ReoStar Energy CORP
Form 10-Q
February 16, 2010

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

FORM 10-Q

x Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended December 31, 2009

o Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from ______________to ______________.

Commission File Number **000-52316**

REOSTAR ENERGY CORPORATION

(Exact name of registrant as specified in its charter)

Nevada	**20-8428738**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

3880 Hulen Street, Suite 500, Fort Worth, Texas 76107
(Address of principal executive offices)

(817) 989-7367
(Registrant's telephone number, including area code)

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 x No o

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

Yes x 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 o

Non-accelerated filer o (Do not check if a smaller reporting company) Smaller reporting company x

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at February 11, 2010
Common Stock, par value $0.001 per share	81,643,912

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PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS.

ReoStar Energy Corporation
Consolidated Balance Sheets

	December 31, 2009 (unaudited)	March 31, 2009
ASSETS		
Current Assets:		
Cash	$ 619,986	$ 426,430
Accounts Receivable:		
Oil & Gas - Related Party	672,660	337,879
Related Party	285,397	1,107,854
Other	6,407	15,760
Inventory	3,397	7,514
Hedging Account	6,317	6,317
Total Current Assets	1,594,164	1,901,754
Note Receivable	112,991	553,536
Oil and Gas Properties - successful efforts method	26,696,331	25,254,777
Less Accumulated Depletion and Depreciation	(7,864,825)	(6,206,558)
Oil & Gas Properties (net)	18,831,506	19,048,219
Other Depreciable Assets:	2,352,855	2,171,654
Less Accumulated Depreciation	(483,579)	(315,093)
Other Depreciable Assets (net)	1,869,276	1,856,561
Leasehold Held for Sale	-	150,000
Total Assets	$ 22,407,937	$ 23,510,070
LIABILITIES		
Current Liabilities:		
Accounts Payable	$ 132,317	$ 22,033
Payable to Related Parties	61,451	148,550
Accrued Expenses	114,236	106,141
Accrued Expenses - Related Party	99,061	130,870
Hedging Liabilities - Current	130,958	-
Current Portion of Long Term Debt	3,200,000	-
Total Current Liabilities	3,738,023	407,594
Notes Payable	10,201,305	8,955,202
Notes Payable - Related Parties	3,518,924	3,518,924
Less Current Portion of Notes Payable	(3,200,000)	-
Total Long-Term Debt	10,520,229	12,474,126

Asset Retirement Obligation		368,810		344,079
Hedging Liability - Noncurrent		-		-
Deferred Tax Liability		703,470		1,702,782
Total Liabilities		15,330,532		14,928,581
Commitments & Contingencies:		-		-
Stockholders' Equity				
Common Stock, $.001 par,200,000,000 shares authorized and 81,643,912 shares outstanding on December 31, 2009 and 80,353,912 shares outstanding on March 31, 2009		81,643		80,353
Additional Paid-In-Capital		11,812,650		10,959,965
Retained Deficit		(4,816,888)		(2,458,829)
Total Stockholders' Equity		7,077,405		8,581,489
Total Liabilities & Stockholders' Equity	$	22,407,937	$	23,510,070

See Accompanying Notes to Consolidated Financial Statements

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ReoStar Energy Corporation
Consolidated Statements of Operations

	Three Months Ended December 31, 2009 (unaudited)	Three Months Ended December 31, 2008 (unaudited)	Nine Months Ended December 31, 2009 (unaudited)	Nine Months Ended December 31, 2008 (unaudited)
Revenues				
Oil & Gas Sales	$ 975,933	$ 904,494	$ 2,150,145	$ 5,939,289
Sale of Leases	173,420	-	311,097	18,005
Other Income	79,856	124,194	253,438	333,178
	1,229,209	1,028,688	2,714,680	6,290,472
Costs and Expenses				
Oil & Gas Lease Operating Expenses	436,640	709,047	1,480,038	2,094,314
Workover Expenses	27,830	35,862	71,828	196,269
Severance & Ad Valorem Taxes	121,486	103,617	186,681	389,854
Expired Leases and Abandonments	45,348	9,925	45,348	9,925
Depletion & Depreciation	827,021	453,736	2,222,948	1,236,372
ARO Accretion	10,222	-	32,003	-
General & Administrative:				
Salaries & Benefits	261,056	133,284	664,551	454,744
Legal & Professional	120,921	44,481	897,751	358,272
Other General & Administrative	106,019	173,336	378,390	384,738
Interest, net of capitalized interest of $129,357 and $170,196 for the three months ended 12/31/09 and 12/31/08, respectively and $383,630 and $482,494 for the nine months ended 12/31/09 and 12/31/08, respectively	-	880	-	3,780
	1,956,543	1,664,168	5,979,538	5,128,268
Other Income (Expense)				
Interest Income	(9,467)	4,966	18,437	66,211
Loss on Equity Method Investments	-	-	-	(142,395)
Hedging Gain (Loss)	(7,307)	-	(110,950)	(6,746)
Income (Loss) from continuing operations before income taxes	(744,108)	(630,514)	(3,357,371)	1,079,274
Income Tax Benefit (Expense)	307,324	220,290	999,312	(412,651)
Net Income (Loss)	$ (436,784)	$ (410,224)	$ (2,358,059)	$ 666,623
Basic & Diluted Loss per Common Share	$ (0.01)	$ (0.01)	$ (0.03)	$ 0.01
Weighted Average Common Shares Outstanding	81,643,912	80,181,310	80,998,912	80,181,310

