Agreement dated June 3, 2014 between David J. Voyticky and Miller Energy Resources, Inc. (incorporated by reference to Exhibit 10.4 to Registrant's Current Report on Form 8-K filed on June 6, 2014).
10.59	–	Purchase and Sale Agreement between the Company and Teras (incorporated by reference to Registrant's Current Report on Form 8-K filed on July 8, 2014).
*†10.60	–	Employment Agreement with Conrad Perry.
*10.61	–	Form of Director and Officer Indemnification Agreement
*21.1	–	Subsidiaries of the registrant
*23.1	–	Consent of Ryder Scott Company, L.P.
*23.2	–	Consent of Ralph E. Davis Associates, Inc.
*23.3	–	Consent of KPMG 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 Ryder Scott Company, L.P. at April 30, 2014 on Cook Inlet assets

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*99.2	–	Reserve Report of Ralph E. Davis Associates, Inc. at April 30, 2014 on Appalachian region assets
**101.INS	–	XBRL Instance Document
**101.SCH	–	XBRL Taxonomy Extension Schema Document
**101.CAL	–	XBRL Taxonomy Extension Calculation Linkbase Document
**101.DEF	–	XBRL Taxonomy Extension Definition Document
**101.LAB	–	XBRL Taxonomy Extension Label Linkbase Document
**101.PRE	–	XBRL Taxonomy Extension Presentation Linkbase Document

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* Filed herewith.

** In accordance with Regulation S-T, the XBRL-formatted interactive data files that comprise Exhibit 101 in this report on Form 10-K shall be deemed "furnished" and not "filed."

† Indicates management contract or compensatory plan or arrangement.

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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 14, 2014

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	Executive Chairman of the Board	July 14, 2014
/s/ SCOTT M. BORUFF Scott M. Boruff	Chief Executive Officer, Director, Principal Executive Officer	July 14, 2014
/s/ JOHN M. BRAWLEY John M. Brawley	Chief Financial Officer, Principal Financial Officer	July 14, 2014
/s/ BOB G. GOWER Bob G. Gower	Director	July 14, 2014
/s/ GERALD E. HANNAHS, JR. Gerald E. Hannahs, Jr.	Director	July 14, 2014
/s/ JOSEPH T. LEARY Joseph T. Leary	Director	July 14, 2014
/s/ WILLIAM B. RICHARDSON William B. Richardson	Director	July 14, 2014
/s/ MARCEAU N. SCHLUMBERGER Marceau N. Schlumberger	Director	July 14, 2014
/s/ CHARLES M. STIVERS Charles M. Stivers	Director	July 14, 2014

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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, 2014 and 2013, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the years in the three-year period ended April 30, 2014. 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, 2014 and 2013, and the results of their operations and their cash flows for each of the years in the three-year period ended April 30, 2014, 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, 2013, based on criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organization of the Treadway Commission, and our report dated July 14, 2014 expressed an adverse opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Knoxville, Tennessee
July 14, 2014

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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, 2014, based on criteria established in Internal Control Integrated Framework (1992) 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, 2014 and 2013, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the years in the three-year period ended April 30, 2014. This material weakness was considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2014 consolidated financial statements, and this report does not affect our report dated July 14, 2014, 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, 2014, based on the criteria established in Internal Control - Integrated Framework (1992) issued by the COSO.

/s/ KPMG LLP

Knoxville, Tennessee
July 14, 2014

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MILLER ENERGY RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands, except share data)

	April 30, 2014	2013
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$5,749	$2,551
Restricted cash	679	7,531
Accounts receivable, net	6,409	3,204
Alaska production credits receivable, net	49,121	12,713
Inventory	5,102	3,382
Prepaid expenses and other	3,940	1,183
Assets held for sale	236	—
Total current assets	71,236	30,564
OIL AND GAS PROPERTIES, NET	644,827	491,314
EQUIPMENT, NET	35,369	37,571
OTHER ASSETS:		
Land	1,848	542
Restricted cash, non-current	12,075	10,207
Deferred financing costs, net	803	2,085
Other assets	664	541
Total assets	$766,822	$572,824
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$38,836	$13,129
Accrued expenses	20,446	6,338
Short-term portion of derivative instruments	3,315	842
Deferred income taxes	2,858	—
Current portion of long-term debt	9,459	6,000
Total current liabilities	74,914	26,309
OTHER LIABILITIES:		
Deferred income taxes	139,768	157,530
Asset retirement obligation	22,872	19,890
Long-term portion of derivative instruments	4,006	—
Long-term debt, less current portion	174,743	48,978
Total liabilities	416,303	252,707
COMMITMENTS AND CONTINGENCIES (Notes 4, 6 and 10)		
MEZZANINE EQUITY:		
Series C Cumulative Preferred Stock, redemption amount of $78,124 and $37,000, 3,250,000 shares authorized, 3,069,968 and 1,454,901 shares issued and outstanding as of April 30, 2014 and 2013, respectively	67,760	31,236
STOCKHOLDERS' EQUITY:		
Series D Fixed Rate/Floating Rate Cumulative Redeemable Preferred Stock, redemption amount of $32,378 and $0, 4,000,000 shares authorized, 1,070,448 and 0 shares issued and outstanding as of April 30, 2014 and 2013, respectively	30,041	—
Series D Fixed Rate/Floating Rate Cumulative Redeemable Preferred Stock, held in escrow (Note 8)	(5,000)	—

Common stock, $0.0001 par, 500,000,000 shares authorized, 45,756,697 and 43,444,694 shares issued and outstanding as of April 30, 2014 and 2013, respectively	4	4
Additional paid-in capital	98,788	88,184
Retained earnings	158,926	200,693
Total stockholders' equity	282,759	288,881
Total liabilities and stockholders' equity	$766,822	$572,824

See accompanying notes to the consolidated financial statements.

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MILLER ENERGY RESOURCES, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(Dollars in thousands, except share data)

	For the Year Ended April 30,		
	2014	2013	2012
REVENUES:			
Oil sales	$64,500	$29,447	$31,880
Natural gas sales	4,969	468	613
Other	1,089	4,886	2,909
Total revenues	70,558	34,801	35,402
OPERATING EXPENSES:			
Lease operating expense	20,187	22,288	11,305
Transportation costs	5,599	2,410	3,556
Cost of other revenue	1,147	4,189	926
General and administrative	31,744	26,067	29,718
Alaska carried-forward annual loss credits, net	(16,342)	(3,268)	—
Exploration expense	2,009	1,458	1,241
Depreciation, depletion and amortization	33,528	13,170	13,310
Accretion of asset retirement obligation	1,239	900	1,072
Other operating (income) expense, net	2,140	(64)	(641)
Total operating expense	81,251	67,150	60,487
OPERATING LOSS	(10,693)	(32,349)	(25,085)
OTHER INCOME (EXPENSE):			
Interest expense, net	(7,470)	(4,276)	(1,837)
Gain (loss) on derivatives, net	(10,179)	6,751	(2,832)
Other income (expense), net	34	(329)	58
Loss on debt extinguishment	(15,145)	—	—
Total other income (expense)	(32,760)	2,146	(4,611)
LOSS BEFORE INCOME TAXES	(43,453)	(30,203)	(29,696)
Income tax benefit	(14,886)	(9,783)	(11,006)
NET LOSS	(28,567)	(20,420)	(18,690)
Accretion of Series A, C and D preferred stock	(2,721)	(2,866)	(847)
Series C and D preferred stock accumulated dividends	(10,479)	(2,209)	—
NET LOSS ATTRIBUTABLE TO COMMON STOCKHOLDERS	$(41,767)	$(25,495)	$(19,537)
LOSS PER COMMON SHARE:			
Basic	$(0.94)	$(0.60)	$(0.48)
Diluted	$(0.94)	$(0.60)	$(0.48)
WEIGHTED AVERAGE NUMBER OF COMMON SHARES:			
Basic	44,445,556	42,682,685	40,811,308
Diluted	44,445,556	42,682,685	40,811,308

See accompanying notes to the consolidated financial statements.

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MILLER ENERGY RESOURCES, INC.
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(Dollars in thousands, except share data)

	Series D Preferred Stock		Common Stock		Additional Paid-in Capital	Retained Earnings	Total
	Shares	Amount	Shares	Amount			
Balance at April 30, 2011	—	—	39,880,251	$4	$49,013	$245,725	$294,742
Net loss	—	—	—	—	—	(18,690)	(18,690)
Accretion of Series A and Series C 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
Net loss	—	—	—	—	—	(20,420)	(20,420)
Series C preferred dividends	—	—	—	—	—	(2,209)	(2,209)
Accretion of Series C Preferred Stock	—	—	—	—	—	(2,866)	(2,866)
Issuance of equity for services	—	—	351,477	—	2,154	—	2,154
Issuance of equity for compensation	—	—	527,665	—	11,694	—	11,694
Other equity issuances	—	—	192,800	—	1,341	—	1,341
Exercise of equity rights	—	—	1,286,001	—	3,832	—	3,832
Preferred stock redemption	—	—	—	—	2,510	—	2,510
Modification of warrants	—	—	—	—	1,840	—	1,840
Balance at April 30, 2013	—	—	43,444,694	4	88,184	200,693	288,881
Net loss	—	—	—	—	—	(28,567)	(28,567)
Series C preferred dividends	—	—	—	—	—	(8,349)	(8,349)
Accretion of Series C Preferred Stock	—	—	—	—	—	(2,459)	(2,459)
Issuance of Series D Preferred Stock	1,284,034	30,041	—	—	—	—	30,041
Series D Preferred Stock held in escrow	(213,586)	(5,000)	—	—	—	—	(5,000)
Series D preferred dividends	—	—	—	—	—	(2,130)	(2,130)
Accretion of Series D Preferred Stock	—	—	—	—	—	(262)	(262)
Dissolution of MEI	—	—	—	—	(3,071)	—	(3,071)
Issuance of equity for services	—	—	—	—	1,103	—	1,103
	—	—	630,349	—	7,931	—	7,931

Issuance of equity for compensation							
Other equity issuances	—	—	—	—	3	—	3
Exercise of equity rights	—	—	1,681,654	—	4,638	—	4,638
Balance at April 30, 2014	1,070,448	25,041	45,756,697	$4	$98,788	$158,926	$282,759

See accompanying notes to the consolidated financial statements.

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MILLER ENERGY RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in thousands)

	For the Year Ended April 30,		
	2014	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net loss	$(28,567)	$(20,420)	$(18,690)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	33,528	13,170	13,310
Amortization of deferred financing fees and debt discount	1,387	828	1,123
Expense from issuance of equity	9,034	10,722	14,072
Dry hole costs, leasehold impairments and non-cash exploration expenses	879	1,264	1,061
Payment-in-kind interest on debt	—	307	—
Non-cash loss on debt extinguishment	14,258	—	—
Deferred income taxes	(14,904)	(9,789)	(11,006)
Derivative contracts:			
(Gain) loss on derivatives, net	10,179	(6,751)	2,832
Cash settlements	(3,815)	1,516	604
Alaska carried-forward annual loss credits, net	(16,342)	(3,268)	—
Accretion of asset retirement obligation	1,239	900	1,072
Other	958	—	—
Changes in operating assets and liabilities (excluding effects of acquisitions):			
Receivables	2,848	(2)	(808)
Inventory	93	(1,676)	(235)
Prepaid expenses and other assets	(655)	(829)	(654)
Accounts payable, accrued expenses, and other	5,202	2,537	4,220
NET CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES	15,322	(11,491)	6,901
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures for oil and gas properties	(136,320)	(26,492)	(7,558)
Proceeds from Alaska expenditure and exploration based credits	18,531	131	—
North Fork acquisition	(59,557)	—	—
Prepayment of drilling costs	(1,692)	—	—
Purchase of land	(356)	—	—
Purchase of equipment and improvements	(2,943)	(11,533)	(26,409)
Savant purchase deposit	(500)	—	—
Proceeds from sale of equipment	—	2,000	—
NET CASH USED IN INVESTING ACTIVITIES	(182,837)	(35,894)	(33,967)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Cash dividends	(8,552)	(1,231)	—
Payments on debt	(75,306)	(24,130)	(8,764)
Proceeds from borrowings	195,000	55,000	30,894
Debt acquisition costs	(5,827)	(3,853)	(2,140)
Redemption of preferred stock	—	(11,240)	—

Issuance of preferred stock	62,738	35,867	10,000
Repayment of MEI loans	(3,071)	—	—
Equity issuance costs	(3,894)	(2,667)	—
Exercise of equity rights	4,638	3,832	1,383
Restricted cash	4,984	(5,613)	(1,895)
Other	3	—	—
NET CASH PROVIDED BY FINANCING ACTIVITIES	170,713	45,965	29,478
NET CHANGE IN CASH AND CASH EQUIVALENTS	3,198	(1,420)	2,412
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	2,551	3,971	1,559
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$5,749	$2,551	$3,971
SUPPLEMENTARY CASH FLOW DATA:			
Cash paid for interest	$12,095	$11,143	$1,986
SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES:			
Capital expenditures in accounts payable and accrued expenses	$28,656	$3,154	$954
Reduction of oil and gas properties and equipment from applications for Alaska expenditure and exploration based credits	$41,841	$6,713	$4,250
Issuance of Series D Preferred Stock held in escrow	$5,000	$—	$—
Accretion of preferred stock	$2,721	$2,866	$847

See accompanying notes to the consolidated financial statements.

