MILLER ENERGY RESOURCES, INC.
Form 10-Q
March 12, 2012

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

(Mark One)

Form 10-Q

þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended January 31, 2012

or

o TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ___________________ to ___________________________
Commission file number: 001-34732

Miller Energy Resources, Inc.
(Name of registrant as specified in its charter)

Tennessee	62-1028629
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

9721 Cogdill Road, Suite 302, Knoxville, TN	37932
(Address of principal executive offices)	(Zip Code)

(865) 223-6575
(Registrant's telephone number, including area code)

(Former name, former address and former fiscal year, if changed since last report)

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 o No þ

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 (§232.405 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 þ No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date. 41,086,751 shares of common stock are issued and outstanding as of March 05, 2012.

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PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS.

MILLER ENERGY RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	January 31, 2012	April 30, 2011
ASSETS		
Current Assets		
Cash and cash equivalents	$3,129,032	$1,558,933
Restricted cash	285,019	202,980
Accounts receivable:		
Related parties	8,610	27,822
Customers and other	2,470,201	1,619,720
State production credits receivable	5,221,817	3,620,336
Inventory	1,350,463	1,043,960
Prepaid expenses	558,982	231,724
Total current assets	13,024,124	8,305,475
Oil and Gas Properties (Successful Efforts Method)		
Cost	502,477,317	496,925,472
Less accumulated depletion	(25,003,130)	(14,873,595)
Oil and gas properties, net	477,474,187	482,051,877
Equipment		
Cost	34,680,049	10,292,514
Less accumulated depreciation and amortization	(2,710,646)	(2,185,981)
Equipment, net	31,969,403	8,106,533
Other Long-Term Assets		
Land	541,500	526,500
Restricted cash, non-current	9,887,485	10,026,516
Deferred financing costs, net of accumulated amortization	1,661,781	63,907
Other assets	416,944	—
Total other long-term assets	12,507,710	10,616,923
Total Assets	$534,975,424	$509,080,808
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$9,945,282	$7,496,786
Accrued expenses	6,669,981	4,185,087
Current portion of derivative liability	1,021,044	2,305,118
Borrowings under credit facility	28,894,615	2,000,000
Total current liabilities	46,530,922	15,986,991

Long-term Liabilities		
Deferred income taxes	171,417,759	178,326,065
Asset retirement obligation	18,098,456	17,293,718
Non-current portion of derivative liability	3,230,445	2,732,659
Total long-term liabilities	192,746,660	198,352,442
Total Liabilities	239,277,582	214,339,433
Commitments and Contingencies (Note 6, 8, 13 and 15)		
Equity		
Common stock, par value $0.0001 per share (500,000,000 shares authorized, 40,986,751 and 39,880,251 shares issued as of January 31, 2012 and April 30, 2011, respectively)	4,099	3,988
Additional paid-in capital	61,146,559	49,012,755
Retained earnings	234,547,184	245,724,632
Total Stockholders' Equity	295,697,842	294,741,375
Total Liabilities and Stockholders' Equity	$534,975,424	$509,080,808

The accompanying notes are an integral part of these unaudited consolidated financial statements.

MILLER ENERGY RESOURCES, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	For the Three Months Ended January 31, 2012	For the Three Months Ended January 31, 2011 (as restated)	For the Nine Months Ended January 31, 2012	For the Nine Months Ended January 31, 2011 (as restated)
Revenues				
Oil and natural gas sales	$7,943,779	$5,609,958	$24,703,999	$14,621,197
Other revenue	499,664	775,664	1,799,980	1,778,601
Total revenues	8,443,443	6,385,622	26,503,979	16,399,798
Costs and Expenses				
Oil and gas operating	3,769,742	1,831,066	11,940,863	6,274,411
Cost of other revenue	296,169	425,827	668,595	873,593
General and administrative	6,729,265	1,753,251	20,450,440	8,934,418
Exploration expense	394,686	—	574,478	—
Depreciation, depletion and amortization	2,826,065	3,110,976	10,437,487	8,663,453
Accretion of asset retirement obligation	268,028	243,806	804,738	855,842
Other operating income (expense), net	255,040	—	(642,238)	—
Total costs and expenses	14,538,995	7,364,926	44,234,363	25,601,717
Operating Loss	(6,095,552)	(979,304)	(17,730,384)	(9,201,919)
Other Income (Expense)				
Interest income	4,764	9,253	8,599	14,980
Interest expense, net of interest capitalized	(817,560)	(111,162)	(2,008,863)	(1,053,696)
Gain (loss) on derivatives, net	(3,668,509)	935,929	1,593,336	2,079,634
Other income (expense), net	(8,338)	—	51,558	(709,223)
Total other income (expense)	(4,489,643)	834,020	(355,370)	331,695
Loss Before Income Taxes	(10,585,195)	(145,284)	(18,085,754)	(8,870,224)
Income tax benefit	4,074,736	58,113	6,908,307	3,548,039
Net Loss	$(6,510,459)	$(87,171)	$(11,177,447)	$(5,322,185)
Loss per Share:				
Basic	$(0.16)	$(0.00)	$(0.27)	$(0.15)
Diluted	$(0.16)	$(0.00)	$(0.27)	$(0.15)
Average Number of Common Shares Outstanding:				
Basic	40,937,023	37,774,861	40,728,374	34,975,126
Diluted	40,937,023	37,774,861	40,728,374	34,975,126

The accompanying notes are an integral part of these unaudited consolidated financial statements.

MILLER ENERGY RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	For the Nine Months Ended January 31, 2012	2011 (as restated)
Cash Flows from Operating Activities		
Net loss	$ (11,177,447)	$ (5,322,185)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion, and amortization	10,437,487	8,663,453
Amortization of deferred financing fees	887,318	312,774
Issuance of equity for compensation	9,629,859	2,535,529
Issuance of equity for services	876,055	609,559
Deferred income taxes	(6,908,306)	(3,617,850)
Loss on sale of equipment	—	625,948
Gain on derivative instruments, net	(786,288)	(2,079,634)
Accretion of asset retirement obligation	804,738	855,842
Changes in operating assets and liabilities:		
Receivables, net	1,472,342	4,621
Inventory	(89,790)	(252,963)
Prepaid expenses	(327,258)	(554,809)
Other assets	(416,944)	392,883
Accounts payable, accrued expenses and other	4,933,390	5,894,093
Net cash provided by operating activities	9,335,156	8,067,261
Cash Flows from Investing Activities		
Purchase of equipment and improvements	(24,387,534)	(770,083)
Capital expenditures for oil and gas properties	(9,471,939)	(9,944,414)
Net cash used by investing activities	(33,859,473)	(10,714,497)
Cash Flows from Financing Activities		
Deferred financing costs	(2,140,192)	—
Proceeds from borrowings	26,894,615	2,500,000
Exercise of equity rights	1,283,001	947,507
Restricted cash	56,992	(392,166)
Net cash provided by financing activities	26,094,416	3,055,341
Net Increase (Decrease) in Cash and Cash Equivalents	1,570,099	408,105
Cash and Cash Equivalents at Beginning of Period	1,558,933	2,994,634
Cash and Cash Equivalents at End of Period	$ 3,129,032	$ 3,402,739
Cash paid for interest	$ 1,366,195	$ 454,304

The accompanying notes are an integral part of these unaudited consolidated financial statements.

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MILLER ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (continued)
(Unaudited)

(1) Organization and Basis of Presentation

The consolidated financial statements as of, and for the period ended January 31, 2012, are unaudited, but in the opinion of management include all adjustments (consisting only of normal recurring adjustments) necessary for a fair statement of the results for the interim periods. Certain information and note disclosures normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles ("GAAP") have been condensed or omitted under Securities and Exchange Commission ("SEC") rules and regulations. The results reported in these unaudited consolidated financial statements should not necessarily be taken as indicative of results that may be expected for the entire year.

The financial information included herein should be read in conjunction with the consolidated financial statements and notes in the Company's Annual Report on Form 10-K for the year ended April 30, 2011, which was filed on August 9, 2012 and which was further amended on August 29, 2011. Certain amounts in the consolidated financial statements and notes thereto have been reclassified to conform to the 2011 financial statement presentation.

Unless specifically set forth to the contrary, when used in this report, the terms “Miller Energy Resources, Inc.,” the "Company," "we," "us," "ours," “MER,” 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").

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 year 2012, we continued to develop our oil and gas operations acquired 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 acres of lease and exploration licenses, along with hundreds of miles of 2-D and 3-D geologic seismic data, miscellaneous roads, pads and facilities.

The accompanying consolidated financial statements include our accounts and those of our wholly-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation. We operate our oil and natural gas properties as one business segment: the exploration, development and production of oil and natural gas. Our management evaluates performance based on one business segment as there are not different economic environments within the operation of our oil and natural gas properties.

(2) Summary of Significant Accounting Policies

Our significant accounting policies are consistent with those discussed in our Annual Report on Form 10-K for the year ended April 30, 2011, as amended.

Investments

On June 24, 2011, we acquired a 48% minority interest in Pellissippi Pointe I, LLC and Pellissippi Pointe II, LLC (the “Pellissippi Pointe” entities or “investee”) for total cash consideration of $399,934. We agreed to indemnify the sellers of the membership interests with respect to their guaranties of certain debt held by the investee, but have not become direct guarantors of the loans. As of January 31, 2012, the gross outstanding debt balance of the investee is $5,105,434. In connection with the transaction, we executed a five-year lease agreement with the investee and relocated our corporate offices to the new facility on November 7, 2011. Due to the fact that we do not exercise control over the financial and operating decisions made by the investee, we have accounted for these investments using the equity method. These investments are reflected in “other assets” in the accompanying Consolidated Balance Sheets.

New Accounting Pronouncements Issued But Not Yet Adopted

In June 2011, the FASB issued a final standard (ASU 2011-05) that requires entities to present net income and other comprehensive income in either a single continuous statement or in two separate, but consecutive, statements of net income and other comprehensive income. The option to present items of other comprehensive income in the statement of changes in equity is eliminated. The adoption of this standard effective December 15, 2011, will not have a material impact on our financial statements or our disclosures.

In May 2011, the FASB issued ASU 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs, and the IASB issued IFRS 13, Fair Value Measurement (together, the "new guidance"). The new guidance results in a consistent definition of fair value and common requirements for measurement of and disclosure about fair value between U.S. GAAP and IFRS. The new guidance changes some fair value measurement principles and disclosure requirements and is effective for interim and annual periods beginning on or after December 15, 2011, with early adoption prohibited. The adoption of this new guidance will not have an impact on our financial statements or our disclosures.

MILLER ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (continued)
(Unaudited)

(4) Concentrations of Credit Risk and Accounts Receivable

Financial instruments that potentially subject us to a concentration of credit risk consist of cash and cash equivalents, accounts receivable and derivative financial instruments. We place our cash with high credit quality financial institutions. We place our derivative financial instruments with financial institutions that maintain an investment grade credit rating. Substantially all of our accounts receivables are due from purchasers of oil and natural gas. These sales are generally unsecured and, in some cases, may carry a parent guarantee. As we have one large customer for our oil and natural gas sales, we routinely assess the financial strength of the customer. Bad debt expense is recognized on an account-by-account basis and when recovery is not probable. For the nine months ended January 31, 2012 and 2011, there was no bad debt expense recognized by us. We have no off-balance-sheet credit exposure related to our operations or customers.

For the three and nine months ended January 31, 2012, Tesoro Corporation accounted for $7,422,135 or 88% and $22,870,931 or 86% of our revenues, respectively. Tesoro Corporation also accounted for $1,785,435 or 72%, and $1,143,667 or 71% of our accounts receivable as of January 31, 2012 and April 30, 2011, respectively.

(5) Related Party Transactions

Transactions with MEI

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

Between August 2009 and April 2010, MEI sold 61.35 units of securities in a private placement resulting in gross proceeds of $3,067,500. Each unit consisted of a $50,000 limited partnership interest in MEI, together with 25,000 shares of our common stock and a five-year warrant to purchase an additional 25,000 shares with an exercise price of $1.00 per share. If the purchasers did not subscribe to a full unit, the unit did not include our securities. We issued a total of 1,329,250 shares of common stock and warrants to purchase an additional 1,329,250 shares.

On November 1, 2009, we executed a promissory note with MEI in the amount of $2,365,174 payable under a four-year term with a simple interest rate of 12% per annum. A monthly interest-only payment of $23,652 is payable on the effective date of the agreement and continues each succeeding month until expiration of the note when both principal and any unpaid interests will be paid in full. On December 15, 2009, we executed a second promissory note with MEI under similar terms for $356,270. On May 15, 2010, we executed a third promissory note with MEI under similar terms for a final $350,000 and granted MEI a first priority security interest in oil and gas drilling equipment owned by us. Pursuant to the terms of the agreement, a third-party escrow agent was retained to hold the certificates of title for the collateral to which title is evidenced by a certificate. The remaining equipment is subject to a financing statement that has been filed with the Tennessee Secretary of State. We used the proceeds from these loans for general corporate purposes including reducing outstanding debt and partially funding the Alaska transaction.

Transactions with Other Related Parties

From time to time our company provides service work on oil and gas wells owned by Mr. Gettelfinger, a member of the Board of Directors, and his wife. The audit committee of our board of directors determined that the amounts paid to us for the services performed were fair to and in the best interests of the Company. As of January 31, 2012 and April 30, 2011, Mr. and Mrs. Gettelfinger owed us $840 and $17,822, respectively.