See Accompanying Notes to Consolidated Financial Statements

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ReoStar Energy Corporation
Consolidated Statements of Cash Flows

	Nine Months Ended	
	December 31, 2009 (unaudited)	December 31, 2008 (unaudited)
Operating Activities:		
Net (Loss) Income	$ (2,358,059)	$ 666,623
Adjustments to reconcile net (loss) income to cash from operating activities:		
Income Tax (Benefit) Expense	(999,312)	412,651
Depletion, Depreciation, & Amortization	2,222,948	1,236,372
Loss on Equity Method Investment	-	142,395
Stock based compensation	273,475	53,880
Non-employee stock based compensation	580,500	-
ARO Accretion	32,003	-
Salvage Proceeds in Excess of Plugging Costs	-	(50,290)
Changes in Operating Assets and Liabilities		
Changes in Accrued Liabilities	8,095	(270,409)
Change in Inventory	4,117	(11,066)
Change in Related Party Receivables/Payables	105,781	(741,859)
Changes in Other Receivables	9,353	-
Changes in Hedging Activity	130,958	6,746
Change in Revenue Receivables	(334,781)	293,777
Changes in Accounts Payable	110,284	(58,533)
Net Cash provided (used) from operating activities	(214,638)	1,680,287
Investing Activities:		
Oil & Gas Drilling, Completing and Leasehold Acquisition Costs	(1,441,647)	(7,724,800)
ARO on Properties Acquired or Drilled	25,335	-
ARO on Sold Properties	(32,607)	-
Change in Related Party Payable related to drilling	597,768	(1,547,136)
Investment in Other Depreciable Assets	(181,201)	(458,569)
Note Receivable (Advances)	(112,991)	-
Note Receivable Collections	553,537	801,691
Net Cash used in investing activities	(591,806)	(8,928,814)
Financing Activities		
Notes Payable (Payments) Advances	1,000,000	7,565,231
Loan Costs	-	(503,340)
Related Party Note (Payments)	(200,000)	(250,750)
Related Party Note Advances	200,000	-
Net Cash provided from financing activities	1,000,000	6,811,141
Net Decrease in cash	193,556	(437,386)
Cash - Beginning of the period	426,430	592,665
Cash - End of the period	$ 619,986	$ 155,279

See Accompanying Notes to Consolidated Financial Statements

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ReoStar Energy Corporation
Consolidated Statements of Cash Flows
(Continued)

	Nine Months Ended			
	December 31, 2009 (unaudited)		December 31, 2008 (unaudited)	
Supplemental Disclosure of Cash Flow Information				
Cash paid during period for:				
Interest	$	423,959	$	290,898
Income Taxes	$	-	$	-
Non Cash Investing and Financing Activities				
Warrants Issued	$	-	$	36,967
Stock Based Consulting Fees	$	580,500	$	-

See Accompanying Notes to Consolidated Financial Statements

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REOSTAR ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) BASIS OF PRESENTATION
The accompanying unaudited consolidated financial statements have been prepared in accordance with generally accepted accounting principles for interim financial information and pursuant to the rules and regulations of the United States Securities and Exchange Commission. They do not include all information and notes required by generally accepted accounting principles for complete financial statements. However, except as disclosed, there has been no material change in the information disclosed in the notes to the consolidated financial statements included in the Annual Report on Form 10-K of ReoStar Energy Corporation for the year ended March 31, 2009. In the opinion of management, all adjustments (consisting of normal recurring accruals) considered necessary for a fair presentation have been included. Operating results for the nine-month period ended December 31, 2009 are not necessarily indicative of the results that may be expected for the year ending March 31, 2010. The consolidated financial statements and notes are representations of the Company's management who are responsible for their integrity and objectivity. The Company's accounting policies conform to accounting principles generally accepted in the United States of America and have been consistently applied in the preparation of these consolidated financial statements.

(2) CAPITAL STOCK
We have authorized capital stock of 200 million shares of common stock. The Company issued 1,290,000 shares of common stock in August to various consultants as compensation for their services. The stock was valued at $580,500 and was reported as an expense during the nine months ended December 31, 2009. There were 81,643,912 shares of common stock issued at December 31, 2009.

