MILLER ENERGY RESOURCES, INC.
Form 10-K/A
August 09, 2011

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K/A

(Amendment No. 1)

(Mark One)

ü **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended: **April 30, 2011**
OR
TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from: _____________ to _____________

MILLER ENERGY RESOURCES, INC.

(Exact name of registrant as specified in its charter)

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

3651 Baker Highway, Huntsville, TN 37756

(Address of Principal Executive Office) (Zip Code)

(423) 663-9457

(Registrant s telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.0001 per share	New York Stock Exchange

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

None
(Title of Class)

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ü 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).
Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ü

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

Large accelerated filer		Accelerated filer	ü
Non-accelerated filer		Smaller reporting company	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ü 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 29, 2010 (the last business day of the registrant s most recently completed second quarter), as reported on the NASDAQ Global Market, was approximately $147,621,755. As of July 15, 2011, there were 40,559,251 shares of common stock of the registrant outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

List hereunder the following documents if incorporated by reference and the Part of the Form 10-K (e.g., Part I, Part II, etc.) into which the document is incorporated: (1) Any annual report to security holders; (2) Any proxy or information statement; and (3) Any prospectus filed pursuant to Rule 424(b) or (c) under the Securities Act of 1933. The listed documents should be clearly described for identification purposes (e.g., annual report to security holders for fiscal year ended December 24, 1980). None.

EXPLANATORY NOTE

On July 29, 2011 we filed our Annual Report on Form 10-K for the year ended April 30, 2011 (the 2011 10-K) with the SEC. The 2011 10-K was filed with the SEC prior to KPMG LLP, our independent registered public accounting firm, completing its review of the annual report and issuing their independent accountants report on the financial statements, as well as the consent to the use of their report filed as Exhibit 23.3. As a result, the 2011 10-K is deficient. In response to comments from the staff of the SEC, we are filing this Amendment No. 1 to the 2011 10-K which identifies the 2011 10-K as deficient, and we have removed the audit report of KPMG LLP and the consent filed as Exhibit 23.3 from the filing and labeled our financial statements at April 30, 2011 and for the year then ended as unaudited.

By this Amendment No. 1 we are amending our 2011 Form 10-K to include corrections to computational errors in our consolidated statement of cash flows which appeared in the 2011 Form 10-K filed on July 29, 2011. This Amendment No. 1 also includes corrections in text portions of the 2011 Form 10-K to conform the disclosure to the corrections in these computational errors, to correct computational errors in the Summary Compensation Table within Item 11. Executive Compensation, as well as to enhance and clarify disclosure appearing in the notes to the consolidated financial statements. We have also revised the disclosure in Item 9A. to reflect the additional weaknesses in disclosure controls and procedures from the filing of our 2011 10-K. This Amendment No. 1 also includes currently dated certifications which appear as Exhibits 31.1, 31.2, 32.1 and 32.2. Notwithstanding, with respect to Exhibits 32.1 and 32.2, this Amendment No. 1 does not contain audited financial statements at April 30, 2011 and for the year then ended.

We expect to file an amended Annual Report on Form 10-K/A for the year ended April 30, 2011 (Amendment No. 2) containing audited financial statements for fiscal year 2011 as soon as (1) the Audit Committee of our Board of Directors completes its review of the events which led to the filing of the 2011 10-K prior to the completion of KPMG s review of our 2011 10-K and the issuance of its audit report, and (2) KPMG LLP has completed its review of our fiscal year 2011 financial statements and issues its report thereon. The Audit Committee has engaged Andrews Kurth LLP as special independent legal counsel to conduct a review of the filing. We anticipate that Andrews Kurth LLP will report its findings to the Audit Committee within approximately one week. This amended Annual Report will remove all references to the deficient filing and to the financial statements as unaudited. We expect that the fiscal year 2011 audited financial statements that will appear in Amendment No. 2 to our 2011 10-K will not contain any material revisions to those appearing in this Amendment No. 1.

MILLER ENERGY RESOURCES, INC.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

The Company has made in this report, and may from time to time otherwise make in other public filings, press releases and discussions with Company management, 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. 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, ta objective, should or similar expressions or variations on such expressions. For such statements, the Company claims the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will prove to be correct. The Company undertakes no obligation to publicly update or revise any forward-looking statements whether as a result of new information, future events or otherwise. These forward-looking statements involve risk and uncertainties. Important factors that could cause actual results to differ materially from the Company s expectations include, but are not limited to, the following risks and uncertainties:

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the capital intensive nature of oil and gas development and exploration operations and our ability to raise adequate capital to fully develop our operations and assets,

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the Company s assumptions about the energy market;

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production levels;

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reserve levels;

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operating results;

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competitive conditions;

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technology;

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the availability of capital resources, capital expenditures and other contractual obligations;

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the supply and demand for and the price of natural gas, oil, natural gas liquids (NGLs) and other products or services;

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volatility in the commodity-futures market;

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the weather;

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inflation;

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the availability of goods and services;

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drilling risks;

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our ability to perform under the terms of the Assignment Oversight Agreement with the Alaska DNR, including meeting the funding commitments of that agreement,

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fluctuating oil and gas prices and the impact on our results of operations,

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the impact of the global economic crisis on our business,

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the impact of natural disasters on our Cook Inlet Basin operations,

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the imprecise nature of our reserve estimates,

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our ability to recover proved undeveloped reserves and convert probable and possible reserves to proved reserves,

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- *the possibility that present value of future net cash flows will not be the same as the market value,*
- *the costs and impact associated with federal and state regulations,*
- *changes in existing federal and state regulations,*
- *our dependence on third party transportation facilities,*
- *insufficient insurance coverage,*
- *conflicts of interest related to our dealings with MEI,*
- *cashless exercise provisions of outstanding warrants,*
- *market overhang related to restricted securities and outstanding options, warrants and convertible notes,*
- *adverse impacts on the market price of our common stock from sales by the selling security holders, and*
- *Uncertainties related to possible legal and regulatory actions related to the filing of the 2011 Form 10-K.*

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.

An investment in our common stock involves a significant degree of risk. You should not invest in our common stock unless you can afford to lose your entire investment. You should consider carefully the following risk factors and other information in this annual report before deciding to invest in our common stock.

OTHER PERTINENT INFORMATION

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

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

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

GLOSSARY OF TERMS

We are engaged in the business of exploring for and producing oil and natural gas. Oil and gas exploration is a specialized industry. Many of the terms used to describe our business are unique to the oil and gas industry. The following glossary clarifies certain of these terms that may be encountered while reading this report:

"Gross" oil or gas well or "gross" acre is a well or acre in which we have a working interest.

"MCF" means thousand cubic feet, used in this report to refer to gaseous hydrocarbons.

MMBbls means million barrels of oil.

MMcf means million cubic feet.

"Net" oil and gas wells or "net" acres are determined by multiplying "gross" wells or acres by our percentage interest in such wells or acres.

"Oil and Gas Lease" or "Lease" means 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 reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

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 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.

"Royalty Interest" is a right to oil, gas, or other minerals, that is not burdened by the costs to develop or operate the related property.

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

PART I

ITEM 1.

BUSINESS.

Overview

We are an independent exploration and production company that utilizes seismic data and other technologies for geophysical exploration and development of oil and gas wells in the Appalachian region of eastern Tennessee and the Cook Inlet Basin in south-central Alaska. During fiscal 2011, we significantly expanded our operations with the December 2009 acquisition of oil and gas operations from Pacific Energy Resources through a bankruptcy proceeding in which we acquired onshore and offshore production and processing facilities, the Osprey offshore energy platform, and over 600,000 lease acres of land, along with hundreds of miles of 2-D and 3-D geologic seismic data, miscellaneous roads, pads and facilities. Our current strategy focuses the majority of our efforts on growing our company, including the following:

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increasing our overall oil and gas production through maintenance and repairs of nonperforming or underperforming wells located in Alaska, and

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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.

Our exploration and production activities

Historically, we focused our exploration, development, and production efforts in the Appalachian region of eastern Tennessee. During fiscal 2011, we continued to benefit from the increase in our operations through the June 2009 acquisitions of the businesses of Ky-Tenn Oil, Inc., a Kentucky corporation (KTO), East Tennessee Consultants, Inc., a Tennessee corporation ("ETC) and East Tennessee Consultants II, LLC, a Tennessee limited liability company ("LLC) in our Appalachian region and business in Alaska, which comprise our CIE operations. As of April 30, 2011, we had approximately 699,965 acres of gross oil and gas leases and exploration license rights (679,045 net acres), which includes 534,383 gross acres under our two Susitna Basin Exploration Licenses.

Cook Inlet Basin

Cook Inlet stretches 180 miles from the Gulf of Alaska to Anchorage in south-central Alaska. The Cook Inlet Basin contains large oil and gas deposits including several offshore fields. There are also numerous oil and gas pipelines running around and under the Cook Inlet.

As of April 30, 2011, we own approximately 115,124 gross acres of leasehold interests, the exploration license rights to an additional 534,383 acres and interests in 10 crude oil and five natural gas wells. The increased acreage from April 30, 2010 is a result of CIE s successful bids in State of Alaska s Division of Oil & Gas Cook Inlet Areawide 2010 Competitive Oil and Gas Lease Sale, and the award of Susitna Basin Exploration License No. 4, consisting of 62,909 acres. The leases, consisting of 17,027 acres, were awarded to CIE on March 1, 2011. All of CIE s bids completed acreage positions covering prospects acquired in its purchase of Pacific Energy Alaska operations in December 2009. The Susitna Basin Exploration License No. 4 was awarded on April 1, 2011. We also sold leases of 8,829 acres to an Alaska limited liability company, but retained overriding royalty interests.

At the time we acquired the Alaskan operations, all ten oil wells, three gas wells and four injection wells except for one gas were shut-in. By June 30, 2010, four of the oil wells had been returned to production. In addition, CIE owns a 30% working interest in two gas wells operated by Aurora Gas, which have been operated continuously.

Oil wells drilled in this area range from 9,000 vertical feet to 10,000 feet in vertical depth while gas wells have a vertical depth of 8,000 feet to 9,000 feet. Wells that are deviated (continue on from the vertical depth either diagonally or horizontally) will have a longer measured depth of approximately 5,000 feet giving total measured depth of 14,000 feet to 15,000 feet. Well spacing is quite variable, as there are large parts of Cook Inlet which are completely undeveloped, and others, that are more mature. Our fields have approximately 60 to 80 acre spacing. The Cook Inlet Basin contains a thick section of terrestrial Tertiary rocks which includes shale, sandstone, and coal. The primary targets in the area are crude oil reserves.

In January 2010 we entered into a Master Services Agreement with Fairweather E&P Services, Inc. (now SolstenXP), a company based in Anchorage, Alaska which provides a wide range of support services for the oil and gas industries, whereby it acts as an independent contractor for us in the development and/or refurbishment of the wells in Cook Inlet Basin. The agreement provides us with engineering, logistics, field and project management support for the well and facility work in Cook Inlet Basin which are anticipated to be completed on or before December 31, 2012. We pay the contractor for all costs associated with these services, including any services that Fairweather E&P may subcontract to third party providers, at its cost plus 15%. Fairweather is required to maintain certain minimum levels of insurance coverage and the agreement contains customary cross-indemnification provisions. We may terminate the agreement at any time without reason.

Susitna Basin Exploration License

Included in the Alaskan operations we acquired is a 100% interest in an Exploration License granted by the State of Alaska in October 2005 covering approximately 471,474 acres in the Susitna basin area north of Anchorage, Alaska. Under the terms of the Exploration License, the licensee was granted a five-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 $3.5 million was fulfilled, and we have the right at any time to covert the license for all or any portion of the acreage into oil and gas leases at any time. In an effort to control the timing of the development of this acreage, in April 2010 we requested a three-year extension of the exploration license for a work commitment of $750,000. The State granted the extension in October 2010. We will have the right to convert the license for all or any portion of the acreage into oil and gas leases upon completion of the new work commitment. If the exploration license is converted into oil and gas leases, we are required to pay an annual rental to the State of Alaska.

On April 1, 2011, we were awarded Susitna Basin Exploration License No. 4, which consists of 62,909 acres. Under the terms of the Exploration License, CIE was granted a ten-year exclusive license to explore for oil and gas on the specified lands, and upon fulfillment of the work commitment of $2,250,000, the license for all or any part of the land can be converted into oil and gas leases. If no work is carried out, CIE will post $225,000 in additional funding each year.

Osprey Platform

Also, included in the operations acquired from Pacific Energy was the Osprey platform which is located in the Redoubt Unit approximately 1.8 miles southeast of the West Foreland in central Cook Inlet at a water depth of approximately 45 feet. The Osprey platform, which produces from the Redoubt Unit, is connected to our Kustatan Production Facility. It relies on our Kustatan Production Facility and our West McArthur River Unit Production Facility to provide all of its electricity and gas, and the Kustatan Production Facility to process all of Osprey's produced fluids. The platform has 21 slots, eight of which are currently used, and an attached 40 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 it was used to conduct exploration drilling operations between January 2001 and July 2002. Eight wells were drilled, which in their present configuration consist of one water flood well, one Class I injection well, and six oil wells. The oil wells were equipped with electrical submersible pumps which were necessary to bring the oil to surface. In 2005, the third-party drilling rig was removed from the platform after a contract dispute. The removal of the rig delayed the ability to maintain and repair the platform s wells or to expand production, and the Osprey platform was shut-in in the spring of 2009.

In order to restore production from the Redoubt Unit, it will be necessary to mobilize a drilling rig to the Osprey platform and repair six wells. We believe that it is cost effective to permanently locate a drilling rig on the platform. Two of the Osprey wells required only the replacement of the electrical submersible pumps (ESPs), but the other four wells will require re-drilling in sections. We estimated that the total cost of restoring full production, including the purchase and construction of a drilling rig, is approximately $45 million. We began bringing the Osprey platform out of lighthouse mode in March 2011. In May, we successfully repaired the first of the two wells needing ESP replacement. In June, we secured financing in the form of a $100 million credit facility with Guggenheim Corporate Funding, LLC, Citibank, N.A., and Bristol Investment Fund, Ltd. The credit facility has an initial availability of $35 million and will be used to purchase the platform drilling rig and to finance the further development of our Alaskan and Tennessee assets. In June 2011, we contracted with Voorhees Equipment and Consulting, Inc. for the custom construction and purchase of a drilling rig for the Osprey platform for $17.9 million.