On August 1, 2009, we entered into a Marketing Agreement with The Dimirak Companies, an affiliate of Dimirak Financial Corp. and Dimirak Securities Corporation, a broker-dealer and member of FINRA. Mr. Boruff, our Chief Executive Officer (“CEO”), is a director and 49% owner of Dimirak Securities Corporation. Under the terms of this agreement, we engaged The Dimirak Companies to serve as our exclusive marketing agent in a $20 million income fund and a $25.5 million drilling offering, which included the MEI offering described earlier in this report. The terms of the agreement will expire upon the termination of the offerings. We agreed to pay The Dimirak Companies a monthly consulting fee of $5,000, a marketing fee of 2% of the gross proceeds received in the offerings or within 24 months from the expiration of the term of the agreement, a wholesaling fee of 2% of the proceeds and a reimbursement of certain pre-approved expenses. The agreement contains customary indemnification, non-circumvention and confidentiality clauses. For the nine months ended January 31, 2012 and 2011, we paid The Dimirak Companies and their affiliates a total of $63,000 and $66,932, respectively.

MILLER ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (continued)
(Unaudited)

We use a number of contract labor companies to provide on demand labor at our Alaska operations. H&H Industrial, Inc. is an entity contracted by CIE, a wholly-owned subsidiary of the Company, to provide services related to the exploration and production of oil and natural gas. The company is owned by the sister and father of David Hall, CEO of CIE and member of our Board of Directors. The audit committee of our board of directors determined that the amounts paid by us for the services performed were fair to and in the best interests of the Company. For the nine months ended January 31, 2012 and 2011, we paid H&H Industrial, Inc. a total of $550,306 and $160,658, respectively.

On August 27, 2010, we entered into a consulting arrangement with Matrix Group, LLC ("Matrix"), an entity through which one of our directors at the time, David J. Voyticky, provided consulting services to us, including assisting us in locating strategic investments and business opportunities. During fiscal 2011, and prior to his appointment as our President (and later, Chief Financial Officer), we paid Matrix $70,000 for consulting services rendered under this arrangement, together with a $250,000 bonus for the successful closing of the credit facility (as described in Note 8). We also reimbursed Matrix $10,000 of related expenses. Following Mr. Voyticky's appointment as our President, we have terminated the consulting arrangement.

On July 13, 2011, CIE entered into a consulting agreement with Jexco LLC, an entity owned by Jonathan S. Gross, a member of our Board of Directors. Under the terms of this agreement, Jexco LLC provided advice to us in areas related to seismic processing services with contractors located in Houston, Texas. The agreement terminated on December 31, 2011. As compensation for the services, we agreed to pay a flat fee of $15,000 for work performed in the Houston metropolitan area and a fee of $2,500 per day for work performed outside of the Houston metropolitan area. Further, we agreed to reimburse Jexco LLC for out of pocket expenses incurred in rendering the services to us. As of January 31, 2012, Jexco LLC had completed all services under the agreement and billed us a total of $15,000.

(6) Oil and Gas Properties and Equipment

Oil and gas properties consist of the following:

Oil and gas properties (successful efforts method)	January 31, 2012	April 30, 2011
Property costs		
Proved property	$348,084,472	$342,889,685
Unproved property	154,392,845	154,035,787
Total property costs	502,477,317	496,925,472
Less: Accumulated depletion	(25,003,130)	(14,873,595)
Total oil and gas properties, net	$477,474,187	$482,051,877

Equipment consists of the following:

	January 31, 2012	April 30, 2011
Machinery and equipment	$28,972,457	$5,454,923
Vehicles	1,622,642	1,618,322
Aircraft	459,698	453,000
Buildings	2,682,810	2,682,810

Office equipment	942,442	83,459
	34,680,049	10,292,514
Less: Accumulated depreciation and amortization	(2,710,646)	(2,185,981)
Total equipment, net	$31,969,403	$8,106,533

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MILLER ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (continued)
(Unaudited)

Depreciation, depletion and amortization consisted of the following:

	Nine Months Ended January 31, 2012	Nine Months Ended January 31, 2011 (as restated)
Depletion of oil and gas related assets	$9,912,822	$ 8,327,169
Depreciation and amortization of equipment	524,665	336,284
Total	$10,437,487	$ 8,663,453

Our depreciation, depletion and amortization expenses related to oil and natural gas properties were $10,437,487 and $8,663,453 for the nine months ended January 31, 2012 and 2011, respectively. Depletion expense is adjusted for costs related to oil inventory.

Useful Lives

Our furniture, fixtures, and equipment are depreciated over a life of one to seven years, machinery and equipment are depreciated over a life of five to twenty years, buildings and oil platforms are depreciated over a life of forty years, and pipeline and gathering systems are depreciated over a life of thirty years.

Exploration and Dry Hole Costs

Our exploration and dry hole costs were $574,478 and $0 for the nine months ended January 31, 2012 and 2011, respectively. These costs represent abandonments of drilling locations, dry hole costs, delay rentals, geological and geophysical costs, and the impairment, amortization, and abandonment associated with leases on our unproved properties.

(7) Derivative and Financial Instruments

We have entered into commodity derivatives to hedge a portion of our expected oil and natural gas sales from currently producing wells through January 2015. We do not apply hedge accounting to any of our derivative instruments. As a result both realized and unrealized gains and losses associated with derivative instruments are recognized in earnings.

For the nine months ended January 31, 2012 and 2011, we recognized mark-to-market gains of $1,593,336 and mark-to-market losses of $2,079,634, respectively. At January 31, 2012 and April 30, 2011, the fair value of our derivatives accounted for as mark-to-market activities amounted to a net liability of $4,251,489 and $5,037,777, respectively.

Fair Value Measurements

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

The following hierarchy prioritizes the inputs used to measure fair value. The three levels of the fair value hierarchy are as follows:

- Level 1—Quoted prices in active markets that are unadjusted and accessible at the measurement date for identical, unrestricted assets or liabilities;

- Level 2—Quoted prices for identical assets and liabilities in markets that are inactive; quoted prices for similar assets and liabilities in active markets or financial instruments for which significant inputs are observable, either directly or indirectly; or

- Level 3—Prices or valuations that require inputs that are both unobservable and significant to the fair value measurement.

MILLER ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (continued)
(Unaudited)

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

We classify assets and liabilities within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset and liability taken as a whole. All of our derivatives are classified as Level 2 because quoted prices in active markets are not readily available. The income valuation approach, which involves discounting estimated cash flows, is primarily used to determine recurring fair value measurements of our derivative instruments classified as Level 2. We prioritize the use of the highest level inputs available in determining fair value.

The following table sets forth by level within the hierarchy our assets (liabilities) that were measured at fair value on a recurring basis as of January 31, 2012 and April 30. 2011.

	Fair Value Measurements		
At January 31, 2012	Level 1	Level 2	Level 3
Warrant derivatives	$—	$(1,741,157)	$—
Commodity derivatives	—	(2,510,332)	—
Total	$—	$(4,251,489)	$—
At April 30, 2011 (as restated)			
Warrant derivatives	$—	$(2,732,659)	$—
Commodity derivatives	—	(2,305,118)	—
Total	$—	$(5,037,777)	$—

Commodity derivative assets and liabilities in the table above represent the current fair value of all open derivative positions. We classify all of our commodity derivative instruments as “derivative liability” or “derivative asset” in our Consolidated Balance Sheets.

We use observable market data or information derived from observable market data in order to determine the fair value amounts associated with our commodity derivatives. We also utilize observable market data for credit default swaps to assess the impact of non-performance credit risk when evaluating our net assets from counterparties. We utilized the cumulative S&P default rating for small, independent exploration and production (“E&P”) companies to assess the impact of non-performance credit risk relating to our net obligations to the counterparties.

At January 31, 2012 and April 30, 2011, we had 817,055 warrants outstanding consisting of 716,716 and 100,339 warrants that were issued in connection with our March 26, 2010 equity transaction. These warrants contain an exercise price reset provision, whereby the exercise price would be adjusted downward in the event our common stock is subsequently issued to others at a price below the initial warrant exercise price. Due to the reset provision, the warrants are considered freestanding derivative instruments and are classified as liabilities with fair value measured on a recurring basis in accordance with generally accepted accounting principles. We utilized the Black-Scholes model to determine fair value at January 31, 2012 and April 30, 2011 with the following weighted average assumptions:

risk-free rate of 0.3% and 1.4%, an expected term of 3.15 years and 3.91 years, expected volatility of 90.8% and 76.9% and a dividend rate of 0.0%.

MILLER ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (continued)
(Unaudited)

During the three months ended January 31, 2012 and 2011, we recorded net gains and losses on derivatives, as follows:

	Gain/(Loss) from Mark-to-Market Activities	
	Three Months Ended January 31, 2012	Three Months Ended January 31, 2011 (as restated)
Derivative Type		
Warrants	$(533,311)	$935,929
Commodity	(3,135,198)	—
Total	$(3,668,509)	$935,929

During the nine months ended January 31, 2012 and 2011, we recorded net gains on derivatives, as follows:

	Gain/(Loss) from Mark-to-Market Activities	
	Nine Months Ended January 31, 2012	Nine Months Ended January 31, 2011 (as restated)
Derivative Type		
Warrants	$991,503	$2,079,634
Commodity	601,833	—
Total	$1,593,336	$2,079,634

Fair Value of Financial Instruments

At January 31, 2012, the carrying values of cash and cash equivalents, accounts receivable, other current assets and current liabilities on the Consolidated Balance Sheets approximate their fair value because of their short-term nature. We believe the carrying value of long-term debt approximates its fair value because the interest rates on the debt approximate market interest rates for debt with similar terms, which represents the amount at which the instrument could be valued in an exchange of a current transaction between willing parties.

(8) Debt

On December 22, 2010, we entered into $5 million credit facility with PlainsCapital Bank with an initial maturity date of February 21, 2011, which was extended to July 15, 2011. The facility was personally secured by certain assets owned by our Chairman and CEO with interest bearing at a rate of 6% per annum. We paid the facility in full on June 16, 2011. As of April 30, 2011, the facility had an outstanding principal balance of $2,000,000.

Credit Facility

On June 13, 2011, we entered into a $100 million credit facility with a syndicate of lenders and Guggenheim Corporate Funding, LLC as administrative agent. The facility matures on June 13, 2013. Borrowings under the facility are secured by substantially all of our assets including all of the oil and natural gas properties that we and certain of our subsidiaries own. The facility was subject to an initial annual fee of $30,000 which was increased to $100,000 when the loan agreement was amended on August 26, 2011 (discussed below). We also agreed to pay a 2% facility fee on any subsequent increase in the borrowing base. Our current lenders and their percentage commitments in the credit facility are: Guggenheim Energy Opportunities Fund, LP 47.1%, Citibank, N.A. 28.6%, Bristol Investment Fund, LTD. 10%, WP Global Mezzanine Capital Strategy II, LP 8.8%, and WP Global Mezzanine Strategy (RLA), LP 5.5%.

On the closing of the facility, we paid Guggenheim, ratably for the benefit of the lenders, a non-refundable facility fee of $730,000. We also paid a finder’s fee of 3% of the initial borrowing base to Bristol Capital, LLC, a consultant and affiliate of Bristol Investment Fund, LTD, in the form of 100,000 shares of restricted stock and a one-time cash payment of $750,000.

On August 26, 2011, we executed an amendment to our $100 million credit facility with our lenders. In addition to the increase in the facility fee (described above), the amendment moved up the repayment schedule from January 2012 to October 2011, revised certain reporting requirements (described below), and revised the make-whole premium so as to exclude certain penalties such as the waiver fee and certain default interest. The amendment also added the requirement that we become compliant with Section 404b of the Sarbanes-Oxley Act of 2002 by our next fiscal year end, or we will be subject to an increase in the applicable margin of 2%. The amendment also waived certain events of default and we paid a waiver fee of $115,593.

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The amount available for borrowing at any one time under the credit facility is limited to the borrowing base for our oil and natural gas properties. As of January 31, 2012, our borrowing base was $35 million. The borrowing base is redetermined semi-annually, and may be redetermined more frequently at our request or by the lenders, in their sole discretion, based upon the loan collateral value assigned to the oil and gas properties along with other credit factors. Our next semi-annual borrowing base redetermination is scheduled during the first quarter of fiscal year 2013. Any increase in our borrowing base must be approved by all of the lenders, and by us.

Borrowings under the credit facility are available for acquisition, exploration, operation and maintenance of oil and natural gas properties, payment of expenses incurred in connection with the credit facility, working capital, and general company purposes. In connection with the amended credit facility, we are required to make payment on the outstanding obligations in an amount equal to 90%, or 100% in the event of default, of our consolidated net revenues, excluding certain operating costs such as royalty interests, lease operating costs and permissible general and administrative expenses up to $750,000 per calendar month. Proceeds from the sale of certain assets, indebtedness, and other proceeds received outside the ordinary course of business (but not Excluded Equity Proceeds, as that term is defined in the Loan Agreement) are required to be used for payment on the facility. As a result, we have classified amounts outstanding under the credit facility as a current liability in the accompanying Consolidated Balance Sheets.