On July 25, 2008, the Board of Directors approved the 2008 Long-Term Incentive Plan whereby the Company reserved 8,000,000 shares of stock for issuance under the plan. The Board also approved the grant of 2,500,000 options to certain officers under the plan. The options have a strike price of $0.35 per share, which was the closing price on July 24, 2008, and expire on July 25, 2018. The options vest over a three year period, with the first third vesting on March 31, 2009. The options were valued at $679,992 using the Black-Scholes model with a volatility of 194%. During the quarter ended December 31, 2009, one of the officers resigned. In lieu of severance, the officer and the company agreed that the balance of the unvested options would vest immediately. Salaries and Benefits included stock option related compensation costs of $273,475 and $0 for the nine months ended December 31, 2009 and 2008, respectively.

On April 1, 2007, ReoStar entered into employment contracts with certain officers. In conjunction with the employment contracts, the company approved the issuance of 700,000 shares of restricted stock. Of the 700,000 shares issued, 350,000 shares vested on March 31, 2008. The unvested portion of the restricted stock grant was cancelled in conjunction with the stock option grant described above. For the six months ended December 31, 2009 and 2008, Salaries and Benefits included stock related compensation costs of $0 and $48,567, respectively.

On April 1, 2007, ReoStar also entered into a stock option arrangement with two outside members of its board of directors. Both board members received stock options of 50,000 shares with a strike price of $1.11, one-third of which vest annually on March 31 2008, 2009, and 2010. For the nine months ended December 31, 2009 and 2008 Salaries and Benefits expense included stock option costs of $6,922 and $5,313, respectively.

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(3) NOTES PAYABLE
On October 30, 2008, the Company entered into a $25,000,000 senior secured credit facility with a bank. Initially, the borrowing base is set at $14,000,000. The borrowing base is based upon the Company's proven oil and gas reserves and is re-evaluated semi-annually.

The note bears interest based upon the greater of 1) the rate announced publicly from time to time by the bank plus a margin that varies between 0.0% and 0.5% depending upon the percentage of borrowing base drawn and 2) the Federal funds rate plus a margin that varies between 0.5% and 1.0% depending upon the percentage of borrowing base drawn. At the Company's option, we may elect to make a Eurodollar advance. The interest rate on a Eurodollar advance is LIBOR plus a margin that ranges between 2.00% and 2.75% depending upon the percentage of borrowing base drawn. The credit facility matures October 30, 2011.

As of December 31, 2009, the Company has drawn $10,800,000 of the $14,000,000 borrowing base. Interest for the nine months totaled $217,930 and was capitalized.

(4) DERIVATIVE INSTRUMENTS AND PRICE RISK MANAGEMENT
The Company does not engage in speculative derivative activities or derivative trading activities, nor does it use derivatives with leverage features. The Company uses derivative instruments from time to time to manage market risks resulting from the fluctuations in the prices of crude oil and natural gas. The gains and losses resulting from changes in the fair value of derivatives are recorded in operations. See Note 5 for the fair values of the derivatives as of December 31, 2009.

The Company may periodically enter into derivative contracts, including price swaps and costless collars utilizing put and call options, which require payments to (or receipts from) counterparties based upon the differential between a fixed price and a variable price for a fixed quantity of crude oil or natural gas without delivering the physical product. The notional amount of the financial instruments is based upon production forecasts from existing wells.

During the nine months ended December 31, 2009, the Company entered into a swap contract for 2,000 barrels of oil per month from August through December 2009. The contract locks in the price of oil at $70.40 per barrel. The Company entered into a swap contract for 20,000 MMBTU of natural gas per month from August through December 2009. The contract locks in the price of natural gas at $4.205 per MMBTU. The Company entered into a swap contract for 20,000 MMBTU of natural gas per month from January 2010 through June 2010. The contract locks in the price of natural gas at $5.54 per MMBTU.

During the nine months ended December 31, 2009, the Company entered into put and call contracts which collar 2,000 barrels of oil per month during calendar 2010. The floor is $65 per barrel and the ceiling is $85 per barrel. The Company also entered into put and call contracts which collar 20,000 MMBTU of natural gas per month from July 2010 through December 2010. The floor is $5.50 per MMBTU and the ceiling is $6.50 per MMBTU.

There were no net premiums paid or received when the Company entered into these contracts.

The following table reflects open commodity derivative hedging contracts as of December 31, 2009, the associated volumes, and the corresponding weighted NYMEX reference price.