We expect the rig to ship and arrive in Alaska in September 2011 and be operational in November 2011. We have also brought the second well requiring ESP replacement online since closing on our credit facility.

Assignment Oversight Agreement

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

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file a monthly summary of expenditures by oil and gas field, tied to objectives in CIE s business plan and plan of development previously presented to the Alaska DNR,

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meet monthly with the Alaska DNR to provide an update on operations and progress towards meeting these objectives,

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notify the Alaska DNR 10 days prior to commitment when CIE is preparing to spend funds on a purchase, project or item of more than $100,000 during the first 12 months, more than $1 million during the second 12 months and more than $5 million thereafter, and

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submit a new plan of development and plan of operations for the Alaska DNR s approval on or before December 15, 2009 and submit a plan of development annually thereafter on or before February 1, 2010. CIE timely met both of these deadlines.

The agreement required CIE to obtain financing in the minimum amount of $5.15 million to provide funds to be used for expenditures approved by the Alaska DNR as part of CIE s plan of development. The funds are to be used for workover and repair of the wells, repair of the physical infrastructure, construction of a grind and inject plant at the West McArthur River facility, normal operating expenses associated with the leases and infrastructure and other capital project which are to be pre-approved by the Alaska DNR. The agreement also required CIE to demonstrate funding commitments to support restoration of the base production at the Redoubt Unit, including bringing a number of the shut-in wells back on line, which was estimated at $31 million in the agreement but which we have internally increased to $45 million primarily to accommodate the contractual purchase price of a drilling rig. We have provided these funds for the West McArthur River facility using a portion of the proceeds of our capital raising efforts described elsewhere herein.

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

CIE fail to submit the information required under the agreement and expenditure of funds for items or activities do not support core oil and gas activities, as reasonably determined by the Alaska DNR.

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

Membership in Cook Inlet Spill Prevention and Response, Inc.

CIE is a member of the Cook Inlet Spill Prevention and Response, Inc., which we refer to as 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, stretching from Palmer to the Barren Islands and out into the Gulf of Alaska. At each annual meeting of CISPRI members adopt a budget for the coming year which includes funds for day to day operational activities of CISPRI, investments in capital equipment and materials to be used in connection with the cleanup activities and research and development and training. The budget is funded though payment of dues by the members and the amount of dues is calculated in accordance with a participation formula. We pay an annual fee of $10,000 together with additional fees based upon the amount of oil we transport.

If a spill 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 of crude oil/synthetic crude oil or refined petroleum products arising from those operations without any further action by the members. Any member that utilizes or receives the benefit of these activities must reimburse CISPRI for all expenses of control and clean up, including costs of equipment, materials and personnel. Each member is required to execute a response action contract providing terms and conditions under which response and cleanup activities will be undertaken. CIE is a party to such an agreement which, in part, requires CIE to maintain worker s compensation insurance, employers liability insurance, comprehensive general and automotive liability insurance covering injury or death or persons and property damage of at least $10 million. CIE is in compliance with this insurance requirement. 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, Cook Inlet Energy is obligated to pay all unpaid dues and assessments levied prior to the notice of resignation. Cook Inlet Energy s membership may be terminated by the Board of Directors of CISPRI upon 60 days notice if its 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 approximately 50,458 gross acres of leasehold interests with 195 producing oil wells and 193 producing gas wells in which we own an interest. Wells drilled in this area range from 1,800 to 4,200 feet in depth and the well spacing is generally from 20 to 40 acres per well and are predominately in the Fort Payne formation.

Our oil and gas properties

The following table provides information on our proved reserves at April 30, 2011 and 2010.

	Net Reserves at April 30,			
	2011		2010	
Reserves category	**Oil (MMBbls)**	**Natural Gas (MMcf)**	**Oil (MMBbls)**	**Natural Gas (MMcf)**
PROVED				
Developed				
Cook Inlet	2.371	1.739	2.551	1.085
Appalachian region	0.100	0.750	0.114	0.652
Undeveloped				
Cook Inlet	7.536	0.584	7.679	3.722
Appalachian region				
Total Proved	10.007	3.073	10.344	5.459

When used in this table, MMBbls means million barrels of oil and MMcf means million cubic feet. We also use a number of terms when describing our 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 (seepage from adjacent areas) and projected reserves based on future recovery methods.

Our reserve estimates for oil and natural gas at April 30, 2011 for our Cook Inlet assets were prepared by Ralph E. Davis Associates, Inc., an independent engineering firm, and our reserve estimates for oil and gas at April 30, 2011 for our Appalachian region assets were prepared by Lee Keeling and Associates, Inc., an independent engineering firm. Our reserve reports, which are filed as exhibits to this annual report, were prepared using engineering and geological methods widely accepted in the industry. All reserve definitions comply with the applicable definitions of the rules of the SEC. The accuracy of the reserve estimates is dependent upon the quality of available data and upon independent geological and engineering interpretation of that data. For the proved developed producing reserves, the estimates were made when considered to be definitive, using performance methods that utilize extrapolations of various historical data including, but not limited to, oil, gas and water production and pressure history. For the other proved producing, proved behind pipe reserves, proved undeveloped reserves, and probable and possible reserves estimates were made using volumetric methods.

Our policies regarding internal controls over reserve estimates require reserves to be in compliance with the SEC definitions and guidance and for reserves to be prepared by an independent engineering firm. Our Chief Financial Officer and the Chief Executive Officer of our CIE subsidiary are primarily responsible for the engagement and oversight of our independent engineering firm. We provide the engineering firm with estimate preparation material such as property interests, production, current operation costs, current production prices and other information. This information is reviewed by the Chief Executive Officer of CIE and our Chief Financial Officer prior to submission to our third party engineering firm. A letter which identifies the professional qualifications of each of the independent engineering firms who prepared the reserve reports are included in those reserve reports which are filed as exhibits to this annual report. There was no conversion of unproved reserves to proved reserves during the fiscal year ended April 30, 2011.

The following table presents our producing wells by operating area at April 30, 2011.

	Producing Wells					
		Gross (a)			**Net (b)**	
Location	**Oil**	**Gas**	**Total**	**Oil**	**Gas**	**Total**
Cook Inlet	3	5	8	3	4	7
Appalachian region	195	193	388	120	130	250
Total	198	198	396	123	134	257

(a)

The number of gross wells is the total number of wells in which a working interest is owned.

(b)

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

Our staff of professional geologists is responsible for identifying areas with potential for economic production of natural gas and oil. Our head geologist is our Vice President of Geology, Gary Bible, Ph.D. Dr. Bible was appointed Vice President of Geology in September 1997. Dr. Bible came from Alamco Inc., where he had served since May 1991 as manager of geology and senior geologist. Dr. Bible earned his BS in geology from Kent State University and his MS and PhD degrees in geology from Iowa State University. He is a proven hydrocarbon finder who drilled his first successful wildcat as a trainee geologist. Dr. Bible brings to the Company over 30 years of experience as a petroleum geologist. In addition, Dr. Bible has spent more than 17 years in the Appalachian Basin in the exploration and development of reserves in the Big Lime zone, in Devonian shale and in deeper horizons. He is credited with managing a drilling program at Alamco that kept its finding cost the lowest in the nation. In addition to Dr. Bible, for our assets in Alaska, we also utilize the consulting services of Mr. Gregory L. Kirkland. Mr. Kirkland is also a professional geologist and has extensive knowledge of the Cook Inlet region of Alaska. Mr. Kirkland has over thirty five years with majors and large independent oil and gas companies in numerous domestic and international provinces, extensive geological, geophysical, reserves estimation and petrophysical background with broad technical and supervisory experience covering Gulf Coast, Mid Continent, Rockies, Alaska, Canada and International areas.

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

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

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

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

The following table presents, by operating area, leased acres or acreage subject to the Susitna Basin Exploration Licenses as of April 30, 2011.

	Developed Acres		**Undeveloped Acres**		**Total Acres**	
Project	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Cook Inlet	34,996	32,800	614,511	591,895	649,507	624,695
Appalachian region	13,760	9,468	43,817	30,159	57,577	39,627
Total acreage	48,756	42,268	658,328	622,054	707,084	664,322

The following table presents the net undeveloped acres that we control under fee leases and the Susitna Basin Exploration License and the period the leases and exploration license are scheduled to expire, absent pre-expiration drilling and production which extends the term of the lease(s) or the fulfillment of the exploration license terms which permits us to convert all or any portion of the exploration license into oil and gas leases. The expiration dates of the leases are subject to one year automatic renewals so long as we are producing oil and/or gas on the lease. The term of the Susitna Basin #2 Exploration License and the two MHT Olson Creek leases were extended, the Susitna Basin #4 Exploration License was issued, the seven leases from the State of Alaska Cook Inlet Areawide 2010 Lease Sale were issued, and the leases covering the parcel known as the Raptor Prospect were sold with the Company retaining a 3% overriding royalty interest.

	Net Undeveloped Acres	
Lease/Exploration License	**Year of Expiration**	**Total Acres**
Cook Inlet		
MHT 9300062 - Olson Creek	2012	5,483
MHT 9300063 - Olson Creek	2012	3,906
ADL 391613 - Olson Creek	2018	107
ADL 391614 - Olson Creek	2018	35
ADL 391615 - Olson Creek	2018	570
ADL 390578 - N Alexander	2012	5,705
ADL 390585 - N Alexander	2012	5,689
ADL 391628 - N Alexander	2018	5,513
ADL 390749 - Otter	2013	2,522
ADL 390579 - Otter	2012	5,760
ADL 391621 - Otter	2018	2,528
ADL 391624 - Otter	2018	2,514
ADL 390078 - Susitna Basin #2 Exploration License	2013	471,474
ADL 391628 - Susitna Basin #4 Exploration License	2021	62,909
ADL 390555 - Tutna	2012	1,280
ADL 390556 - Tutna	2012	2,522
ADL 390557 - Tazlina	2012	2,529
ADL 391608 - Tazlina	2018	5,760
ADL 17602 Sabre	1967, Held by Unit	896
ADL 18758 - Sabre	1967, Held by Unit	280
ADL 17594	1967, Held by Unit	80
ADL 17597	1967, Held by Unit	2,280
ADL 18730	1967, Held by Unit	480
ADL 18777	1967, Held by Unit	553
Total		591,375
Appalachian region		
Lindsay	Held by production	1,535
Edwards-Fowler, Gann	Held by production	81
Butler et al	Held by production	24
Gunsight	Held by production	1,335
Phillips et al from Gunsight acreage	Held by production	901
KTO acreage and wells	Held by production	19,128
ETC acreage and wells	Held by production	3,507
Baker-Senior lease farm out	Held by production	1,020
Other Undeveloped, net	2011 to 2013	2,628
Total		30,159

Total acreage	621,534

The following table presents our development and exploratory drilling activities during the past three fiscal years ended April 30. There is no correlation between the number of productive wells completed during any period and the aggregate reserves to those wells. Productive wells consist of producing wells capable of commercial production.

	Drilling Activities					
	2011		**2010**		**2009**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Development:						
Producing						
Cook Inlet						
Appalachian region						
Total producing						
Non-Producing						
Cook Inlet						
Appalachian region						
Total non-producing						
Injection						
Cook Inlet						
Appalachian region						
Total injection						
Dry						
Cook Inlet						
Appalachian region						
Total dry						
Total development						
Exploratory:						
Productive						
Cook Inlet						
Appalachian region	3	3				
Total productive	3	3				
Dry						
Cook Inlet						
Appalachian region						
Total dry						
Pending determination						
Total exploratory	3	3				
Total drilling activity	3	3				

Our current efforts are focused on reworking certain of the wells in Cook Inlet and ongoing drilling operations in the Appalachian region. The Company incurred $9.1 million and $5.8 million of development cost in the Cook Inlet region in fiscal years 2011 and 2010, respectively. These costs were primarily related to recompletion and repair of wells that were shut in by Pacific Energy, as well as repair of the physical infrastructure. Three oil wells and four gas wells were producing in Cook Inlet by April 30, 2010 and three oil wells and five gas wells were producing in Cook Inlet during the year ended April 30, 2011. We do not currently have any ongoing drilling operations in Cook Inlet, other than the workover of the wells in Alaska as described elsewhere herein. Much of the work associated with drilling, completing and connecting wells, including fracturing, logging and pipeline construction is performed by subcontractors, under our direction, specializing in those operations, as is common in the industry. When judged advantageous, we acquire materials and services used in the development process through competitive bidding by approved vendors. We also directly negotiate rates and costs for services and supplies when conditions indicate that such an approach is warranted.

Principal markets and principal customers

The existing markets for natural gas production in south-central Alaska are the Tesoro Nikiski Refinery, utility companies, petrochemical manufacturing, the production of liquefied natural gas (LNG) for export to Alaskan or Asian markets, and the production of synthetic crude oil (syncrude). Presently, the sole market for our crude oil produced at our Alaskan operations is the Tesoro Nikiski Refinery. Crude oil is shipped by pipeline and tanker vessel to the Tesoro Nikiski Refinery, operated by Tesoro Alaska Petroleum Company. The main export pipeline is operated by the Cook Inlet Pipeline Company, which is operated by Chevron Pipelines and tanker vessels operate under contract to Tesoro.

As a result of the acquisition of the Alaskan operations in December 2009, CIE is a successor to the September 2003 contract with Tesoro Refining and Marketing Company. Under the terms of this agreement, Tesoro has agreed to purchase at the Drift River Terminal all of the Alaskan Cook Inlet crude oil which is produced from leases on the west side of Cook Inlet for the maximum annual capacity of the lesser of the average proportionate share of the Alaskan Cook Inlet crude oil produced or 40,000 barrels per day. The per barrel pricing is based upon the simple arithmetic average of the published daily New York Mercantile Exchange (NYMEX) settlement prices for light sweet crude oil less certain adjustments and deductions. This pricing may be modified upon the mutual agreement of the parties if the volume falls below 9,000 barrels per day or exceeds 24,000 barrels per day. The initial term of the agreement was to December 31, 2008 and thereafter it has automatically renewed in additional one year terms. The agreement may be terminated by either party upon notice 60 days prior to the automatic renewal. All of our present and planned future oil production is from the west side of Cook Inlet, and would be covered by this contract. Sales to Tesoro Refining and Marketing Company under this agreement represented approximately 85% of our total revenue in fiscal 2011.