Interest for borrowings is determined by reference to (i) the U.S. Prime Rate as published each business day in the Wall Street Journal or (ii) 5%, whichever is greater, plus an applicable margin of 4.5% per annum. In the event of non-compliance with Section 404b of the Sarbanes-Oxley Act of 2002 by April 30, 2012, the applicable margin, with respect to all borrowings under the credit facility and until compliance is reached, shall be increased to 6.5% per annum. In addition, the credit facility is subject to a make-whole premium when the facility is paid in full with the premium determined based on an internal rate of return to the lenders equal to (i) 25% per annum if the facility is repaid prior to June 30, 2012, (ii) 30% if repaid between July 1, 2012 and December 1, 2012, or (iii) 35% per annum if the facility is repaid after January 1, 2013.

Our credit facility contains various covenants that limit, among other things, our ability and our subsidiaries' ability to incur certain indebtedness, grant certain liens, merge or consolidate, sell all or substantially all of our assets, make certain loans, acquisitions, and capital expenditures and investments. In addition, we are required to issue to our lenders (i) audited financial statements within 90 days after the end of each fiscal year and (ii) unaudited financial statements within 45 days after the end of each fiscal quarter beginning with the first quarter of fiscal year 2012. On a monthly basis, we submit to our lenders (i) net revenue payment statements and a lease acquisition report for the immediately preceding calendar month and (ii) production reports and lease operating statements specifying the volume of production and sales attributable to the related production (including prices at which the sales were made) and all costs and expenditures resulting from production including, but not limited to, ad valorem, severance, production taxes, capital expenditures and lease operating expenses attributable to and incurred for each calendar month. We are also required to issue to our lenders a weekly cash flow forecast projecting our cash flow from operations in the forthcoming 13 weeks.

In addition, we are required to maintain (i) a ratio of consolidated EBITDA to interest expense (the "Interest Coverage Ratio") of at least 4.00 to 1.00 for the quarter ending January 31, 2012, a ratio of (a) the sum of (i) the orderly liquidation value of our equipment, as determined by an independent third-party appraiser plus (ii) NYMEX value to (b) total debt (the "Asset Coverage Ratio"), tested as of each redetermination date and any time between such dates that we acquire or dispose of oil and gas properties with an aggregate NYMEX value equal to $500,000 or more, of at least 2.50 to 1.00 for periods on or before April 29, 2012, and (iii) a daily average of gross production (the "Minimum Gross

Production"), calculated at the point of sale on a barrel of oil equivalent basis, from the Cook Inlet oil and gas properties starting with fiscal quarter ending October 31, 2011 and thereafter. As relevant, all financial covenants are calculated using our consolidated financial information.

The credit facility also includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties in any material respect when made or when deemed made, violation of covenants, cross-defaults, bankruptcy and insolvency events, certain unsatisfied judgments, limitation or termination of the any obligation by any guarantor under the Guarantee and Collateral Agreement, the death or incapacitation of either Mr. Scott Boruff or Mr. David Hall or the termination of their substantial involvement in our operations, and the breach or termination of the Shareholders Agreement as described below. If an event of default occurs, the lenders may accelerate the maturity of the credit facility and exercise other rights and remedies. The credit facility contains as a condition to borrowing a representation that no material adverse change has occurred, which includes, among other things, (a) a material adverse change in the business, prospects, operations, results of operations, assets, our liabilities or condition (financial or otherwise) together with our subsidiaries taken as a whole, (b) a material adverse effect on our ability (or the ability of our subsidiaries) to carry out our business, (c) the material impairment of any loan's party ability to perform its obligations under the loan documents to which it is a party or of the lender group to enforce the obligations or realize upon the collateral, or (d) a material impairment of the enforceability or priority of the administrative agent's liens with respect to the collateral. If a material adverse change were to occur, we would be prohibited from borrowing under the credit facility and would be in default, which could cause all of our existing indebtedness to become immediately due and payable, if the lenders chose to accelerate the indebtedness.

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

The credit facility requires us to hedge our projected monthly production at no less than 70% or more than 100% of the volume of production of proved developed producing reserves projected in the most recent reserve report to be produced on a rolling 24-month period, provided that we enter into hedging agreements with a lender or lender-related person or one or more investment grade counterparties, rated Aa3 or better by Moody's, A+ or better according to Standard & Poor's, or the equivalent by a rating agency acceptable to our lenders.

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

Debt Issue Costs

As of January 31, 2012 and April 30, 2011, our unamortized debt issue costs were $1,661,781 and $63,907, respectively. These costs are being amortized over the life of the credit facility through June 13, 2012.

Compliance with Debt Covenants

Our preliminary assessment indicates that we were in compliance with the financial covenant ratios and all other compliance requirements contained in our credit facility as of January 31, 2012. Our compliance report and certification are due to Guggenheim concurrently with delivery of our financial statements, which are due, at the latest, 45 days after the end of our fiscal quarter, and will be subject to their review and approval.

(9) Asset Retirement Obligation

We recognize the fair value of a liability for an asset retirement obligation ("ARO") in the period in which it is incurred if a reasonable estimate of fair value can be made. Each period, we accrete the ARO to its then present value. The associated asset retirement cost ("ARC") is capitalized as part of the carrying amount of our oil and natural gas properties, equipment and facilities. Subsequently, the ARC is depreciated using a systematic and rational method over the asset's useful life. The AROs recorded by us relate to the plugging and abandonment of oil and natural gas wells.

Inherent in the fair value calculation of ARO are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions result in adjustments to the recorded fair value of the existing ARO, corresponding adjustment is made to the ARC capitalized as part of the oil and natural gas property balance.

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The following table is a reconciliation of the ARO as of January 31:

	2012	2011
Asset retirement obligation, as of April 30	$17,293,718	$16,017,572
Accretion expense	804,738	855,842
Asset retirement obligation, as of January 31	$18,098,456	$16,873,414

Any additional retirement obligations will increase the liability associated with new oil and natural gas wells and other facilities. Actual expenditures for abandonments of oil and natural gas wells and other facilities reduce the liability for asset retirement obligations. At January 31, 2012 and April 30, 2011, there were no significant expenditures for abandonments.

(10) Share-Based Compensation

During fiscal year 2010 and 2011, our Compensation Committee and Board of Directors adopted a share-based compensation plan authorizing 3,000,000 and 8,250,000 shares of common stock under each plan, respectively. The share-based compensation plans allow us to offer our employees, officers, directors and others an opportunity to acquire a proprietary interest in the Company and enable us to attract, retain, motivate and reward such persons in order to promote the success of the Company. Each plan authorizes the issuance of incentive stock options, nonqualified stock options and restricted stock. All awards issued under the share-based compensation plans must be approved by our Compensation Committee. At January 31, 2012 and April 30, 2011, there were 1,355,000 and 5,400,000 additional shares available under the compensation plans.

We recognized $9,395,722 and $2,535,546 of employee expense related to our share-based compensation plans in the nine months ended January 31, 2012 and 2011, respectively. We also recognized $777,670 and $443,669 of non-employee expense related to warrants issued under the plans for the nine months ended January 31, 2012 and 2011, respectively. These expenses are included on our Consolidated Statements of Operations as part of "general and administrative expenses."

The following table summarizes our share-based compensation activities for the nine months ended January 31, 2012 and 2011:

	Nine Months Ended January 31, 2012		Nine Months Ended January 31, 2011 (as restated)	
	Number of Options and Warrants	Weighted Average Exercise Price	Number of Options and Warrants	Weighted Average Exercise Price
Beginning balance	11,079,955	$3.98	12,306,305	$ 2.44
Granted	4,345,000	5.16	3,275,000	5.82
Exercised	(869,000)	1.48	(4,052,534)	.62
Expired	—	—	—	—

Cancelled	(50,000)	5.94	(140,816)	4.59
Ending balance	14,505,955	4.53	11,387,955	3.90
Options exercisable at January 31	6,543,456	$3.23	4,562,955	$ 1.92

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MILLER ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (continued)
(Unaudited)

The following table summarizes our stock options and warrants outstanding, including exercisable shares at January 31, 2012:

Options and Warrants Outstanding				Options and Warrants Exercisable	
Range of Exercise Price	Number Outstanding	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$0.01 to $1.82	2,293,900	2.6	$ 0.74	2,231,400	$ 0.75
$2.00 to $4.98	2,020,000	4.6	2.78	1,553,332	2.42
$5.25 to $5.53	3,817,055	4.6	5.34	1,300,388	5.35
$5.89 to $5.94	3,750,000	8.6	5.92	791,669	5.94
$6.00 to $6.94	2,625,000	3.9	6.03	666,667	6.04
	14,505,955	5.2	$ 4.53	6,543,456	$ 3.23

(11) Shareholder’s Equity

Fiscal Year 2012 Equity

At January 31, 2012, we had 40,986,751 shares outstanding. We issued 1,106,500 shares during the nine months ended January 31, 2012, of which 869,000 shares were related to the exercise of equity rights, 100,000 shares were issued to Bristol Capital, LTD as payment for fees related to the closing of our credit facility, and 137,500 shares were issued to employees and non-employees for compensation of services.

Fiscal Year 2011 Equity

At January 31, 2011, we had 39,409,751 shares outstanding. We issued a total of 7,184,857 shares during the nine months ended January 31, 2011, of which 3,954,858 shares were related to the exercise of equity rights, 3,099,999 shares were issued in conversion of the then outstanding 6% secured convertible note, and 130,000 shares were issued to employees and non-employees for compensation of services.

(12) Income Tax

We have a significant deferred income tax liability related to the excess of the book carrying value of oil and gas properties over their collective income tax bases. This difference will reverse (through lower tax depletion deductions) over the remaining recoverable life of the properties, resulting in future taxable income in excess of income for financial reporting purposes. As an independent producer of domestic oil and gas, we take advantage of certain elective provisions presently in the Internal Revenue Code allowing for expensing of specified intangible drilling and development costs that are typically capitalized for book purposes. This temporary difference also reverses over the remaining life of the properties. As a result of these elections, we presently have U.S. federal and state net operating loss carryovers that are expected to be fully utilized against future taxable income resulting solely from the reversal of the temporary differences between the book carrying value of oil and gas properties and their tax bases. We are not relying on forecasts of taxable income from other sources in concluding that no valuation allowance is needed against any of our deferred tax assets. Our provision for income taxes for the first interim reporting period in fiscal 2012 was based on an estimate of our annual effective tax rate for the full fiscal year. The computation of the annual effective tax rate includes a forecast of our estimated “ordinary” income (loss), which is our annual income (loss) from operations before tax, excluding unusual or infrequently occurring (or discrete) items. Significant management judgment is required in the projection of ordinary income (loss) in order to determine the estimated annual effective tax rate. The low absolute levels of income (or loss) projected for fiscal 2012 cause an unusual relationship between income (loss) and income tax expense (benefit), with small changes resulting in: (i) a significant impact on the rate possibly and, (ii) potentially unreliable estimates. As a result, we computed the provision for income taxes for the quarters and year-to-dates ended October 31, 2011 and January 31, 2012 by applying the actual effective tax rate to the year-to-date loss, as permitted by accounting principles generally accepted in the United States of America. The effective tax rate for the year-to-date period ended January 31, 2012 was a benefit of 38.2%. No cash payments of income taxes were made during the year-to-date period ended January 31, 2012, and no significant payments are expected during the succeeding 12 months.

In light of the adjustments to our consolidated financial statements during the year ended April 30, 2010, we are in the process of amending our U.S. federal and state income tax returns for that year. These adjustments have a carryforward effect into future years, beginning with the tax year ended April 30, 2011. Due to the significance and complexity of these tax adjustments, we did not file our U.S. federal and state income tax returns for the year ended April 30, 2011 by their extended due date of January 17, 2012, and February 15, 2012, respectively. We expect to have these amended and initial filings completed by April 30, 2012. We do not expect significant cash taxes, interest, or penalties to result from these amended or delinquent filings and do not expect that the failure to timely amend or file our returns could reasonably be expected to result in a Material Adverse Change (as such term is defined under our loan agreement).

MILLER ENERGY RESOURCES, INC.
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(13) Commitments and Contingencies

In the course of our normal business affairs, we are subject to possible loss contingencies arising from federal, state and local environmental, health and safety laws and regulations. These laws and regulations can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations. We are also subject to possible loss contingencies from third-party litigation. As of January 31, 2012, other than the matters discussed below, there were no matters which, in the opinion of management, would have a material adverse effect on the financial position, results of operations or cash flows of MER and its subsidiaries, taken as a whole.

On November 5, 2009, CIE entered into an Assignment Oversight Agreement with the Alaska Department of Natural Resources ("DNR") which set our 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:

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

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

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

- submit a new plan of development and plan of operations for the Alaska DNR's approval on or before December 15, 2009 and submit a plan of development annually thereafter on or before February 1, 2010.

The agreement required CIE to obtain financing in the minimum amount of $5,150,000 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, and construction of a grind and inject plant at the West McArthur River facility, normal operating expenses associated with the leases and infrastructure and other capital project which are to be pre-approved by the Alaska DNR. The agreement also required CIE to demonstrate funding commitments to support restoration of the base production at the Redoubt Unit, including bringing a number of the shut-in wells back on line, which was estimated at $31 million in the agreement but which we have internally increased to $35 million to accommodate the purchase of drilling rights. We have subsequently provided these funds for the West McArthur River facility using a portion of the proceeds of our capital raising efforts described elsewhere herein, and intend to seek alternative sources of funding for the balance of the necessary capital.