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Settlement Period	Monthly Volumes		Fixed Price	Price Floor	Price Ceiling
Crude Oil Swaps					
12/01/09 - 12/31/09	2,000	BBLS	$ 70.40	N/A	N/A
Natural Gas Swaps					
1/01/10 - 6/30/10	20,000	MMBTU	$ 5.54	N/A	N/A
Crude Oil Collars					
1/01/10 - 12/31/10	2,000	BBLS	N/A	$ 65.00	$ 85.00
Natural Gas Collars					
7/1/10 - 12/31/10	20,000	MMBTU	N/A	$ 5.50	$ 6.50

(5) FAIR VALUE MEASUREMENTS

FASB Codification Topic 820-10, Fair Value Measurements and Disclosures defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. However, it does not require new or additional fair value measurements, rather, its application is made pursuant to other accounting pronouncements that require or permit fair value measurements.

The Company measures its derivative instruments in accordance with FASB Codification Topic 820-10. 820-10 specifies a valuation hierarchy based on whether the inputs to those valuation techniques are observable or unobservable. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect the Company's own assumptions. These two types of inputs have created the following fair value hierarchy:

Level 1 - Quoted prices for identical instruments in active markets;

Level 2 - Quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations in which all significant inputs and significant value drivers are observable in active markets; and

Level 3 - Valuations derived from valuation techniques in which one or more significant inputs or significant value drivers are unobservable.

This hierarchy requires the Company to minimize the use of unobservable inputs and to use observable market data, if available, when estimating fair value. The following table represents our derivative assets and liabilities measured at fair value as of December 31, 2009.

Type of Contract	Balance Sheet Location	Estimated Fair Value
Crude Oil Swaps	Other Current Liabilities	$ 8,406
Natural Gas Swaps	Other Current Liabilities	6,858
Crude Oil Collars	Other Current Liabilities	121,208
Natural Gas Collars	Other Current Liabilities	(5,514)
Total Current Derivative Liabilities		$ 130,958
Crude Oil Collars	Other Non-Current Liabilities	$ -
Natural Gas Collars	Other Non-Current Liabilities	-
Total Non-Current Derivative Liabilities		$ -
Total Derivative Liabilities		130,958

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(6) NOTES RECEIVABLE
In December 2009, the Company reached a Compromise Settlement Agreement with the drilling contractor. In accordance with the Compromise Settlement Agreement, the drilling contractor paid the Company $425,000 and the Company agreed to release the lien the Company held on the drilling contractor's rig. The $425,000 represented full payment of the outstanding principal balance of $407,985 and $17,015 accrued interest. The balance of accrued interest of $6,682 was waived. A bad debt expense equal to the waived interest was included in other general and administrative expenses.

During the quarter ended December 31, 2009, the Company sold two oil and gas leases in east Texas. The purchase and sales agreement provides for monthly production payments equal to 10% of the gross revenue attributable to the working interests sold commencing with May 2010 production. The production payments will continue until a total of $165,000 has been collected by the Company. The Company estimates the present value of the production payments to be $112,991 using a discount rate of 10%.

(7) SALE OF LEASES
During the quarter ended December 31, 2009, the Company sold approximately 290 acres of non-contiguous, non-producing Barnett Shale leasehold for $290,100. The Company realized a pre-tax gain of approximately $200,000 on the sale.

Additionally, during the quarter ended December 31, 2009, as discussed in Note 6, the Company sold two oil and gas leases in east Texas. The Company realized a pre-tax loss of approximately $27,000 on the sale.

(8) SUBSEQUENT EVENTS
Effective February 1, 2010, the Company sold its remaining east Texas leases, a service drilling rig, and other miscellaneous equipment. The total proceeds from the sale were $122,500, with $10,000 received at closing and a promissory note with payments beginning in May 2010. Payments will be equal to $50 per billable hour for rig work completed in the previous thirty day period and 50% of the proceeds attributable to production from the oil and gas leases. Additionally, the buyer has surrendered 102,000 shares of ReoStar stock.

On February 10, 2010, the Company was notified that Union Bank had completed the redetermination of the borrowing base under the Credit Agreement dated October 30, 2008 (See Note 3 for more details). The borrowing base was reduced to $7.6 million, leaving a borrowing base deficiency of $3.2 million effective February 4, 2010.

Under the Credit Agreement, the Company is required to take any of the following actions:
1) Repay the borrowing base deficiency;
2) Pledge additional oil and gas properties as collateral such that the borrowing base deficiency is cured;
3) Repay the borrowing base deficiency in six monthly installments; or
4) Cure the borrowing base deficiency by a combining the second and third options.

The Company is currently evaluating which actions are the most appropriate for the Company to take.

Additionally, Union Bank notified the Company that the Company was in technical default for the following reasons:
1) The Company's failure to comply with leverage ratio requirements for the fiscal quarters ended June 30, 2009 and September 30, 2009;
2) The Company's failure to comply with the interest coverage ratio requirements for the fiscal quarters ended June 30, 2009 and September 30, 2009; and

Union Bank is considering what actions, if any, they are determined to take in respect of the above specified defaults, but has expressly retained and reserved all of the rights and remedies under the Credit Agreement. These rights and remedies include, but are not limited to A) the right to declare all amounts payable (including principal advanced and accrued interest) to be due and payable immediately, and B) the right to charge a default rate of interest.

