US ENERGY CORP
Form 10-Q
August 08, 2011

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 quarter ended June 30, 2011 or

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: 0-6814

U.S. ENERGY CORP.
(Exact name of registrant as specified in its charter)

Wyoming (State or other jurisdiction of incorporation or organization)	83-0205516 (I.R.S. Employer Identification No.)
877 North 8th West, Riverton, WY (Address of principal executive offices)	82501 (Zip Code)
Registrant's telephone number, including area code:	(307) 856-9271

Not Applicable
(Former name, address and 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 Company 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 Regulations 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 o 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 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 x
Non-accelerated filer o (Do not check if a smaller reporting company)	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 x

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

At, August 4, 2011 there were issued and outstanding 27,259,391 shares of the Company’s common stock, $0.01 par value.

U.S. ENERGY CORP. and SUBSIDIARIES

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PART I. FINANCIAL INFORMATION

ITEM 1. Financial Statements

U.S. ENERGY CORP.
CONDENSED CONSOLIDATED BALANCE SHEETS
ASSETS
(Unaudited)
(In thousands)

	June 30, 2011	December 31, 2010
CURRENT ASSETS:		
Cash and cash equivalents	$7,751	$5,812
Marketable securities		
Held to maturity - treasuries	1,106	17,843
Available for sale securities	937	1,364
Accounts receivable		
Trade	3,821	3,890
Reimbursable project costs	408	114
Income taxes	104	104
Assets held for sale	20,979	20,979
Other current assets	467	456
Total current assets	35,573	50,562
INVESTMENT	2,705	2,834
PROPERTIES AND EQUIPMENT:		
Oil & gas properties under full cost method, net of $20,469 and $14,563 accumulated depletion, depreciation and amortization	88,696	70,374
Undeveloped mining claims	20,771	21,077
Property, plant and equipment, net	9,069	9,336
Net properties and equipment	118,536	100,787
OTHER ASSETS	2,021	1,833
Total assets	$158,835	$156,016

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
(Unaudited)
(In thousands, except shares)

	June 30, 2011	December 31, 2010
CURRENT LIABILITIES:		
Accounts payable	$10,148	$14,830
Accrued compensation	801	1,669
Commodity risk management liability	827	1,725
Current portion of debt	200	200
Liabilities held for sale	10,236	323
Other current liabilities	55	16
Total current liabilities	22,267	18,763
LONG-TERM DEBT, net of current portion	3,400	400
DEFERRED TAX LIABILITY	3,142	5,015
ASSET RETIREMENT OBLIGATIONS	447	303
OTHER ACCRUED LIABILITIES	895	847
SHAREHOLDERS' EQUITY:		
Common stock, $.01 par value; unlimited shares		
authorized; 27,239,391 and 27,068,610		
shares issued, respectively	272	271
Additional paid-in capital	121,616	121,062
Accumulated surplus	6,429	8,713
Unrealized gain on marketable securities	367	642
Total shareholders' equity	128,684	130,688
Total liabilities and shareholders' equity	$158,835	$156,016

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)
(In thousands except per share data)

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
REVENUES:				
Oil and gas	$7,025	$6,218	$13,704	$13,927
Realized (loss) on risk management activities	(1,015)	--	(1,570)	--
Unrealized gain on risk management activities	2,138	--	897	--
	8,148	6,218	13,031	13,927
OPERATING EXPENSES:				
Oil and gas	1,955	1,498	6,034	2,628
Oil and gas depreciation, depletion and amortization	3,120	2,396	5,905	4,651
Water treatment plant	498	459	927	808
Mineral holding costs	37	(5)	80	52
General and administrative	2,138	2,167	4,549	4,835
	7,748	6,515	17,495	12,974
OPERATING (LOSS) INCOME	400	(297)	(4,464)	953
OTHER INCOME AND (EXPENSES):				
Gain on the sale of assets	137	--	137	115
Equity gain/(loss) in unconsolidated investment	(65)	179	(129)	1,142
Gain on sale of marketable securities	9	8	9	8
Miscellaneous income and (expenses)	(37)	(50)	(38)	(80)
Interest income	10	2	30	61
Interest expense	(115)	(18)	(138)	(35)
	(61)	121	(129)	1,211
(LOSS) INCOME BEFORE INCOME TAXES AND DISCONTINUED OPERATIONS	339	(176)	(4,593)	2,164

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)
(In thousands except per share data)