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MILLER ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in thousands, except per share data and per unit data)

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 U.S. generally accepted accounting principles ("GAAP"). Significant policies are discussed below.

Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Miller Energy Resources, Inc. and our wholly owned subsidiaries (collectively, the "Company"). 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. All intercompany balances and transactions are eliminated in the consolidation.

Reclassifications

Certain amounts in prior fiscal years have been reclassified to conform with the presentation adopted in the current fiscal year.

We reclassified a $5,305 contra asset related to Alaska production tax credits from oil and gas properties to equipment. The credits that resulted in the recognition of the contra asset related to our drilling rigs, the costs of which are classified in equipment. We have determined the reclassification to be immaterial to the prior period consolidated balance sheet taken as a whole. This error did not have an impact on the prior period consolidated statements of operations, equity or cash flows.

	As Presented April 30, 2013	Reclassifications	As Adjusted April 30, 2013
Oil and gas properties, net	$486,009	$5,305	$491,314
Equipment, net	$42,876	$(5,305)	$37,571

In addition, we reclassified certain costs related to the issuance of debt under our Prior Credit Facility that were paid to our lender. The costs were initially recorded and reflected as deferred financing costs on our consolidated balance sheet and have been reclassified as a debt discount. We have determined the reclassification to be immaterial to the prior period consolidated balance sheet taken as a whole. This error did not have an impact on the prior period consolidated statements of operations, equity or cash flows.

	As Presented April 30, 2013	Reclassifications	As Adjusted April 30, 2013
Deferred financing costs, net	$4,666	$(2,581)	$2,085
Long-term debt, less current portion	$51,559	$(2,581)	$48,978

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 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; our ability to comply with covenants related to our credit facilities; 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.

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MILLER ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)
(Dollars in thousands, except per share data and per unit data)

Use of Estimates
The preparation of consolidated financial statements in conformity with GAAP 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 assumed, 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
As of April 30, 2014 and 2013, current restricted cash includes $38 and $7,144, respectively, of cash temporarily held in an account that is controlled by our lender. Current restricted cash balances also include amounts held in escrow to secure Company related credit cards. Non-current restricted cash balances include amounts held in escrow to provide for the future plugging and abandonment of wells, 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, 2014 and 2013, we established a reserve of $250 and $0, respectively.
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 developed 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 established 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 are included in oil and gas operating expense and impairments of unsuccessful leases are included in exploration expense. In fiscal 2014, our consolidated statement of operations includes $296 in abandoned leases, $1,695 in seismic and delay rentals incurred in the Cook Inlet region, and $19 related to delay rentals incurred in the Appalachian 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 at the lowest level for which identifiable cash flows are independent of cash flows from other assets. 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.

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 $14,433, $9,289 and $5,500 of interest expense and amortization of deferred financing costs in fiscal years 2014, 2013 and 2012, respectively, of which $8,569, $5,880 and $3,700, respectively, were 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 DD&A or impairment, along with other capitalized costs related to that asset.

Asset Retirement Obligations

Asset retirement obligations ("ARO") 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 reasonably assured. Cash received relating to future revenues is deferred and recognized when all revenue recognition criteria are met.

Derivative Instruments

We utilize derivatives to manage our commodity price risk.

We account for our derivative instruments in accordance with 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 consolidated balance sheets at fair value as either a current or non-current asset or liability, depending on the derivative position and the expected timing of settlement. We report these amounts on a gross basis. The Company's derivative instruments were not designated as hedges for accounting purposes for any of the periods presented. Accordingly, the changes in fair value are recognized in the consolidated statements of operations in the period of change. Gains and losses on derivatives are included in cash flows from operating activities.

Fair Value Measurements

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 - Measurements are based on quoted prices in active markets that are unadjusted and accessible at the measurement date for identical, unrestricted assets or liabilities;
- Level 2 - Measurements are based on significant observable pricing inputs other than quoted prices included in Level 1 that are either directly or indirectly observable as of measurement date; or
- Level 3 - Measurements are based on process or valuation models that use inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity). These inputs generally reflect management’s own assumptions about the assumptions a market participant would use in pricing the asset or liability.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. Reclassifications of fair value between level 1, level 2, and level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter.

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 or the date of change in estimate for income taxes.

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.

Investments

On June 24, 2011, we acquired a 48% minority interest in Pellissippi Pointe I, LLC and Pellissippi Pointe II, LLC (the "Pellissippi Pointe" entities or "investee") for total cash consideration of $400. In connection with the transaction, we executed a five-year lease agreement with the investee and relocated our corporate offices to the new facility on November 7, 2011. Since we do not exercise control over the financial and operating decisions made by the investee, we have accounted for these investments using the equity method. These investments are reflected in "other assets" in the accompanying consolidated balance sheets.

Guarantees

On July 12, 2012, we signed a direct guarantee for 55% of the loan obligations outstanding of $5,074 with FSG Bank for the Pellissippi Pointe equity investment. The Company's guarantee is included within the scope of ASC 460, "Guarantees" and a liability was recorded at the estimated fair value of $250; such amount is included in accrued expenses on our consolidated balance sheet as of April 30, 2013 and April 30, 2014 and is being amortized over the five year life of the guarantee. The fair value was calculated using the income approach and the estimated default rate was determined by obtaining the average cumulative issuer-weighted corporate default rate based on the credit rating of Pellissippi Pointe and the term of the underlying loan obligations. The default rates are published by Moody's Investors Service. To the extent we are required to make payments under the guarantee, we will record the differences between the liability and the associated payments in earnings. At April 30, 2014, our maximum potential undiscounted payment under this arrangement is $2,791 plus additional lender's costs.

Income (Loss) Per Share

We determine basic income (loss) per share and diluted income (loss) per share in accordance with the provisions of ASC 260, “Earnings Per Share.” Basic income (loss) per share excludes dilution and is computed by dividing earnings available to common stockholders by the weighted-average number of common shares outstanding for the 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. We compute the numerator for basic income (loss) by subtracting accretion of preferred stock and cumulative preferred stock dividends from net income (loss) to arrive at net income (loss) attributable to common stockholders. Preferred stock dividends include dividends declared on preferred stock (regardless of whether the dividends have been paid) and dividends accumulated for the period on cumulative preferred stock (regardless of whether the dividends have been declared).

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.

New Accounting Pronouncements Issued But Not Yet Adopted

In July 2013, the FASB issued ASU 2013-11, "Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists." The amendments in ASU 2013-11 require an entity to present an unrecognized tax benefit in the financial statements as a reduction to a deferred tax asset for a net operating loss ("NOL") carryforward, a similar tax loss, or a tax credit carryforward except when: (1) a NOL carryforward, a similar tax loss, or a tax credit carryforward is not available as of the reporting date under the governing tax law to settle taxes that would result from the disallowance of the tax position; or (2) the entity does not intend to use the deferred tax asset for this purpose (provided that the tax law permits a choice). If either of these conditions exists, an entity should present an unrecognized tax benefit in the financial statements as a liability and should not net the unrecognized tax benefit with a deferred tax asset. The amendment does not affect the recognition or measurement of uncertain tax positions under ASC Topic 740, "Income Taxes". The amendments in this ASU are effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The amendments should be applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application is permitted. We do not expect this ASU to have a material impact to our consolidated financial statements.

In May 2014, the FASB issued ASU 2014-09, “Revenue from Contracts with Customers (Topic 606)” (“ASU 2014-09”). ASU 2014-09 is intended to improve the financial reporting requirements for revenue from contracts with customers by providing a principle based approach. The core principal of the standard is that revenue should be recognized when the transfer of promised goods or services is made in an amount that the entity expects to be entitled to in exchange for the transfer of goods and services. ASU 2014-09 also requires disclosures enabling users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. This standard will be effective for financial statements issued by public companies for annual reporting periods beginning after December 15, 2016. Early adoption is not permitted. The Company is currently evaluating the potential impact of ASU 2014-09 on the consolidated financial statements.

There are no other recently issued accounting pronouncements that are expected to have a material impact on our financial condition, results of operations or cash flows.

MILLER ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)
(Dollars in thousands, except per share data and per unit data)

2. DERIVATIVE INSTRUMENTS

Derivative Instruments
Commodity Derivatives
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 derivatives for crude oil on a portion of our crude oil production. We utilize over-the-counter variable-to-fixed price swap contracts to manage fluctuations in cash flows resulting from changes in commodity prices.
As of April 30, 2014, we had the following open crude oil derivative positions. All are priced based on the ICE Brent crude oil futures as traded on the New York Mercantile Exchange.

	Fixed - Price Swaps	
Production Period ending April 30,	Bbls	Weighted Average Fixed Price
2015	785,000	$100.75
2016	787,600	$95.66
2017	232,600	$94.27

Derivative Activities Reflected on Consolidated Balance Sheets
The following table presents the fair value of commodity derivatives. The fair value amounts are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements.

	Asset Derivatives				Liability Derivatives			
	April 30, 2014		April 30, 2013		April 30, 2014		April 30, 2013	
Derivatives not designated as hedging instruments under ASC 815	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity derivatives	Prepaid expenses and other	$88	Prepaid expenses and other	$—	Current portion of derivative instruments	$(3,315)	Current portion of derivative instruments	$(842)
Commodity derivatives	Other assets	26	Other assets	—	Long-term portion of derivative instruments	(4,006)	Long-term portion of derivative instruments	—
Total derivatives not designated as hedging instruments		$114		$—		$(7,321)		$(842)

under ASC
815

(Dollars in thousands, except per share data and per unit data)

Offsetting of Derivative Assets and Liabilities

The following table presents our gross and net derivative assets and liabilities:

	Gross Amount Presented on Balance Sheet	Netting Adjustments [a]	Net Amount
April 30, 2014			
Derivative assets with right of offset or master netting agreements	$114	$(114)	$—
Derivative liabilities with right of offset or master netting agreements	$(7,321)	$114	$(7,207)
April 30, 2013			
Derivative assets with right of offset or master netting agreements	$—	$—	$—
Derivative liabilities with right of offset or master netting agreements	$(842)	$—	$(842)

(a) The Company has an agreement in place that allows for the financial right of offset for derivative assets and derivative liabilities at settlement or in the event of default under the agreement.

Derivative Activities Reflected on Consolidated Statements of Operations

Gains and losses on derivatives are reported in the consolidated statements of operations. The following represents the Company's reported gains and losses on derivative instruments for the years presented:

	For the Year Ended April 30,		
	2014	2013	2012
Gain (loss) on derivatives, net	$(10,179)	$6,751	$(2,832)

Credit Risk Related Contingent Features in Derivatives

None of the Company's derivative instruments contains credit-risk related contingent features. No collateral was posted by the Company related to net positions as of April 30, 2014 and 2013.

Warrant Derivatives

Series A Cumulative Preferred Stock. In April 2012, purchasers of our Series A Cumulative Preferred Stock (the "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 were subject to a reset provision requiring adjustment of the exercise price, from $5.28 to $3.00, if the preferred stock was not redeemed within 30 days of our refinancing and repayment of the Guggenheim Credit Facility.

The Series A Preferred Stock was redeemed on June 29, 2012 in connection with the initiation of the Prior Credit Facility and the repayment of the Guggenheim Credit Facility. The mark-to-market adjustment from May 1, 2012 to June 29, 2012 of $443 was recorded to gain on derivatives, net, and the remaining liability of $2,510 was reclassified to additional paid-in capital.

Warrants Issued in Connection with Other Equity Transactions

From time to time we issue warrants to third parties in exchange for services. Certain warrants that we issued contained exercise reset provisions, which were considered freestanding derivatives, and were accounted for as liabilities measured at fair value in accordance with ASC 815, "Derivatives and Hedging."

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 was required if, at any time after issuance, we issue warrants at an exercise price lower than $5.28.

On September 21, 2012, the Company entered into a Special Warrant Exercise Agreement with warrant holders, pursuant to which, warrant holders agreed to exercise 586,001 warrants immediately for $4.00 per share and waived their right to a cashless exercise. In addition, 42,857 warrants were cancelled in exchange for a settlement payment of $75. These modifications resulted in a loss of $210, which is included in other income (expense), net on our consolidated statement of operations for the year ended April 30, 2013.

(Dollars in thousands, except per share data and per unit data)

The term for the remaining 138,197 warrants outstanding was extended for one year in exchange for the removal of the exercise price reset provision. The mark-to-market adjustment from May 1, 2012 to September 21, 2012 of $260 was recorded to gain (loss) on derivatives, net, and the remaining liability of $1,840 was reclassified to additional paid-in capital.

3. ACQUISITIONS

On November 22, 2013, the Company entered into a purchase and sale agreement by and among Armstrong Cook Inlet, LLC, GMT Exploration Company, LLC, Dale Resources Alaska, LLC, Jonah Gas Company, LLC and Nerd Gas Company, LLC and the Company. Pursuant to the North Fork Purchase Agreement, the Company (i) acquired a 100% working interest in six natural gas wells and related leases (consisting of approximately 15,465 net acres) referred to as the "North Fork Unit" in the Cook Inlet region of the State of Alaska, together with other associated rights, interests and assets for cash consideration of $59,557 and (ii) all the issued and outstanding membership interests of Anchor Point Energy, LLC, a limited liability company owning certain pipeline facilities and related assets which service the North Fork Properties, for 213,586 shares (valued at approximately $5,000) of the Company's Series D Preferred Stock. The Company used $56,577 of funds under the Second Lien Credit Facility to finance the acquisition and paid $3,000 in cash as a deposit on November 22, 2013 that was applied toward the purchase price.