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

The principal markets for our crude oil and natural gas produced in the Appalachian region are refining companies, utility companies and private industry end users. Crude oil is stored in tanks at the well site until the purchaser retrieves it by tank truck. Direct purchases of our crude oil are made statewide at our well sites by Barrett Oil Purchasing Company. Our natural gas has multiple markets throughout the eastern United States through gas transmission lines. Access to these markets is presently provided by three companies in northeastern Tennessee, Cumberland Valley Resources, NAMI Resources Company, and Tengasco. Local markets in Tennessee are served by Citizens Gas Utility District and the Powell Clinch Utility District. Natural gas is delivered to the purchaser via gathering lines into the main gas transmission line. Surplus gas is placed in storage facilities or transported to East Tennessee Natural Gas which serves Tennessee and Virginia. In fiscal years 2011 and 2010, sales to Barrett Oil Purchasing and Sunoco, collectively, represented approximately 2% and approximately 9%, respectively, of our total revenues and sales to Cumberland Valley Resources, which purchases natural gas produced from a joint venture with Delta Producers, Inc., accounted for approximately 4% of our total revenue for fiscal 2010 and approximately 12% of our total revenue in fiscal 2011.

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

	Year Ended April 30,	
	2011	**2010**
Oil production (Bbls)		

Cook Inlet				
Production (Gross)		312,583		46,445
Average sales price	$	83.43	$	78.76
Average production cost	$	23.03	$	54.05
Appalachian region				
Production (Gross)		28,502		2,945
Average sales price	$	76.25	$	71.33
Average production cost	$	60.23	$	54.64

On November 19, 2010, the Regulatory Commission of Alaska accepted a settlement agreement between CIE and the Cook Inlet Pipe Line Company ("CIPL"). CIPL, a subsidiary of Chevron Pipeline Co., operates a 42-mile pipeline on the west side of Cook Inlet, and is the sole means by which CIE can export its oil production. This settlement reduced transportation costs for all CIE production by $6.57 per barrel to a rate of $8.00 per barrel for the remainder of 2010. The settlement lays out a methodology for determining CIE's future pipeline transportation rates. The rates to be paid by CIE to CIPL during calendar years 2011 through 2014 shall be determined by dividing the agreed annual CIPL revenue requirement of $17.28 million for each year of the term of the Settlement Agreement by the forecasted total annual CIPL throughput. CIE paid for transportation of 260,063 barrels of production in fiscal 2010 and has committed to pay for a minimum of 346,750 barrels in each of the fiscal years 2011 through 2014. Each February, a true-up adjustment for the previous year will be made by dividing the $17.28 million revenue requirement of the pipeline by the actual number of barrels put through the line by all shippers to determine the rate due to CIPL.

We currently pay a minimum of 5% in royalties to the State of Alaska from any oil or gas sold from the West McArthur River Unit and the Redoubt Unit, although with increased production at the West McArthur River Unit these escalate to a maximum of 12.5%. The Redoubt Unit is scheduled to have a royalty rate of 5% until December 2012 when it will increase to 12.5%. We are also obligated to pay Cook Inlet Region, Inc. a 12.5% royalty on any gas sold from the portion of the West Foreland Gas Field located outside of the West McArthur River Unit. Finally, there are overriding royalty interests totaling approximately 12.4% for West McArthur River Unit, 4% for Redoubt Unit, and 5% for the portion of the West Foreland Gas Field located outside the West McArthur River Unit.

Other ancillary services

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

Competition

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

Government Regulation

While the prices of oil and natural gas are set by the market, other aspects of our business and the industry in general are heavily regulated. The availability of a ready market for oil production and natural gas depends on several factors beyond our control. These factors include regulation of production, federal and state regulations governing environmental quality and pollution control, the amount of oil and natural gas available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. State and federal regulations generally are intended to protect consumers from unfair treatment and oppressive control, to reduce the risk to the public and workers from the drilling, completion, production and transportation of oil and natural gas, to prevent waste of oil and natural gas, to protect rights among owners in a common reservoir and to control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies.

Our exploration and production business is subject to various federal, state and local laws and regulations on the taxation of natural gas and oil, the development, production and marketing of natural gas and oil and environmental and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, water discharge, prevention of waste and other matters. Prior to commencing drilling activities for a well, we must procure permits and/or approvals for the various stages of the drilling process from the applicable state and local agencies in the state in which the area to be drilled is located. The permits and approvals include those for the drilling of wells. Additionally, other regulated matters include the following:

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bond requirements in order to drill or operate wells;

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the location of wells;

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the method of drilling and casing wells;

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the surface use and restoration of well properties;

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the plugging and abandoning of wells; and

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the disposal of fluids.

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

CIE has posted $825,000 in state and federal bonds. The Alaska DNR requires $600,000 in bonding to operate of oil and gas leases on state lands, the Alaska Oil and Gas Conservation Commission (AOGCC) requires a $200,000 bond to drill wells in the state, and the U.S. Bureau of Land Management (BLM) requires a bond of $25,000 to operate on federal lands. These bonds are fully funded and are held by the First National Bank of Alaska in certificates of deposit for benefit of the various beneficiates.

CIE has a total of $1,490,000 in designated accounts to satisfy future abandonment obligations. An additional $14,740,000 will need to be placed into escrow over the next eight years to fund various future abandonment liabilities. A $490,000 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 $490,000. 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; $1.5 million was required to cover future abandonment expenses related to the three West Foreland gas wells for benefit of CIRI, of which $1,000,000 has already been funded, and $500,000 will be due December 10, 2011. An additional $750,000 is for future abandonment expenses associated with surface facilities and pipelines for benefit of CIRI and Salamatof, none of which has yet been funded. The account is owed $500,000 pending the resolution between CIRI and Salamatof over who will be the named party for the account. The final $250,000 is payable in May 2012.

In March 2011, CIE entered into a Performance Bond Agreement that set the bond for the Osprey platform at an inflation-adjusted $18 million. The agreement sets a payment schedule totaling $12 million in annual payments between July 2013 and July 2019. An existing interest bearing account containing approximately $6.8 million is to be credited against the inflation-adjusted $18 million liability. Annual payments will be made after 2019 as necessary to the degree that inflation has caused the liability to increase over the amount contained in the funded accounts.

Under the Oil Pollution Act of 1990, CIE is required to fund a citizens advisory group, the Cook Inlet Regional Citizen s Advisory Council, under which its commitment is approximately $55,000 per year.

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

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

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

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

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

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limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and

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impose substantial liabilities for pollution resulting from our operations.

CERCLA, also known as "Superfund," imposes liability for response costs and damages to natural resources, without regard to fault or the legality of the original act, on some classes of persons that contributed to the release of a "hazardous substance" into the environment. These persons include the "owner" or "operator" of a disposal site and entities that disposed or arranged for the disposal of the hazardous substances found at the site. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of our ordinary operations, we may generate waste that may fall within CERCLA's definition of a "hazardous substance." We may be jointly and severally liable under CERCLA or comparable state statutes for all or part of the costs required to clean up sites at which these wastes have been disposed.

We currently lease properties that for many years have been used for the exploration and production of oil and natural gas. Although we have used operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed or released on, under or from the properties owned or leased by us or on, under or from other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose actions with respect to the treatment and disposal or

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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:

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remove or remediate previously disposed wastes, including wastes disposed or released by prior owners or operators,

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clean up contaminated property, including contaminated groundwater; or to perform remedial operations to prevent future contamination, and/or

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clean up contaminated property, including contaminated groundwater; or to perform remedial operations to prevent future contamination.

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

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

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

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

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

In addition, our existing and proposed operations could result in liability for fires, blowouts, oil spills, discharge of hazardous materials into surface and subsurface aquifers and other environmental damage, any one of which could result in personal injury, loss of life, property damage or destruction or suspension of operations. We

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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.

Consultants

We have entered into two agreements with Bristol Capital, LLC, an affiliate of Bristol Capital Advisors, LLC which is the investment advisor to Bristol Investment Fund, Ltd. (Bristol), both an investor in a securities offering we undertook in fiscal 2010 and one of the lenders in our recent debt financing, including the following:

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On March 12, 2010, we entered into a one year consulting agreement with Bristol under which it agreed to assist us with strategic planning, management and business operations, introductions to further our business goals, advice and services regarding our growth initiative and other similar services we might request. As compensation for these services we granted Bristol a five year warrant to purchase 300,000 shares of our common stock at an exercise price of $2.50 and five year options to purchase an additional 300,000 shares of our common stock at an exercise price of $2.50 per share. Bristol is contractually limited under the terms of this consulting agreement so that its beneficial ownership of our common stock cannot exceed 9.9% of our outstanding shares. It may waive this limitation upon 61 days notice to us. This agreement was renewed and extended for an additional one year term by an amendment executed April 29, 2011. The amendment revised the compensation issuable to Bristol by removing the exercise price reset provision. We agreed to issue 300,000 additional warrants as consideration for the second year. The additional warrants were granted on May 22, 2011. Additional consideration was also provided in the form of a finder s fee of three percent (3%) for any mezzanine debt financing secured by us during the term of the agreement, including 3% of the initial borrowing base of $35 million in the Loan Agreement with Guggenheim. See exhibit 10.49 filed with the current report on June 17, 2011.

We agreed to pay all out-of-pocket expenses incurred by Bristol under this agreement, subject to our prior approval. The agreement also contains customary indemnification and confidentiality provisions.

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On April 26, 2010, we entered into a finder s agreement with Bristol pursuant to which on our behalf it has commenced preliminary discussions with two parties regarding our possible acquisition of certain specified assets. We agreed that if within two years from the date of the agreement we should enter into a definitive agreement with either named party or any of their affiliates for the acquisition of these assets, we will pay Bristol a finder s fee of either an assignment of 5% of the interest in the assets or shares of our common stock valued at 5% of the aggregate purchase price at its election. We also agreed to pay a fee equal to 5% of the transaction value. If the efforts by Bristol on our behalf should result in a joint venture or similar partnership related to these assets, we agreed to pay it a finder s fee of 5% of the anticipated economic value of such an agreement.

Employees

At April 30, 2011, we had 70 full-time and one part-time employee.

Our history

We were incorporated in the State of Delaware in November 1985 originally under the name Longhorn Development Company, Inc. for the purpose of searching out and acquiring or participating in a business or business opportunity. In

August 1988 we changed our name to Single Chip Systems International, Inc. In August 1988 we acquired all of the issued and outstanding securities of Single Chip Systems, Inc., a California corporation, in exchange for shares of our common stock. Our then current officers and directors resigned and the officers and directors of Single Chip Systems, Inc. were appointed officers and directors of our company. Prior thereto, on July 1, 1988, Single Chip Systems, Inc. had entered into a technology utilization license agreement with Ramtron International Corporation which granted Single Chip Systems, Inc. the royalty-bearing, non-exclusive licenses to use the ferroelectric technologies and the certain trademarks in production, manufacture and sales of Single Chip Systems, Inc. products. We failed to receive any economic benefit related to the license agreement and we recorded a $100,000 loss on the license agreement in the period ended December 31, 1988.

Thereafter, we had no business or operations until the transaction in January 1997 as hereinafter described. In May 1996 we changed our name to Triple Chip Systems, Inc.

Mr. Deloy Miller formed Miller Petroleum, Inc. (pre-merger Miller), a company which is the basis of our current operations, in January 1978. In January 1997, we closed an Agreement and Plan of Reorganization with pre-merger Miller whereby we issued 5,582,535 shares of our common stock in exchange for all of the outstanding common stock of pre-merger Miller. The acquisition was accounted for as a recapitalization of our company because the shareholders of pre-merger Miller controlled the company after the acquisition. Following the transaction, in January 1997, pre-merger Miller was merged into our company and we changed our name to Miller Energy Resources, Inc. in conjunction with the re-domestication of our company into the State of Tennessee.

Effective June 13, 2008, we entered into an agreement with Atlas Energy Resources, LLC under which we assigned it:

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an unencumbered, undivided 100% working interest and an 80% net revenue interest in and to the oil and gas lease comprising 27,620 acres known as Koppers North and Koppers South and located in Campbell County, Tennessee; and an unencumbered, undivided 100% interest and an 82.5% net revenue interest (net of a 5% overriding royalty interest to us) in and to the oil and gas lease comprising 1,952 acres adjacent to Koppers North and Koppers South and located in Campbell County, Tennessee; and

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an unencumbered, undivided 100% working interest and an 80% net revenue interest in eight gas wells on Koppers South. We have the option to repurchase the wells within one year from the closing date or within 30 days after the pipeline to be built by Atlas Energy has been completed and is ready to accept gas for transport.

The transaction was subject to unwinding pursuant to a pending litigation between our company and CNX Gas Company LLC as disclosed in Item 3. Legal Proceedings. Transferring any of the leases or any interest therein was also subject to a 60-day standstill period which has since expired. The aggregate consideration for the assignment of the leases and wells to Atlas Energy was $19,625,000, $9,025,000 of which was paid us and the remaining $10,600,000 of which was paid directly to Wind City Oil & Gas, LLC in consideration of a settlement of claims between Wind City and our company described below.

As part of the transaction, we also agreed to contract with Atlas Energy for two rigs for two years to drill wells, commencing a significant commitment to contract drilling. To give Atlas Energy the level of service required, during the first quarter of fiscal 2009 we acquired a 2007 COPCO Model RD III drilling rig and related equipment drilling rig from Atlas to assist in drilling the wells. For two years after the closing date, Atlas Energy granted us the opportunity to bid on any other drilling or service work that Atlas Energy bids on in the State of Tennessee. In addition, we entered into:

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a natural gas transportation agreement with Atlas Energy which provides us access to the Atlas Volunteer Pipeline, to the extent that capacity is available, on substantially the same terms as those offered to the producers delivering into the system; and

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a natural gas processing agreement pursuant to which Atlas Energy will provide gas processing services to us on substantially the same terms as those services are provided to other producers delivering gas into the Atlas Volunteer

Pipeline and deliver back to us gas with a heating value of 1,100 BTUs per cubic foot.