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

CAUTIONARY STATEMENT

You should read the following discussion and analysis in conjunction with our unaudited condensed consolidated financial statements and the related notes thereto contained elsewhere in this report. The information contained in this quarterly report on Form 10-Q is not a complete description of our business or the risks associated with an investment in our common stock. We urge you to carefully review and consider the various disclosures made by us in this report and in our other reports filed with the Securities and Exchange Commission, or SEC, including our annual report on Form 10-K for the year ended March 31, 2009 and subsequent reports on Form 8-K, which discuss our business in greater detail.

In this report we make, and from time to time we otherwise make, written and oral statements regarding our business and prospects, such as projections of future performance, statements of management's plans and objectives, forecasts of market trends, and other matters that are 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. Statements containing the words or phrases "will likely result," "are expected to," "will continue," "is anticipated," "estimates," "projects," "believes," "expects," "anticipates," "intends," "target," "goal," "plans," "objective," "should" or similar expressions identify forward-looking statements, which may appear in documents, reports, filings with the Securities and Exchange Commission, news releases, written or oral presentations made by officers or other representatives made by us to analysts, stockholders, investors, news organizations and others, and discussions with management and other of our representatives. For such statements, we claim the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995.

Our future results, including results related to forward-looking statements, involve a number of risks and uncertainties. Such risks and uncertainties include, but are not limited to, changes in local, regional, and national economic and political conditions, the effect of governmental regulation, competitive market conditions, our ability to obtain additional financing, and other risks detailed herein and from time to time in our SEC reports. No assurance can be given that the results reflected in any forward-looking statements will be achieved. Any forward-looking statement speaks only as of the date on which such statement is made.

Overview of Our Business

We are engaged in the exploration, development and acquisition of oil and gas properties, primarily located in the state of Texas. We seek to increase oil and gas reserves and production through internally generated drilling projects, coupled with complementary acquisitions.

We own approximately 9,300 gross acres of leasehold, which include 5,500 acres of exploratory and developmental prospects as well as 3,800 acres of enhanced oil recovery prospects. We have built a multi-year inventory of drilling projects and drilling locations and currently have enough acreage to sustain several years of drilling.

Our corporate offices are located at 3880 Hulen Street, Suite 500, Fort Worth, Texas 76107. Our telephone number is (817) 989-7367.

Business Strategy

Our objective is to build shareholder value by establishing and consistently growing our production and reserves with a strong emphasis on cost control and risk mitigation. Our strategy is (1) to control operations of all our leases via our affiliated operating companies, (2) to acquire and develop leasehold in key regional resource development plays while utilizing existing infrastructure and engaging in long-term drilling and development programs, and (3) to acquire leasehold in mature fields and implement enhanced oil recovery programs.

Industry Environment

The globalization of the world's economy, the rapid development of the emerging markets, and increased commodity speculation have recently resulted in unprecedented commodity pricing and volatility. Oil prices peaked at unprecedented highs in July 2008 before contracting significantly. At their low in January 2009, oil prices were down more than 75% from the July highs. Prices have since doubled to approximately $75 per barrel.

While natural gas is also a fungible commodity, it is more regional in nature than oil. Constant changes in regional supplies and demand have resulted in significant pricing volatility in the natural gas market as well. Natural gas prices (the Houston Ship

Channel index) peaked at $13 per MMBTU in early July 2008 and have since then dropped by more than 75%. Natural gas prices remain weak with current pricing of approximately $5.50 per MMBTU.

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The rapid run up in commodity prices encouraged substantial drilling, which resulted in upward pressure on finding and development costs. For example, during last fiscal year, a shortage of pipe caused casing and tubing prices to dramatically increase, which resulted in a material increase in total completion costs.

The commodity pricing volatility accompanied with cost volatility has significantly reduced operating margins and has negatively impacted our ability to accurately forecast cash flows.

The recent reduction in commodity pricing for natural gas has helped ease drilling and service costs pressures. However, we expect them to remain at a high level relative to past pricing. In addition, we expect lease operating expenses to continue to rise as producers are forced to make operational enhancements to maintain production in more mature fields.

We believe that in order for an independent oil and gas producer to be successful, the producer must either operate its leases effectively or have significant operational control over its oil and gas properties. As commodity prices fluctuate, controlling costs through operations will make the difference between turning a profit and incurring a financial loss.

Principal Components of Our Cost Structure

Direct Operating Expenses. These are day-to-day costs incurred to bring hydrocarbons out of the ground and to the market together with the daily costs incurred to maintain our producing properties. Such costs also include work-over repairs to our oil and gas properties not covered by insurance. To minimize and help control our costs, we acquired a work-over drilling rig and a swab rig in June of 2007. We recently purchased and refurbished a shallow well oil drilling rig which is used to drill our Corsicana Nacatoch and Pecan Gap wells.