The acquisition of the North Fork Properties closed on February 4, 2014 and the acquisition of the Anchor Point Equity will close upon receiving approval from the Regulatory Commission of Alaska, which has not occurred as of April 30, 2014. The consideration consisting of the Company’s Series D Preferred Stock for Anchor Point Equity was deposited into an escrow account and will be disbursed to the North Fork Sellers upon the closing of the Anchor Point Equity acquisition pursuant to the terms of the North Fork Purchase Agreement.

The purchase of the North Fork Properties has been accounted for under ASC 805, "Business Combinations." Under ASC 805, the Company is required to allocate the purchase price to assets acquired and liabilities assumed based on their fair values at the acquisition date. The estimated fair value of the properties approximates the fair value of consideration, and as a result, no goodwill was recognized. The following table summarizes the consideration paid for the North Fork Properties and the preliminary allocation of the purchase price to the assets acquired and liabilities assumed that have been included in the Company's consolidated financial statements for periods subsequent to the acquisition date.

Accounts receivable	$49	
Proved oil and gas properties	55,454	
Unproved oil and gas properties	5,958	
Accounts payable	(433	)
Asset retirement obligation	(1,437	)
Long-term liabilities	(34	)
Consideration paid	$59,557	

Acquisition-related costs of $404 were expensed by the Company and are included in general and administrative expenses in the consolidated statement of operations. Net revenue of $4,124 is included in the consolidated statements of operation for the year ended April 30, 2014 related to the North Fork Properties. Pro forma presentation of revenue and earnings for the years ended April 30, 2014 and April 30, 2013, as required by ASC 805 is impractical due to the present inaccessibility of sufficient financial records to produce relevant and reliable financial information.

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4. DEBT

As of April 30, 2014 and 2013, we had the following debt obligations reflected at their respective carrying values on our consolidated balance sheets:

	As of April 30,	
	2014	2013
Second Lien Credit Facility	$175,000	$—
Debt discount related to Second Lien Credit Facility	(3,296)	—
Gunsight Promissory Note payable	950	—
Apollo prepayment and extension fee note payable	9,223	—
Apollo senior secured Credit Facility	—	55,307
Debt discount related to Apollo senior secured Credit Facility	—	(2,581)
Series B Preferred Stock	2,325	2,252
Total debt obligations	184,202	54,978
Less: Current maturities	(9,459)	(6,000)
Total debt less current maturities	$174,743	$48,978

Second Lien Credit Facility
On February 3, 2014, we refinanced the Prior Credit Facility by entering into the New Apollo Loan Agreement which set forth the terms of the Second Lien Credit Facility.
The New Apollo Loan Agreement provides for a $175,000 term credit facility, all of which was made available to and drawn by us on the closing date. The amounts drawn were subject to a 2% original issue discount. Amounts outstanding under the Second Lien Credit Facility bear interest at a rate of LIBOR plus 9.75%, subject to a 2% LIBOR floor. The Second Lien Credit Facility permitted us to enter into the First Lien RBL discussed below in Note 16 - Subsequent Events. Upon entering into such revolving credit facility and a related intercreditor agreement, and subject to the terms of those agreements, the Second Lien Credit Facility became a second-lien credit facility subordinated to the First Lien RBL. We entered into the First Lien RBL on June 2, 2014, and amended the New Apollo Loan Agreement. The Second Lien Credit Facility carries a four year maturity. The Second Lien Credit Facility contains a leverage ratio, interest coverage ratio, current ratio, asset coverage ratio, minimum gross production and change of management control covenants, as well as other covenants customary for a transaction of this type. As we entered into an amendment to the New Apollo Loan Agreement in connection with the First Lien RBL, we did not calculate whether we were in compliance with the required financial and production covenants as of April 30, 2014 as such compliance (or non-compliance) was no longer relevant. Subject to certain conditions contained in the New Apollo Loan Agreement, the Second Lien Credit Facility also allows for us to implement a discretionary share repurchase plan on terms and conditions reasonably satisfactory to Apollo (as "administrative agent") and the lenders.
We used $75,306 of the proceeds drawn under the Second Lien Credit Facility to refinance the Prior Credit Facility with Apollo and $56,577 to finance the acquisition of the North Fork Unit. In addition, $3,071 was used to retire the obligations owed under the MEI Loan Documents (as defined below). The remainder of the proceeds from the Second Lien Credit Facility will be used for general corporate purposes. The fair value of the outstanding balance of the New Credit Facility was $176,785 as of April 30, 2014, as calculated using the discounted cash flows method.
On the closing date, in connection with the Second Lien Credit Facility, we, along with all of our consolidated subsidiaries (other than MEI), entered into an Amended and Restated Guarantee and Collateral Agreement (the "Second Lien Guarantee") with Apollo, for the benefit of the lenders from time to time party to the New Loan Agreement. Under the terms of the Second Lien Guarantee and related security documents each of our consolidated

subsidiaries (other than MEI) have guaranteed our obligations under the Second Lien Credit Facility and we and those subsidiaries have granted a security interest in substantially all of their assets to secure the performance of the obligations arising under the Second Lien Credit Facility.

Subsequent to quarter end, we entered into the First Lien RBL, and made certain amendments to the New Apollo Loan Agreement to conform certain provisions to the First Lien Loan Agreement. See Note 16 - Subsequent Events below for more detail.

Apollo Senior Secured Credit Facility ("Prior Credit Facility")

On June 29, 2012, we entered into a Loan Agreement (the "Prior Loan Agreement") with Apollo, as administrative agent and sole initial lender. The Prior Loan Agreement provided for a $100,000 credit facility with an initial borrowing base of $55,000 (the "Original Availability"). Of that initial $55,000, $40,000 was drawn by us on the closing date. On February 7, 2013 and April 25, 2013, we borrowed an additional $5,000 and $10,000, respectively, under the Prior Credit Facility, exhausting the Original Availability. On August 5, 2013, the amount available to Miller under the Prior Credit Facility was increased by an additional $20,000 to a total of $75,000, when a second tranche of loans (the "Additional Availability") was added to the Prior Loan Agreement after negotiations with Apollo. This additional $20,000 in availability was immediately drawn by us.

As noted above, on February 3, 2014, we refinanced the Prior Credit Facility by entering into the New Apollo Loan Agreement among us, as borrower, Apollo, as administrative agent, and the lenders from time to time party thereto, which amended and replaced the terms of the Prior Credit Facility with the terms of the Second Lien Credit Facility. The Prior Credit Facility was scheduled to mature on June 29, 2017 and was secured by substantially all of our assets and those of our consolidated subsidiaries (other than MEI), which subsidiaries also guarantee the loans. Except as described below in connection with the Additional Availability, amounts outstanding under the Prior Credit Facility bore interest at a rate of 18% per annum, with interest payable on the last day of each of our fiscal quarters. We would have been required to pay the outstanding balance of the loan in full on the maturity date; however, beginning with the fiscal quarter ending July 31, 2013, if requested by Apollo (at the direction of lenders holding a majority of the commitments under the Prior Loan Agreement), we could have been required to repay up to $1,500 in principal quarterly. Such payments of principal would have been made, together with any interest due on such date, on the last day of our fiscal quarter. No such request to repay principal was made by Apollo.

In addition, the outstanding debt included paid in kind interest of $307 added to the principal amount as a part of the "PIK Election" as defined in the Prior Loan Agreement. In connection with the Prior Loan Agreement, we 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 Prior Credit Facility and one year thereafter. The Prior Loan Agreement contained interest coverage, asset coverage, minimum gross production covenants, as well as other affirmative and negative covenants. As previously reported, these covenants were amended several times to adjust the covenant levels and the date on which compliance with the covenants would be measured, and to include our Tennessee production in the minimum production covenant. On December 9, 2013, we received an amendment and waiver from Apollo which, among other matters, waived our non-compliance with the interest coverage ratio requirement as of October 31, 2013 and amended our next testing date for the interest coverage ratio to October 31, 2014. As we refinanced the Prior Credit Facility by entering into the New Apollo Loan Agreement on February 3, 2014, we did not calculate whether we were in compliance with the required financial and production covenants as of April 30, 2014 as such compliance (or non-compliance) was no longer relevant.

On the closing date of the Prior Loan Agreement, we paid Apollo a non-refundable structuring fee of $2,750, payable to the account of the lenders, and we agreed to pay an additional 5% fee to Apollo for the benefit of the lenders on the amount of every additional borrowing over and above the Original Availability. In addition, we paid Apollo a supplemental fee of $500 on the closing date and the first anniversary of the closing date.

Additional compensation was due to Bristol Capital, LLC, a consultant to us, in connection with the closing of the Prior Loan Agreement. This fee was paid by issuing 312,500 shares of the Company's restricted common stock based on the amount of the Original Availability.

We used a portion of the initial $40,000 loan made available under the Prior Credit Facility to repay in full the amounts outstanding under the Guggenheim Senior Secured Credit Facility ("Guggenheim Credit Facility") of approximately $26,200. The remaining $13,800 was used to (i) redeem our outstanding Series A Preferred Stock; (ii) pay certain outstanding payables; and (iii) pay transaction costs associated with the closing of the Prior Credit Facility, such as attorneys' fees. The February and April 2013 borrowings were used to fund our drilling projects and pay outstanding operational and general and administrative expenses otherwise permitted under the Prior Credit Facility.

On August 5, 2013, we entered into Amendment No. 6 to the Prior Credit Facility (the "Sixth Amendment") as modified by an Extension of Date for Prepayment of Tranche B Loan without Prepayment Premium (the "Extension Agreement"). The Amendment added the Additional Availability to the Prior Loan Agreement. This Additional Availability was drawn by us immediately and used for capital projects and working capital and was not initially subject to any pre-payment penalty, and would have been subject to an initial reduced interest rate of 9%. Under the terms of the Sixth Amendment as modified by the Extension Agreement, in the event that we had not repaid the entire outstanding amount of the loans made to date under the Prior Credit Facility on or before February 28, 2014, then the pre-payment penalty would have applied to the Additional Availability after that date and the interest rate on the Additional Availability would increase to 18%. The Sixth Amendment clarified that when and if any prepayment of the amounts outstanding under the Prior Credit Facility is made from the proceeds of tax credits received by us under Alaska's Clear and Equitable Share program, that pre-payment will be applied pro rata to both the Additional Availability and previously drawn amounts.

In addition to the increase in the amounts available to be borrowed and the adjustment to the interest rate and prepayment penalties on those amounts, among other things, the Sixth Amendment: (i) clarified that the option under the Prior Loan Agreement to pay interest in-kind, rather than in cash, applies to the amounts drawn prior to the Sixth Amendment only and not the Additional Availability, (ii) established separate conditions precedent to borrowings from the Additional Availability, (iii) adjusted restrictions contained in Sections 7.10 and 7.12 of the Prior Loan Agreement, and (iv) established interpretive rules related to the repayment and pre-payment of the amounts owed under the Prior Credit Facility.

On September 20, 2013, we entered into Revised and Restated Consent and Amendment No. 7 (the "Seventh Amendment") with Apollo under the Prior Loan Agreement. The Seventh Amendment amended and made certain acknowledgments regarding certain provisions of the Prior Loan Agreement allowing for our issuance of our Series D Preferred Stock and the payment of dividends on the series. Among other things, the Seventh Amendment: (i) permitted the filing of supplementary articles amending our charter designating the terms of the Series D Preferred Stock; (ii) clarified the treatment of the Series D Preferred Stock under the Prior Loan Agreement; (iii) so long as no default or event of default has occurred, allowed payment of dividends on our Series D Preferred Stock, our Series B Preferred Stock and our Series C Preferred Stock either out of Excluded Equity Proceeds (as defined in the Prior Loan Agreement) or during a Capital Covenant Compliance Period (as defined in the Prior Loan Agreement), provided that we are in compliance with the Capital Covenants (as defined in the Prior Loan Agreement) on a pro forma basis on the date of payment, (iv) restricted our ability to redeem the Series D Preferred Stock prior to the 30th day following Security Termination (as defined in the Prior Loan Agreement); and (v) prohibited us from modifying the terms of the Series D Preferred Stock without Apollo's prior written consent.

The Seventh Amendment also extended the date by which certain liens must be lifted, as a result of the rescheduling of the Voorhees arbitration (see Note 10 - Litigation).

As noted above, on February 3, 2014, we refinanced the Prior Credit Facility by entering into the New Apollo Loan Agreement among us, Apollo as the administrative agent, and the lenders party thereto from time to time. The New Apollo Loan Agreement provides for a $175,000 credit facility, which was fully drawn by us at closing, at an interest rate of LIBOR plus 9.75%, with a 2% LIBOR floor. The New Apollo Loan Agreement is discussed above under "Second Lien Credit Facility."