Effective June 13, 2008, we also settled all issues and controversies with Wind City Oil & Gas, LLC, Wind Mill Oil & Gas, LLC and Wind City Oil & Gas Management, LLC. Under the terms of the settlement, we paid Wind City $10,600,000 for the re-purchase of 2,900,000 shares of our common stock and reacquisition of all leases previously assigned by us to Wind City or the related parties, all wells and equipment associated with these leases, all pipeline rights and rights of way, all contract rights, and all other equipment, property and real property rights. As set forth above, we used a portion of the proceeds from the Atlas Energy transaction to pay the settlement amounts.

On June 8, 2009, we acquired oil and gas properties from KTO, an unrelated third party, including KTO's:

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undivided interest in approximately 170 oil and gas wells in Morgan, Scott and Fentress counties in Tennessee, together with all property, fixtures and improvements, leasehold interest and contract rights related to these wells;

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undivided interest in approximately 35,325 acres of oil and gas leases in Scott and Morgan counties, Tennessee;

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interest in an operating agreement with the Tennessee State Energy Development Partnership;

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interest in a gas gathering pipeline system; and

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other rights related to these assets, including royalty and working interests, licenses, permits, and similar incidental rights.

As consideration for these assets we issued KTO 1,000,000 shares of our common stock valued at $320,000 and we granted the seller piggy-back registration rights covering these shares. Pursuant to Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 805, *Business Combinations* , we valued these oil and gas properties at $1,310,019 and recorded a before-tax gain on the transaction of $990,019.

On June 18, 2009, we acquired 100% of the stock of ETC and 100% of the membership interests in LLC from the owners of these entities. Pursuant to ASC 805, we have valued the assets for these companies at $1,862,369 and have recorded a before-tax gain on the transaction of $1,409,609. As consideration for these companies we issued the sellers, who were unrelated third parties, 1,000,000 shares of our common stock valued at $250,000. We granted the sellers registration rights covering these shares.

Under the terms of the stock purchase agreement, the sellers agreed not to engage in oil and gas operations for a period of three years following the closing date. We also agreed that each of the sellers, Messrs. Eugene D. Lockyear, Douglas G. Melton and Jerry G. Southwood, would continue their employment with the acquired companies for at least three years from the closing date of the transaction at their same compensation and benefit levels to which they were entitled in May 2009. In addition, Mr. Lockyear was appointed Vice President of Operations of our company. We also agreed that if any or all of the sellers incur any income tax liability as a result of the receipt of the above shares, we would pay a bonus to such seller equal to the amount of his tax liability within 30 days from the request of the sellers.

On December 10, 2009, CIE acquired, through a Delaware Chapter 11 bankruptcy proceeding, former Alaskan operations of Pacific Energy Resources. The acquisition included onshore and offshore oil and gas production facilities. We acquired total reserves of over 13.2 million barrels of oil and 15.5 BCF of natural gas, including total proved reserves of 5.6 million barrels of oil and 3.7 BCF of natural gas as reported by the Pacific Energy in their most recent reserve report of January 1, 2009. The fair value of the Alaska reserves that we acquired is over $327 million dollars, including $119 million dollars of proven reserves, $185 million of probable reserves and $23 million of possible reserves, as stated in its reserve report as of January 1, 2009. The purchased operations included the West McArthur River oil field, the West Foreland natural gas field, and the Redoubt unit with the Osprey offshore platform, all located along the west side of the Cook Inlet. We also acquired 602,000 acres of oil and gas leases, including 471,474 acres under the Susitna Basin Exploration License as well as completed 3D seismic geology and other production facilities, together with:

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all easements, wells and tangible assets,

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all oil and gas or proceeds from the sale of oil and gas produced in connection with the acquired assets from the closing date,

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all contracts, unitization, communization and pooling declarations, orders and agreements,

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all permits, records, royalty interests, partnership and joint venture interests,

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to the extent assignable, all rights to indemnities,

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all leases for real property used by the seller in connection with the operation of the acquired assets,

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escrow accounts and bonds deposited with government entities with respect to the acquired assets,

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all surety bonds, plugging bonds, abandonment bonds, standby trust agreements, escrow accounts for plugging, abandonment, decommissioning, removal and restoration obligations, together with security deposits,

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all imbalances owed to the sellers by a third party at the closing, as well as all oil and gas in pipelines and tanks or held by or for the account of the sellers related to the assets acquired, and

In this transaction, CIE assumed certain liabilities related to the acquired assets, including:

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all liabilities associated with or arising out of the ownership of, or operation of, the assets after the closing date,

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all environmental liabilities with respect to the acquired assets,

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all accounts payable from the closing date,

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all royalty obligations associated with or related to the acquired assets after the closing date,

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all claims arising out of the ownership or operation of the acquired assets after the closing date,

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all plugging, abandonment, decommissioning, removal and/or restoration liabilities associated with or arising from the acquired assets with respect to all periods prior to, on or after the closing date,

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permitted encumbrances and imbalances owed by the sellers to third parties, and

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post-petition suspended royalties maintained by Royalty Distributors Inc.

At closing we paid Pacific Energy Resources $2.25 million and provided $2.22 million for bonds, contract cure payments and other federal and State of Alaska requirements to operate the facilities. Under the terms of the purchase agreement, Donkel Oil & Gas, LLC was granted a 0.5% overriding royalty interest in the oil and gas leases acquired by CIE, a 1% overriding royalty interest on Pacific Energy s working interest in all exploration oil and gas leases acquired by CIE in the transaction, and a 0.5% overriding royalty interest owned by Pacific Energy on the leases that comprise the Cosmopolitan Unit and Falls Creek. In addition, Donkel Oil & Gas, LLC received a 1% overriding royalty interest on CIE s working interest in any oil and gas lease which arises from certain properties included in an exploration license, which includes one lease, together with a 1% overriding royalty on our working interest in two additional oil and gas leases.

On December 10, 2009, we acquired 100% of the membership interests in CIE. As consideration, we issued the sellers, who were unrelated third parties, 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. In addition, we are required to deliver $250,000 in cash to satisfy certain expenses as well as reimbursement for reasonable out of pocket expenses. Under the terms of the stock purchase agreement, the sellers agreed not to engage in competing oil and gas operations for a period of three years following the closing date. We also agreed that each of the sellers, Messrs. David M. Hall, Walter J. Wilcox II and Troy Stafford, would continue their employment with the acquired company for at least three years from the closing date of the transaction at their specifically defined compensation and benefit levels. In addition, Mr. Hall was appointed as a member of our Board of Directors and as Chief Executive Officer of CIE.

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

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 a total cash consideration of $384,000. We have also agreed to indemnify the sellers of the membership interests with respect to their guaranties of the construction loans held by the Pellissippi Pointe entities, but have not become direct guarantors of the loans ourselves. The gross outstanding amount under the loans is $5,193,699. The Pellissippi Pointe entities own two office buildings in West Knoxville, Tennessee. We will be moving our corporate headquarters into the building located at 9721 Cogdill Road, Knoxville, TN as soon as the space is ready for our occupancy. We have executed a five year lease for the space, and with the addition of us, the building will be fully occupied by tenants. The forms of assignment of membership interest, and the lease are filed as exhibits to this annual report.

ITEM 1A.

RISK FACTORS.

Risks Related to Our Business

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

We reported an operating loss of approximately $15.1 million in fiscal 2011 and approximately $11.3 million in 2010. Our net loss of approximately $4.4 million in 2011 is primarily attributable to the operating loss, partially offset by an approximate $4.9 million in other income and a $5.7 million benefit from income taxes. Our net income of approximately $250.9 million in fiscal 2010 is attributable to $461.1 million in gains on the acquisitions of the Alaska and Tennessee businesses. As a result of the continued expansion of our business during fiscal 2011, our operating expenses presently exceed our revenues. We anticipate that our operating expenses will continue to increase as we fully develop our operations following the acquisition of the Alaskan assets. Although we expect an increase in our revenues to come from these development activities, we will continue depleting our cash resources to fund operating expenses until such time as we are able to significantly increase our revenues. We may have to reduce our expansion efforts if we have not seen an increase in revenues in the next few months. While we believe that our revenue will increase and exceed our operating expenses, there are no assurances that we will develop profitable operations.

We will be subject to new debt costs under the terms of our Credit Facility with Guggenheim, Citibank N.A., and Bristol Investment Fund, Ltd. Monies borrowed are subject to an interest rate of the higher of 9.5% or the prime rate plus 4.5% per annum. In addition, we are required to pay an additional make-whole payment upon termination or payment in full of the credit facility, bringing the effective interest rate to 25% to 35%, depending on the timing of repayment. In January 2012, we will be required to devote 90% of our consolidated monthly net revenues toward paying back outstanding amounts under the credit facility.

As described later in this report, in June 2011 we entered into a Loan Agreement with Guggenheim Corporate Funding, LLC, Citibank N.A., and Bristol Investment Fund, Ltd., under which a credit facility of up to $100 million has been made available to us. At July 15, 2011 we had drawn approximately $10.875 million under the Credit Facility. Any monies borrowed by us will bear interest at mezzanine rates and will be subject to a make whole premium that could amount to as much as 35%, depending on the date we repay the Credit Facility. These debt costs may be substantial, and will adversely impact our results until such time as the facility has been repaid. In addition, beginning in January 2012 we are required to use 90% of our consolidated monthly net revenues (after deducting general and administrative expenses up to certain limitations) to repay the amounts outstanding under the Credit Facility. If we have not repaid the facility in full prior to January 2012, we could be forced to reduce our general and administrative expenses. This could mean that we would need to make reductions in salaries and/or staffing, which could impact our ability to operate our business and achieve our aggressive plan for development. Depending on our success in increasing revenue and/or raising equity, the facility may not be repaid prior to January 2012.

The restatement of our historical financial statements has already consumed, and may continue to consume, a significant amount of our time and resources and may have a material adverse effect on our business and stock price.

As described elsewhere in this report, we have restated our consolidated statement of cash flows for the year ended April 30, 2011 as well as restated our unaudited consolidated financial statements for our first three quarters of fiscal year 2011. The restatement process was highly time and resource-intensive and involved substantial attention from management and significant accounting costs. Furthermore, we cannot guarantee that we will have no inquiries from the SEC or the NYSE regarding our restated financial statements or matters relating thereto. Any future inquiries from the SEC as a result of the restatement of our historical financial statements will, regardless of the outcome, likely consume a significant additional amount of our resources in addition to those resources already consumed in connection with the restatement itself. Further, many companies that have been required to restate their historical financial statements have experienced a decline in stock price and stockholder lawsuits related thereto.

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

In connection with a review of our Annual Report on Form 10-K for the year ended April 30, 2010, the staff of the SEC has concluded that we omitted required audited financial statements of three acquired businesses, including ETC, KTO and CIE, from our Forms 8-K reporting these acquisitions. Until such time as we file audited financial statements, the staff has advised us it considers those Forms 8-K to be materially deficient and that it will not waive these financial statement requirements. As a result, we are unable to utilize a short-form registration statement on SEC Form S-3. In addition, until such time as the audited financial statements of the acquired businesses are filed, the staff of the SEC has advised us it will not declare effective any registration statements or post-effective registration statements. We believe that the acquisitions of ETC and KTO were not material and did not rise to the level which required audited financial statements. Further, the CIE assets and liabilities were acquired through bankruptcy and via the newly formed CIE. These oil and gas producing assets were not operational for several months prior to the acquisition, were consolidated in, as they were part of a larger enterprise, and as accounting records were not adequately maintained by Pacific Energy Alaska Operating LLC and Pacific Energy Alaska Holdings, we were unable to carve out historical operational results on these specified assets. At the time of acquisition of these assets, we determined that the resulting assets and liabilities were not a separate business for purposes of preparing pro forma financials with historical results for the past year and / or related stub period and our Current Report on Form 8-K/A as filed included only a pro forma balance sheet to reflect the acquisition. We do not believe we will be able to obtain audited financial statements on this acquisition for the periods provided in Regulation S-X.

In addition, under the terms of the registration rights agreement for our 2010 offering, we are required to keep the registration statement current which registered the resale of the shares sold in that private offering effective until either all of the shares have been sold or Rule 144 is available to the holders without our compliance with the current public information requirements of Rule 144. As a result of our current inability to file a post-effective amendment to that registration statement, we will begin accruing registration rights penalties which will adversely impact our results in future periods.

We expect to continue our discussions with the staff of the SEC regarding this matter in an effort to obtain waivers to the financial statement requirements of Form 8-K for these acquisitions. There are no assurances we will be successful in our efforts. Until such time, if ever, that we are able to obtain a waiver from the SEC on the requirement to include audited financial statements in these Forms 8-K, our ability to register additional capital will be materially impacted.

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 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. Our financial statements contained herein do not contain any reserves for any potential damages associated with this pending litigation. If we should not be successful in our defense of this pending litigation, our results of operations in future periods could be materially adversely impacted.

Our ability to draw under the Credit Facility is subject to a 15 business day waiting period and subject to the Lenders approval in their sole discretion.

When we wish to make a draw under the Credit Facility, we are required to file a borrowing request in a particular form outlining the monies requested and their intended use. The lenders have 15 business days during which to assemble the funds requested. We may not be able to identify our need for capital three weeks in advance, and the timing requirement under the loan may hinder our ability to operate at the pace we are used to. There is no guarantee that the request will be approved at all as the required lenders may approve or deny the borrowing request in their sole and absolute discretion.

CIE s operations are subject to oversight by the Alaska DNR and the CIE oil and gas leases could be terminated if it fails to uphold the terms of the Assignment Oversight Agreement. If these leases were terminated, we would be unable to continue our operations as they are presently conducted and could be liable for significant additional costs associated with decommissioning the Osprey platform.