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

On March 11, 2011, CIE entered into a Performance Bond Agreement with the Alaska 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 $18,000,000 for the bond. The Agreement includes a funding schedule, which requires payments annually on July 1, beginning in 2013, of amounts ranging from $1,000,000 to $2,500,000 per year, and totaling $12,000,000. The Agreement also clarifies that approximately $6,600,000 (as of June 30, 2010) from a bond funded by the previous owner and held in a State 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 (which currently holds the $6.6 million) 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.

MILLER ENERGY RESOURCES, INC.
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The Agreement confirms that the obligation to post a performance bond for the Onshore Assets (as that term is defined in the Assignment Oversight Agreement) has been eliminated, and this Agreement supersedes the Assignment Oversight Agreement's requirements to post a performance bond under the Assignment Oversight Agreement for the Offshore Assets (as that term is defined in the Assignment Oversight Agreement).

The amount of the performance bond is subject to adjustment if a material change in the assets occurs, for annual inflation, and upon the completion of certain performance obligations. CIE will be in default of the Agreement if it fails to comply with a material obligation under the Agreement or if it becomes insolvent. Certain conditions that would entitle DNR to declare CIE in default are subject to a 30 day cure period.

At January 31, 2012, we had $475,000 in exploration work commitments arising from two exploration licenses of 534,383 acres located in the Susitna River Basin in Alaska. These commitments require the Company to invest in exploration efforts on those leases. In addition to the exploration work commitments, we have a $250,000 performance obligation relating to our two Olsen Creek leases in Alaska. The performance obligation requires the Company to spud a well on a lease by December 31, 2012 or one of the leases, to be chosen at the sole discretion of the lessor, will be terminated. If a well is not spud on the remaining lease by December 31, 2013, the unspent portion of the $250,000 will be forfeited.

(14) Alaska Production Credits

The Company qualifies for several credits under Alaska statute 43.55.023:

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

We recognize a receivable when the amount of the credit is reasonably estimable and receipt is probable of occurrence (based on actual qualifying expenditures incurred). For expenditure and exploration based credits, the credit is recorded as a reduction to the related assets. For carried-forward annual loss credits, the credit is recorded as a reduction to the Alaska production tax. To the extent the credit amount exceeds the Alaska production tax, the credit is recorded as a reduction to general and administrative expenses.

At January 31, 2012 and April 30, 2011, we reduced the basis of capitalized assets by $7,563,446 and $3,658,354 for expenditure and exploration credits. The reductions are recorded on our Consolidated Balance Sheets in "oil and gas properties." We also had outstanding receivables from the State of Alaska in the amount of $5,221,817 and $3,620,336 at January 31, 2012 and April 30, 2011, respectively.

(15) Litigation

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

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On May 11, 2011, the Court of Appeals of Tennessee at Knoxville returned its opinion in the case styled CNX Gas Company, LLC v. Miller Petroleum, Inc., et al. As previously reported, CNX Gas Company, LLC (“CNX”) commenced litigation on June 11, 2008 in the Chancery Court of Campbell County, State of Tennessee to enjoin us from assigning or conveying certain leases described in the Letter of Intent signed by CNX and our company on May 30, 2008, to compel us to specifically perform the assignments as described in the Letter of Intent, and for damages. After the trial court granted the motion for summary judgment of the company and other party defendants and dismissed the case, finding that there were no genuine issues of material fact and we were entitled to judgment as a matter of law, CNX appealed. All parties filed briefs and the Court of Appeals heard oral arguments on May 18, 2010. In its May 11, 2011 opinion, the Court of Appeals reversed the trial court’s grant of summary judgment in favor of our company and the other party defendants, and remanded the case back to the trial court for further proceedings. On July 28, 2011, the case was dismissed without prejudice on the motion of CNX. On August 4, 2011, a breach of contract case was filed against us in the United States District Court for the Eastern District of Tennessee. The case, styled CNX Gas Company, LLC v. Miller Energy Resources, Inc., Chevron Appalachia, LLC as successor in interest to Atlas America, LLC, Cresta Capital Strategies, LLC and Scott Boruff, arises from the same allegations as the previous action filed in state court and voluntarily dismissed on July 28, 2011. The federal case seeks money damages from us for breach of contract; however, unlike the previous action, it does not seek specific performance of the assignments at issue. The Plaintiff claims that the other defendants tortiously interfered with, or induced the breach of, the letter of intent between us and the Plaintiff. We have filed our Answer and intend to vigorously defend this suit.

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

On June 15, 2011, a breach of contract lawsuit was filed against us and CIE in the United States District Court for the Eastern District of Pennsylvania styled VAI, Inc. v. Miller Energy Resources, Inc., f/k/a Miller Petroleum, Inc. and Cook Inlet Energy, LLC. The Plaintiff alleges three causes of action: (1) breach of contract, (2) unfair enrichment, and (3) breach of the implied covenant of good faith and fair dealing. The case seeks damages in warrants to purchase our common stock and monetary damages for certain fees and expenses. The Sale Agreement with David Hall, Walter “JR” Wilcox, and Troy Stafford dated December 10, 2009 contains indemnification provisions relevant to this claim. We have filed a Motion to Dismiss for lack of personal jurisdiction, which is pending while limited discovery is conducted.

Class Action Lawsuits

In August 2011, five class action lawsuits were filed against us in the United States District Court for the Eastern District of Tennessee. These lawsuits make similar claims, and we expect that they will be consolidated into one case. We have retained DLA Piper to defend us in these actions. Three motions for consolidation and appointment of a lead plaintiff have been filed, but have not been heard yet. Pursuant to stipulation, no response to the complaint is required until after a lead plaintiff is appointed and a consolidated complaint is filed. Descriptions of the individual cases follow.

On August 12, 2011, a lawsuit was filed against us in the United States District Court for the Eastern District of Tennessee. The case, styled Ruben Husu, Individually and on behalf of all others similarly situated v. Miller Energy Resources, Inc. f/k/a Miller Petroleum, Inc., Scott M. Boruff, and Paul W. Boyd was filed on August 12, 2011.   The Plaintiff alleges two causes of action against the Defendants: (1) violation of Section 10(b) and Rule 10b-5 of the Exchange Act, (2) violation of Section 20(a) of the Exchange Act. The case seeks money damages against the Company and the other defendants, and payment of the Plaintiffs' attorney's fees.

On August 16, 2011, a lawsuit was filed against us in the United States District Court for the Eastern District of Tennessee. The case, styled James D. DiCenso, Individually and on behalf of all others similarly situated v. Miller Energy Resources, Inc. f/k/a Miller Petroleum, Inc., Deloy Miller, Scott M. Boruff, and Paul W. Boyd and David J. Voyticky. The Plaintiff alleges two causes of action against the Defendants: (1) violation of Section 10(b) and Rule 10b-5 of the Exchange Act, (2) violation of Section 20(a) of the Exchange Act. The case seeks money damages against the Company and the other defendants, and payment of the Plaintiffs' attorney's fees.

MILLER ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (continued)
(Unaudited)

On August 16, 2011, a lawsuit was filed in the United States District Court for the Eastern District of Tennessee. The case is styled Steven Arlow, Individually and on behalf of all others similarly situated v. Miller Energy Resources, Inc. f/k/a Miller Petroleum, Inc., Scott M. Boruff, and Paul W. Boyd. The Plaintiff alleges two causes of action against the Defendants: (1) violation of Section 10(b) and Rule 10b-5 of the Exchange Act, (2) violation of Section 20(a) of the Exchange Act. The cases seek unspecified money damages against the Company and the other defendants, and payment of the Plaintiffs' attorney's fees.

On August 18, 2011, a lawsuit was filed against us in the United States District Court for the Eastern District of Tennessee. The case is styled Yingtao Liu, Individually and on behalf of all others similarly situated v. Miller Energy Resources, Inc. f/k/a Miller Petroleum, Inc., Scott M. Boruff, Paul W. Boyd, Deloy Miller, David J. Voyticky, Herman Gettelfinger, Jonathan S. Gross, David M. Hall, Merrill A. McPeak, Charles Stivers, and Don A. Turkleson. The Plaintiff alleges two causes of action against the Defendants: (1) violation of Section 10(b) and Rule 10b-5 of the Exchange Act, (2) violation of Section 20(a) of the Exchange Act. The case seeks unspecified money damages against the Company and the other defendants, and payment of the Plaintiffs' attorney's fees.

On August 19, 2011, a lawsuit was filed in the United States District Court for the Eastern District of Tennessee. The case is styled Brandon W. Ward, Individually and on behalf of all others similarly situated v. Miller Energy Resources, Inc. f/k/a Miller Petroleum, Inc., Scott M. Boruff, and Paul W. Boyd. The Plaintiff alleges two causes of action against the Defendants: (1) violation of Section 10(b) and Rule 10b-5 of the Exchange Act, (2) violation of Section 20(a) of the Exchange Act. The cases seek unspecified money damages against the Company and the other defendants, and payment of the Plaintiffs' attorney's fees.

Shareholder Derivative Lawsuits

In August 2011, three shareholder derivative actions were filed against us. Two were filed in the United States District Court for the Eastern District of Tennessee; the other, Valdez, was filed in Knox County Chancery Court. We removed the Valdez case to federal court, but it was remanded to state court. We expect that the federal cases will be consolidated. We have retained DLA Piper to defend us in these actions. Descriptions of the individual cases follow.

On August 23, 2011, a derivative action was filed against us in Knox County Chancery Court. The case is styled Marco Valdez, derivatively on behalf Miller Energy Resources, Inc. v. Deloy Miller, Scott M. Boruff, Jonathan S. Gross, Herman Gettelfinger, David Hall, Merrill A. McPeak, Charles M. Stivers, Don A. Turkleson, and David J. Voyticky, and Miller Energy Resources, Inc., nominal defendant. The suit alleges the following causes of action: (1) Breach of Fiduciary Duty for disseminating false and misleading information; (2) Breach of Fiduciary Duty for failure to maintain internal controls; (3) Breach of Fiduciary Duty for failing to properly oversee and manage the company; (4) Unjust Enrichment; (5) Abuse of Control; Gross Mismanagement, and; (6) Waste of Corporate Assets. The Plaintiff seeks unspecified money damages from the individual defendants, that the Company take certain actions with respect to its management, restitution to the Company, and the Plaintiff's attorney fees and costs. By agreement, no responsive pleading is required to be filed by us in this case until March 30, 2012.

On August 25, 2011, a derivative action, styled Jacquelyn Flynn, derivatively on behalf Miller Energy Resources, Inc. v. Scott M. Boruff, Paul W. Boyd, Deloy Miller, Jonathan S. Gross, Herman Gettelfinger, David Hall, Merrill A. McPeak, Charles M. Stivers, Don A. Turkleson, and David Voyticky, and Miller Energy Resources, Inc., nominal defendant, was filed in the District Court for the Eastern District of Tennessee. It contains substantially similar claims as Valdez. The suit alleges the following causes of action: (1) Breach of Fiduciary Duty for disseminating false and misleading information; (2) Breach of Fiduciary Duty for failure to maintain internal controls; (3) Breach of Fiduciary Duty for failing to properly oversee and manage the company; (4) Unjust Enrichment; (5) Abuse of Control; Gross Mismanagement, and; (6) Waste of Corporate Assets. The Plaintiff seeks unspecified money damages from the individual defendants, that the Company take certain actions with respect to its management, restitution to the Company, and the Plaintiff's attorney fees and costs. We have filed a motion to dismiss this case.

On August 31, 2011, a derivative action, styled Patrick P. Lukas, derivatively on behalf Miller Energy Resources, Inc. v. Merrill A. McPeak, Scott M. Boruff, Deloy Miller, Jonathan S. Gross, Herman Gettelfinger, David Hall, Charles M. Stivers, Don A., Turkleson, and David J. Voyticky, and Miller Energy Resources, Inc., nominal defendant, was filed in the District Court for the Eastern District of Tennessee. It contains substantially similar claims as the other two purported derivative actions. The suit alleges the following causes of action: (1) Breach of Fiduciary Duty for disseminating materially false and misleading information; (2) Breach of Fiduciary Duty for failing to properly oversee and manage the company; (3) Unjust Enrichment; (4) Abuse of Control; (5) Gross Mismanagement and Waste of Corporate Assets. The Plaintiff seeks unspecified money damages from the individual defendants, that the Company take certain actions with respect to its management, restitution to the Company, and the Plaintiff's attorney fees and costs. We have filed a motion to dismiss this case.

MILLER ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (continued)
(Unaudited)

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.

(16) Restatement

During our fiscal 2011 third quarter ended January 31, 2011, we identified misstatements related to our interim unaudited consolidated balance sheet as of January 31, 2011, our unaudited consolidated statements of operations for the three and nine month periods ended January 31, 2011, and our statement of cash flows for the nine month period ended January 31, 2011. As a result, we restated our interim unaudited consolidated financial statements in our fiscal 2011 third quarter Form 10-Q filed with the SEC on March 22, 2011. During our fiscal 2011 fourth quarter ended April 30, 2011, we identified additional misstatements that related to our interim unaudited consolidated financial statements. As a result, we reported a second restatement of our interim unaudited consolidated financial statements in our fiscal 2011 Form 10-K filed with the SEC on August 29, 2011. A summary of the corrected misstatements is as follows:

- We overstated depreciation, depletion and amortization for the three and nine months ended January 31, 2011 by $2,872 and $1,091,592 due to our failure to properly record depletion, depreciation and amortization expense related to leasehold costs, wells and equipment, fixed assets, asset retirement obligations and a failure to appropriately record state production credits related to our Alaska operations.