Series B Preferred Stock

On September 24, 2012, we sold 25,750 shares of our Series B Preferred Stock to 10 accredited investors and issued those investors warrants to purchase 128,750 shares of common stock in a private offering exempt from registration under the Securities Act of 1933, as amended. We received gross proceeds of $2,575. We paid issuance costs of $167, which have been capitalized and are being amortized over the term of the instrument. The outstanding Series B Preferred Stock is classified as long-term debt, in accordance with ASC 480, "Distinguishing Liabilities from Equity." As of April 30, 2014, the fair value of Series B Preferred Stock was $2,197, as calculated using the discounted cash flow method.

The designations, rights and preferences of the Series B Preferred Stock, include:

- a stated value of $100 per share and a liquidation preference equal to the stated value;
- the holders are not entitled to any voting rights and the shares of Series B Preferred Stock are not convertible into any other security;
- the holders are entitled to receive annual cumulative dividends at the rate of 12% per annum, payable in arrears semi-annually, beginning on March 1, 2013;
-

dividends will be paid in cash on each relevant dividend date provided that (i) we are in compliance with certain financial covenants (designated the "Capital Covenants") under the Prior Credit Facility or any amendments thereto, with compliance to be determined as of the most recent reporting date and, on a pro forma basis, on the dividend date, and (ii) no "Default" or "Event of Default" (as defined in the Prior Credit Facility or any amendments thereto) has occurred or is continuing on the dividend date;

- the shares may not be redeemed until 30 days after "Security Termination" (as defined in the Prior Credit Facility), but otherwise may be redeemed at any time by the Company, with a required redemption on the fifth anniversary of issuance or, if later, on the 30th day after Security Termination.

On March 1, 2013, in accordance with our charter and the designations for the Series B Preferred Stock, we paid a semiannual dividend of approximately $5.16 per share on the Series B Preferred Stock.

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On July 18, 2013, our Board approved the payment of a semiannual dividend, of approximately $6.05 per share, which was paid on September 3, 2013 as the regularly scheduled payment date of September 1, 2013 was not a business day. The record date was August 15, 2013.
On January 28, 2014, our Board approved the payment of a semiannual dividend, of approximately $5.95 per share, which was paid on March 3, 2014 as the regularly scheduled payment date of March 1, 2014 was not a business day. The record date was February 17, 2014.

Repayment of MEI Loans

On February 3, 2014, we repaid all obligations under the MEI Loan Documents between MEI and us. The MEI Loan Documents have terminated.

Promissory Note to Gunsight Holdings, LLC

On February 27, 2014, in connection with our acquisition of certain acreage in Tennessee, we signed a promissory note in the amount of $950 payable to the seller, Gunsight Holdings, LLC (the "Gunsight Note"). Interest accrues at a rate of 5% per annum. The Gunsight Note provides for quarterly interest payments and a balloon payment of the principal amount is due on February 27, 2017, and may be prepaid without penalty. The Gunsight Note is secured by a purchase money deed of trust on the property acquired dated February 27, 2014.

Debt Issuance Costs

As of April 30, 2014 and April 30, 2013, our unamortized deferred financing costs were $803 and $2,085, respectively, which relates to the Second Lien Credit Facility, Prior Credit Facility, and the Series B Preferred Stock. As of April 30, 2014 and April 30, 2013, our unamortized debt discount, which relates to the Second Lien Credit Facility and Prior Credit Facility, was $3,296 and $2,581, respectively. These costs are being amortized over the term of the respective debt instruments.

Debt Extinguishment Costs

In connection with the termination and repayment of the loans outstanding under the Prior Credit Facility, the Company determined that the Second Lien Credit Facility had substantially different terms from the Prior Credit Facility and recorded a loss on debt extinguishment of $15,145, consisting of a $9,223 prepayment and extension fee owed to Apollo payable in four equal installments of $2,306 on the last day of each calendar quarter, commencing June 30, 2014, and a charge of $5,185 to extinguish the debt discount, the unamortized deferred financing costs and prepaid administrative fee. Additionally, there was a charge of $737 in connection with the termination and repayment of all obligations under the MEI Loan Documents.

5. ASSET RETIREMENT OBLIGATIONS

The following table presents changes to the Company's asset retirement obligation liability for the years ended April 30, 2014 and 2013:

	2014	2013
Asset retirement obligation, beginning of year	$19,890	$18,366
Additions	1,744	64
Accretion expense	1,239	900
Settlements	(36)	—
Revisions	35	560
Asset retirement obligation, end of year	$22,872	$19,890

The ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with the Company's oil and gas properties. The Company utilizes current retirement costs to estimate the expected cash outflows for retirement obligations. The Company estimates 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. 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.

Any additional retirement obligations will increase the liability associated with new oil and natural gas wells and other facilities. Actual expenditures for abandonments of oil and natural gas wells and other facilities reduce the liability for asset

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retirement obligations. There were no significant expenditures for abandonments during the years ended April 30, 2014, 2013 or 2012.

6. COMMITMENTS AND CONTINGENCIES

On November 5, 2009, CIE entered into the Alaska Oversight Agreement ("AOA") with the Alaska DNR which set out certain terms under which the Alaska DNR would approve the transfer of oil and gas leases owned by the State of Alaska 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 the Redoubt Unit and West McArthur River Unit. Under the terms of the AOA, until the Alaska DNR determines that CIE has completed certain development and operational commitments relating to the WMRU and Redoubt Units, CIE must do the following, in addition to the normal requirements under the terms of the leases:

- file a quarterly 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 quarterly 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 relating to the WMRU or Redoubt Unit Leases of more than $5,000,
- annually submit a new plan of development for the Alaska DNR's approval.

The AOA required CIE to demonstrate funding commitments of $5,150 to support the redevelopment of the WMRU and an estimated $31,000 to support the development of the Redoubt Unit. The Company believes it has adequately fulfilled these commitments.
The AOA prohibited CIE from using proceeds from operations at the WMRU or Redoubt Unit for non-core oil and gas activities, or activities unrelated to the WMRU or Redoubt Unit, without the prior written approval of the Alaska DNR until the parties mutually agreed that the full dismantlement obligation under the assigned leases was funded
On March 11, 2011, the Company entered into a Performance Bond Agreement under its AOA with the State of Alaska. Under the Performance Bond Agreement, the Company is required to post a total bond of $18,000 for the dismantling and abandonment of the properties. As agreed with the State of Alaska, the Performance Bond Agreement fulfills our commitment under the AOA to fund the full dismantlement costs with respect to our onshore and offshore assets. The Performance Bond Agreement also stipulated that funds held by the state in an escrow account will be credited towards the $18,000.
Failure to submit the information required by the AOA would constitute a default under the AOA. If the default could not be cured within 30 days, the leases would be subject to termination by the Alaska DNR.
Under the terms of the Performance Bond Agreement, the Company is obligated to fund an additional $12,000 towards the bond in addition to the amount held by the state in the escrow account. As of April 30, 2014, $1,000 of this amount has been funded. The remaining $11,000 (subject to annual inflation adjustments) will be funded through annual payments as follows:

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

$11,000

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7. INCOME TAXES

The components of income tax benefit are as follows:

	For the Year Ended April 30,		
	2014	2013	2012
Federal:			
Current	$—	$—	$—
Deferred	(14,132)	(10,023)	(10,168)
Total	(14,132)	(10,023)	(10,168)
State:			
Current	18	6	—
Deferred	(772)	234	(838)
Total	(754)	240	(838)
Total income tax benefit	$(14,886)	$(9,783)	$(11,006)

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,		
	2014	2013	2012
Provision calculated at federal statutory rate	(35.0)%	(35.0)%	(35.0)%
State and local income taxes, net of federal benefit	(8.4)	(8.4)	(7.8)
Change in effective state tax rate	(1.5)	9.3	5.0
State valuation allowance	8.1	—	—
Other	2.5	1.7	0.7
Total income tax benefit	(34.3)%	(32.4)%	(37.1)%

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

	April 30, 2014	2013
Deferred tax assets:		
Unrealized derivative loss	$2,995	$397
Apollo prepayment penalty	3,832	—
Net operating loss carryforwards	36,542	31,136
Stock options and warrants	12,865	11,384
Other	3,055	2,126
Total deferred tax assets	59,289	45,043
Valuation allowance	(3,527)	—
Total deferred tax assets, net of valuation allowance	55,762	45,043
Deferred tax liabilities:		
Excess of book basis over tax basis of oil and gas properties and equipment	(191,389)	(200,912)
Alaska carried-forward annual loss credits	(6,845)	(1,401)
Other	(154)	(260)
Total deferred tax liabilities	(198,388)	(202,573)
Net deferred tax liability	$(142,626)	$(157,530)

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 have taken 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 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, 2014, we had net operating loss carryforwards for federal income tax purposes of approximately $81,737 with expiration beginning 2028.

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. Management believes, based on the 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 with the exception of certain state net operating losses and credits. At April 30, 2014, we determined that our Tennessee net operating loss carryforwards and credits may not be fully utilized; as such, we recorded a full valuation allowance of $3,527 against them.

In our assessment that no valuation allowance is needed against our remaining deferred tax assets, we are relying solely on the reversal of significant existing temporary differences related to the excess of the Company's book carrying value of its oil and gas properties over their collective tax bases to support the recovery of our deferred tax assets (primarily net operating loss carryovers). 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). No valuation allowance was maintained against deferred tax assets at April 30, 2013.

Pursuant to ASC 718-740-25-10, we have not recorded the tax benefit and related deferred tax asset for the windfall portion of stock compensation tax deductions that either create a net operating loss carry-forward or increase a net operating loss carry-forward. As such, the amount of net operating loss carry-forwards for which a tax benefit would be recorded to additional paid-in capital when the tax benefit is realized is approximately $175 as of April 30, 2014.
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, 2014, 2013, 2012 and 2011 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.
The Company and its consolidated subsidiaries are currently undergoing a U.S. federal income tax examination for the tax year ended April 30, 2012. The State of Alaska's Department of Revenue is also examining income tax returns of the Company and its Cook Inlet subsidiary (CIE) for the tax years 2010 through 2012. No significant cash tax payments or adjustments to tax attribute carryforwards are expected to result from the examinations at this time. No other state income tax examinations are currently ongoing.
We have not identified any uncertain tax positions. No significant payments are expected during the succeeding 12 months.

8. STOCKHOLDERS' EQUITY

Common Stock
At April 30, 2014, we had 45,756,697 shares of common stock outstanding. We issued 2,312,003 shares during the year ended April 30, 2014, of which 630,349 shares were issued to employees for compensation and 1,681,654 shares were related to the exercise of equity rights.
At April 30, 2013, we had 43,444,694 shares of common stock outstanding. We issued 2,357,943 shares during the year ended April 30, 2013, of which 351,477 shares were issued for services, 527,665 shares were issued to employees for compensation, and 1,286,001 shares were related to the exercise of equity rights, and 192,800 shares for other equity issuances.
At April 30, 2012, we had 41,086,751 shares of common stock outstanding. We issued 1,356,500 shares during the year ended April 30, 2012, of which 130,000 shares were issued for services and equipment, 257,500 shares were issued to employees for compensation, and 96,900 shares were related to the exercise of equity rights.
Series C Preferred Stock
On September 28, 2012, we sold 685,000 shares of the Company's newly designated Series C Preferred Stock pursuant to the Company's shelf registration statement on Form S-3, which became effective on September 28, 2012. The shares were offered to the public at $23.00 per share for gross proceeds of $15,755. We incurred issuance costs of $1,335, yielding net proceeds of $14,420.
On October 12, 2012, we entered into the Series C ATM Agreement with MLV. The Series C ATM Agreement contemplates periodic sales by MLV of our Series C Preferred Stock as and when directed by the Company. These securities are registered for sale to the public pursuant to a prospectus, dated September 18, 2012, a prospectus supplement dated October 12, 2012, and the Company's registration statement on Form S-3 (Registration No. 333-183750) which was declared effective by the SEC on September 18, 2012. On and after October 12, 2012 and through April 30, 2014, we sold 924,968 shares of Series C Preferred Stock under the Series C ATM Agreement and related prospectus supplement at prices ranging from $21.48 per share to $26.71 per share. We received gross proceeds of $20,935 and incurred issuance costs of $733, yielding net proceeds of $20,202.
On February 12, 2013, we entered into an Underwriting Agreement with MLV as representative for a group of underwriters for a follow-on "best efforts" offering of our Series C Preferred Stock. We sold an additional 625,000 shares of the Series C Preferred Stock in this offering at a price of $22.90 per share. We received gross proceeds of $14,312 and incurred issuance costs of $1,052, yielding net proceeds of $13,260 in connection with the offering. These securities are registered for sale to the public pursuant to a prospectus, dated September 18, 2012, a prospectus supplement dated February 13, 2013, and the Company’s registration statement on Form S-3 (Registration No. 333-183750) which was declared effective by the SEC on September 18, 2012.

On May 7, 2013, we entered into an Underwriting Agreement with MLV as representative for a group of underwriters for a follow-on "best efforts" offering of our Series C Preferred Stock. We sold an additional 500,000 shares of our Series C Preferred Stock, at a price of $22.25 per share. We received gross proceeds of $11,125 and incurred issuance costs of $805, yielding net proceeds of $10,320. These securities are registered for sale to the public pursuant to a prospectus, dated September 18, 2012, a prospectus supplement dated May 7, 2013, and the Company’s registration statement on Form S-3 (Registration No. 333-183750) which was declared effective by the SEC on September 18, 2012.