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 between these two parties dated November 5, 2009. The performance bond is intended to ensure that CIE has sufficient funds to meet its dismantlement, removal and restoration obligations under the applicable agreements, leases, and state laws and regulations. The Performance Bond Agreement applies only to the Redoubt Unit and Redoubt Shoal Field, and sets forth an amount of $18.0 million for the bond. The Agreement includes a funding schedule, which requires payments annually on July 1, beginning in 2013, of amounts ranging from $1.0 million to $2.5 million per year, and totaling $12.0 million. The Agreement also clarifies that approximately $6.8 million as of April 30, 2011 from a bond funded by the previous owner and held in a State Trust Account since the sale of the assets is included in the account holding the performance bond for our dismantlement, restoration, and rehabilitation obligations under the Agreement. The monies deposited under the Agreement may be held in the State Trust Account or in private bank or surety company accounts. Until the performance bond is fully funded, all interest on either account will be retained in the account.

If the State Trust Account, which is currently an interest-bearing account, becomes a non-interest bearing account, CIE may transfer the funds to a private account with the DNR Commissioner s consent. If CIE is more than 10 days late with a payment to the State Trust Account or more than 10 days late providing proof of a payment into a private account, the State will assess a late payment fee of $50,000. Our obligation to pay one or more late payment fees 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.

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.

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.

Approximately 75% of our total estimated proved reserves at April 30, 2011 were proved undeveloped reserves. In addition, there are no assurances that probable and possible reserves will be converted to proved reserves.

Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve engineer reports assumes that substantial capital expenditures are required to develop such reserves. Although cost and reserve estimates attributable to our natural gas and crude oil reserves have been prepared in accordance with industry standards, we cannot be sure that the estimated costs are accurate, that development will occur as scheduled or that the results of such development will be as estimated. We also have a significant amount of unproved reserves at April 30, 2011. There is significant uncertainty attached to unproved reserve estimates, which include probable and possible reserves. Proved reserves are more likely to be produced than probable reserves and probable reserves are more likely to be produced than possible reserves. There are no assurances that we can develop probable or possible reserves into proved reserves, or that if developed, probable reserves will become producing reserves to the level of the estimates.

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.

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 oil spill, the costs for complying with government regulation could increase.

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

- acquire permits before commencing drilling;
- restrict spills, releases or emissions of various substances produced in association with our operations;
- limit or prohibit drilling activities on protected areas such as wetlands or wilderness areas;

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take reclamation measures to prevent pollution from former operations;

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take remedial measures to mitigate pollution from former operations, such as plugging abandoned wells and remedying contaminated soil and groundwater; and

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take remedial measures with respect to property designated as a contaminated site.

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

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

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

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

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

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.

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

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

Our 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.

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

Risks Related to the Ownership of Our Securities

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

At April 30, 2011 we have common stock warrants outstanding to purchase an aggregate of 85,400 shares of our common stock with an average exercise price of $1.74 per share which are exercisable on a cashless basis. This means that the holders, rather than paying the exercise price in cash, may surrender a number of warrants equal to the exercise price of the warrants being exercised. It is possible that the warrant holders will utilize the cashless exercise feature which will deprive us of additional capital which might otherwise be obtained if the warrants did not contain a cashless feature.

A large portion of our outstanding common shares are restricted securities and we have outstanding options, warrants and purchase rights to purchase approximately 35% of our currently outstanding common stock. The exercise of these options, warrants and purchase rights would be dilutive to our current shareholders.

At July 15, 2011 we had 40,559,251 shares of common stock outstanding together with outstanding options and warrants to purchase an aggregate of 13,975,955 shares of common stock at exercise prices of between $0.01 and $6.94 per share. Of our outstanding shares of common stock at July 15, 2011, approximately 11,135,338 shares are "restricted securities." Future sales of restricted common stock under Rule 144 or otherwise could negatively impact the market price of our common stock. In addition, in the event of the exercise of the warrants and options, the number of our outstanding common stock will increase by approximately 34%, which will have a dilutive effect on our existing shareholders.

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

As of April 30, 2011, we have warrants with full-ratchet or reset provisions, which means that the exercise or conversion price adjusts to pricing in subsequent sales or issuances. These instruments require liability classification and mark to market accounting with changes in the estimated fair value recorded to our consolidated statement of operations in Loss on derivatives, net. As of April 30, 2011, we have recorded a long-term derivative liability of

$2,732,659. In addition, we recognized a non-cash gain on warrant derivative securities of $1,297,544 in fiscal 2011, as compared to a non-cash loss of $13,299,430 in fiscal 2010. In fiscal 2011, we also recorded a loss on commodity derivatives of $2,305,118, resulting in a net loss on derivatives of $1,007,574. Beginning in the first quarter of fiscal 2012, we expect to record either a gain or loss based upon the market price of our common stock. The amount of quarterly non-cash gains or losses we will record in future periods is unknown at this time as the measurement is based upon the fair market value of our common stock on the measurement date. It is likely, however, that these non-cash gains or losses will continue to have a material impact on our financial results in future periods.

ITEM 1B.

UNRESOLVED STAFF COMMENTS.

Not applicable to a smaller reporting company.

ITEM 2.

PROPERTIES.

Our executive offices presently comprise approximately 4,968 square feet and 6,600 square feet for the shop building, both located on 14.05 acres of land that we own in Huntsville, Tennessee. We own or rent facilities in the following locations:

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Knoxville, Huntsville and Sunbright, Tennessee

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Anchorage, Alaska

We also own a membership interest in each of two limited liability companies that own two office buildings in West Knoxville. Once the space is ready for our occupancy, we intend to move our corporate headquarters into one of those buildings in order to accommodate the growth of our company and additional employees.

Production facilities

CIE operates two onshore production facilities and one offshore platform located on or near the West Foreland field, which is a small peninsula located in a remote area on the west side of Cook Inlet. The West Foreland is accessible by barge and fixed wing aircraft, and is not tied in with the Alaskan road system or electrical grid. CIE maintains its own 10-mile road system and local electrical system.

The West McArthur River Unit Production Facility is one of our two onshore production facilities. It is located 3.5 miles south of Chevron's Trading Bay Production Facility, which is near the site of the local airstrip and barge landing. The West McArthur River Unit Production Facility can process 5,000 barrels of oil and seven MMcf of natural gas per day, generate three megawatts of electricity and contains 10,000 barrels of on-site tankage. The West McArthur River Unit Production Facility also includes our onshore camp, which provides housing and life support facilities sufficient for 65 people.

The Kustatan Production Facility is our other onshore production facility. This facility can process 30,000 barrels of oil a day, generate 16 megawatts of electricity, treat up to 20 MMcf of natural gas and contains 50,000 barrels of on-site tankage. The facility, which is located five miles south of The West McArthur River Unit Facility, is currently supporting our off-shore activity.

Oil and gas properties

Information on our oil and gas properties appears earlier in this report and in Notes 1, 2, 5 and 17 of Notes to Consolidated Financial Statements in this annual report.

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

On May 17, 2011 we were served with a lawsuit filed in the United States District Court for the Eastern District of Tennessee at Knoxville by Troy D. Stafford, the former Chief Financial Officer of our wholly owned subsidiary, CIE, LLC (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 warrant and violated a duty of good faith and fair dealing. The suit seeks damages in excess of $3,000,000, which includes $2,686,700 of damages for loss of vested warrants. We believe the all of the asserted claims are baseless, particularly in view of the fact that we issued the warrants in accordance with the terms of the PSA. We believe that we had appropriate cause to fire Mr. Stafford after discovering that he had breached certain representations and warranties in the PSA, and had acted in violation of our Code of Conduct. We intend to vigorously defend this action.

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 CIE, LLC. The Plaintiff alleges three causes of action against the Defendants: (1) breach of contract, (2) unfair enrichment, and (3) breach of the implied covenant of good faith and fair dealing. The case seeks damages in warrants to purchase our common stock and monetary damages for certain fees and expenses. The Sale Agreement with David Hall, Walter JR Wilcox, and Troy Stafford dated December 10, 2009 contains indemnification provisions relevant to this claim. We have retained counsel and are currently drafting a responsive pleading.

On October 8, 2009 we filed an action styled Miller Petroleum, Inc. v. Maynard, Civil Action No. 9992 in the Chancery Court for Scott County, Tennessee, seeking a declaratory judgment that there has been continuing commercial production of oil, and oil and gas lease owned by us is still in full force and effect. The defendant filed an Answer and Counterclaim, seeking in the Counterclaim a declaration that the oil and gas lease has expired. Although no compensatory monetary damages have been sought against us, the Counterclaim does seek attorney fees, expenses and costs. On October 27, 2010, a temporary injunction was granted allowing us access to the property at issue in this case. We are presently conducting discovery.

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.

(REMOVED AND RESERVED).

PART II

ITEM 5.

MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

On April 12, 2011 our common stock 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 reported high and low sales prices for the common stock as reported on the various markets on which our stock was quoted during the periods indicated are shown below. The quotations reflect inter-dealer prices, without retail mark-up, markdown or commission, and may not represent actual transactions.

		High		Low
2010				
First quarter ended July 31, 2009	$	0.38	$	0.22
Second quarter ended October 31, 2009	$	0.70	$	0.28
Third quarter ended January 31, 2010	$	2.95	$	0.60
Fourth quarter ended April 30, 2010	$	6.60	$	1.95
2011				
First quarter ended July 31, 2010	$	7.48	$	4.40
Second quarter ended October 31, 2010	$	6.31	$	4.05
Third quarter ended January 31, 2011	$	5.69	$	4.20
Fourth quarter ended April 30, 2011	$	6.11	$	4.80

On July 15, 2011, the last sale price of our common stock as reported on the NYSE was $8.02. As of July 15, 2011, there were approximately 355 record owners of our common stock.

Dividend Policy

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.

ITEM 6.

SELECTED FINANCIAL DATA.

Not applicable to a smaller reporting company.

ITEM 7.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Overview

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

Currently, we are continuing to develop the acreage we acquired during fiscal 2010 and 2011. These acquisitions have grown our Alaskan acreage position to approximately 649,507 acres of gross oil and gas leases and exploration license rights (630,462 net acres), which includes 471,474 acres under the Susitna Basin Exploration License No. 2 and 62,909 acres under the Susitna Basin Exploration License No. 4 (also referred to as our North Susitna Exploration License). We are continuing to assess and add strategic acreage to our Alaska leases and licenses. Our Tennessee leases consist of 37,916 acres, making our total gross acreage 687,423 acres.

During the year ended April 30, 2011, we began completion work on three Alaska wells that were previously shut in, and we have completed work on two of these wells. We capitalized approximately $8.6 million of costs associated with those efforts. In addition, we plan to recomplete eight previously shut in wells in the next three to six months.

Our management is focusing the majority of its efforts on growing our company. In addition to raising capital we are continuing to focus our short-term efforts on two distinct areas:

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increasing our overall oil and gas production through maintenance and repairs of nonperforming or underperforming oil and gas wells, and

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organically growing production through drilling for our own benefit on existing leases and under license rights, leveraging our 100,000 plus well log database and approximately 700,000 acres which are either under lease or part of the Susitna Basin Exploration License, with a view towards retaining the majority of working interest in the new wells.

Our ability to implement one or more of these goals in a timely manner has been greatly increased by our securing of a $100 million credit facility with an initial borrowing base of $35 million. These funds will be used to rework certain wells, to drill new wells, and to purchase a custom drilling rig that we expect will allow us to bring our Osprey offshore platform into full production. As of June 30, 2011, two wells have been reworked on the platform by replacing their electronic submersible pumps. The wells, RU-1 and RU-7, are producing above the expected rates of 200 bbls/day. As of June 30, 2011, the wells have averaged 335 bbls/day (RU-1) and 245 bbls/day (RU-7).

During fiscal 2011 and the first quarter of fiscal 2012 we had a number of significant accomplishments:

FINANCING:

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On December 27, 2010, we obtained a $5,000,000 line of credit from PlainsCapital Bank that provided financial flexibility to us while we continued to seek longer-term financing.

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On June 13, 2011, we closed on a $100 million credit facility with an initial availability of $35 million with Guggenheim Corporate Funding, LLC, Citibank, N.A., and Bristol Investment Fund, Ltd. The PlainsCapital facility allowed us to stay on track with our development plans as we sought the larger, longer-term facility. We used a portion of the proceeds from the Credit Facility to satisfy the PlainsCapital line of credit in June 2011.

LAND AND DEVELOPMENT:

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We entered into our Performance Bond Agreement regarding the Redoubt Offshore assets with the Alaska DNR, and received approval of CIE s Amended Redoubt Unit Plan of Development, which was approved on February 17, 2011, as well as approval of the Redoubt Redevelopment Plan, which was approved March 16, 2011. This agreement and these approvals allowed us to restart the operation of our Osprey offshore Platform in March 2011. Since the platform has come back online, we have successfully reworked two wells on it, substantially adding to our production in Alaska.

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In June 2011 we contracted with Voorhees Equipment and Consulting, Inc. for the custom construction and purchase of a drilling rig for the Osprey platform for $17.9 million. We expect the rig to be moved to arrive in Alaska in September 2011 and become operational in November 2011.

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In June 2011, we signed a five year lease for new office space for our corporate headquarters, and acquired a minority ownership interest in the entities that own the building that will be our new home. This lease and acquisition should allow us to meet our demands for increased space for our growing team of employees.

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We were the successful bidder on additional acreage in Alaska that complements our current acreage, adding another 17,027 acres. This acreage was awarded with an effective date of April 1, 2011.

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We were awarded our North Susitna exploration license (No. 4), and along with leases won at auction, these new properties result in an increase of 79,936 acres in our gross acreage to 687,423 acres

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We secured a three-year extension of the Susitna Basin Exploration License No. 2, which is comprised of 471,474 acres. The terms of the extension require us to spend an aggregate of $750,000 over the next three years under a new work commitment. This extension will allow us to identify the most valuable acres covered by the license and convert only the most promising prospects to leases at the expiration of the license.

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We strategically assigned four leases with a total gross acreage of 8,828.5 acres to Buccaneer Alaska for total consideration of $12,500, as of June 1, 2010. We retained the overriding royalty interests in each lease including 2% in the ADL-391108 and ADL-17595-2 leases and 4% in the ADL-390379 and ADL-390370 leases. If Buccaneer Alaska fails to drill at least one well on the leased acreage by 2013, we will be entitled to a payment of $303,613, and may choose to cause Buccaneer Alaska to assign any of the leases to us that remain active.