- We overstated oil and gas revenue and oil and gas operating expense for the three and nine month periods ended January 31, 2011 by $1,429,499 and $3,291,232 due to our failure to appropriately account for overriding royalty interests. We incorrectly accounted for overriding royalty interests on a gross basis rather than on a net basis.

- We overstated oil and gas operating and cost of other revenue for the three and nine month periods ended January 31, 2011 by $1,429,499 and $3,291,232 due to the erroneous classification of certain expense accounts as oil and gas operating that should have been recorded in cost of other revenue.

- We understated general and administrative expense for the three and nine month periods ended January 31, 2011 by $549,135 and $881,936 due to our failure to appropriately calculate share based compensation expense for stock options and warrants.

- We reported a net gain on derivatives of $1,444,900 rather than gain of $935,929, for a total adjustment of $508,971 for the three month period ended January 31, 2011 and reported a gain of $5,132,795 rather than a gain of $2,079,634, for a total adjustment of $3,053,161 for the nine month period ended January 31, 2011, due to our failure to appropriately calculate the mark-to-market adjustment for each of our warrant derivatives.

- We failed to record a loss on exchange of $638,468 related to an unproved leasehold that was disposed of during the nine months ended January 31, 2011.

- We did not consolidate MEI, an entity that we control, the correction of which resulted in a decrease to notes payable, an increase to stockholders’ equity, and minor adjustments to cash, other assets and accrued expenses.

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We did not appropriately record the income tax benefit, which after consideration of the restatement adjustments described herein, resulted in an increase in the tax benefit for the three and nine month periods ended January 31, 2011 of $58,113 and $3,617,830.

MILLER ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (continued)
(Unaudited)

The following is a summary presentation of corrections made to the Company's unaudited consolidated balance sheet as of January 31, 2011, as previously filed with the SEC on March 22, 2011 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	$3,402,739
Restricted cash	290,531	—	290,531
Accounts receivable, net	1,487,669	—	1,487,669
State production credits receivable	5,417,126	—	5,417,126
Inventory	528,573	—	528,573
Prepaid expenses	1,926,357	132,207	2,058,564
Oil and gas properties, net	480,387,148	(287,058)	480,100,090
Equipment, net	8,016,302	105,719	8,122,021
Land	526,500	—	526,500
Restricted cash, non-current	2,299,538	—	2,299,538
Other assets	289,009	(289,009)	—
TOTAL ASSETS	$504,327,699	$(94,348)	$504,233,351
LIABILITIES AND STOCKHOLDERS' EQUITY			
LIABILITIES			
Accounts payable	$9,183,616	$—	$9,183,616
Accrued expenses	766,507	278,247	1,044,754
Derivative liability	1,261,291	1,960,274	3,221,565
Unearned revenue	41,443	—	41,443
Deferred income taxes	184,468,878	(3,479,612)	180,989,266
Asset retirement obligation	16,913,376	(39,962)	16,873,414
Notes payable	4,850,419	(2,350,419)	2,500,000
Total	217,485,530	(3,631,472)	213,854,058
STOCKHOLDERS' EQUITY			
Common stock	3,941	—	3,941
Additional paid-in capital	43,866,501	2,236,633	46,103,134
Retained earnings	242,971,727	1,300,491	244,272,218
Total	286,842,169	3,537,124	290,379,293
TOTAL LIAB. AND STOCKHOLDERS' EQUITY	$504,327,699	$(94,348)	$504,233,351

MILLER ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (continued)
(Unaudited)

The following is a summary presentation of corrections made to the Company's unaudited consolidated statement of operations for the three month period ended January 31, 2011, as previously filed with the SEC on March 22, 2011 on Form 10-Q for the quarter ended January 31, 2011:

	For the Three Months Ended Jan. 31, 2011 (as reported)	Corrections	For the Three Months Ended Jan. 31, 2011 (as restated)
REVENUES			
Oil and gas revenue	$ 7,039,457	$ (1,429,499)	$ 5,609,958
Other revenue	775,664	—	775,664
Total revenues	7,815,121	(1,429,499)	6,385,622
COSTS AND EXPENSES			
Oil and gas operating	2,994,888	(1,163,822)	1,831,066
Cost of other revenue	691,504	(265,677)	425,827
General and administrative	1,204,116	549,135	1,753,251
Depreciation, depletion and amortization	3,357,654	(2,872)	3,354,782
Total costs and expenses	8,248,162	(883,236)	7,364,926
OPERATING LOSS	(433,041)	(546,263)	(979,304)
OTHER INCOME (EXPENSE)			
Interest income	9,253	—	9,253
Interest expense	(111,162)	—	(111,162)
Gain (loss) on derivatives, net	1,444,900	(508,971)	935,929
Total other income (expense)	1,342,991	(508,971)	834,020
LOSS BEFORE INCOME TAXES	909,950	(1,055,234)	(145,284)
INCOME TAX BENEFIT	—	58,113	58,113
NET LOSS	$ 909,950	$ (997,121)	$ (87,171)
LOSS PER SHARE:			
Basic	$ 0.02	$ (0.02)	$ (0.00)
Diluted	$ 0.02	$ (0.02)	$ (0.00)
AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:			
Basic	37,774,861		37,774,861
Diluted	41,392,130		37,774,861

MILLER ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (continued)
(Unaudited)

The following is a summary presentation of corrections made to the Company's unaudited consolidated statement of operations for the nine month period ended January 31, 2011, as previously filed with the SEC on March 22, 2011 on Form 10-Q for the quarter ended January 31, 2011:

	For the Nine Months Ended Jan. 31, 2011 (as reported)	Corrections	For the Nine Months Ended Jan. 31, 2011 (as restated)
REVENUES			
Oil and gas revenue	$17,912,429	$(3,291,232)	$14,621,197
Other revenue	1,778,601	—	1,778,601
Total revenue	19,691,030	(3,291,232)	16,399,798
COSTS AND EXPENSES			
Oil and gas operating	8,910,577	(2,636,166)	6,274,411
Cost of other revenue	1,528,659	(655,066)	873,593
General and administrative	8,052,482	881,936	8,934,418
Depreciation, depletion and amortization	10,610,887	(1,091,592)	9,519,295
Total costs and expenses	29,102,605	(3,500,888)	25,601,717
OPERATING LOSS	(9,411,575)	209,656	(9,201,919)
OTHER INCOME (EXPENSE)			
Interest income	14,980	—	14,980
Interest expense	(740,922)	(312,774)	(1,053,696)
Gain on derivatives, net	5,132,795	(3,053,161)	2,079,634
Other expense, net	(70,755)	(638,468)	(709,223)
Total other income (expense)	4,336,098	(4,004,403)	331,695
LOSS BEFORE INCOME TAXES	(5,075,477)	(3,794,747)	(8,870,224)
INCOME TAX BENEFIT	(69,791)	3,617,830	3,548,039
NET LOSS	$(5,145,268)	$(176,917)	$(5,322,185)
LOSS PER SHARE:			
Basic	$(0.14)	$(0.01)	$(0.15)
Diluted	$(0.12)	$(0.03)	$(0.15)
AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:			
Basic	37,774,861		34,975,126
Diluted	41,392,130		34,975,126

MILLER ENERGY RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (continued)
(Unaudited)

The following is a summary presentation of corrections made to the Company's unaudited consolidated statement of cash flows for the nine month period ended January 31, 2011, as previously reported in the Company's Form 10-Q for the fiscal 2011 third quarter, filed with the SEC on March 22:

	For the Nine Months Ended January 31, 2011 (as reported)	Corrections	For the Nine Months Ended January 31, 2011 (as restated)
Cash Flows from Operating Activities			
Net loss	$(5,145,266)	$(176,919)	$(5,322,185)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation, depletion and amortization	10,506,628	(674,559)	9,832,069
Loss (gain) on sale of equipment	(7,500)	633,448	625,948
Gain on sale of oil and gas properties	(12,500)	12,500	—
Issuance of equity for compensation	2,042,165	493,364	2,535,529
Issuance of equity for services	—	609,559	609,559
Gain on derivative instruments	(5,132,795)	3,053,161	(2,079,634)
Deferred income taxes	—	(3,617,850)	(3,617,850)
State production tax credits	(908,535)	908,535	—
Changes in operating assets and liabilities:			
Accounts receivable	4,621	—	4,621
Inventory	(6,934)	(246,029)	(252,963)
Prepaid expenses	(1,650,747)	1,095,938	(554,809)
Accounts payable	5,604,504	—	5,604,504
Accrued liabilities	344,569	(96,423)	248,146
Deferred revenue	(65,000)	106,443	41,443
Asset retirement liability	125,387	(125,387)	—
Other assets	603,434	(210,551)	392,883
Net cash provided by operating activities	6,302,031	1,765,230	8,067,261
Cash Flows from Investing Activities			
Purchase of equipment and improvements	(808,662)	38,579	(770,083)
Capital expenditures for oil and gas properties	(8,573,846)	(1,370,568)	(9,944,414)
Proceeds from sale of oil and gas properties	12,500	(12,500)	—
Proceeds from sale of equipment	7,500	(7,500)	—
Net cash used by investing activities	(9,362,508)	(1,351,989)	(10,714,497)
Cash Flows from Financing Activities			
Proceeds from borrowing	2,850,000	(350,000)	2,500,000
Exercise of equity rights	1,010,748	(63,241)	947,507
Restricted cash	(164,467)	—	(164,467)
Restricted cash non-current	(227,699)	—	(227,699)

Net cash provided by financing activities	3,468,582	(413,241)	3,055,341
Net increase in Cash in Cash and Cash Equivalents	408,105	—	408,105
Cash and Cash Equivalents at Beginning of Period	2,750,841	243,793	2,994,634
Cash and Cash Equivalents at End of Period	$3,158,946	$243,793	$3,402,739
Cash paid for interest	$—	$454,304	$454,304

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

The following discussion and analysis should be read in conjunction with the consolidated financial statements and the summary of significant accounting policies and notes included herein and in our most recent Annual Report on Form 10-K, as amended.

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," "target," " "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:

- 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,
- the Company's assumptions about the energy market;
- production levels;
- reserve levels;
- operating results;
- competitive conditions;
- technology;
- the availability of capital resources, capital expenditures and other contractual obligations;
- the supply and demand for and the price of natural gas, oil, natural gas liquids (NGLs) and other products or services;
- volatility in the commodity-futures market;
- the weather;

- inflation;
- the availability of goods and services;
- drilling risks;
- our ability to perform under the terms of the Assignment Oversight Agreement with the Alaska DNR, including meeting the funding commitments of that agreement,
- fluctuating oil and gas prices and the impact on our results of operations,
- the impact of the global economic crisis on our business,
- the impact of natural disasters on our Cook Inlet Basin operations,
- the imprecise nature of our reserve estimates,
- our ability to recover proved undeveloped reserves and convert probable and possible reserves to proved reserves,

- 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 our annual report, as amended, in its entirety, including the risks described in Item 1A. Risk Factors, along with our subsequent filings with the SEC. 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 quarterly report, and you should not rely on these statements without also considering the risks and uncertainties associated with these statements and our 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 in south central Alaska's Cook Inlet and Susitna Basins. While our primary focus is the exploration for and production of crude oil and natural gas, we also provide drilling and other services to oil and gas companies on a contract basis.

During the nine months ended January 31, 2012, we continued to focus our efforts on developing oil and natural gas properties that were acquired in fiscal year 2010 and 2011. At January 31, 2012 we had a total acreage position of 689,991 gross acres of oil and gas leases and exploration licenses consisting of 49,895 gross acres of oil and gas leases in Tennessee, 105,713 gross acres of oil and gas leases in Alaska and 534,383 gross acres of oil and gas exploration licenses in Alaska. Our exploration licenses include 471,474 acres under the Susitna Basin Exploration License No. 2 (South Susitna) and 62,909 acres under the Susitna Basin Exploration License No. 4 (North Susitna). Our short-term efforts are focused on the following strategies:

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

- organically grow 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 future oil and natural gas reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing current reserves and economically finding, developing and acquiring additional recoverable reserves. We may not be able to find, develop or acquire additional reserves to replace our current and future production at acceptable costs, which could materially adversely affect our business, financial condition and results of operations. 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.

Further, 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. We will continue to focus on adding reserves through drilling and well recompletions, as well as the corresponding costs necessary to produce such reserves. Our ability to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to timely obtain drilling permits and regulatory approvals. In accordance with our business plan, we intend to invest the capital necessary to maintain our production and our asset base over the long term. We seek to maintain or grow our production and our asset base by pursuing both organic growth opportunities and acquisitions of producing oil and natural gas reserves that are suitable for us.