On June 27, 2013, we entered into an Underwriting Agreement with MLV as representative for a group of underwriters for a follow-on "best efforts" offering of our Series C Preferred Stock. We sold an additional 335,000 shares of our Series C Preferred Stock, at a price of $21.50 per share. We received gross proceeds of $7,203 and incurred issuance costs of $547, yielding net proceeds of $6,656. These securities are registered for sale to the public pursuant to a prospectus, dated September 18, 2012,

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a prospectus supplement dated June 28, 2013, and the Company's registration statement on Form S-3 (Registration No. 333-183750) which was declared effective by the SEC on September 18, 2012.

The Series C Preferred Stock is classified as temporary equity in accordance with ASC 480 and is being accreted to redemption value through the earliest repayment date of November 1, 2017, which resulted in accretion of $2,459 during the year ended April 30, 2014. The fair value of the Series C Preferred Stock was $77,976 as of April 30, 2014, based on the closing price on that date. The designations, rights and preferences of the Series C Preferred Stock include:

- The holders are entitled to receive a 10.75% per annum cumulative quarterly dividend, on March 1, June 1, September 1, and December 1, payable in cash on each dividend date unless the Company is prohibited by making such payment pursuant to the terms of any agreement of the Company (including any other class or series of equity securities or any agreement related to indebtedness);
- The dividend may increase to a penalty rate of 12.75% if we fail to (A) pay dividends for four or more quarterly dividend periods, whether or not consecutive, or (B) maintain the listing of our Series C Preferred Stock on a national securities exchange (the events listed in clauses (A) and (B) being "Penalty Events");
- There is no mandatory redemption or stated maturity with respect to the Series C Preferred Stock, and it is not redeemable prior to November 1, 2017 unless: (A) there is a change in control and redemption occurs pursuant to a special right of redemption related to that change in control or (B) the Closing Bid Price of our common stock has equaled or exceeded the conversion price initially set at $10.00 per share by 150% for at least 20 trading days in any 30 consecutive trading day period (a "Market Trigger");
- The redemption price is $25.00 per share plus any accrued and unpaid dividends;
- Liquidation preference is $25.00 per share plus any accrued and unpaid dividends;
- The Series C Preferred Stock is senior to all our other securities except our Series B Redeemable Preferred Stock, which is senior to the Series C Preferred Stock;
- There is a general conversion right with respect to the Series C Preferred Stock with an initial conversion price of $10.00 per share, a special conversion right upon a change in control, and a market trigger conversion at our option in the event of a Market Trigger;
- The Series C Preferred Stock has been listed on the NYSE and is registered under our universal shelf; and
- Holders of the Series C Preferred Stock have no voting rights, except: 1) as otherwise required by law; 2) with respect to any proposal to (A) create, authorize or increase the authorized or issued amount of any class or series of our equity securities which rank senior to the Series C Preferred Stock or (B) amend, alter or repeal any provision of our charter, as amended, in a manner which materially and adversely affects any right, preference, privilege or voting power of the holders of the Series C Preferred Stock; and 3) the holders of the Series C Preferred Stock will have the right to elect two directors to our board of directors upon the occurrence of a Penalty Event.

On April 30, 2013, our Board of Directors declared a dividend of approximately $0.67 per share on our Series C Preferred Stock which was paid on the next regularly scheduled dividend payment date of June 3, 2013, in accordance with the terms of our charter as June 1, 2013 was not a business day. The dividend payment is equivalent to an annualized 10.75% per share, based on the $25.00 per share stated liquidation preference for the Series C Preferred Stock, accruing from March 2013 through May 2013. The record date, as required in accordance with our charter, was May 15, 2013.

On July 18, 2013, our Board of Directors declared a dividend of approximately $0.67 per share on our Series C Preferred Stock which was paid on the next regularly scheduled dividend payment date of September 3, 2013, in accordance with the terms of our charter, as September 1, 2013 was not a business day. The dividend payment is equivalent to an annualized 10.75% per share, based on the $25.00 per share stated liquidation preference for the Series C Preferred Stock, accruing from June 2013 through August 2013. The record date was August 16, 2013.

On October 17, 2013, our Board of Directors declared a dividend of approximately $0.67 per share on our Series C Preferred Stock which was paid on the next regularly scheduled dividend payment date of December 2, 2013, in accordance with the terms of our charter, as December 1, 2013 was not a business day. The dividend payment is equivalent to an annualized 10.75% per share, based on the $25.00 per share stated liquidation preference for the Series C Preferred Stock, accruing from September 2013 through November 2013. The record date was November 15, 2013.

On January 28, 2014, our Board of Directors declared a dividend of approximately $0.67 per share on our Series C Preferred Stock which was paid on the next regularly scheduled dividend payment date of March 3, 2014, in accordance with the terms of our charter, as March 1, 2014 was not a business day. The dividend payment is equivalent to an annualized 10.75% per share, based on the $25.00 per share stated liquidation preference for the Series C Preferred Stock, accruing from December 2014 through February 2014. The record date was February 17, 2014.

On April 16, 2014, our Board of Directors declared a dividend of approximately $0.67 per share on our Series C Preferred Stock which was paid on the next regularly scheduled dividend payment date of June 2, 2014, in accordance with the terms of our charter, as June 1, 2014 was not a business day. The dividend payment is equivalent to an annualized 10.75% per share, based on the $25.00 per share stated liquidation preference for the Series C Preferred Stock, accruing from March 2014 through May 2014. The record date, as required in accordance with our charter, was May 15, 2014.

Series D Preferred Stock

On September 30, 2013, we sold 1,000,000 shares of the Company’s newly designated Series D Preferred Stock. These securities are registered for sale to the public pursuant to a prospectus, dated September 18, 2012, a prospectus supplement dated September 26, 2013, and the Company’s registration statement on Form S-3 (Registration No. 333-183750), which was declared effective by the SEC on September 18, 2012. The shares were offered to the public at $25.00 per share for gross proceeds of $25,000. We incurred issuance costs of $1,875, yielding net proceeds of $23,125.

On October 17, 2013, we entered into the Series D ATM Agreement with MLV. The Series D ATM Agreement contemplates periodic sales by MLV of our Series D Preferred as and when directed by the Company. These securities are registered for sale to the public pursuant to a prospectus, dated September 18, 2012, a prospectus supplement dated October 17, 2013, and the Company's registration statement on Form S-3 (Registration No. 333-183750) which was declared effective by the SEC on September 18, 2012. On and after October 17, 2013 through April 30, 2014, we sold 70,448 shares of our Series D Preferred Stock under the Series D ATM Agreement and a prospectus supplement at prices ranging from $23.95 to $24.38 per share. We received gross proceeds of $1,701 and incurred issuance costs of $47, yielding net proceeds of $1,654 in connection with these sales.

On January 31, 2014, pursuant to our Purchase and Sale Agreement with by and among Armstrong Cook Inlet, LLC, GMT Exploration Company, LLC, Dale Resources Alaska, LLC, Jonah Gas Company, LLC and Nerd Gas Company, LLC, we issued 213,586 shares of our Series D Preferred Stock to be held in escrow for the benefit of the North Fork Sellers, valued at approximately $5,000. For purposes of determining the number of shares of the Series D Preferred Stock, it was valued on January 31, 2014 as the average of its daily volume weighted average prices for the 10 trading days ending on and including January 31, 2014. The Series D Preferred Stock was issued in reliance on an exemption from registration under Section 4(a)(2) of the Securities Act of 1933, as amended. The Series D Preferred Stock will be held in escrow until the transfer of the equity interests in Anchor Point Energy, LLC has been completed and certain necessary regulatory approvals have been received. Pursuant to the Purchase and Sale Agreement, we are required to pay dividends on the Series D Preferred Stock held in escrow that are declared after January 31, 2014. The dividends are also required to be paid into escrow.

The Series D Preferred Stock is classified as permanent equity in accordance with ASC 480 and is being accreted to redemption value through the earliest redemption date of September 30, 2018, which resulted in an accretion of $262 during the year ended April 30, 2014. The fair value of the Series D Preferred Stock was $31,330 as of April 30, 2014, based on the closing price at that date. The designations, rights and preferences of the Series D Preferred Stock include:

- From the date of original issuance to (but not including) December 1, 2018 the holders are entitled to receive a 10.5% per annum cumulative quarterly dividend based on the $25.00 per share liquidation preference per annum, on March 1, June 1, September 1, and December 1, payable in cash on each dividend date unless the Company is prohibited from making such payment pursuant to the terms of any agreement of the Company (including any other class or series of equity securities or any agreement related to indebtedness);
-

After (and including) December 1, 2018, the holders are entitled to receive a cumulative quarterly dividend at an annual rate equal to the sum of (a) Three-Month LIBOR (as defined below) as calculated on each applicable date of determination and (b) 9.073%, based on the $25.00 per share liquidation preference per annum, on March 1, June 1, September 1, and December 1, payable in cash on each dividend date unless the Company is prohibited from making such payment pursuant to the terms of any agreement of the Company (including any other class or series of equity securities or any agreement related to indebtedness);

- With respect to the Series D Preferred Stock, "Three-Month LIBOR" means: on any date of determination, the rate (expressed as a percentage per year) for deposits in U.S. dollars for a three-month period as appears on Bloomberg, L.P. page US0003M, as set by the British Bankers Association at 11:00 am (London time) on such date of determination.

- The dividend may increase by 2% to a penalty rate of (a) 12.5% (before December 1, 2018) or (b) an annual rate equal to the sum of (i) Three-Month LIBOR as calculated on each applicable date of determination and (ii) 11.073%, based on the $25.00 per share liquidation preference per annum (after and including December 1,

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2018) if we fail to (A) pay dividends for four or more quarterly dividend periods, whether or not consecutive, or (B) maintain the listing of our Series D Preferred Stock on a national securities exchange (the events listed in clauses (A) and (B) being "Penalty Events");

- There is no mandatory redemption or stated maturity with respect to the Series D Preferred Stock, and it is not redeemable prior to September 30, 2018 unless there is a change in control and redemption occurs pursuant to a special right of redemption related to that change in control;
- The redemption price is $25.00 per share plus any accrued and unpaid dividends;
- Liquidation preference is $25.00 per share plus any accrued and unpaid dividends;
- The Series D Preferred Stock is senior to all our other securities except our Series B Preferred Stock, which is senior to the Series D Preferred Stock, and ranks on parity with our Series C Preferred Stock;
- The Series D Preferred Stock has been listed on the NYSE and is registered under our universal shelf; and
- Holders of the Series D Preferred Stock have no voting rights, except: 1) as otherwise required by law; 2) with respect to any proposal to (A) create, authorize or increase the authorized or issued amount of any class or series of our equity securities which rank senior to the Series D Preferred Stock or (B) amend, alter or repeal any provision of our charter, as amended, in a manner which materially and adversely affects any right, preference, privilege or voting power of the holders of the Series D Preferred Stock; and 3) the holders of the Series D Preferred Stock will have the right to elect two directors to our board of directors upon the occurrence of a Penalty Event.

On October 17, 2013, our Board of Directors declared a dividend of approximately $0.44 per share on our Series D Preferred Stock which was paid on the next regularly scheduled dividend payment date of December 2, 2013, in accordance with the terms of our charter, as December 1, 2013 was not a business day. The dividend payment is equivalent to an annualized 10.5% per share, based on the $25.00 per share stated liquidation preference for the Series D Preferred Stock, accruing from issuance in September 2013 through November 2013. The record date was November 15, 2013.

On January 28, 2014, our Board of Directors declared a dividend of approximately $0.66 per share on our Series D Preferred Stock which was paid on the next regularly scheduled dividend payment date of March 3, 2014, in accordance with the terms of our charter, as March 1, 2014 was not a business day. The dividend payment is equivalent to an annualized 10.5% per share, based on the $25.00 per share stated liquidation preference for the Series D Preferred Stock, accruing from December 2013 through February 2014. The record date was February 17, 2014.

On April 16, 2014, our Board of Directors declared a dividend of approximately $0.66 per share on our Series D Preferred Stock which was paid on the next regularly scheduled dividend payment date of June 2, 2014, in accordance with the terms of our charter, as June 1, 2014 was not a business day. The dividend payment is equivalent to an annualized 10.5% per share, based on the $25.00 per share stated liquidation preference for the Series D Preferred Stock, accruing from March 2014 through May 2014. The record date was May 15, 2014.

Issuance of Common Stock

On September 18, 2013, we issued a warrant to purchase 150,000 shares of our common stock as compensation for services rendered. The warrant had an exercise price of $6.63 per share and a term of three years. The grant date fair value of $442 was determined using the Black-Scholes model. Key assumptions used in the model included a risk-free rate of 0.7%, expected volatility of 67%, and an expected term of three years.

On July 8, 2013, we issued a warrant to purchase 12,500 shares of our common stock as compensation for services. The warrant has an exercise price of $4.15 per share and an expiration date of July 8, 2016. The grant date fair value of $22 was determined using the Black-Scholes model. Key assumptions used in the model included a risk-free rate of 0.7%, expected volatility of 66%, and an expected term of 3 years.

On January 8, 2013, we issued a warrant to purchase 12,500 shares of our common stock as compensation for services. The warrant has an exercise price of $3.56 per share and an expiration date of January 8, 2016. The grant date fair value of $24 was determined using the Black-Scholes model. Key assumptions used in the model included a risk-free rate of 0.1%, expected volatility of 75%, and an expected term of 3.5 years.