Production and Ad Valorem Taxes. These costs are primarily paid based on a percentage of market prices or at fixed rates established by federal, state or local taxing authorities.

Exploration Expense. The costs include geological and geophysical costs, seismic costs, delay rentals and the costs of unsuccessful wells or dry holes. While our current asset mix requires a minimum of geological and geophysical costs and seismic costs, it is possible this component of our cost structure could sharply increase depending upon future property acquisitions.

Plugging Costs. The Corsicana field is over one hundred years old and has hundreds of abandoned well bores scattered throughout the properties. In order to properly execute our enhanced oil recovery projects, we need to plug these abandoned, worn out well bores. Since the wells are fairly shallow, we are able to cement in the entire well bore at a cost of less than $1,500 per well. To date, we have plugged over 200 well bores in this field.

General and Administrative Expenses. Overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of finding our working interest partners, costs of managing our production and development operations, audit and other professional fees and legal compliance are included in general and administrative expense. General and administrative expense includes stock-based compensation expense (non-cash), amortization of restricted stock grants as part of employee compensation.

Interest. We increased our levels of debt during fiscal year 2009, and in the future, we may finance a larger portion of our working capital requirements and acquisitions with borrowings under a credit facility or with longer-term public traded debt securities. As a result, interest expense could become a much more prevalent component of our cost structure.

Depreciation, Depletion and Amortization. As a successful efforts company, we capitalize all costs associated with our acquisition and all successful development and exploration efforts, and apportion these costs to each unit of production through depreciation, depletion and amortization expense. This also includes the systematic, monthly depreciation of our oilfield equipment assets.

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Changes in Estimates. Changes in estimates of proved reserves significantly impact the depletion expense we record each year. When proved reserves increase, our depletion rate decreases, resulting in a lower depletion expense and higher net income. Conversely, as proved reserves decrease, our depletion rate increases, resulting in a higher depletion expense and lower net income. Changes in estimates of proved reserves are frequently the result of changes in commodity prices, changes in operating costs, and reservoir performance history. While depletion is a non-cash expense, volatility in commodity prices and the resulting volatility in depletion can have a material impact on our profitability and on certain leverage ratios.

Income Taxes. We are subject to federal income taxes but are currently not in a tax paying position for regular federal income taxes, primarily due to the current deductibility of intangible drilling costs ("IDC"). Currently, we are not subject to state income taxes. Virtually all of our Federal taxes are deferred; however, at some point, we will utilize all of our net operating loss carry-forwards and we will recognize current income tax expense and continue to recognize current tax expense as long as we are generating taxable income.

Results and Analysis of Financial Condition, Cash Flows and Liquidity

During the quarter ended December 31, 2009, we sold approximately 7,107 barrels of oil compared with approximately 9,651 barrels of oil for the quarter ended December 31, 2008. The average price for oil sold during the quarter ended December 31, 2009 was $73.60 per barrel compared with the average price for the quarter ended December 31, 2008 of $55.89 per barrel.

We sold approximately 100,561 mcf of gas for the quarter ended December 31, 2009 compared with approximately 123,350 mcf of gas for the same period a year earlier. The average price for natural gas sold during the quarter ended December 31, 2009 was $4.50 per mcf (net of transportation, compression and CO_2 charges) compared with $3.11 per mcf for the quarter ended December 31, 2008.

Oil and gas revenues for the quarter ended December 31, 2009 were $975,933 compared with $904,494 for the three months ended December 31, 2008, an increase of approximately 8%. Oil and gas revenues for the nine months ended December 31, 2009 were $2,150,145, compared with $5,939,289 for the nine months ended December 31, 2008, a decrease of approximately 64%.

During the nine months ended December 31, 2009, we incurred drilling and completion costs of approximately $1,440,000.

On December 31, 2009, we had $620,000 in cash and total assets of $22.4 million. Debt consisted of accounts and notes payables to non-related parties of $11 million, of which, $7.6 million is long-term. We also had accounts and notes payables to related parties of $3.7 million.

During the quarter, we did not draw on the Union Bank credit facility secured by our assets. The material terms of the credit facility were reported on our Form 8-K filed on November 4, 2008. The remaining credit available under the credit facility at quarter end was $3.2 million.

We continue to consider various other financing options which may or may not be implemented during this fiscal year.

Cash Flow

Our principal sources of cash are operating cash flow, the sale of a portion of the working interest in our drilling projects, the credit facility and other financing options, including debt and equity, which may be available to us from time to time. Our operating cash flow is highly dependent on oil and gas prices.

Based on current projections and oil and gas futures prices, the balance of the 2010 capital program is expected to be funded with internal cash flow.