How We Evaluate Our Operations

Non-GAAP Financial Measure – Adjusted EBITDA

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

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

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

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

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

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

	For the Three Months Ended January 31,		For the Nine Months Ended January 31,	
	2012	2011	2012	2011
Net loss before taxes	$(10,585,195)	$(145,284)	$(18,085,754)	$(8,870,224)
Adjusted by:				
Interest expense, net	812,796	101,909	2,000,264	1,038,716
Depreciation, depletion and amortization	2,826,065	3,110,976	10,437,487	8,663,453
Accretion of asset retirement obligation	268,028	243,806	804,738	855,842
Loss on sale of assets	—	—	—	625,948
Exploration expense	394,686	—	574,478	—
Share-based compensation	4,049,841	845,506	10,505,915	2,979,215
Unrealized (gain) loss on MTM activities	3,598,048	(935,929)	(786,289)	(2,079,634)
Adjusted EBITDA	$1,364,269	$3,220,984	$5,450,839	$3,213,316

Significant Operational Factors

- Realized Prices: Our average oil and natural gas realized prices for the three and nine months ended January 31, 2012 were $97.87 and $92.52 compared to $87.24 and $79.73 for the same periods in the prior year. After deducting lease operating expenses, the average realized prices were $63.22 and $60.24 compared to $68.20 and $58.05. These results exclude the impact of commodity derivative settlements.
- Production: Our production for the three and nine months ended January 31, 2012 was approximately 89,234 BOE and 306,250 BOE as compared to 78,498 BOE and 241,741 BOE for the same periods in the prior year. The increase in production is attributable to the completion of two wells in the Redoubt Shoals field in the current fiscal year.

- Capital Expenditures and Drilling Results: During the nine months ended January 31, 2012, we spent approximately $34 million in cash expenditures. Rig 34 is completed pending certification from the State of Alaska. Rig 35 has been successfully mobilized to the Osprey Platform in Alaska and is currently being assembled.

We experience earnings volatility as a result of not using hedge accounting for our oil and natural gas commodity derivatives used to hedge our exposure to changes in commodity prices. This accounting treatment can cause earnings volatility as the positions of future oil and natural gas production are marked-to-market. The non-cash unrealized gains or losses are included on our Consolidated Statement of Operations until the derivatives are cash settled as the commodities are produced and sold. We do not enter into speculative trading positions and we only use commodity derivatives to lock in the future sales price for a portion of our expected oil and natural gas production.

During the three months ended January 31, 2012, we completed our modifications to Rig 34, allowing the rig to drill in winter conditions, accommodate a larger Blowout Preventer ("BOP") stack, and install a mud handling system. The rig was mobilized to the Kustatan Gas Field to prepare for a workover on our KF-1 well. CIE has been working with the Alaska Oil and Gas Conservation Commission (AOGCC) to receive final approvals to operate the rig. We expect this will be received during the fourth quarter of fiscal year 2012, after which the workover of KF-1 will commence.

All components of Rig 35 have been mobilized to Alaska. The process of mobilizing the equipment to the Osprey Platform began in the second quarter of fiscal year 2012, as well as the assembly of the rig's substructure. In January 2012 the region experienced prolonged near-record cold weather, which caused us to temporarily delay our construction efforts due to concerns of safety. The cold weather also led to the generation of a very large volume of ice in the Cook Inlet, which made shipping and the operation of workboats challenging. Warmer temperatures in the third quarter of 2012 have allowed us to resume work on the assembly of Rig 35.

Results of Operations

The following table sets forth selected operating data for the periods indicated:

	Three Months Ended January 31,			Nine Months Ended January 31,		
	2012	2011	Variance	2012	2011	Variance
Gross Sales Volumes (Alaska)						
Oil (BBLs)	88,462	78,506	9,956	303,142	232,764	70,378
Gas (Mcf)	9,607	9,865	(258)	36,111	18,299	17,812
Gross Sales Volumes (Tennessee)						
Oil (BBLs)	6,893	5,219	1,674	21,558	18,652	2,906
Gas (Mcf)	71,153	64,807	6,346	235,517	209,597	25,920
Gross Sales Volumes (Total)						
Oil (BBLs)	95,355	83,725	11,630	324,700	251,416	73,284
Gas (Mcf)	80,760	74,672	6,088	271,628	227,896	43,732
Sales Volumes (BOE)	108,815	96,170	12,645	369,971	289,399	80,572
Net Production Volume (BOE/day)						
Alaska	80,280	71,232	9,048	277,097	218,797	58,300
Tennessee	8,954	7,266	1,688	29,153	22,944	6,209
Production Volume	89,234	78,498	10,736	306,250	241,741	64,509
Net Oil and Gas Revenue	$7,943,779	$5,609,958	$2,333,821	$24,703,999	$14,621,197	$10,082,802
Lease Operating Expenses	$3,769,742	$1,831,066	$1,938,676	$11,940,863	$6,274,411	$5,666,452
DD&A	$2,826,065	$3,110,976	$(284,911)	$10,437,487	$8,663,453	$1,774,034
Additional BOE Data:						
Realized Sales Price	$97.87	$87.24	$10.63	$92.52	$79.73	$12.79
Lease Operating Expenses	$34.64	$19.04	$15.60	$32.28	$21.68	$10.60

DD&A	$25.97	$32.35	$(6.38)	$28.21	$29.94	$(1.73)

Revenue

Three months ended January 31, 2012 compared to three months ended January 31, 2011

The following table illustrates the components of our revenues for the comparative fiscal quarters indicated.

	Three Months ended January 31,			
	2012	2011 (as restated)	$ Variance	% Variance
Oil and natural gas sales	$7,943,779	$5,609,958	$2,333,821	42 %
Other revenues	499,664	775,664	(276,000)	(36 %)
Total revenues	$8,443,443	$6,385,622	$2,057,821	32 %

Oil and natural gas sales. For the three months ended January 31, 2012, oil and natural gas sales increased $2,333,821, or 42%, to $7,943,779 as compared to $5,609,958 for the same period in fiscal year 2011. The increase is correlated with an increase in net production of 10,736 BOE, or 14%, and an approximate $11, or 12%, increase in the average realized sales price. Total net production was 89,234 BOE at an average net realized sales price of $97.87 per BOE and 78,498 BOE at an average net realized sales price of $87.24 per BOE for the three months ended January 31, 2012 and 2011, respectively. Broken down by region, Alaska contributed 80,280 BOE, or 90%, and 71,232 BOE, or 91%, to total net production during the three months ended January 31, 2012 and 2011, respectively. The remaining difference of approximately 10% represents Tennessee's contribution to total net production for the respective periods.

Our net natural gas production remained relatively constant in comparison to prior periods with a minor increase of 7,735 Mcf to 132,432 Mcf for the three months ended January 31, 2012, compared to 124,697 Mcf for the same period in fiscal year 2011. Broken down by region, Tennessee produced and sold approximately 71,153 Mcf, or 54%, and 64,807 Mcf, or 52%, of total net natural gas production for the three months ended January 31, 2012 and 2011, respectively. Alaska produced approximately 61,279 Mcf, or 46%, and 59,890 Mcf, or 48%, during the same comparative periods, of which 51,672 Mcf and 50,025 Mcf were used as fuel gas to operate certain of our production facilities in Alaska.

Other revenues. Other revenues consist primarily of servicing and drilling revenue. For the three months ended January 31, 2012, servicing revenue decreased due to a decrease in contract services associated with plugging, drilling, maintenance and repair of third party wells. This decrease is partially offset by $299,320 in miscellaneous income generated from the rental of our facilities in Alaska. We did not generate the same income in the three months ended January 31, 2011.

Nine months ended January 31, 2012 compared to nine months ended January 31, 2011

The following table illustrates the components of our revenues for the comparative fiscal periods indicated.

	Nine Months ended January 31,			
	2012	2011 (as restated)	$ Variance	% Variance
Oil and natural gas sales	$24,703,999	$14,621,197	$10,082,802	69 %

Other revenues	1,799,980	1,778,601	21,379	1	%
Total revenues	$26,503,979	$16,399,798	$10,104,181	62	%

Oil and natural gas sales. For the nine months ended January 31, 2012, oil and natural gas sales increased $10,082,802, or 69%, to $24,703,999 as compared to $14,621,197 for the same period in fiscal year 2011. This is attributable to a 64,510 BOE, or 27%, increase in net production and an approximate $13, or 16%, increase in the average realized sales price per BOE. Total net production was 306,250 BOE at an average net realized sales price of $92.52 per BOE and 241,741 BOE at an average net realized sales price of $79.73 per BOE for the nine months ended January 31, 2012 and 2011, respectively. Broken down by region, Alaska contributed 277,097 BOE, or 90%, and 218,797 BOE, or 91%, during the nine months ended January 31, 2012 and 2011, respectively. The remaining difference of approximately 10% represents Tennessee's contribution to total net production for the respective periods.

Our net natural gas production increased 34,993 Mcf, or 9%, to 424,132 Mcf for the nine months ended January 31, 2012, compared to 389,139 Mcf for the nine months ended January 31, 2011. Broken down by region, Tennessee produced and sold 235,517 Mcf, or 56%, and 209,597 Mcf, or 54%, of total net natural gas production during the nine months ended January 31, 2012 and 2011, respectively. Alaska produced approximately 188,615 Mcf, or 44%, and 179,542, or 46%, during the same comparative periods, of which 152,504 Mcf and 161,243 Mcf were used as fuel gas to operate certain of our production facilities in Alaska.

Other revenues. Other revenues for the nine months ended January 31, 2012 remained relatively constant in comparison to the nine months ended January 31, 2011. This is attributable to the combination of a decrease in servicing revenues and an increase in rental income. During the nine months ended January 31, 2012, we generated $525,927 in facility rental income that was not similarly earned in the nine months ended January 31, 2011.

Costs and Expenses

Three months ended January 31, 2012 compared to three months ended January 31, 2011

The following table illustrates the components of our costs and expenses for the comparative fiscal quarters indicated.

	Three Months Ended January 31,			
	2012	2011 (as restated)	$ Variance	% Variance
Oil and gas operating costs	$3,769,742	$1,831,066	$1,938,676	106 %
Cost of other revenues	296,169	425,827	(129,658)	(30 %)
General and administrative	6,729,265	1,753,251	4,976,014	284 %
Exploration expense	394,686	—	394,686	100 %
Depreciation, depletion, and amortization	2,826,065	3,110,976	(284,911)	(9 %)
Accretion of asset retirement obligation	268,028	243,806	24,222	10 %
Other operating expense (income), net	255,040	—	255,040	100 %
Total costs and expenses	$14,538,995	$7,364,926	$7,174,069	97 %

Oil and gas operating costs. Our operating costs generally consist of lease operating expenses, labor, vehicle, supervision, transportation, minor maintenance, tools and supplies expenses, as well as production and ad valorem taxes.

For the three months ended January 31, 2012, oil and gas operating costs increased $1,938,676, or 106%, to $3,769,742, compared to $1,831,066 for the same period in fiscal year 2011. This increase in operating costs is primarily related to $1.8 million in higher total spending associated with our operation of the Redoubt Shoals field and Kustatan production facility that were newly operational in May 2011. Consequently, our lease operating costs increased $16, or 82%, to $34.64 per BOE for the three months ended January 31, 2012, compared to $19.04 per BOE for the three months ended January 31, 2011. As production from the Redoubt Shoals field increases, we expect our operating costs to increase in the aggregate, but decrease on a per BOE basis.

Cost of other revenues. Cost of other revenues represent costs incurred in the performance of drilling and related services to third parties. The primary component is direct labor costs associated with these services, as well as costs associated with equipment, parts and repairs.

During the three months ended January 31, 2012, cost of other revenues decreased by 30% as a result of the 36% decrease in other revenues. This is directly correlated with the decrease in certain contracted services 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.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees, and other costs not directly associated with field operations.

General and administrative expenses increased $4,976,014, or 284%, to $6,729,265 for the three months ended January 31, 2012, compared to $1,753,251 for the same period in fiscal year 2011. This increase is attributable to an increase of $3,204,335 in non-cash compensation, $306,314 in travel expenses, and $1,421,362 in professional and other fees. As of January 31, 2012 and for the nine months then ended, we granted a total 4,045,000 shares of stock options and warrants to certain directors, officers, employees and outside consultants of the Company. These grants were strategic in our ability to obtain services without impairing our cash flow. Travel expenses increased primarily due to the operation and maintenance of our Corporate airplane and increased travels to Alaska and other locations for financing purposes. The remaining increase is associated with increased professional fees including legal, consulting and audit related fees.

Exploration expense. Exploration expense incurred in the three months ended January 31, 2012 comprise of abandonments of drilling locations, dry hole costs, delay rentals, geological and geophysical costs, and the impairment, amortization, and abandonment associated with leases on our unproved properties. These expenses were not incurred during the three months ended January 31, 2011.

Depreciation, depletion and amortization. Depreciation, depletion and amortization (“DD&A”) expenses include the depreciation, depletion and amortization of acquisition costs and equipment costs. Depletion is calculated using units-of-production. Assuming everything else remains unchanged, as oil and natural gas production changes, depletion would change in the same direction.

DD&A expense for the three months ended January 31, 2012 was $2,826,065 compared to $3,110,976 for the three months ended January 31, 2011. The decrease in DD&A expense largely reflects the increase in our reserve base primarily due to price-related reserve revisions, higher capital expenditures for our drilling program, and the addition of the Redoubt Shoals field and related Kustatan production facility in May 2011. For the three months ended January 31, 2012, our average DD&A rate per unit decreased $6, or 20%, to $25.97 as compared to $32.35 for the three months ended January 31, 2011. In terms of depletion, our West MacArthur River field experienced a decrease in its depletion rate from $2.57 per unit at April 30, 2011 to $2.07 per unit at January 31, 2012. Our Redoubt Shoals field’s depletion rate decreased from $0.58 per unit at October 31, 2011 to $0.28 per unit at January 31, 2012. When combined with higher production from the Redoubt Shoals field and lower production at West MacArthur River, the result is a decrease in DD&A expense in total and per unit of production in comparison to the same period in fiscal year 2011.