SETTLEMENT OF DISPUTES:

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We settled two of our significant lawsuits, entering into a settlement agreement with Petro Capital III, LP and Petro Capital Advisors, LLC and with Prospect Capital Corporation; which resolved litigation that had been pending in federal court in Texas. The settlement agreement resulted in our issuing a total of 518,510 shares of our common stock to Petro Capital III, LP and Petro Capital Advisors, LLC. We also settled similar claims with Prospect Capital Corporation. We issued a total of 2,013,814 shares of our common stock to Prospect Capital Corporation upon the cashless exercise of certain warrants. In addition to the attorney fee savings and certainty that comes from the settlement and dismissal of the Petro lawsuit and Prospect claims, we have eliminated a substantial amount of the derivative liability that we had booked as a result of the anti-dilution clause in the warrants at issue in this matter. These warrants accounted for the majority of our long-term derivative liability, and their elimination has contributed in a decrease in our total derivative liability from $16,897,275 at April 30, 2010 to $5,037,777 at April 30, 2011. On January 28, 2011, we entered into a settlement agreement with Gunsight Holdings, LLC. The lease in dispute in the lawsuit was declared to be in full force and effect, and we agreed to drill at least one well on the property subject to the lease each year for the next four years.

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We reduced our transportation costs in Alaska substantially by settling a tariff dispute. On November 19, 2010, the Regulatory Commission of Alaska accepted a settlement agreement between CIE and the Cook Inlet Pipe Line Company ("CIPL"). CIPL, a subsidiary of Chevron Pipeline Co., operates a 42-mile pipeline on the west side of Cook Inlet, and is the sole means by which CIE can export its oil production. This settlement reduced transportation costs for all CIE production by $6.57 per barrel to a rate of $8.00 per barrel for the remainder of 2010. On February 15, 2011, we received a cash payment of approximately $1,500,000 pursuant to the true-up mechanism in the settlement agreement. CIPL retained another $250,000 that was credited toward the costs of our future shipments.

CORPORATE GOVERNANCE and LEADERSHIP:

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We moved the primary listing of our common stock from the NASDAQ Global Market to the New York Stock Exchange on April 12, 2011.

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On January 17, 2011 we added to our Board of Directors an experienced oil and gas accounting executive who has over 35 years of accounting and financial experience with an emphasis in the oil and gas business, and we appointed him as chairman of our Audit Committee on March 11, 2011.

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We held our annual shareholders meeting for fiscal 2010 on March 11, 2011. At that meeting the current members of our Board were re-elected, we adopted a stock plan compliant with Section 162(m) of the Internal Revenue Code to allow us to deduct certain compensation under the exemption in that section, changed our name officially to Miller Energy Resources, Inc., and adjusted the quorum required for shareholders meetings going forward.

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We entered into a revised employment agreement with our CEO, Scott Boruff, and a new employment agreement with our CFO, Paul Boyd, ensuring continuity in our management. In early fiscal 2012, we hired Director David Voyticky as our President. Along with Founder, Chairman of the Board, and Chief Operating Officer Deloy Miller and CIE CEO David Hall, we have assembled and retained a management team to lead us into our next phase of development.

Results of Operations

Fiscal 2011 as compared to fiscal 2010.

Fiscal 2011 as compared to fiscal 2010 was a year of growth and development. We recorded a loss of $3,879,749, for fiscal 2011 which compares to net income of $250,940,568 for fiscal 2010. As seen below, if you exclude interest income and expense, income tax expense and depletion, depreciation and amortization (DD&A) from the numbers, fiscal 2011 shows this adjusted earnings before interest, income taxes, depreciation, depletion and amortization (EBITDA) to be a positive $3,142,532 as compared to an EBITDA of $439,172,941 for fiscal 2010. Revenues increased $16,974,865 between the years while costs and expenses increased $20,744,218. Other income dropped significantly from $446,930,429 in fiscal 2010 to $4,921,656 in fiscal 2011 as fiscal 2010 had large one-time acquisition gains driving this total as compared to fiscal 2011. The major components of our Consolidated Statement of Income for fiscal 2011 and 2010 are as follows:

	For the Year Ended April 30, 2011	2010	% Change
Revenues	$ 22,841,869	$ 5,867,004	289%
Costs and expenses	(37,924,325)	(17,180,107)	121%
Other income	4,921,656	446,930,429	(99)%
Income tax benefit (expense)	6,281,051	(184,676,760)	(103)%
Net income (loss)	$ (3,879,749)	$ 250,940,566	(102)%

EBITDA

To assess the operating results of the Company, the chief operating decision maker analyzes income (loss) before income taxes, interest income and expense, and depreciation, depletion and amortization (DD&A). EBITDA is not a GAAP measure. DD&A and impairments are excluded from EBITDA as a measure of operating performance because capital expenditures are evaluated at the time capital costs are incurred. Management believes that the presentation of EBITDA provides information useful in assessing the Company s financial condition and results of operations and that EBITDA is a widely accepted financial indicator of a company s ability to incur and service debt, fund capital expenditures and make distributions to stockholders.

EBITDA, as defined by the Company, may not be comparable to similarly titled measures used by other companies. Therefore, our EBITDA should be considered in conjunction with net income (loss) and other performance measures prepared in accordance with GAAP, such as operating income or cash flow from operating activities. EBITDA has important limitations as an analytical tool because it excludes certain items that affect net income (loss) and net cash provided by operating activities. EBITDA should not be considered in isolation or as a substitute for an analysis of the Company s results as reported under GAAP.

Reconciliation of EBITDA for fiscal 2011 and 2010 is as follows:

	For the Year Ended April 30,			
		2001		2010
Net income (loss)	$	(3,879,749)	$	250,940,566
Add (deduct):				
Interest income		(546,274)		(25,616)
Interest expense		990,235		156,617
Income tax expense (benefits)		(6,281,051)		184,676,760
Depreciation, depletion and amortization		12,859,371		3,424,614
EBITDA	$	3,142,532	$	439,172,941

The following table shows the components of our revenues for fiscal 2011 and 2010, together with their percentages of total revenue in each year and percentage change on a year-over-year basis.

	For the Year Ended April 30,				
		2011		2010	% Change
Revenues					
Oil sales	$	19,999,423	$	4,064,909	392%
Natural gas sales		525,694		372,306	41%
Other revenue		2,316,752		1,429,789	62%
Total revenues	$	22,841,869	$	5,867,004	289%

Oil and gas revenue represents revenues generated from the sale of oil and natural gas produced from the wells in which we have an ownership interest. Oil and gas revenue is recognized as income as production is extracted and sold. We reported a 392% increase in oil revenues for fiscal 2011 over 2010. The increase was primarily due to the addition of the Alaskan oil well production during fiscal 2011 which accounted for revenues of approximately $19.4 million for the year then ended. In addition, we produced 397,113 Mcf of gas in fiscal 2011 in Alaska but we did not sell this as substantially all was used in our Alaska oil production.

The increase in our oil and gas revenue from fiscal 2010 to 2011 was primarily due to increased production from the Alaska acquisition as well as increased oil and gas prices. For fiscal 2011 we sold 312,583 barrels of oil and sold at an average price of $83.43 per barrel in Alaska and we sold 28,502 barrels of oil at an average price of $76.25 per barrel in Tennessee. We also produced 397,113 Mcf of natural gas in Alaska which we converted 208,954 Mcf to electricity and used internally and banked 188,159 Mcf for future use, and produced and sold 288,983 Mcf in Tennessee at an average of $2.67 per Mcf. In 2010 we produced 49,390 barrels of oil and sold at an average price of $78.76 per barrel in Alaska and $71.33 in Tennessee. We also produced 154,291 Mcf of natural gas in Alaska which we primarily converted to electricity and used internally and produced 202,283 and sold Mcf and sold at $3.96 per Mcf in Tennessee during fiscal 2010.

Other revenue represents revenues generated from contracts for plugging, drilling, maintenance and repair of third party wells as well as rental income we received for use of our Alaska facility. Service and drilling income is recognized at the time it is both earned and we have a contractual right to receive the revenue. Our other revenue increased 62% for fiscal 2011 as compared to fiscal 2010.

The increase was impacted by a $0.4 million increase in rental income.

In summary, our total revenues increased 289% to $22,841,869 in fiscal 2011 as compared to fiscal 2010. If our efforts to turn non-productive wells into productive wells and drill new wells reach our expectations, and the price of oil and gas does not drop significantly, we expect revenue to continue to increase in fiscal 2012.

Costs and Expenses

The following table shows the components of our direct costs and expenses for fiscal 2011 and 2010. Percentages listed in the table reflect margins for each component of direct expenses and percentage change on a year-over-year basis for each component of other expenses.

	For the Year Ended April 30, 2011	2010	% Change
Costs and Expenses			
Oil and gas operating	$ 9,702,548	$ 2,737,774	254%
Cost of other revenue	807,739	754,559	7%
General and administrative	14,554,667	10,263,160	42%
Depletion, depreciation and amortization	12,859,371	3,424,614	275%
Total costs and expenses	$ 37,924,325	$ 17,180,107	121%

Oil and gas operating expenses increased approximately $7.0 million or 254% from fiscal 2010 to 2011 primarily due to costs associated with the Alaska business we acquired in December 2009. Expenses associated with the work on the Alaska operation to return non-productive wells to producing status increased approximately $2.1 million between fiscal 2010 and fiscal 2011 and direct labor and contract services increased $1.0 million and $0.3 million, respectively, surface materials increased approximately $0.4 million and pipeline expenses contributed another approximately $0.6 million to this variance as well. During fiscal 2012, we expect to continue to turn more non-productive wells to producing status and if that occurs, we expect these expenses will continue to rise; however, we are not able at this time to quantify the amount of any anticipated increase in expenses.

Our central business activity is exploration and production and the cost of other revenue represents costs of services to third parties as a result of excess capacity, and are primarily derived from the direct labor costs of employees associated with these services, as well as costs associated with equipment, parts and repairs. Fiscal 2011 showed $807,739 for this component, up 7% from $754,559 in fiscal 2010. During fiscal 2011, we drilled three wells for ourselves and also entered into a contract with the U.S. Department of Interior for plugging non-company related abandoned wells located in the Big South Fork area in Tennessee and Kentucky. During fiscal 2010, we drilled 10 wells for Atlas Energy, and in preparation for the Atlas Energy drilling contract we spent significant time and expense maintaining and repairing our drilling equipment in fiscal 2010 which contributed to the costs for that year

General and administrative expense includes salaries, general overhead expenses, insurance costs, professional fees and consulting fees. Salaries were $2,580,444 for fiscal 2011, which was an increase of $1,263,251, as compared to fiscal 2010, and was primarily due to the increased staff in Alaska. Professional fees were $3,203,782 for fiscal 2011, which is an increase of $180,902 or 6% due primarily to increased costs associated with the new acquisitions and onetime costs associated with a registration statement filed with the SEC, as well as increases in investor relations and public relations expenses. In addition, we incurred expenses of $5,125,647 in non-cash items, which were recorded as compensation expense during fiscal 2011, an increase of $1,750,839, or 52%, from the non-cash compensation amount recorded for fiscal 2010 of $3,374,808. These expenses were associated primarily with director and employee equity awards granted or vesting during the year. This new layer of expense will continue in future periods and may increase as further development in Alaska occurs. As we continue to grow our business, particularly in Alaska, we expect these general and administrative expenses will continue to rise in fiscal 2012, however, we are unable at this time to quantify the amount of these expected increases.

Depletion, depreciation and amortization expense increased 275% to $12,859,371 in fiscal 2011 from fiscal 2010. We capitalize costs of proved oil and gas properties and record depreciation, depletion and amortization provide on a pooled basis using the units-of-production method based upon proved reserves. During fiscal 2011, depletion, depreciation and amortization expense was 56% of total revenue, as compared to $3,424,614 or 58% of total revenue for fiscal 2010. The primary reason for the increase in expense for fiscal 2011 was the addition of wells and equipment as a result of the Alaska business combination. These non-cash expenses will continue at this higher level as the Alaska assets are being depleted over a range of 30 to 40 years.

As a result of these components, total costs and expenses were $37,924,325, which reflected an operating loss of $15,082,456 for fiscal 2011. This compares to an operating loss of $11,323,101 for fiscal 2010.

Other Income (Expense)

The following table shows the components of certain of our other income and expenses for fiscal 2011 and 2010. Percentages listed in the table reflect percentages of total revenue for each component of other expenses.

	For the Year Ended April 30,					
		2011	% of Revenue		2010	% of Revenue
Interest expense, net of interest income	$	(443,961)	(2)%	$	(131,001)	(2)%
Loss on derivative securities		(1,007,574)	(4)%		(13,299,430)	(227)%
Other expense, net		(537,157)	(2)%		(751,064)	(13)%
Gain on acquisitions		6,910,348	30%		461,111,924	NM
Total	$	4,921,656	22%	$	446,930,429	NM

NM = not meaningful

Interest expense, net of interest income decreased $312,960 or 239% in fiscal 2011 compared to fiscal 2010. This was primarily due to non-cash expenses in fiscal 2010 related to the fair value of warrants issued in connection with a prior financing transaction. This was partially offset by fiscal 2011 interest expense associated with our 6% convertible note program as these notes were issued during fiscal 2010, but converted into equity during the fiscal year 2011, as described more fully in Other Recent Financing Transactions further in this report.

Our derivative liability fluctuates from period to period based on changes in the price of oil for our commodity derivative pricing as well as for changes in components of the Black-Scholes pricing model including the Company's ending stock price, risk free rates, expected life terms, expected volatility and expected dividend rates for our outstanding warrants that have reset provisions. During fiscal 2010 and fiscal 2011, the Company recorded a non-cash losses of $13,299,430 and $1,007,574, respectively, relating to the change in fair value of these derivative instruments. The loss in fiscal 2010 was comprised of three transactions, 3,000,000 warrants issued in the current and past years, 817,055 warrants issued in an equity financing in March 2010 and 300,000 warrants issued pursuant to a consulting arrangement in March 2010. Two of these transactions are no longer applicable at April 30, 2011, as we made a settlement on the 3,000,000 warrants, and the derivative language was removed from a consultant agreement related to the 300,000 warrants, so we only need value the 817,055 warrants program as of April 30, 2011. The application of this accounting treatment on our financial statements in future periods could likewise result in non-cash gains or losses, which could be significant.