On July 11, 2012, we issued a warrant to purchase 150,000 shares of our common stock under an existing consulting agreement as compensation for services rendered. The warrant had an exercise price of $5.28 per share and a term of five years. The grant date fair value of $406 was determined using the Black-Scholes model. Key assumptions used in the model included a risk-free rate of 0.6%, expected volatility of 79%, and an expected term of 5 years.

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On July 3, 2012, we issued 38,977 shares of common stock to non-employee directors in lieu of cash payments for compensation of services rendered. The fair value of the shares issued was $194 based on the closing price of our common stock on the transaction date.
On June 29, 2012, we issued 312,500 shares of common stock as compensation for services rendered in relation to the Apollo agreement. The fair value of the shares issued was $1,563 based on the closing price of our common stock on the transaction date.
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 $100 based on the closing price of our common stock on the transaction date.
On August 4, 2011, we issued 100,000 shares of common stock under an existing consulting agreement as compensation for services rendered. The fair value of the shares issued was $300 based on the closing price of our common stock on the transaction date.
On May 20, 2011, we issued a warrant to purchase 300,000 shares of our common stock as compensation for services. The warrant had an exercise price of $5.51 per share and an expiration date of May 20, 2016. The grant date fair value of $1,100 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.

9. STOCK-BASED COMPENSATION

During fiscal years 2010 and 2011, our Compensation Committee and Board of Directors adopted share-based compensation plans authorizing 3,000,000 and 8,250,000 shares of common stock under each plan, respectively. On April 16, 2014, the number of shares of common stock available for issuance increased by 5,000,000 shares of common stock under the 2011 compensation plan. The increase was adopted by our Board of Directors on March 10, 2014, and approved by our shareholders on April 16, 2014. The share-based compensation plans allow us to offer our employees, officers, directors and others an opportunity to acquire a proprietary interest in the Company and enable us to attract, retain, motivate and reward such persons in order to promote the success of the Company. Each plan authorizes the issuance of incentive stock options, nonqualified stock options and restricted stock. All awards issued under the share-based compensation plans must be approved by our Compensation Committee. At April 30, 2014 and 2013, there were 3,134,578 and 329,328 additional shares available under the compensation plans, respectively.
We recorded $4,298, $8,791 and $12,545 of employee compensation expense related to stock options during the years ended April 30, 2014, 2013 and 2012, respectively. The grant date fair value of employee stock options and warrants granted during the years ended April 30, 2014, 2013 and 2012 was $5,513, $1,847 and $13,839, respectively. The weighted average grant date fair value of employee stock options and warrants granted during the 2014, 2013 and 2012 fiscal years was $3.16, $2.73 and $3.40, 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:

	2014	2013	2012
Risk-free interest rate	1.9%	0.8%	1.4%
Term (in years)	5.8	5.8	4.7
Volatility	70%	83%	83%
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.

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Expected volatility:
In addition to our own historical volatility, we also consider the implied volatility of our options 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 implied volatility to estimate our future volatility. Our historical volatility 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, 2014, 2013 and 2012, we also recorded $1,103, $2,154 and $1,501 of non-employee equity related expense for services, respectively. These expenses are included in general and administrative expenses in our consolidated statements of operations. The grant date fair value of non-employee awards granted during 2014, 2013 and 2012 was $1,671, $431 and $1,119, respectively. The weighted average grant date fair value of non-employee awards issued for services during the 2014, 2013 and 2012 fiscal years was $2.73, $2.65 and $3.73, 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:

	2014	2013	2012
Risk-free interest rate	1.8%	0.6%	1.8%
Term (in years)	5.8	4.9	5.0
Volatility	70%	79%	86%
Dividend yield	—%	—%	—%

The following table summarizes our stock-based compensation activities for the years ended April 30, 2014, 2013 and 2012:

	2014		2013		2012	
	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	14,403,847	$4.61	15,405,955	$4.60	11,079,955	$3.98
Granted	2,357,500	5.70	966,750	4.34	5,345,000	5.34
Exercised	(1,681,654)	2.76	(1,286,001)	2.98	(969,000)	1.43
Canceled	(58,346)	4.27	(682,857)	5.33	(50,000)	5.94
Balance at end of year	15,021,347	4.99	14,403,847	4.61	15,405,955	4.60
Options exercisable at April 30	10,621,164	$4.73	9,821,403	$4.25	8,268,459	$3.78

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The following table summarizes our stock options and warrants outstanding, including exercisable shares at April 30, 2014:

Options and Warrants Outstanding				Options and Warrants Exercisable	
Range of Exercise Price	Number Outstanding	Weighted Average Remaining Contractual Life (in years)	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$0.01 to $1.82	1,506,400	1.2	$0.70	1,506,400	$0.70
$2.00 to $4.99	1,783,000	5.4	3.55	1,391,154	3.39
$5.25 to $5.53	4,491,947	3.4	5.32	2,636,947	5.32
$5.89 to $5.94	3,295,000	6.4	5.92	2,936,663	5.93
$6.00 to $6.95	3,945,000	3.6	6.13	2,150,000	6.08
	15,021,347	4.1	$4.99	10,621,164	$4.73

The following table summarizes restricted stock activity for the years ended April 30, 2014, 2013 and 2012:

	2014	2013	2012
Unvested at beginning of year	591,030	147,000	97,000
Granted	520,000	997,172	130,000
Vested	(630,348)	(536,142)	(75,000)
Forfeited	(15,250)	(17,000)	(5,000)
Unvested at end of year	465,432	591,030	147,000

The aggregate intrinsic value of stock options and warrants exercised during the years ended April 30, 2014, 2013 and 2012 was $3,533, $1,201 and $3,782, 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, 2014, 2013 and 2012, we received cash of $4,638, $3,832 and $1,383 for options and warrants exercised, respectively. As of April 30, 2014, we have employee-related unrecognized stock-based compensation expense of $7,931 with a weighted average vesting term of 1.33 years, over which the expense will be recognized. The impact on our basic loss per common share that resulted from employee stock-based non-cash compensation is $0.17, $0.21 and $0.31 for the years ended April 30, 2014, 2013 and 2012, respectively.

10. LITIGATION

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. As previously reported, 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 that 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.

This action was revived on August 4, 2011, when 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, arose from the same allegations as the previous action in the state court. The federal case sought money damages from us for breach of contract; however, unlike the previous action, it did not seek specific performance of the assignments at issue. The Plaintiff claimed that the other defendants tortiously interfered with, or induced the breach of, the letter of intent between us and the Plaintiff. We reached a settlement with the Plaintiff on January 24, 2014, wherein we would pay the Plaintiff $1,250 in exchange for their agreement to dismiss the case with prejudice. The Company recorded a loss of $1,250 in other income (expense), net in its consolidated statement of operations for the year ended April 30, 2014 in connection with this settlement.

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 CIE. 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 warrants and violated a duty of good faith and fair dealing. The suit sought damages in excess of $3,000, which includes $2,687 of damages for loss of vested warrants. We believe that all of the asserted claims were 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 filed our Answer and conducted discovery. On January 21, 2013, Mr. Stafford's attorney filed a motion to withdraw as counsel, and on April 2, 2013, Mr. Stafford filed a motion to proceed pro se. On February 24, 2014, we filed a Motion to Dismiss with Prejudice based on Plaintiff’s failure to prosecute his case since April 2, 2013, Plaintiff’s having missed filing deadlines, and his having failed to appear to give his deposition both times we have noticed it. On February 26, 2014, the Court entered an Order to Show Cause, requiring the plaintiff to demonstrate why his case should not be dismissed. On March 14, 2014, the plaintiff filed a Motion for Voluntary Dismissal, Without Prejudice through his new attorney. On June 3, 2014, the court granted plaintiff’s motion to dismiss without prejudice, but did so with the condition that plaintiff must reimburse us for costs incurred by us as a result of his failure to cooperate in discovery in this case in the amount of $9 prior to his being allowed to refile the case. As such, this case has been dismissed and there is no further action currently required.

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) unjust 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 filed a Motion to Dismiss for lack of personal jurisdiction, but this motion was not granted by the court. We filed an Answer to the complaint in this case on October 10, 2012, and we have conducted discovery. Trial was previously set for November 4, 2013. On October 21, 2013, the trial was postponed with no new trial date having been set. On October 31, 2013, the judge ruled on our outstanding Motion for Summary Judgment, granting it as to the unjust enrichment claim and breach of the implied covenant of good faith and fair dealing claim, and denying it as to the breach of contract claim. We expect to proceed to trial on the breach of contract claim once a new trial date is set. In February 2014, we received notice from a third party seeking to intervene in the case in order to secure payment of a debt allegedly owed by the Plaintiff to the third party. On June 5, 2014, the court entered an order denying the motion to intervene. On May 29, 2014, the court put down a new scheduling order setting forth certain pre-trial deadlines with the final pre-trial conference being set for October 30, 2014. We expect the court to set a trial date that will be shortly after the final pre-trial conference. 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 lawsuits 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 us and the other defendants, and payment of the Plaintiffs' attorney's fees. We have filed a Motion to Dismiss the case, which was denied on February 4, 2014 as to all defendants save Ford Graham. On July 3, 2014, we agreed upon a potential settlement with the Plaintiffs would dismiss the lawsuit with prejudice in exchange for a settlement payment of $2,950, which is within the remaining policy limits of our director and officer insurance policy. The proposed settlement remains subject to court approval and class notice administration before it will be effective. We expect to complete full documentation of the settlement and file a motion for preliminary approval of the class action settlement and approval of the class no later than August 31, 2014.

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 alleged 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 sought 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. The Plaintiff agreed to stay this case awaiting a ruling on the plaintiff's appeal in the federal derivatives case in Lukas v. Miller Energy Resources, Inc., et al, as described in the next paragraph. The Plaintiff also agreed to voluntarily dismiss the case in the event the plaintiff's appeal in Lukas was denied. Following the dismissal of Lukas, on October 1, 2013, the Court entered an Order dismissing the case without prejudice on the motion of the Plaintiff. On October 24, 2013, we filed a Motion to Amend the Order of Dismissal as the agreement with the Plaintiff was that the case would be dismissed with prejudice if the Sixth Circuit Court of Appeals affirmed the dismissal of the Lukas case, which it has. On June 3, 2014, after reaching an agreement with the Plaintiff, we filed an amended agreed final order of dismissal with prejudice in this case.

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. As noted below, this case had been dismissed by the trial court, and that dismissal was unsuccessfully appealed by the plaintiffs. It contained substantially similar claims as Valdez. The suit alleged 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 sought unspecified money damages from the individual defendants, to have us take certain actions with respect to our management, restitution to us, and the Plaintiffs' attorney fees and costs. We filed a Motion to Dismiss, which was granted on September 21, 2012. On October 16, 2012, a notice of appeal of this dismissal was filed by the Plaintiffs with the Sixth Circuit Court of Appeals. On September 19, 2013, the Court of Appeals affirmed the judgment of the District Court dismissing the case. On October 3, 2013, the Plaintiff filed a Motion for Rehearing En Banc. The Court denied the motion on January 8, 2014. The Plaintiffs had three months to file a petition to the Supreme Court of the United States, but did not do so. Therefore, these cases have ended.

On August 31, 2012, we terminated an agreement with Voorhees Equipment and Consulting, Inc. ("Voorhees") for the construction and sale of the rig currently being used on the Osprey Platform, Rig 35, (the "Rig 35 Agreement"). We terminated the agreement based on our belief that Voorhees was in breach of its obligations thereunder. Voorhees later indicated its desire to arbitrate claims it believes it has under invoices arising between May 29, 2012 and August 31, 2012. We believed we had grounds to dispute liability with respect to some or all of those invoices, in addition to having certain counterclaims we expected to assert. The parties elected to engage a private arbitrator to settle this dispute (the "Voorhees Matter") and conducted discovery. On September 18, 2013, we received a third-party complaint from Voorhees in connection with a lawsuit by Carlile Transportation Systems, Inc., in the Superior Court for the State of Alaska. The case is styled Carlile Transportation Systems, Inc. v. Voorhees Rig International, Inc. v. Cook Inlet Energy, LLC (the "Carlile Matter"). The dispute in the Carlile Matter related solely to unpaid transportation fees arising from the transportation of equipment for Rig 35. These fees were already the subject of the planned arbitration with Voorhees over the Voorhees Matter. As all disputes under the Rig 35 Agreement are subject to mandatory arbitration, we filed a motion to compel arbitration in the Carlile Matter, which the Court granted, along with an award of our legal costs incurred in connection with the Carlile Matter. On February 20, 2014, we reached an agreement in principle to settle the Voorhees Matter (including the transportation fees at issue in the Carlile Matter), and we entered into a settlement agreement which was effective as of May 12, 2014. We agreed to return to Voorhees the following equipment previously delivered to us under the Rig 35 Agreement, but which we subsequently replaced on that rig:

- An iron roughneck that we had to replace on Rig 35 due to mechanical unreliability; and
- A BOP stack originally included on Rig 35, but later removed and replaced with a better functioning replacement.

We also agreed to return to Voorhees two moving containers, left-over electrical equipment and tools belonging to Voorhees but left with CIE when Voorhees ceased working on Rig 35. No costs of defense or other cash payment are expected to be required of us in connection with this settlement, although we will pay the transportation costs of the equipment being returned. Accordingly, we have accrued our best estimate, based on the terms in the settlement agreement, of the potential loss on our consolidated balance sheet.