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Capital Requirements
Our primary needs for cash are for exploration of the Pecan Gap acreage in our Corsicana leasehold, development drilling in our Barnett Shale properties, expanding the enhanced oil recovery projects in our Corsicana properties, and the acquisition of additional oil and gas properties. Due to the tightening credit and equity markets, the increased costs, and the recent contraction in commodity pricing, we have suspended our development drilling program in the Barnett Shale and have deferred planned expansion of the enhanced oil recover project in Corsicana. Management has reduced the capital expenditure budget to $1.75 million for fiscal year 2010.

The capital expenditure budget will primarily be invested on the Pecan Gap drilling program. The wells are approximately 1,500 feet deep and cost approximately $100,000 each to drill. We have working interest partners that have agreed to participate in the drilling program and we may drill as many as 15 wells during the fiscal year. We expect to retain between 50% and 75% of each well.

There can be no assurance that internal cash flow and other capital sources will provide sufficient funds to maintain capital expenditures that we believe are necessary to efficiently develop our properties and offset inherent declines in production and proved reserves. Even if we are successful in raising capital through the sources specified, there can be no assurances that any such financing would be available in a timely manner or on terms acceptable to us and our shareholders. Additional equity financing could be dilutive to our shareholders, and any debt financing could involve restrictive covenants with respect to future capital raising activities and other financial and operational matters.

Future Commitments
In addition to our capital expenditure program, we are committed to making cash payments in the future on two types of contracts: note agreements and operating leases. As of December 31, 2009, we have no capital leases nor have we entered into any material long-term contracts for equipment, nor do we have any off-balance sheet debt or other such unrecorded obligations.

The table below provides estimates of the timing of future payments that we are obligated to make based on agreements in place at December 31, 2009. In addition to the contractual obligations listed on the table below, our balance sheet at December 31, 2009 reflects accrued interest payable on our debt of $113,572.

	Fiscal Years Ending March 31,				
	2010	2011	2012	Thereafter	Total
Office Lease Payments	$ 13,300	$ -	$ -	$ -	$ 13,300
Notes Payable - Related Parties	-	-	-	3,518,924	3,518,924
Senior Secured Note Payable	-	3,200,000	7,600,000	-	10,800,000
	$ 13,300	$ 3,200,000	$ 7,600,000	$ 3,518,924	$ 14,332,224

Off-Balance Sheet Arrangements
We do not currently utilize any off-balance sheet arrangements to enhance liquidity and capital resource position, or for any other purpose.

Inflation and Changes in Prices
Our revenues, the value of our assets, and our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in oil and gas prices and the costs to produce our reserves. Oil and gas prices are subject to significant fluctuations that are beyond our ability to control or predict. The hedges put in place in the prior year have all expired.

In July, the Company placed hedges on a portion of our future production. The hedging contracts we entered into have locked the price we receive for oil for the balance of calendar 2009 in at $70.40 per barrel for 2,000 barrels per month. We also collared prices for 2,000 barrels of oil per month for calendar year 2010 with a floor of $65 per barrel and a ceiling of $85 per barrel. For natural gas, we locked the price we receive for 20,000 MMBTU per month for the balance of 2009 at $4.205 per MMBTU. From January through June 2010, we locked natural gas prices for 20,000 MMBTU per month at $5.54 per MMBTU. From July through December 2010, we collared natural gas prices for 20,000 MMBTU per month at a floor of $5.50 per MMBTU and a ceiling of $6.50 per MMBTU.

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As our production grows, we may increase the number of hedges we have in place. Additionally, we may place hedges further into the future.

Although certain of our costs and expenses are affected by general inflation, inflation does not normally have a significant effect on our business. In a trend that began in 2004 and accelerated during the first quarter, commodity prices for oil and gas increased significantly. The higher prices led to increased activity in the industry and, consequently, rising costs. These costs trends have put pressure not only on our operating costs but also on our capital costs. Industry capital costs have nearly doubled during the last two years. Industry analysts expect the trend to continue during the next fiscal year.

Critical Accounting Estimates

Our discussion and analysis of our financial condition and results of operations are based upon consolidated financial statements which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at year-end and the reported amounts of revenues and expenses during the year. We base our estimates on historical experience and various other assumptions that we believe are reasonable; however, actual results may differ.

Certain accounting estimates are considered to be critical if (a) the nature of the estimates and assumptions is material due to the level of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to changes; and (b) the impact of the estimates and assumptions on financial condition or operating performance is material.

Successful Efforts Method of Accounting

We account for our exploration and development activities utilizing the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Oil and natural gas lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and natural gas leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. The sale of a partial interest in a proved property is accounted for as a cost recovery and no gain or loss is recognized as long as this treatment does not significantly affect the unit-of-production amortization rate. A gain or loss is recognized for all other sales of producing properties.