During fiscal 2010, we recorded a gain on acquisitions of $461,111,924. This was primarily due from the Alaskan acquisition as previously discussed. During fiscal 2011, we recorded a gain of $6,910,348 primarily related to approximately $6.8 million of restricted cash, which we could not verify was ours until we entered into the Performance Bond Agreement with the state of Alaska on February 17, 2011. On March 11, 2011, CIE entered into a Performance Bond Agreement with the Alaska DNR that applies to the offshore obligations under the Assignment Oversight Agreement. Under the Performance Bond Agreement, CIE is required to post a total bond of $18 million; however, the Performance Bond Agreement also makes clear that approximately $6.8 million held by the state will apply to the total bond required. Therefore, we recorded this event as a gain on acquisition for our Alaska subsidiary. We do not anticipate recording similar gains on acquisitions in future periods.

Liquidity and capital resources

Liquidity is the ability of a company to generate sufficient cash to satisfy its needs for cash. We experienced operating losses for fiscal year 2011 and 2010 and had a working capital deficit as of April 30, 2011. We anticipate that our operating expenses will continue to increase as we fully develop our operations following the acquisition of the Alaskan assets. Although we expect an increase in our revenues to come from these development activities, we will continue depleting our cash resources to fund operating expenses until such time as we are able to significantly increase our revenues. We may have to reduce our expansion efforts if we have not seen an increase in revenues over the next few months.

Subsequent to year-end we secured a $100 million credit facility which we will utilize to further develop our Alaskan subsidiary for off-shore and on-shore oil and gas wells. We do not have any other external sources of working capital. Management believes that the credit facility, along with projected cash flow, are adequate to meet our funding needs for fiscal 2012. See Loan Commitment from Financial Institutions and Guggenheim Corporate Funding, LLC.

At April 30, 2011 we had a working capital deficit of $7,691,517 as compared to a working capital surplus of $239,384 at April 30, 2010. This decrease in capital surplus is primarily due to an increase in trade payables of $3,917,674, an increase in accrued expenses of $3,388,480 and an increase in notes payable of $2,000,000, partially offset by an increase in state tax credits receivable of $2,513,336.

From April 30, 2010 to April 30, 2011, cash decreased from $2,994,634 to $1,558,933. This decrease was primarily due from an increase in cash used in investment activities of $11,313,999, partially offset by increases in cash provided by operations of $7,734,027 and cash provided by financing activities of $2,144,271.

We presently have internal plans for capital expenditures of approximately $66 million for fiscal 2012; $45 million of this earmarked to restore production from our Redoubt Unit, including the purchase and construction of a drilling rig. We anticipate we will draw on our $100 million credit facility to access these cash needs. We also believe we will have increased cash flow from our planned increased production. However, if those avenues are not sufficient, we may be required to raise additional capital or change our capital expenditure plans.

As previously discussed, on November 5, 2009, CIE, LLC entered into an Assignment Oversight Agreement with the Alaska DNR which set out certain terms under which the Alaska DNR would approve the assignment of certain specified state oil and gas leases from Pacific Energy Resources CIE. The agreement required CIE to obtain financing in the minimum amount of $5,150,000 to provide funds to be used for expenditures approved by the Alaska DNR as part of CIE s plan of development. We have subsequently provided these funds for the West McArthur River facility using a portion of the proceeds of our capital raising efforts described elsewhere herein.

Cash flows

Net cash provided by operating activities for fiscal 2011 was $7,734,027. This primarily reflects a gain on acquisitions of $6,910,348, and losses on derivative securities of $1,007,574, along with increases in accounts payable and accrued liabilities of $7,306,153, which were partially offset by operating losses of $15,082,456 for fiscal 2011.

Net cash used by operating activities for fiscal 2010 was $730,466. This primarily reflects the cash paid for the operating expenses and selling, general and administrative expense in excess of revenues received for the period, which included the gain from the Alaska transaction, but partially offset by the issuance of equity for services, compensation and financing costs of $4,514,190.

Net cash used in investing activities for fiscal 2011 of $11,313,999 is primarily due to additions to property and improvements of $825,463 and capital expenditures for oil and gas properties of $10,488,536.

Net cash used by investing activities for fiscal 2010 of $9,443,653 is primarily due to the cash we paid for the Alaska assets of $4,541,252 and the purchase of oil and gas properties of $4,153,222, which were primarily costs associated with well startups.

Net cash provided by financing activities of $2,144,271 for fiscal 2011 primarily reflects the proceeds from borrowings of $5,500,000, which were partially offset payments on notes payable of $3,500,000; and restricted cash of $1,121,245.

Net cash provided by financing activities of $13,122,167 for fiscal 2010 primarily reflects the net cash received from the sale of stock of $9,646,478, proceeds received from borrowings of $5,576,444 which was partially offset by payments on notes payable of $3,762,980.

Loan Commitment from Financial Institutions and Guggenheim Corporate Funding, LLC

On June 13, 2011, we entered into a Loan Agreement (the Loan Agreement) with Guggenheim Corporate Funding, LLC (Guggenheim), as Administrative Agent, Arranger and Lender and Citibank, N.A. and Bristol Investment Fund as Lenders.

The Loan Agreement provides for a credit facility of up to $100 million with an initial borrowing base of $35 million. The credit facility matures on June 13, 2013 and is secured by substantially all of our assets and those of our subsidiaries. Amounts outstanding under the credit facility bear interest at a rate per annum equal to the higher of 9.5% or the prime rate plus 4.5%. In addition, we are required to pay an additional make-whole payment upon termination or payment in full of the credit facility, bringing the effective interest rate to 25% to 35%, depending on the timing of repayment. Beginning on January 1, 2012, or earlier under certain circumstances, we are required to use 90% of our consolidated monthly net revenues (after deducting general and administrative expenses to the extent permitted under the Loan Agreement) to repay the loans outstanding under the Credit Facility. Proceeds of certain asset sales and indebtedness and other proceeds received outside the ordinary course of business are required to be used to repay loans outstanding under the Credit Facility.

Draws under the credit facility are subject to the discretion of the administrative agent and the lenders. The borrowing base is determined on a scheduled basis twice per year, and more often our or the required lender s request. The redetermination of the borrowing base is at the discretion of the lenders. The Loan Agreement contains interest coverage, asset coverage and minimum gross production covenants, as well as other affirmative and negative covenants. In connection with the Loan Agreement, we granted Guggenheim a right of first refusal to provide financing for the acquisition, development, exploration or operation of any oil and gas related properties including wells during the term of the Credit Facility and one year thereafter.

Upon an event of default under the Loan Agreement, all amounts outstanding accelerate and become immediately due and payable, the Lenders may stop making advances under the credit facility and may terminate the agreement. An event of default includes, among other things, our failure to pay any amounts when due, our failure to perform under or observe any term, covenant or provision of the Loan Agreement, the occurrence of a Material Adverse Change (as that term is defined in the Loan Agreement), the seizure of or levy upon our assets or properties, our insolvency or bankruptcy, judgments against us in excess of certain amounts, defaults under certain other agreements, the limitation or termination of the any of the guarantors, which include us and all of our subsidiaries, under the Guarantee and Collateral Agreement described below, the death or incapacitation of either Mr. Scott Boruff or Mr. David Hall, or if either of them cease to be substantially involved in our operations or the breach or termination of the Shareholders Agreement described below.

On the closing date of the Loan Agreement we paid the administrative agent, ratably for the benefit of the Lenders a non-refundable facility fee of $700,000. We also agreed to pay a non-refundable fee of 2% on increase in the borrowing base from the borrowing base limit then in effect. At closing we paid the administrative agent a non-refundable fee of $30,000 and agreed to pay annual additional fees in this amount so long as the Loan Agreement remains in effect. A finder s fee of 3% of the initial borrowing base of $35 million to Bristol Capital, LLC, a consultant to us and an affiliate of Bristol Investment Fund, Ltd., was also due.

In connection with the credit facility, certain of our executive officers and directors entered into a Shareholders Agreement which is described later in this report.

We expect to use the proceeds of the loans made under the Credit Facility to increase oil production both onshore and offshore in Alaska through the drilling of new wells and the reworking of previously producing oil wells and for the purchase of a new drilling rig. The first draws, totaling $10,874,612, have been used to pay fees associated with the transaction, such as attorney s fees, to pay off our line of credit with PlainsCapital Bank, to make the first progress payment under the Rig contract, and for working capital.

Other Recent Financing Transactions

In order to finance the expansion of our operations into Alaska and to provide capital for our other operations, we entered into the following financing transactions:

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In December 2009 we issued $2,855,000 principal amount 6% convertible secured promissory notes to provide funds for the Alaskan asset transaction. Included in the sales of these notes was an aggregate of $500,000 purchased by Mr. Scott Boruff, our Chief Executive Officer and a member of our Board of Directors, and Mr. Deloy Miller, member of our Board of Directors. We paid a finder s fee of $20,000. Interest on the notes is paid quarterly and the principal is due December 4, 2016. The holders of all of these notes, including Messrs. Boruff and Miller, have subsequently converted the notes into shares of our common stock. As of April 30, 2011, none of the notes remain outstanding.

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Between December 2009 and January 2010 we sold 6,015,000 shares of our common stock in private transactions to accredited investors for $1.00 per share. This was a discount of 16.67% from market value on the date of determination. The $5,657,000 in net cash proceeds from this offering, after payment of offering costs, commissions and finder s fees, was used for general corporate purposes, including reducing debt and partially financing the Alaska asset acquisition. We paid Sutter

Securities Incorporated, a FINRA member firm, cash compensation of $200,000 as well as a non-accountable sum of $10,000 for its legal fees and expenses and issued it five-year warrants to purchase an aggregate of 280,000 shares of our common stock at exercise prices ranging from $1.35 to $1.815 per share. We also paid finder s fees of $123,000 and issued five-year warrants to purchase an aggregate of 52,500 shares of our common stock at exercise price of $1.35 per share. In addition, we paid Seaside 88 Advisors, LLC, the general partner of one of the purchasers of the shares, a non-accountable sum of $25,000. The warrants are exercisable on a cashless basis. If we make any subsequent sales of our securities within one year to any purchaser introduced to us by Sutter Securities Incorporated, we are obligated to pay that firm a finder s fee on those sales. Under the terms of the Securities Purchase Agreements we agreed that until 12 months from the closing date, if in connection with a Subsequent Financing (as defined in the Securities Purchase Agreement), either our company or any of our subsidiaries should issue any common stock or common stock equivalents entitling any person or entity to acquire shares of common stock at an effective price per share less than the per share purchase price of $1.00 (subject to reverse and forward stock splits and the like), that we will issue to the purchaser of this current stock sale, a number of additional shares of common stock to the aforementioned purchasers to prevent the follow-on investment from being a dilutive issuance. If shares are issued for a consideration other than cash, the per share selling price shall be the fair value of such consideration as determined in good faith by the Board of Directors. We also granted the purchasers of stock certain piggy back registration rights until such time as the purchasers are able to resell the shares of common stock purchased in the offering pursuant to Rule 144 of the Securities Act until the requirement for adequate public information on our company is no longer applicable.

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On March 26, 2010, we executed a Securities Purchase Agreement pursuant to which at closing we agreed to sell units of our securities, including 1,433,432 shares of our common stock at a purchase price of $3.50 per share and five year warrants to purchase an additional 716,716 shares of common stock with an exercise price of $5.28 per share to 14 accredited and/or institutional purchasers. This offering closed on April 1, 2010. We received gross proceeds $5,017,002. Sutter Securities Incorporated, a broker-dealer and member of FINRA, acted as finder for us in this unit offering. Under the terms of a Finder s Agreement with the firm, we paid Sutter Securities Incorporated a fee of $346,190 and issued the firm five-year common stock purchase warrants to purchase an aggregate of 100,339 shares of our common stock at an exercise price of $5.28 per share. In addition, we paid a finder s fee of $5,000 to Viriathus Capital LLC and paid the attorney for Sutter Securities Incorporated legal expenses totaling $10,000 incurred in the preparation of the various transactional documents. We used the net proceeds of this offering for general corporate purposes.

The Securities Purchase Agreement for the March 2010 unit offering provided that until September 26, 2010 any securities sold in the offering are subject to a per share price protection. In the event we were to issue any shares of common stock, or securities convertible into or exercisable for shares of common stock, to any third party purchaser at a purchase price or exercise price per share which is less than $3.50 per share, or less than the exercise price of $5.28 per warrant share (collectively, the Discounted Per Share Purchase Price), we would automatically issue additional shares of our common stock to the purchasers in the March 2010 unit offering without the payment of any additional consideration by those purchasers. We did not issue any shares lower than $3.50 or issue any exercisable shares at less than $5.28.

Under the terms of the Registration Rights Agreement entered into with the purchasers in the March 2010 unit offering, we were obligated to file a registration statement with the SEC covering the shares of common stock issued and sold in the offering, as well as the shares of common stock underlying the warrants, on or before April 15, 2010 so as to permit the public resale thereof. We filed the registration statement on August 13, 2010, and it was declared effective on August 25, 2010. Because we did not timely file the registration statement, we have recorded liquidated damages during the fourth quarter of fiscal 2010.

Off Balance Sheet Arrangements

We do not have any off-balance sheet arrangements that we are required to disclose pursuant to these regulations. In the ordinary course of business, we enter into operating lease commitments, purchase commitments and other contractual obligations. These transactions are recognized in our financial statements in accordance with generally accepted accounting principles in the United States.

Critical Accounting

General

The preparation of financial statements requires management to utilize estimates and make judgments that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. These estimates are based on historical experience and on various other assumptions that management believes 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, management believes that the estimates used in the preparation of our financial statements are reasonable. The critical accounting policies affecting our financial reporting are summarized in Note 1 to the consolidated financial statements included in this annual report. Policies involving the most significant judgments and estimates are summarized below.