We calculate depletion using a units-of-production under the successful efforts method of accounting. Other assets are depreciated using the straight-line basis. Consistent with prior practice, we used our fiscal 2011 reserve report to calculate our depletion rate during the first three quarters of fiscal 2012. We will use our fiscal 2012 reserve report to record depletion in the fourth quarter of fiscal 2012.

Other operating expense(income), net. We recognized a loss of $255,040 during the three months ended January 31, 2012 related to a true up of estimated royalties owed to the State of Alaska.

Nine months ended January 31, 2012 compared to nine months ended January 31, 2011

The following table illustrates the components of our revenues for the comparative fiscal periods indicated.

	Nine Months Ended January 31,			
	2012	2011 (as restated)	$ Variance	% Variance
Oil and gas operating costs	$11,940,863	$6,274,411	$5,666,452	90 %
Cost of other revenue	668,595	873,593	(204,998)	(23 %)
General and administrative	20,450,440	8,934,418	11,516,022	129 %
Exploration expense	574,478	—	574,478	100 %
Depreciation, depletion, and amortization	10,437,487	8,663,453	1,774,034	20 %
Accretion of asset retirement obligation	804,738	855,842	(51,104)	(6 %)
Other operating income, net	(642,238)	—	(642,238)	100 %
Total costs and expenses	$44,234,363	$25,601,717	$18,632,646	73 %

Oil and gas operating costs. For the nine months ended January 31, 2012, oil and gas operating costs increased $5,666,452, or 90%, to $11,940,863 as compared to $6,274,411 for the nine months ended January 31, 2011. This increase in operating costs is primarily related to $5.2 million in higher total spending associated with our operation of the Redoubt Shoals field and Kustatan production facility that were newly operational in May 2011. Consequently, our lease operating costs increased $11, or 49%, to $32.28 per BOE for the nine months ended January 31, 2012, compared to $21.68 per BOE for the nine months ended January 31, 2011. As production from the Redoubt Shoals field increases, we expect our operating costs to increase in the aggregate, but decrease on a per BOE basis.

Cost of other revenues. Cost of other revenues represent costs incurred in the performance of drilling and related services to third parties. The primary component is direct labor costs associated with these services, as well as costs associated with equipment, parts and repairs.

During the nine months ended January 31, 2012, cost of other revenues decreased by 23% primarily due to the reduction in labor costs associated with the decrease of certain contracted services 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.

General and administrative expenses. General and administrative expenses include the costs of our employees, related benefits, field office expenses, professional fees, and other costs not directly associated with field operations.

General and administrative expenses increased $11,516,022, or 129%, to $20,450,440 for the nine months ended January 31, 2012, compared to $8,934,418 for the same period in fiscal year 2011. The increase is attributable to higher cash and non-cash compensation, employee benefits, travel expenses and certain professional fees. A major component of this increase is a $7,526,700, or 253%, increase in non-cash compensation associated with the grant of an additional 4,045,000 shares of stock options and warrants to selected individuals including certain outside consultants of the Company. Cash salaries also increased by $742,340, or 41%, primarily as a result of an increase in bonuses and an addition of 16 employees during the nine months ended January 31, 2012 as compared to the nine months ended January 31, 2011. Employee benefits increased $726,516, or 103%, to $1,429,589 due to higher benefits costs for a larger number of employees. Travel costs increased by $884,918, or 191%, related to the use of our Corporate airplane and increased travels to Alaska and other locations for financing purposes. The remaining increase is associated with increased professional fees including a $348,758 increase in legal fees, $347,185 increase in accounting and audit fees, and $171,418 increase in compliance fees.

Exploration expense. Exploration expense incurred in the nine months ended January 31, 2012 comprise of abandonments of drilling locations, dry hole costs, delay rentals, geological and geophysical costs, and the impairment, amortization, and abandonment associated with leases on our unproved properties. These expenses were not incurred during the nine months ended January 31, 2011.

Depreciation, depletion and amortization. Depreciation, depletion and amortization ("DD&A") expenses include the depreciation, depletion and amortization of acquisition costs and equipment costs. Depletion is calculated using units-of-production. Assuming everything else remains unchanged, as oil and natural gas production changes, depletion would change in the same direction.

DD&A expense for the nine months ended January 31, 2012 was $10,437,487 compared to $8,663,453 for the nine months ended January 31, 2011. While we experienced an overall increase in DD&A expense, our DD&A rate per BOE decreased approximately $2, or 6%, to 28.21 per BOE for the nine months ended January 31, 2012 as compared to $29.94 per BOE for the same period in fiscal year 2011. The decrease in our DD&A rate per BOE largely reflects the increase in our reserve base due to price-related reserve revisions, higher capital expenditures for our drilling program, and the addition of the Redoubt Shoals field and related Kustatan production facility in May 2011.

In terms of depletion, the West MacArthur River field had a depletion rate of $2.57 per unit of production at April 30, 2011 and $2.07 per unit of production at January 31, 2012. The Redoubt Shoals field had a depletion rate of $0.58 per unit at October 31, 2011 and $0.28 per unit at January 31, 2012. The combination of higher depletion rates and higher production when RU-1 was producing during the first five months of the fiscal year resulted in an overall higher DD&A expense for the nine months ended January 31, 2012 as compared to the same period in fiscal year 2011.

We calculate depletion using a units-of-production under the successful efforts method of accounting. Other assets are depreciated using the straight-line basis. Consistent with prior practice, we used our fiscal 2011 reserve report to calculate our depletion rate during the first three quarters of fiscal year 2012. We will use our fiscal year 2012 reserve report to record depletion in the fourth quarter of fiscal year 2012.

Other operating expense(income), net. We recognized net gain of $642,238 during the nine months ended January 31, 2012 related to a true up of estimated royalties owed to the State of Alaska.

Other Income (Expense)

Three months ended January 31, 2012 compared to three months ended January 31, 2011

The following table illustrates the components of our other income (expense) for the comparative fiscal quarters indicated.

	Three Months Ended January 31, 2012	2011 (as restated)	$ Variance	% Variance
Interest expense, net	$ (812,796)	$ (101,909)	$ (710,887)	698 %
Gain (loss) on derivatives, net	(3,668,509)	935,929	(4,604,438)	(492 %)
Other income (expense), net	(8,338)	—	(8,338)	100 %
Total	$ (4,489,643)	$ 834,020	$ (5,323,663)	(638 %)

Interest expense. Interest expense, net of interest income, increased $710,887, or 698%, to $812,796 for the three months ended January 31, 2012 as compared to $101,909 for the three months ended January 31, 2011. This increase is attributable to the $28,894,615 million increase in borrowings from our Guggenheim credit facility, which we entered into in June 2011. Offsetting this increase a $2,080,069 reduction in interest expense associated with capitalized interest for the three months ended January 31, 2012.

Mark-to-market activities. For the three months ended January 31, 2012, we recognized an unrealized mark-to-market loss of $3,598,048 associated with the change in fair value of our warrants and commodity hedges. Realized hedge settlements were $94,014 offset by $164,475 in hedging expenses.

Nine months ended January 31, 2012 compared to nine months ended January 31, 2011

The following table illustrates the components of our other income (expense) for the comparative fiscal periods indicated.

	Nine Months Ended January 31,			
	2012	2011 (as restated)	$ Variance	% Variance
Interest expense, net	$(2,000,264)	$(1,038,716)	$(961,548)	93 %
Gain on derivatives, net	1,593,336	2,079,634	(486,298)	(23 %)
Other income (expense), net	51,558	(709,223)	760,781	(107 %)
Total	$(355,370)	$331,695	$(687,065)	(207 %)

Interest expense. Interest expense, net of interest income, increased $961,548, or 93%, to $2,000,264 for the nine months ended January 31, 2012, compared to $1,038,716 for the nine months ended January 31, 2011. This increase is attributable to the $28,894,615 in borrowings from our Guggenheim credit facility, which we entered into in June 2011. Offsetting this increase a $3,722,014 reduction in interest expense associated with capitalized interest for the nine months ended January 31, 2012.

Mark-to-market activities. For the nine months ended January 31, 2012, we recognized an unrealized mark-to-market gain of $786,289 associated with the change in fair value of our warrants and commodity hedges. Realized hedge settlements were $971,522, net of $164,475 in hedging expenses.

Other income and expense. For the nine months ended January 31, 2012, other income and expense increased $760,781, or 107%, to $51,558 in income as compared to a net loss of $709,223 for the nine months ended January 31, 2011. Of this increase, $625,948 was related to losses from the sale of equipment during the nine months ended January 31, 2011 that did not recur during the current fiscal year.

Liquidity and Capital Resources

During fiscal year 2011 and 2012, we utilized cash flow from operations and borrowings from our credit facilities to fund the development of our oil and natural gas assets. As of February 29, 2012, the borrowing base under our credit facility was $35 million and we had approximately $24 million of outstanding debt under the facility leaving us with $11 million in unused borrowing capacity. All future draws, however, must be approved by our lenders. Our credit facility is subject to future borrowing base redeterminations and will have to be renewed or replaced before its maturity on June 13, 2013. There is no guarantee the lenders will increase our borrowing base or approve any draw requests for future capital expenditures.

At January 31, 2012, we had a working capital deficit of $33,506,798 primarily as a result of increased short-term borrowings and increased capital expenditures associated with our development and drilling programs. Consequently, our current expectation is that we will manage our business to operate within the cash flows that are generated and focus our efforts on finding additional funding to support the execution of our capital projects. As we pursue our business plan, we will be monitoring the capital resources available to us to meet our future financial obligations and planned capital expenditures. We anticipate that operating expenses will continue to rise as we fully develop certain of our oil and natural gas assets under the 2012 plan. However, we also expect a simultaneous increase in revenues resulting from the successful development of the aforementioned assets.

We believe that the credit facility, along with projected cash flow and other potential sources of funds, will be adequate to meet our funding needs for the next twelve months; however, we are restricted under the credit facility to commit to certain financial requirements and provisions as described under section “Credit Facility” below. Our capital expenditures budget for the remainder of fiscal year 2012 is between $3 million and $6 million. The majority of the budget is allocated to restoring additional production from our Redoubt Shoals field in Alaska. Our ability to fully utilize the remaining budget will be dependent on a number of factors including, but not limited to, access to capital, Rig 35 being operational in a timely manner, weather and regulatory approval. We will continue to identify and evaluate additional capital sources to fulfill our projected capital expenditures.

Credit Facility

On June 13, 2011, we entered into a $100 million credit facility with a syndicate of lenders and Guggenheim Corporate Funding, LLC as administrative agent. The facility matures on June 13, 2013. Borrowings under the facility are secured by substantially all of our assets including all of the oil and natural gas properties that we and certain of our subsidiaries own. Our current lenders and their percentage commitments in the credit facility are: Guggenheim Energy Opportunities Fund, LP 47.1%, Citibank, N.A. 28.6%, Bristol Investment Fund, LTD. 10%, WP Global Mezzanine Capital Strategy II, LP 8.8%, and WP Global Mezzanine Strategy (RLA), LP 5.5%.

On August 26, 2011, we executed an amendment to our $100 million credit facility with our lenders. The amendment moved up the repayment schedule from January 2012 to October 2011, revised certain reporting requirements (described below), and revised the make-whole premium so as to exclude certain penalties such as the waiver fee and certain default interest. The amendment also added the requirement that we become compliant with Section 404b of the Sarbanes-Oxley Act of 2002 by our next fiscal year end, or we will be subject to an increase in the applicable margin of 2%. The amendment also waived certain events of default.

The amount available for borrowing at any one time under the credit facility is limited to the borrowing base for our oil and natural gas properties. As of January 31, 2012, our borrowing base was $35 million. The borrowing base is redetermined semi-annually, and may be redetermined more frequently at our request or by the lenders, in their sole discretion, based upon the loan collateral value assigned to the oil and gas properties along with other credit factors. Our next semi-annual borrowing base redetermination is scheduled during the first quarter of fiscal year 2013. Any increase in our borrowing base must be approved by all of the lenders, and by us.

Borrowings under the credit facility are available for acquisition, exploration, operation and maintenance of oil and natural gas properties, payment of expenses incurred in connection with the credit facility, working capital, and general company purposes. In connection with the amended credit facility, we are required to make payment on the outstanding obligations in an amount equal to 90%, or 100% in the event of default, of our consolidated net revenues, excluding certain operating costs such as royalty interests, lease operating costs and permissible general and administrative expenses up to $750,000 per calendar month. Proceeds from the sale of certain assets, indebtedness, and other proceeds received outside the ordinary course of business (but not Excluded Equity Proceeds, as that term is defined in the Loan Agreement) are required to be used for payment on the facility. As a result, we have classified amounts outstanding under the credit facility as a current liability in the accompanying Consolidated Balance Sheets.