The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive and actually deliver oil and natural gas in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. The evaluation of oil and natural gas leasehold acquisition costs requires managerial judgment to estimate the fair value of these costs with reference to drilling activity in a given area.

The successful efforts method of accounting can have a significant impact on the operational results reported when we enter a new exploratory area in hopes of finding an oil and natural gas field that will be the focus of future developmental drilling activity. The initial exploratory wells may be unsuccessful and will be expensed. Seismic costs can be substantial which will result in additional exploration expenses when incurred.

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To ensure the reliability of our reserve estimates, we engage independent petroleum consultants to prepare an estimate of proved reserves. The SEC defines proved reserves as those volumes of crude oil, condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods. Although our engineers are knowledgeable of and follow the guidelines for reserves established by the SEC, the estimation of reserves requires engineers to make a significant number of assumptions based on professional judgment. Reserve estimates are updated at least annually and consider recent production levels and other technical information. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price and cost changes and other economic factors. Changes in oil and gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions in turn cause adjustments in the depletion rates utilized by us. We cannot predict what reserve revisions may be required in future periods.

We monitor our long-lived assets recorded in property, plant and equipment in our consolidated balance sheet to ensure they are fairly presented. We must evaluate our properties for potential impairment when circumstances indicate that the carrying value of an asset could exceed its fair value. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future oil and natural gas sales prices, an estimate of the ultimate amount of recoverable oil and gas reserves that will be produced from a field, the timing of future production, future production costs, future abandonment costs, and future inflation. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for oil and/or gas, unfavorable adjustment to reserves, physical damage to production equipment and facilities, a change in costs, or other changes to contracts, environmental regulations or tax laws. All of these factors must be considered when testing a property's carrying value for impairment. We cannot predict whether impairment charges may be required in the future. We are required to develop estimates of fair value to allocate purchase prices paid to acquire businesses to the assets acquired and liabilities assumed under the purchase method of accounting. The purchase price paid to acquire a business is allocated to its assets and liabilities based on the estimated fair values of the assets acquired and liabilities assumed as of the date of acquisition. We use all available information to make these fair value determinations.

Deferred Taxes

We are subject to income and other taxes in all areas in which we operate. When recording income tax expense, certain estimates are required because income tax returns are generally filed many months after the close of a calendar year, tax returns are subject to audit which can take years to complete and future events often impact the timing of when income tax expenses and benefits are recognized. We have deferred tax assets relating to tax operating loss carry forwards and other deductible differences. We routinely evaluate deferred tax assets to determine the likelihood of realization. A valuation allowance is recognized on deferred tax assets when we believe that certain of these assets are not likely to be realized. In determining deferred tax liabilities, accounting rules require OCI to be considered, even though such income or loss has not yet been earned.

At December 31, 2009, deferred tax liabilities exceeded deferred tax assets by $700,000. We may be challenged by taxing authorities over the amount and/or timing of recognition of revenues and deductions in our various income tax returns. Although we believe that we have adequately provided for all taxes, gains or losses could occur in the future due to changes in estimates or resolution of outstanding tax matters.

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Contingent Liabilities

A provision for legal, environmental and other contingent matters is charged to expense when the loss is probable and the cost or range of costs can be reasonably estimated. Judgment is often required to determine when expenses should be recorded for legal, environmental and contingent matters. In addition, we often must estimate the amount of such losses. In many cases, our judgment is based on the input of our legal advisors and on the interpretation of laws and regulations, which can be interpreted differently by regulators and/or the courts. We monitor known and potential legal, environmental and other contingent matters and make our best estimate of when to record losses for these matters based on available information. We currently have no material accruals for contingent liabilities.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

As a "smaller reporting company" defined in Item 10(f)(1) of Regulation S-K, we are electing scaled disclosure reporting obligations and therefore are not required to provide the information requested by this item.

ITEM 4T. CONTROLS AND PROCEDURES.

Our management, with the participation of our principal executive officer and principal financial officer, has evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Based on such evaluation, our principal executive officer and principal financial officer have concluded that, as of the end of such period, our disclosure controls and procedures were effective.

There have not been any changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS.

Not applicable

ITEM 1A. RISK FACTORS.

As a "smaller reporting company" defined in Item 10(f)(1) of Regulation S-K, we are electing scaled disclosure reporting obligations and therefore are not required to provide the information requested by this item.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS.

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES.

Not applicable.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

Not applicable.

ITEM 5. OTHER INFORMATION.

Not applicable.

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ITEM 6. EXHIBITS.

EXHIBIT NUMBER	DESCRIPTION
31.1	CEO Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	CFO Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	CEO Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	CFO Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

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SIGNATURES

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

REOSTAR ENERGY CORPORATION

February 16, 2010

By _ /s/ Scott D. Allen
Scott D. Allen, Chief Financial Officer
(Principal Financial Officer and duly authorized signatory)

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