Impact of Derivative Accounting

Generally, warrants, with full-ratchet or reset provisions, which mean that the exercise or conversion price adjusts to pricing in subsequent sales or issuances, require liability classification and mark to market accounting. The amount of non-cash gains or losses we record is based upon the fair market value of our common stock on the measurement date.

Estimates of Proved Reserves and Future Net Cash Flows

Estimates of our proved oil and gas reserves and related future net cash flows are used in impairment tests of goodwill and other long-lived assets. These estimates are prepared as of year-end by independent petroleum engineers and are updated internally at mid-year. There are many uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures. The accuracy of any reserve estimate is dependent on the quality of available data and is subject to engineering and geological interpretation and judgment. Results of our drilling, testing and production after the date of these estimates may require future revisions, and actual results could differ materially from the estimates.

Impairment of Long-Lived Assets

Our long-lived assets include property, equipment and goodwill. Long-lived assets with an indefinite life are reviewed at least annually for impairment, and all long-lived assets are reviewed whenever events or changes in circumstances indicate that their carrying values may not be recoverable.

Oil and Gas Activities

We follow the successful efforts method of accounting for our oil and gas activities. Accordingly, costs associated with the acquisition, drilling and equipping of successful exploratory wells are capitalized. Geological and geophysical costs, delay and surface rentals and drilling costs of unsuccessful exploratory wells are charged to expense as incurred. Costs of drilling development wells are capitalized. Upon the sale or retirement of oil and gas properties, the cost thereof and the accumulated depreciation or depletion are removed from the accounts and any gain or loss is credited or charged to operations.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization of capitalized costs of proved oil and gas properties is provided on a pooled basis using the units-of-production method based upon proved reserves. Acquisition costs of proved properties are amortized by using total estimated units of proved reserves as the denominator. All other costs are amortized using total estimated units of proved developed reserves.

Fair Value of Financial Instruments

ASC 820, *Fair Value Measurements and Disclosures* , establishes a common definition for fair value to be applied to existing generally accepted accounting principles that require the use of fair value measurements, establishes a framework for measuring fair value, and expands disclosure about such fair value measurements.

The FASB defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Additionally, the FASB requires the use of valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

These inputs are prioritized below:

Level 1:	Observable inputs such as quoted market prices in active markets for identical assets or liabilities.
Level 2:	Observable market-based inputs or unobservable inputs that are corroborated by market data
Level 3:	Unobservable inputs for which there is little or no market data, which require the use of the reporting entity's own assumptions.

In addition, the FASB issued, "The Fair Value Option for Financial Assets and Financial Liabilities," effective for May 1, 2008. This guidance expands opportunities to use fair value measurements in financial reporting and permits entities to choose to measure many financial instruments and certain other items at fair value. We did not elect the fair value option for any of our qualifying financial instruments.

Equity-Based Compensation

The computation of the expense associated with stock-based compensation requires the use of a valuation model. ASC 718, *Compensation Stock Compensation* , requires significant judgment and the use of estimates, particularly surrounding Black-Scholes assumptions such as stock price volatility, expected terms, and expected forfeiture rates, to value equity-based compensation. We currently use a Black-Scholes pricing model to calculate the fair value of our stock options and warrants. We primarily use historical data to determine the assumptions to be used in the Black-Scholes model. However, changes in the assumptions to reflect future stock price volatility and future stock award exercise experience could result in a change in the assumptions used to value awards in the future and may result in a material change to the fair value calculation of stock-based awards. This accounting guidance requires the recognition of the fair value of stock compensation in net income. 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 stock option expense that may materially impact our financial statements for each respective reporting period.

Recent Accounting Pronouncements

ASC 805 requires an acquirer to recognize the assets acquired, the liabilities assumed, and any non-controlling interest in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exceptions. This guidance also requires the acquirer in a business combination achieved in stages to recognize the identifiable assets and liabilities, as well as the non-controlling interest in the acquiree, at the full amounts of their fair values. Additionally, this guidance requires acquisition-related costs to be expensed in the period in which the costs were incurred and the services are received instead of including such costs as part of the acquisition price. This guidance makes various other amendments to authoritative literature intended to provide additional guidance or to conform the guidance in that literature to that provided in this Statement. Our acquisition of the Ky-Tenn Oil, Inc and Cook Inlet assets and the stock and membership interests of East Tennessee Consultants, Inc. and East Tennessee Consultants II, LLC were recorded in accordance with this guidance.

We determined that all other issued, but not yet effective accounting pronouncements are inapplicable or insignificant to us and once adopted are not expected to have a material impact on our financial position.

Restatement of Unaudited Interim Consolidated Financial Statements

The Company has restated its unaudited consolidated balance sheets as of July 31, 2010, October 31, 2010 and January 31, 2011 and our unaudited consolidated statements of operations for the quarterly and year to date periods then ended. In each of the first two quarters of fiscal 2011, we failed to properly record depletion, depreciation and amortization expense related to leasehold costs, wells and equipment, fixed assets and asset

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retirement obligations and did not properly record the state tax credits expected from our Alaska operations. In the third quarter of fiscal 2011, it was determined that we inappropriately recorded revenue on a gross basis for overriding royalty interests (rather than recording revenue on a net basis). The correction of this classification error resulted in a decrease to oil and gas revenue and oil and gas operating of $824,746, $1,036,987, and $1,429,499, respectively, for the quarters ended July 31, 2010, October 31, 2010, and January 31, 2011. We also determined that we failed to properly record sufficient compensation expense on equity awards, did not properly calculate the liability for our derivative instruments, and did not properly consolidate an entity we control. The consolidation of MEI resulted in a decrease to notes payable, an increase to stockholders equity, and minor adjustments to cash, other assets and accrued expenses.

The corrections recorded to restate the unaudited consolidated financial statements as of July 31, 2010 include errors related to 2010 that were identified during the review of our 2011 fiscal third quarter. Such errors were originally corrected in the Company s restated unaudited consolidated financial statements for the first quarter ended July 31, 2010. After identifying additional errors, we determined that the aggregate impact of such errors was material to the unaudited consolidated financial statements for the quarter ended July 31, 2010. Accordingly, the 2010 consolidated financial statements were revised to correct these errors, which are considered immaterial to 2010. Such corrections to our unaudited consolidated financial statements for the quarter ended July 31, 2010 resulted in a decrease to general and administrative of $1,107,000 and a decrease to depreciation, depletion, and amortization of $715,306.

The following is a summary presentation of corrections made to the Company s unaudited consolidated balance sheet as of July 31, 2010, previously filed on Form 10-Q for the quarter ended July 31, 2010:

	July 31, 2010 As Reported	**Corrections**	**July 31, 2010 As Restated**
ASSETS			
Cash and cash equivalents	$ 472,543	$ 243,793	$ 716,336
Restricted cash	126,379		126,379
Accounts receivable, net	1,489,620		1,489,620
State production credits receivable	1,603,358		1,603,358
Inventory	767,678		767,678
Prepaid expenses	177,556	698,813	876,369
Oil and gas properties, net	483,238,369	(239,865)	482,998,504
Equipment, net	7,243,536	37,529	7,281,065
Land	526,500		526,500
Restricted cash, non-current	2,070,445		2,070,445
Other assets	599,550	(302,916)	296,634
TOTAL ASSETS	$ 498,315,534	$ 437,354	$ 498,752,888
LIABILITIES AND STOCKHOLDERS EQUITY			
Accounts payable	$ 5,244,203	$	$ 5,244,203
Accrued expenses	440,570	278,227	718,797
Derivative liability	14,523,830	(531,412)	13,992,418
Unearned revenue	41,442		41,442
Deferred income taxes	184,367,963	(697,373)	183,670,590
Asset retirement obligation	16,301,020	(39,962)	16,261,058
Notes payable	3,104,744	(2,219,323)	885,421
Total Liabilities	224,023,772	(3,209,843)	220,813,929

STOCKHOLDERS EQUITY						
Common stock		3,339				3,339
Additional paid-in capital		28,733,128		756,947		29,490,075
Retained earnings		245,555,295		2,890,250		248,445,545
Total Stockholders Equity		274,291,762		3,647,197		277,938,959
TOTAL LIAB. AND STOCKHOLDERS EQUITY	$	498,315,534	$	437,354	$	498,752,888

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The following is a summary presentation of corrections made to the Company s unaudited consolidated statement of operations for the three month period ended July 31, 2010, previously filed on Form 10-Q for the quarter ended July 31, 2010:

	For the Three Months Ended July 31, 2010 As Reported	Corrections	For the Three Months Ended July 31, 2010 As Restated
REVENUES			
Oil and gas revenue	$ 4,791,179	$ (824,746)	$ 3,966,433
Other revenue	409,068		409,068
Total	5,200,247	(824,746)	4,375,501
COSTS AND EXPENSES			
Oil and gas operating	2,304,107	(579,194)	1,724,913
Cost of other revenue	495,747	(245,552)	250,195
General and administrative	3,769,415	(458,978)	3,310,437
Depreciation, depletion and amortization	3,736,177	(757,821)	2,978,356
Total	10,305,446	(2,041,545)	8,263,901
LOSS FROM OPERATIONS	(5,105,199)	1,216,799	$ (3,888,400)
OTHER INCOME(EXPENSE)			
Interest income	4,553		4,553
Interest expense	(219,338)		(219,338)
Gain (loss) on derivatives, net	2,905,957	(1,100)	2,904,857
Other expense, net	(77,880)	(638,468)	(716,348)
Total	2,613,292	(639,568)	1,973,724
INCOME (LOSS) BEFORE INCOME TAXES	(2,491,907)	577,231	(1,914,676)
INCOME TAX BENEFIT (EXPENSE)	(69,791)	835,611	765,820
NET LOSS	$ (2,561,698)	$ 1,412,842	$ (1,148,856)
LOSS PER SHARE			
Basic	$ (0.08)	$ 0.04	$ (0.04)
Diluted	$ (0.08)	$ 0.04	$ (0.04)
WEIGHTED AVERAGE SHARES OUTSTANDING			
Basic	32,835,722		32,835,722
Diluted	32,835,722		32,835,722

The following is a summary presentation of corrections made to the Company s unaudited consolidated balance sheet as of October 31, 2010, previously filed on Form 10-Q for the quarter ended October 31, 2010:

	October 31, 2010 As Reported	Corrections	October 31, 2010 As Restated
ASSETS			
Cash and cash equivalents	$ 986,547	$ 243,793	$ 1,230,340
Restricted cash	126,697		126,697
Accounts receivable, net	1,726,215		1,726,215
State production credits receivable	2,167,044		2,167,044
Inventory	627,746		627,746
Prepaid expenses	1,487,444	415,510	1,902,954
Oil and gas properties, net	481,630,866	(257,899)	481,372,967
Equipment, net	7,087,429	73,688	7,161,117
Land	526,500		526,500
Restricted cash, non-current	2,314,517		2,314,517
Other assets	476,050	(302,916)	173,134
TOTAL ASSETS	$ 499,157,055	$ 172,176	$ 499,329,231
LIABILITIES AND STOCKHOLDERS EQUITY			
LIABILITIES			
Accounts payable	$ 8,604,077	$	$ 8,604,077
Accrued expenses	399,517	278,227	677,744
Derivative liability	13,741,892	(271,928)	13,469,964
Unearned revenue	108,473		108,473
Deferred income taxes	184,468,878	(3,421,479)	181,047,399
Asset retirement obligation	16,544,505	(39,962)	16,504,543
Notes payable	2,284,871	(2,284,871)	
Total	226,152,213	(5,740,013)	220,412,200
STOCKHOLDERS EQUITY			
Common stock	3,617		3,617
Additional paid-in capital	30,939,449	3,614,577	34,554,026
Retained earnings	242,061,776	2,297,612	244,359,388
Total	273,004,842	5,912,189	278,917,031
TOTAL LIAB. AND STOCKHOLDERS EQUITY	$ 499,157,055	$ 172,176	$ 499,329,231

The following is a summary presentation of corrections made to the Company s unaudited consolidated statement of operations for the three month period ended October 31, 2010, previously filed on Form 10-Q for the quarter ended October 31, 2010:

	For the Three Months Ended Oct. 31, 2010 As Reported	Corrections	For the Three Months Ended Oct. 31, 2010 As Restated
REVENUES			
Oil and gas revenue	$ 6,081,793	$ (1,036,987)	$ 5,044,806
Other revenue	593,869		593,869
Total	6,675,662	(1,036,987)	5,638,675
COSTS AND EXPENSES			
Oil and gas operating	3,611,582	(893,150)	2,718,432
Cost of other revenue	341,408	(143,837)	197,571
General and administrative	3,078,951	791,779	3,870,730
Depreciation, depletion and amortization	3,517,056	(18,125)	3,498,931
Total	10,548,997	(263,333)	10,285,664
LOSS FROM OPERATIONS	(3,873,335)	(773,654)	(4,646,989)
OTHER INCOME (EXPENSE)			
Interest income	1,174		1,174
Interest expense	(410,422)		(410,422)
Gain (loss) on derivatives, net	781,938	(2,543,090)	(1,761,152)
Other income, net	7,125		7,125
Total	379,815	(2,543,090)	(2,163,275)
LOSS BEFORE INCOME TAXES	(3,493,520)	(3,316,744)	(6,810,264)
INCOME TAX BENEFIT		2,724,106	2,724,106
NET LOSS	$ (3,493,520)	$ (592,638)	$ (4,086,158)
LOSS PER SHARE			
Basic	$ (0.10)	$ (0.02)	$ (0.12)
Diluted	$ (0.10)	$ (0.02)	$ (0.12)
WEIGHTED AVERAGE SHARES OUTSTANDING			
Basic	34,314,794		34,314,794
Diluted	34,314,794		34,314,794

The following is a summary presentation of corrections made to the Company s unaudited consolidated balance sheet as of January 31, 2011, previously filed on Form 10-Q for the quarter ended January 31, 2011:

	January 31, 2011 As Reported	Corrections	January 31, 2011 As Restated
ASSETS			
Cash and cash equivalents	$ 3,158,946	$ 243,793	