On April 4, 2013, we filed suit against a former contractor of CIE and its parent company (collectively "Cudd") in the United States District Court for the District of Alaska at Anchorage. This case is styled Cook Inlet Energy, LLC v. Cudd Pressure Control Inc. and RPC, Inc. In our suit we are seeking declaratory relief and damages for breach of contract, breach of implied warrant of merchantability, breach of implied covenant of fitness for a particular purpose and breach of the implied covenant of good faith and fair dealing arising out of a dispute regarding certain equipment and services provided by Cudd on the Osprey

(Dollars in thousands, except per share data and per unit data)

Platform that did not meet our needs or expectations as promised. We have not yet determined the full amount of damages claimed. On May 29, 2013, Cudd filed its Answer denying our claims and including a counterclaim for equipment and services, totaling approximately $1,889, plus the costs of defense. We have filed our counteranswer and denied that these amounts are owed, in whole or in part. We are presently conducting discovery. Given the current stage of the proceedings with respect to this case, we believe that any loss would be limited to $1,889 plus the cost of defense, related to this matter. Based on the information currently available, we have accrued our best estimate of the potential loss on our consolidated balance sheet.

On February 7, 2014, we were served with a lawsuit filed by Vulcan Capital Corporation in the District Court for the Southern District of New York styled Vulcan Capital Corp. v. Miller Energy Resources, Inc. and PlainsCapital Bank. The suit asserts various causes of action against PlainsCapital Bank, and appears to assert the following causes of action against us: (1) Breach of Fiduciary Duty and (2) Concert of Action. The case stems from an agreement Plaintiff had with PlainsCapital Bank wherein Plaintiff secured certain loans by pledging four warrants to purchase our common stock that were issued as part of the employment package of Ford F. Graham, our former President. Upon Plaintiff's default of the loan agreement, PlainsCapital presented the warrants to us for transfer, and, after requesting certain tenders required under Tennessee law, we registered the transfer of the warrants. We have retained counsel and we have filed a Motion to Transfer as the warrants have a valid exclusive forum clause that requires the case be tried in Knox County, Tennessee. In addition, PlainsCapital Bank has agreed to indemnify us for our first $500 of expenses related to this dispute. Given the current state 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 MEASUREMENTS

Fair Value Measurements on a Recurring Basis

The carrying amounts reported in the consolidated balance sheets for cash and cash equivalents, trade receivables, account payables and other short-term liabilities approximate fair value due to the nature of the instrument and/or the short-term maturity of these instruments. The fair values of the Company's commodity derivative instruments are classified as level 2 measurements as they are calculated using industry standard models using assumptions and inputs which are substantially observable in active markets throughout the full term of the instruments. These include market price curves, contract terms and prices, credit risk adjustments, and discount factors. The following summarizes the fair value of the Company's commodity derivative assets and liabilities according to their fair value hierarchy as of the reporting dates indicated:

	Fair Value Measurements		
At April 30, 2014	Level 1	Level 2	Level 3
Commodity derivative asset	$—	$114	$—
Commodity derivative liability	—	(7,321)	—
Total	$—	$(7,207)	$—
At April 30, 2013			
Commodity derivative asset	$—	$—	$—
Commodity derivative liability	—	(842)	—
Total	$—	$(842)	$—

There were no transfers between Level 1, Level 2 or Level 3 during the years ending April 30, 2014 or 2013.

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12. OIL AND GAS PROPERTIES AND EQUIPMENT

Oil and gas properties (successful efforts method) are summarized as follows:

	April 30, 2014	2013
Property costs		
Proved property	$467,740	$332,241
Unproved property	243,107	196,500
Total property costs	710,847	528,741
Less: Accumulated depletion	(66,020)	(37,427)
Oil and gas properties, net	$644,827	$491,314

Equipment is summarized as follows:

	April 30, 2014	2013
Machinery and equipment	$7,759	$7,413
Vehicles	1,877	1,851
Aircraft	—	476
Buildings	2,726	2,725
Office equipment	1,108	759
Leasehold improvements	527	482
Drilling rigs	30,210	30,117
Payment on drilling rig	1,500	—
	45,707	43,823
Less: Accumulated depreciation	(10,338)	(6,252)
Equipment, net	$35,369	$37,571

The Company classified its aircraft as an asset held for sale on our consolidated balance sheet as of April 30, 2014. The aircraft is recorded at estimated fair value less cost to sell. During fiscal 2014, the Company recorded an impairment charge of $168, which is recorded in other operating (income) expense, net on our consolidated statement of operations. Proceeds received from the sale of the aircraft are required to pay down the Company's Second Lien Credit Facility.

Depreciation, depletion and amortization consisted of the following:

	For the Year Ended April 30, 2014	2013	2012
Depletion of oil and gas related assets	$29,292	$9,803	$12,537
Depreciation and amortization of equipment	4,236	3,367	773
Total	$33,528	$13,170	$13,310

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13. MAJOR CUSTOMERS AND CONCENTRATIONS OF CREDIT RISK

During the years ended April 30, 2014, 2013 and 2012, Tesoro accounted for 88%, 80%, and 100% of our consolidated total revenues, respectively. Tesoro also accounted for 5% and 55% of our accounts receivable as of April 30, 2014, and 2013, respectively.

Credit is extended to customers based on an evaluation of their credit worthiness and collateral is generally not required. We experienced no credit losses of significance during the years ended April 30, 2014, 2013 and 2012.

We maintain our cash and cash equivalents, which at times may exceed federally insured amounts, in highly rated financial institutions. As of April 30, 2014, we held $5,062 in excess of the $250 limit insured by the Federal Deposit Insurance Corporation.

Derivative assets and liabilities

We have a risk of loss from counterparties not performing pursuant to the terms of their contractual obligations. We attempt to minimize credit-risk exposure to derivative counterparties through formal credit policies, consideration of credit ratings from public ratings agencies, monitoring procedures, master netting agreements and collateral support under certain circumstances. Collateral support could include letters of credit, payment under margin agreements and guarantees of payment by credit worthy parties.

We also enter into master netting agreements to mitigate counterparty performance and credit risk. During the years ending April 30, 2014, 2013, and 2012, we did not incur any significant losses due to counterparty bankruptcy filings. We assess our credit exposure on a net basis to reflect master netting agreements in place with certain counterparties. We offset our credit exposure to each counterparty with amounts we owe the counterparty under derivative contracts.

14. ALASKA PRODUCTION CREDITS

During the years ended April 30, 2014 and 2013, the Company qualified for several credits under Alaska Statutes 43.55.023 and 43.55.025:

- 43.55.023(a)(1) Qualified capital expenditure credit (20%)
- 43.55.023(l)(1) Well lease expenditure credit (effective June 30, 2010) (40%)
- 43.55.023(a)(2) Qualified capital exploration expenditure credit (20%)
- 43.55.023(l)(2) Well lease exploration expenditure credit (effective June 30, 2010) (40%)
- 43.55.023(b) Carried-forward annual loss credit (25%)
- 43.55.025 Seismic exploration credits (40%)

We recognize a receivable when the amount of the credit is reasonably estimable and receipt is probable. For expenditure and exploration based credits, which we receive in the ordinary course of business, the credit is recorded as a reduction to the related assets. For carried-forward annual loss credits, which we receive in the ordinary course of business, the credit is recorded as a reduction to the Alaska production tax. We did not incur any Alaska production taxes in fiscal 2014, 2013 or 2012, and accordingly, the carried-forward annual loss credits are presented separately in our operating expenses on the consolidated statement of operations.

Balance, April 30, 2013	$12,713	
Applications for carried-forward annual loss credits[1]	16,342	
Applications for expenditure and exploration based credits[1]	41,841	
Cash collections for carried-forward annual loss credits	(3,244	)
Cash collections for expenditure and exploration based credits	(18,531	)

Balance, April 30, 2014	$49,121

[1] Applications for carried-forward annual loss credits for expenditure and exploration based credits are recorded net of established reserves and also include revisions to prior period applications, if applicable.

During the years ended April 30, 2014, 2013 and 2012, the Company recorded net carried-forward annual loss credits of $16,342, $3,268 and $0, respectively. As of April 30, 2014 and 2013, the Company has reduced the basis of capitalized assets by

$54,570 and $14,547 for expenditure and exploration credits. The reductions are recorded on our consolidated balance sheets in "oil and gas properties" and "equipment." As of April 30, 2014 and 2013, the Company had outstanding net receivables from the State of Alaska in the amount of $49,121 and $12,713, 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. ("H&H Industrial") 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. H&H Industrial is owned by the sister and father of David Hall, who is a member of our Board of Directors and COO of Miller, as well as the Chief Executive Officer ("CEO") of CIE. For fiscal 2014, 2013 and 2012, we paid H&H Industrial a total of $2,003, $1,024 and $632, respectively. We have used Rediske Air, Inc. ("Rediske Air") to provide transportation to our facilities. Rediske Air was owned by David Hall's brother-in-law, who passed away on July 7, 2013. Rediske Air is no longer owned by a related party. For fiscal 2014, 2013 and 2012, we paid Rediske Air, Inc. a total of $1,060, $680 and $463, respectively. The audit committee of our Board of Directors determined that the amounts paid by us for the services performed were fair and in the best interest of the Company.

From time to time the Company provides service work on oil and gas wells owned by Mr. Herman Gettelfinger (and family), a member of the Board of Directors until April 16, 2014 and an emeritus member of the Board from that date until his death on May 17, 2014. As of April 30, 2014 and 2013, Mr. Gettelfinger (and family) owed us $24 and $11, respectively. The audit committee of our Board of Directors determined that the amounts paid to us for the services performed were fair and in the best interests of the Company.

During fiscal 2014, Mr. Gettelfinger paid the Company $3 for the profit he made from the purchase and sale of our common stock within a six month period. The $3 proceeds are presented in other cash flows from financing activities in our consolidated statements of cash flows.

The Company is required to remit payroll taxes related to certain stock-based compensation transactions. As of April 30, 2014, we had a payable of $157 and no receivable. As of April 30, 2013, we had recorded a related payable of $620 as well as a corresponding receivable from the respective employees of $593. This receivable was collected subsequent to April 30, 2013.

In 2009 we formed both Miller Energy GP and MEI to raise capital necessary to support strategic business initiatives. From November 2009 to May 2010 we entered into the MEI Loan Documents with MEI to borrow $3,071 with maturity dates ranging from November 2013 to May 2014. On June 29, 2012, the maturity dates on the promissory notes were amended to reflect, (i) the later of 91 days after the date on which the Prior Credit Facility is extinguished, or (ii) July 31, 2017. Our wholly owned subsidiary, Miller Energy GP, owned 1% of MEI, however due to the shared management of our company and MEI, we have consolidated this entity. We have not presented noncontrolling interest on our consolidated balance sheets or our consolidated statements of operations due to the fact that these amounts are immaterial. On February 3, 2014, we repaid all obligations under and terminated the MEI Loan Documents. Once paid, in accordance with the governing documents of MEI, the interests of the limited partners in MEI were effectively redeemed and ceased to exist. As a result, under Delaware law, MEI ceased to be a "limited partnership" when no new limited partners were admitted within the statutorily prescribed time limit. As the Company was the sole general partner and sole remaining holder of any equity interest in MEI, MEI has therefore been legally consolidated into the Company. We are in the process of preparing a certificate of cancellation for filing with the State of Delaware with respect to MEI.

On September 18, 2013, the Company entered into a one-year consulting agreement with William R. Weakley under which he agreed to assist us with investor relations and outreach, including advising the company on its communications with high net-worth individuals, helping to further the Company's related business goals, assisting with our strategic planning, providing management and business advice, and other consulting services we may reasonably request. Mr. Weakley is a related party to the Company as a result of aggregating his personal holdings in our stock with those of his brother, son-in-law and other of his relatives which, taken together, exceed 5% of the outstanding common stock of the Company. As compensation for these services, we granted Mr. Weakley a warrant to purchase 300,000 shares of our common stock at an exercise price of $6.63 per share. So long as the warrant has not otherwise terminated prior to that date, this warrant will vest in full and be exercisable on September 18, 2014. The warrant will terminate if the related consulting agreement is terminated prior to the end of its one-year term. The warrant will otherwise terminate on the earlier of the one-year anniversary of the death or disability of Mr. Weakley or September 18, 2016. The audit committee of our Board of Directors determined that the consideration given by us for the services to be performed was fair and in the best interest of the Company. We further note that in an unrelated transaction, Mr. Weakley's son-in-law extended a personal loan to our CEO, Scott M. Boruff. The Company is not a party to or otherwise involved in this loan, though this transaction was disclosed to the audit committee of our Board of Directors in connection with its evaluation of the consulting agreement with Mr. Weakley. As of April 30, 2014, we paid Mr. Weakley a total of $5.

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Two adult children of our Chief Operating Officer, Mr. David Hall, are non-executive employees of CIE. During the year ended April 30, 2014, their compensation exceeded $120 and thereby required review by the Audit Committee and disclosure herein. Mr. Hall's sons earned $161 and $148, respectively, during fiscal 2014. Their compensation was determined in accordance with our standard employment and compensation practices applicable to employees with similar responsibilities and positions.