Interest for borrowings is determined by reference to (i) the U.S. Prime Rate as published each business day in the Wall Street Journal or (ii) 5%, whichever is greater, plus an applicable margin of 4.5% per annum. In the event of non-compliance with Section 404b of the Sarbanes-Oxley Act of 2002 by April 30, 2012, the applicable margin, with respect to all borrowings under the credit facility and until compliance is reached, shall be increased to 6.5% per annum. In addition, the credit facility is subject to a make-whole premium when the facility is paid in full with the premium determined based on an internal rate of return to the lenders equal to (i) 25% per annum if the facility is repaid prior to June 30, 2012, (ii) 30% if repaid between July 1, 2012 and December 1, 2012, or (iii) 35% per annum if the facility is repaid after January 1, 2013.

Our credit facility contains various covenants that limit, among other things, our ability and our subsidiaries' ability to incur certain indebtedness, grant certain liens, merge or consolidate, sell all or substantially all of our assets, make certain loans, acquisitions, and capital expenditures and investments. In addition, we are required to issue to our lenders (i) audited financial statements within 90 days after the end of each fiscal year and (ii) unaudited financial statements within 45 days after the end of each fiscal quarter beginning with the first quarter of fiscal year 2012. On a monthly basis, we submit to our lenders (i) net revenue payment statements and a lease acquisition report for the immediately preceding calendar month and (ii) production reports and lease operating statements specifying the volume of production and sales attributable to the related production (including prices at which the sales were made) and all costs and expenditures resulting from production including, but not limited to, ad valorem, severance, production taxes, capital expenditures and lease operating expenses attributable to and incurred for each calendar month. We are also required to issue to our lenders a weekly cash flow forecast projecting our cash flow from operations in the forthcoming 13 weeks.

In addition, we are required to maintain (i) a ratio of consolidated EBITDA to interest expense (the "Interest Coverage Ratio") of at least 4.00 to 1.00 for the quarter ending January 31, 2012, a ratio of (a) the sum of (i) the orderly liquidation value of our equipment, as determined by an independent third-party appraiser plus (ii) NYMEX value to (b) total debt (the "Asset Coverage Ratio"), tested as of each redetermination date and any time between such dates that we acquire or dispose of oil and gas properties with an aggregate NYMEX value equal to $500,000 or more, of at least 2.50 to 1.00 for periods on or before April 29, 2012, and (iii) a daily average of gross production (the "Minimum Gross Production"), calculated at the point of sale on a barrel of oil equivalent basis, from the Cook Inlet oil and gas properties starting with fiscal quarter ending October 31, 2011 and thereafter. As relevant, all financial covenants are calculated using our consolidated financial information.

The credit facility also includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties in any material respect when made or when deemed made, violation of covenants, cross-defaults, bankruptcy and insolvency events, certain unsatisfied judgments, limitation or termination of the any obligation by any guarantor under the Guarantee and Collateral Agreement, the death or incapacitation of either Mr. Scott Boruff or Mr. David Hall or the termination of their substantial involvement in our operations, and the breach or termination of the Shareholders Agreement as described below. If an event of default occurs, the lenders may accelerate the maturity of the credit facility and exercise other rights and remedies. The credit facility contains as a condition to borrowing a representation that no material adverse change has occurred, which includes, among other things, (a) a material adverse change in the business, prospects, operations, results of operations, assets, our liabilities or condition (financial or otherwise) together with our subsidiaries taken as a whole, (b) a material adverse effect on our ability (or the ability of our subsidiaries) to carry out our business, (c) the material impairment of any loan's party ability to perform its obligations under the loan documents to which it is a party or of the lender group to enforce the obligations or realize upon the collateral, or (d) a material impairment of the enforceability or priority of the administrative agent's liens with respect to the collateral.

If a material adverse change were to occur, we would be prohibited from borrowing under the credit facility and would be in default, which could cause all of our existing indebtedness to become immediately due and payable, if the lenders chose to accelerate the indebtedness.

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

The credit facility requires us to hedge our projected monthly production at no less than 70% or more than 100% of the volume of production of proved developed producing reserves projected in the most recent reserve report to be produced on a rolling 24-month period, provided that we enter into hedging agreements with a lender or lender-related person or one or more investment grade counterparties, rated Aa3 or better by Moody's, A+ or better according to Standard & Poor's, or the equivalent by a rating agency acceptable to our lenders.

Compliance with Debt Covenants

Our preliminary assessment indicates that we were in compliance with the financial covenant ratios and all other compliance requirements contained in our credit facility as of January 31, 2012. Our compliance report and certification are due to Guggenheim concurrently with delivery of our financial statements, which are due, at the latest, 45 days after the end of our fiscal quarter, and will be subject to their review and approval.

Cash flows

From April 30, 2011 to January 31, 2012, cash increased by $1,570,099 to $3,129,032. This increase was primarily due to cash provided by financing activities of $26,094,416 and cash provided by operating activities of $9,335,156, offset by an increase in cash used by investing activities of $33,859,473.

Net cash provided by operating activities for the first nine months of fiscal year 2012 and fiscal year 2011 was $9,335,156 and $8,067,261 respectively. These increases primarily reflect the increase in oil and natural gas sales in excess of costs paid during the period, partially offset by the cash portions of general and administrative expense.

Net cash used by investing activities for the first nine months of fiscal year 2012 was $33,859,473 comprising of $24,387,534 for additions to equipment and improvements and $9,471,939 for capital expenditures on oil and gas properties. Net cash used by investing activities for the first nine months of fiscal year 2011 was $10,714,497 comprising of $770,083 for additions to equipment and improvements and $9,944,414 for capital expenditures on oil and gas properties.

Net cash provided by financing activities for the first nine months of fiscal year 2012 was $26,094,416 primarily reflecting proceeds from borrowings of $26,894,615, exercise of equity rights of $1,283,001, and the release of certain restricted cash of $56,992, offset by a payment of $2,140,192 for financing costs. Net cash provided by financing activities for the first nine months of fiscal year 2011 was $3,055,341 reflecting $2,500,000 in borrowings under the then in-effect credit facility and $947,507 in exercise of equity rights, offset by $392,166 in increased restricted cash requirements.

Our cash flow from operations is subject to many variables, the most significant of which are the volatility of oil and natural gas prices and our level of production of oil and natural gas. Oil and natural gas prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather and other factors beyond our control. Our future cash flow from operations will depend on our ability to maintain and increase production through our development program, as well as the market prices of oil and natural gas and our hedging program.

Off Balance Sheet Arrangements

On June 24, 2011, we acquired a 48% minority interest in Pellissippi Pointe I, LLC and Pellissippi Pointe II, LLC (the “Pellissippi Pointe” entities or “investee”) for total cash consideration of $399,934. We agreed to indemnify the sellers of the membership interests with respect to their guaranties of certain debt held by the investee, but have not become direct guarantors of the loans. As of January 31, 2012, the gross outstanding debt balance of the investee is $5,105,434. In connection with the transaction, we executed a five-year lease agreement with the investee and relocated our corporate offices to the new facility on November 7, 2011. Due to the fact that we do not exercise control over the financial and operating decisions made by the investee, we have accounted for these investments using the equity method. These investments are reflected in “other assets” in the accompanying Consolidated Balance Sheets.

We have no other off-balance sheet arrangements that should be disclosed pursuant to SEC 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.

Effects of Inflation and Changes in Price

Our results of operations and cash flows are affected by changing oil and natural gas prices. If the price of oil and natural gas increases or decreases, there could be a corresponding increase or decrease in the operating cost that we are required to bear for operations, as well as an increase or decrease in revenues.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

The term “market risk” refers to the risk of loss arising from adverse changes in commodity prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our oil production and, to some extent, our natural gas production. Realized pricing is primarily driven by the NYMEX West Texas Intermediate (Cushing, Oklahoma) for our oil production adjusted to ANS (West Coast Alaskan North Slope) and ACI (Alaska Cook Inlet). Historically, pricing for oil and natural gas has been volatile and unpredictable and we expect this volatility to continue in the future. The prices we receive for oil and natural gas production depend on many factors outside our control, including weather, economic conditions, and the total supply of oil and natural gas available for sale in the market.

We have entered into hedging arrangements with respect to a portion of our projected future production through various derivatives that hedge the future prices received. These hedging activities are intended to support commodity sales prices at targeted levels and to manage our exposure to commodity price fluctuations. We do not hold or issue derivative instruments for speculative trading purposes. The use of hedging transactions also involves the risk that our counterparty will be unable to meet the financial terms of the transactions executed. We attempt to minimize this risk by entering into derivative transactions with a counterparty that is a creditworthy financial institution deemed by management and our lenders as a competent and competitive market maker.

The following tables summarize, for the periods indicated, our hedges currently in place through January 2015. All of these derivatives are accounted for as mark-to-market activities.

	For the Quarter Ended (in Bbls)									
	July 31,		October 31,		January 31,		April 30,		Total	
	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price	Volume	Avg. Price
2012	—	$ —	—	$ —	—	$ —	63,000	$ 100.67	63,000	$ 100.67
2013	64,400	95.42	64,400	95.42	61,300	94.80	53,400	92.95	243,500	94.65
2014	55,200	92.95	55,200	92.95	55,200	92.86	53,400	92.50	219,000	92.82
2015	55,200	92.50	55,200	92.50	36,600	92.50	—	—	147,000	92.50
									672,500	

Interest Rate Risk

At January 31, 2012, all of our debt consists of borrowings under the Guggenheim credit facility. Interest for borrowings is determined by reference to (i) the U.S. Prime Rate as published each business day in the Wall Street Journal or (ii) 5%, whichever is greater, plus an applicable margin of 4.5% per annum. The credit facility is also subject to a make-whole premium when the facility is paid in full with the premium determined based on an internal rate of return to the lenders equal to (i) 25% per annum if the facility is repaid prior to June 30, 2012, (ii) 30% if repaid between July 1, 2012 and December 1, 2012, or (iii) 35% per annum if the facility is repaid after January 1, 2013. Because interest on borrowings is predominantly fixed as a result of the make-whole premium, our exposure to market fluctuations in interest rates is negligible. Thus, we have elected not to hedge the price volatility associated with changes in the U.S. Prime rate.

ITEM 4. CONTROLS AND PROCEDURES.

Evaluation of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) under the Securities Exchange Act of 1934, as amended, at the end of the period covered by this report (the "evaluation date"). In conducting its evaluation, management considered the material weaknesses in our disclosure controls and procedures and internal control over financial reporting described in Item 9A. of our amended Annual Report on Form 10-K for the year ended April 30, 2011 as filed with the SEC on August 29, 2011.

We have made significant progress remediating the material weaknesses identified in our amended Annual Report on Form 10-K for the year ended April 30, 2011 as filed with the SEC on August 29, 2011. However, as of the evaluation date, certain controls are still being evaluated by us and, as a result, our Chief Executive Officer and Chief Financial Officer have concluded that we did not maintain disclosure controls and procedures that were effective in providing reasonable assurances that information required to be disclosed in our reports filed under the Securities Exchange act of 1934 was recorded, processed, summarized and reported within the time periods prescribed by SEC rules and regulations, and that such information was accumulated and communicated to our management to allow timely decisions regarding required disclosures.

Our management, including the Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures will prevent all errors and all fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the control system's objectives will be met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. The design of any system of controls is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS.

The information set forth under Note 14 Litigation, to our unaudited consolidated financial statements included in Item 1 of Part 1 of this report is incorporated herein by reference.

ITEM 1A. RISK FACTORS.

There have been no material changes to the risk factors previously disclosed in Item 3 to Part I of our report as well as those described our amended Annual Report on Form 10-K for the year ended April 30, 2011 as filed with the SEC on August 29, 2011. An investment in our common shares involves various risks. When considering an investment in us, careful consideration should be given to the risk factors described in our amended 2011 Form 10-K. These risks and uncertainties are not the only ones facing us and there may be additional matters that are not known to us or that we currently consider immaterial. All of these risks and uncertainties could adversely affect our business, financial condition or future results and, thus, the value of an investment in us.

ITEM 6. EXHIBITS

The following documents are filed as a part of this report:

Exhibit No.	Description of Exhibit
31.1	Rule 13a-14(a)/15d-14(a) certification of Chief Executive Officer *
31.2	Rule 13a-14(a)/15d-14(a) certification of Chief Financial Officer *
32.1	Section 1350 certification of Chief Executive Officer and Chief Financial Officer*
101.INS	XBRL Instance Document *
101.SCH	XBRL Taxonomy Extension Schema Document *
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document*
101.LAB	XBRL Taxonomy Extension Label Linkbase Document *
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document *
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document *

* filed herewith

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	MILLER ENERGY RESOURCES, INC.	
Dated: March 12, 2012	By:	/s/ Scott M. Boruff Scott M. Boruff, Chief Executive Officer, principal executive officer
Dated: March 12, 2012	MILLER ENERGY RESOURCES, INC.	
	By:	/s/ David J. Voyticky David J. Voyticky, Chief Financial Officer, principal financial officer

EXHIBIT INDEX

Exhibit No.	Description of Exhibit
31.1	Rule 13a-14(a)/15d-14(a) certification of Chief Executive Officer *
31.2	Rule 13a-14(a)/15d-14(a) certification of Chief Financial Officer *
32.1	Section 1350 certification of Chief Executive Officer and Chief Financial Officer*
101.INS	XBRL Instance Document *
101.SCH	XBRL Taxonomy Extension Schema Document *
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document*
101.LAB	XBRL Taxonomy Extension Label Linkbase Document *
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document *
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document *

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* filed herewith