16. SUBSEQUENT EVENTS

Acquisition of Rig 36 and Related Capital Lease
On May 5, 2014, we entered into the Rig Equipment Purchase Agreement with Baker Process, Inc. to purchase the Company's Rig 36 and related equipment. Subsequent to purchasing Rig 36, on May 9, 2014, the Company entered into a capital lease with First National Capital, LLC to finance the purchase of and planned future modifications to Rig 36. As of July 7, 2014, we have drawn $3,250 under the capital lease, which can be expanded to $5,000 as we continue to upgrade Rig 36.
Entry into Merger Agreement with Savant Alaska, LLC
On May 8, 2014, we entered into the Merger Agreement to acquire Savant, subject to due diligence and regulatory approval, for $9,000. We have formed a wholly-owned subsidiary, Miller Colorado, which will merge with Savant to facilitate the acquisition. Savant currently owns, and we would indirectly acquire as a result of this merger of Miller Colorado with Savant, a 67.5% working interest in the Badami Unit and 100% ownership in certain nearby leases. ASRC Exploration, LLC owns the remaining 32.5% working interest in the Badami Unit. In addition to the working interest in the Badami Unit and the leases, we would acquire certain midstream assets located in the North Slope with a design capacity of 38,500 bopd, a 500,000 gallon diesel storage tank, 20 megawatts of power generation, a grind and inject solid waste disposal facility and Class 1 disposal well, a one mile airstrip, and two pipelines each running 25 miles in length from Badami to the Endicott Pipeline. Current production from the Savant assets is approximately 1,100 bopd gross (600 bopd net).
We expect the transaction to close following receipt of regulatory approval, which we expect will be received by the end of December 2014. The merger will have an effective date of May 1, 2014.
Entry into First Lien RBL
On June 2, 2014, we entered into the First Lien Loan Agreement, among the Company, as borrower, KeyBank, as the RBL Administrative Agent, and the RBL Lenders. In addition to KeyBank, the syndicate includes CIT Finance LLC, Mutual of Omaha Bank and OneWest Bank N.A.
The First Lien Loan Agreement provides for a $250,000 senior secured, reserve-based revolving credit facility, $60,000 of which was made available to us on the closing date. Amounts outstanding under the First Lien RBL are priced on a sliding scale, based on LIBOR plus 300 to 400 basis points and an undrawn commitment fee, depending upon the level of borrowing (per the table below).
Borrowing Base Utilization Grid

Borrowing base utilization percentage	<25%	≥ 25%, but <50%	≥ 50%, but <75%	≥ 75%, but <90%	≥ 90%, but ≤100%
Spread above LIBOR	3.00%	3.25%	3.50%	3.75%	4.00%
Undrawn commitment fee rate	0.50%	0.50%	0.75%	0.75%	0.75%

The First Lien RBL will expire on the third anniversary of the closing. The facility includes contains customary covenants, including a leverage, interest coverage, current ratio, minimum gross production, minimum liquidity, asset coverage and change of management control covenants as well as other covenants customary for a transaction of this type. Subject to certain conditions contained in the First Lien Loan Agreement, the First Lien RBL also allows us to implement a discretionary share repurchase plan on terms and conditions reasonably satisfactory to the RBL Administrative Agent and the RBL Lenders. The First Lien RBL contemplates up-front fees, arrangement fees, and ongoing commitment and other fees customary for transactions of this nature.

The Company drew $20,000 on the closing date under the First Lien RBL, which will be used to provide working capital for development drilling in Alaska. The amounts drawn were subject to an original issue discount equal to 1% of the initial borrowing base. On June 24, 2014, we drew an additional $10,000 under the First Lien RBL.

Also on June 2, 2014, in connection with the First Lien RBL, the Company, along with all of its consolidated subsidiaries (other than MEI, Miller Energy, and Miller Energy Drilling 2009-A, L.P.), entered into a First Lien Guarantee and Collateral

Agreement with KeyBank, for the benefit of the RBL Lenders from time to time party to the First Lien Loan Agreement. Under the terms of the First Lien Guarantee and related security documents each of the consolidated subsidiaries of the Company (other than MEI, Miller Energy Colorado, and Miller Energy Drilling 2009-A, L.P.) have guaranteed the our obligations under the First Lien RBL and we and those subsidiaries have granted a security interest in substantially all of our assets to secure the performance of the obligations arising under the First Lien RBL.

Amendment of New Apollo Loan Agreement

On June 2, 2014, we entered into the Amendment No. 1 to Credit Agreement and Guarantee and Collateral Agreement to the Second Lien Credit Facility and the Second Lien Guarantee. This amendment conforms certain of the covenants, terms and conditions in the Second Lien Credit Facility to match those of the First Lien RBL, including the financial covenants.

Payment of Dividends

On June 2, 2014, we paid a quarterly dividend of approximately $0.67 per share on the Series C Preferred Stock. The dividend payment is equivalent to an annualized 10.75% per share, based on the $25.00 per share stated liquidation preference, accruing from March 1, 2014 through May 30, 2014. The record date was May 15, 2014.

On June 2, 2014, we paid a quarterly dividend of approximately $0.66 per share on the Series D Preferred Stock. The dividend payment is equivalent to an annualized 10.5% per share, based on the $25.00 per share stated liquidation preference, accruing from March 1, 2014 through May 30, 2014. The record date was May 15, 2014.

Intended Disposition of Tennessee Assets

On June 24, 2014, we announced our intent to divest our Tennessee assets in order to allocate our capital to our Alaskan operations and investment opportunities. No definitive agreement has been reached with any potential buyer in connection with this proposed transaction and, until that has occurred, we will continue to conduct our business as usual in Tennessee.

Proposed Class Action Settlement

On July 3, 2014, we agreed upon a potential settlement with the Plaintiffs in the purported class action lawsuit styled In re Miller Energy Resources, Inc. Securities Litigation wherein the Plaintiffs would dismiss the lawsuit with prejudice in exchange for a settlement payment of $2,950, expected to be funded by our director and officer insurance policy. The proposed agreement, when and if it becomes effective, would not be an admission of wrongdoing or acceptance of fault by us or any of the individual defendants named in the complaint. We, along with those individual defendants, have agreed upon the terms of this proposed settlement to eliminate the uncertainties, risk, distraction and expense associated with protracted litigation. The proposed settlement remains subject to court approval and class notice administration before it will be effective. We expect to complete full documentation of the settlement and file a motion for preliminary approval of the class action settlement and approval of the class no later than August 31, 2014. The estimated potential loss and expected insurance recovery are accrued on our consolidated balance sheet as of April 30, 2014.

Entry into Glacier Rig Purchase Option

Effective as of July 4, 2014, we entered into a Purchase and Sale Agreement with Teras which grants us the right to purchase the Glacier Rig and the Glacier PSA. The Glacier PSA is dated as of July 3, 2014, but was signed by Teras the following day. A payment of $700 was required in connection with the execution and delivery of the Glacier PSA, which we are entitled to have refunded if we fail to close by August 8, 2014, if it should be determined that Teras lacks clear title to the Glacier Rig, there are liens or encumbrances (other than immaterial defects in title or liens to which we consented) or if the Glacier Rig is affected by a significant casualty prior to closing. An additional payment of $6,300 will be due if the sale is finalized.

MILLER ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)
(Dollars in thousands, except per share data and per unit data)

SUPPLEMENTAL OIL AND GAS DISCLOSURES (UNAUDITED)

The following tables show our capital and operational costs for fiscal years 2014, 2013 and 2012:
a. Capitalized Costs Relating to Oil and Gas Producing Activities at April 30, 2014, 2013 and 2012 are as follows:

	2014	2013	2012
Natural gas and oil properties:			
Proved properties	$467,740	$332,241	$321,066
Unproved properties	243,107	196,500	182,704
	710,847	528,741	503,770
Accumulated depletion	(66,020)	(37,427)	(27,968)
Net capitalized costs	$644,827	$491,314	$475,802

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

	2014	2013	2012
Property acquisition costs			
Proved properties	$54,535	$689	$—
Unproved properties	7,564	704	785
Acquisition costs	62,099	1,393	785
Exploration costs	1,713	1,268	180
Development costs	133,778	24,968	6,773
Total	$197,590	$27,629	$7,738

c. Results of Operations for Producing Activities:

	2014	2013	2012
Production revenues	$69,469	$29,915	$32,493
Lease operating expense	(20,187)	(22,288)	(11,305)
Transportation costs	(5,599)	(2,410)	(3,556)
Alaska carried-forward annual loss credits, net	16,342	3,268	—
Depletion	(35,212)	(13,041)	(13,094)
Results of operations for producing activities (excluding corporate overhead and interest costs)	$24,813	$(4,556)	$4,538

d. Reserve Quantity Information (Unaudited)
The following reserve quantity information was derived from reserve and engineering reports prepared for the Company. During the fiscal 2014 year we made a change in our independent reserve engineer from Ralph E. Davis Associates, Inc. to Ryder Scott Company, L.P. for our Alaska properties. The decrease in PUD volumed resulted primarily from changes in the professional judgment of our independent petroleum engineer, additional production history leading to lower projected recovery estimates and to a lesser extent, changes in price and cost. The reserve and engineering reports for both Alaska and Tennessee properties were prepared by Ralph E. Davis Associates, Inc. for the years ended April 30, 2013 and 2012.
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.

(Dollars in thousands, except per share data and per unit data)

	Oil (MBbls)	Gas (MMcf)	MBoe
Proved reserves			
Balance, April 30, 2011	8,948	3,243	9,489
Extensions, discoveries and other additions	94	1,850	402
Revisions of previous estimates	(124)	(359)	(183)
Acquisition of reserves in place	—	—	—
Production	(384)	(177)	(414)
Balance, April 30, 2012	8,534	4,557	9,294
Extensions, discoveries and other additions	26	35	32
Revisions of previous estimates	(317)	(519)	(404)
Acquisition of reserves in place	6	—	6
Production	(295)	(133)	(317)
Balance, April 30, 2013	7,954	3,940	8,611
Extensions, discoveries and other additions	2,113	—	2,113
Revisions of previous estimates	(3,286)	(231)	(3,325)
Acquisition of reserves in place	—	24,726	4,121
Production	(685)	(794)	(817)
Balance, April 30, 2014	6,096	27,641	10,703
Proved developed reserves at April 30, 2012	2,325	2,601	2,759
Proved developed reserves at April 30, 2013	1,697	513	1,783
Proved developed reserves at April 30, 2014	4,264	12,202	6,298
Proved undeveloped reserves at April 30, 2012	6,209	1,956	6,535
Proved undeveloped reserves at April 30, 2013	6,257	3,427	6,828
Proved undeveloped reserves at April 30, 2014	1,832	15,439	4,405

We acquired 13,273 MMcf of proved undeveloped gas in the North Fork Acquisition that closed on February 4, 2014. As a result of ongoing drilling and completion activities during 2014, the Company reported extensions and discoveries, of 2,113 MBbls mainly with the Sword prospect within the West Macarthur area. The downward revisions were primarily driven by a decrease in PUD volumes. During the fiscal 2014 year we made a change in our independent reserve engineer from Ralph E. Davis Associates, Inc. to Ryder Scott Company, L.P. The decrease in PUD volumes resulted primarily from changes in the professional judgment of our independent petroleum engineer, and to a lesser extent, changes in price and cost.

The following schedule presents the standardized measure of estimated discounted future net cash flows from the Company's proved reserves for the years ended April 30, 2014, 2013 and 2012. 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, 2014, 2013 and 2012, it should be emphasized that such conditions continually change. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

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 $102.21 and the price per MMcf of natural gas was $6.90 for the Cook Inlet reserves and $86.37 per barrel of oil and $2.27 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. All of the Company's reserves are located in the United States.

(Dollars in thousands, except per share data and per unit data)

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. For purposes of the Standardized Measure calculation, it was assumed that our NOLs, attributable to our oil and gas assets, will be realized within future carryforward periods.

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, 2014, 2013 and 2012 are as follows:

	2014	2013	2012
Future cash flows	$810,184	$801,134	$894,027
Future production costs and taxes	(218,407)	(178,779)	(158,938)
Future development costs	(90,812)	(72,434)	(75,332)
Future income tax expense	(117,263)	(150,568)	(217,312)
Future cash flows	383,702	399,353	442,445
Discount at 10% for timing of cash flows	(99,574)	(124,905)	(139,242)
Discounted future net cash flows from proved reserves	$284,128	$274,448	$303,203

The following table sets forth the changes in the standardized measure of discounted future net cash flows from proved reserves for April 30, 2014, 2013 and 2012.

	April 30, 2014	2013	2012
Balance, beginning of year	$274,448	$303,203	$206,801
Sales, net of production costs and taxes	(43,683)	(5,217)	(17,632)
Changes in prices and production costs	(45,258)	(59,253)	116,689
Extensions, discoveries and other additions	100,868	1,302	58,906
Acquisition of reserves in place	73,946	295	—
Changes in estimated future development costs	11,744	(2,856)	7,641
Development costs incurred	10,131	5,522	6,773
Revisions of previous quantity estimates	(143,565)	(21,828)	(42,857)
Net changes in income taxes	15,502	49,486	(48,571)
Sales of reserves in place	—	—	—
Accretion of discount	37,176	39,472	30,503
Changes in timing and other	(7,181)	(35,678)	(15,050)
Balance, end of year	$284,128	$274,448	$303,203