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
Income taxes:				
Deferred benefit from (provision for)	(618)	17	1,976	(871)
	(618)	17	1,976	(871)
(LOSS) INCOME FROM CONTINUING OPERATIONS	(279)	(159)	(2,617)	1,293
DISCONTINUED OPERATIONS				
Discontinued operations, net of taxes	204	28	333	103
DISCONTINUED OPERATIONS	204	28	333	103
NET (LOSS) INCOME	$(75)	$(131)	$(2,284)	$1,396
NET (LOSS) INCOME PER SHARE				
(Loss) income from continuing operations, basic	$(0.01)	$--	$(0.09)	$0.05
Income from discontinued operations, basic	0.01	--	0.01	--
Net (loss) income, basic	$--	$--	$(0.08)	$0.05
(Loss) from continuing operations, diluted	$(0.01)	$--	$(0.09)	$0.05
Income from discontinued operations, diluted	0.01	--	0.01	--
Net (loss) income, diluted	$--	$--	$(0.08)	$0.05
Weighted average shares outstanding				
Basic	27,220,049	26,734,636	27,203,336	26,611,583
Diluted	27,866,544	26,734,636	27,203,336	27,813,215

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	(In thousands) For the six months ended June 30, 2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net (loss) income	$(2,284)	$1,396
(Income) from discontinued operations	(333)	(103)
(Loss) income from continuing operations	(2,617)	1,293
Adjustments to reconcile net (loss) income to net cash provided by operations		
Depreciation, depletion & amortization	6,206	4,935
Change in fair value of commodity price risk management activities, net	(897)	--
Accretion of discount on treasury investment	(21)	(34)
Gain on sale of marketable securities	(9)	(8)
Equity (gain)/loss from Standard Steam	129	(1,142)
Net change in deferred income taxes	(1,725)	944
(Gain) on sale of assets	(137)	(115)
Noncash compensation	758	752
Noncash services	(16)	30
Net changes in assets and liabilities	373	311
NET CASH PROVIDED BY OPERATING ACTIVITIES	2,044	6,966
CASH FLOWS FROM INVESTING ACTIVITIES:		
Net redemption (investment in) treasury investments	16,758	(12,332)
Cash distributions from Standard Steam	--	1,138
Acquisition & development of oil & gas properties	(29,780)	(23,734)
Acquisition & development of mining properties	(48)	(32)
Acquisition of property and equipment	(44)	(444)
Proceeds from sale of marketable securities	11	13
Proceeds from sale of property and equipment	147	118
Net change in restricted investments	(206)	(22)
NET CASH USED IN INVESTING ACTIVITIES	(13,162)	(35,295)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Issuance of common stock	(186)	503
Proceeds from new debt	13,069	--
Repayments of debt	(61)	--
NET CASH PROVIDED BY FINANCING ACTIVITIES	12,822	503

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	(In thousands) For the six months ended June 30, 2011	2010
Net cash provided by operating activities of discontinued operations	241	557
Net cash used in investing activities of discontinued operations	(6)	(22)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	1,939	(27,291)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	5,812	33,403
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$7,751	$6,112
SUPPLEMENTAL DISCLOSURES:		
Interest paid	$90	$11
NON-CASH INVESTING AND FINANCING ACTIVITIES:		
Unrealized gain	$367	$196
Acquisition and development of oil and gas properties through accounts payable	$5,687	$458
Acquisition and development of oil and gas through asset retirement obligations	$134	$14
Amounts receivable from the release of funds held in escrow	$354	$--

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.

Notes to Cendensed Consolidated Financial Statemnts (Unaudited)

1) Basis of Presentation

The accompanying unaudited condensed consolidated financial statements for the periods ended June 30, 2011 and June 30, 2010 have been prepared by U.S. Energy Corp. the ("Company") in accordance with generally accepted accounting principles ("GAAP") in the United States of America. The financial statements at June 30, 2011 include the Company's wholly owned subsidiary Energy One LLC ("Energy One") which owns the majority of the Company's oil and gas assets. The Condensed Consolidated Balance Sheet at December 31, 2010 was derived from audited financial statements. In the opinion of the Company, the accompanying condensed consolidated financial statements contain all adjustments (consisting of only normal recurring adjustments) necessary to present fairly the financial position of the Company for the reported periods. Entities in which the Company holds at least 20% ownership or in which there are other indicators of significant influence are generally accounted for by the equity method, whereby the Company records its proportionate share of the entities' results of operations. Certain information and footnote disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted. The unaudited condensed consolidated financial statements should be read in conjunction with the Company's December 31, 2010 Annual Report on Form 10-K. Subsequent events have been evaluated for financial reporting purposes through the date of the filing of this Form 10-Q. See Note 13.

2) Summary of Significant Accounting Policies

For detailed descriptions of our significant accounting policies, please see Form 10-K for the year ended December 31, 2010 (Note B pages 85 to 92).

We follow accounting standards set by the Financial Accounting Standards Board, commonly referred to as the "FASB." The FASB sets generally accepted accounting principles (GAAP) that we follow to ensure we consistently report our financial condition, results of operations, and cash flows.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates include oil and gas reserves used for depletion and impairment considerations and the cost of future asset retirement obligations. Due to inherent uncertainties, including the future prices of oil and gas, these estimates could change in the near term and such changes could be material.

Oil and Gas Properties

The Company follows the full cost method in accounting for its oil and gas properties. Under the full cost method, all costs associated with the acquisition, exploration and development of oil and gas properties are capitalized and accumulated in a country-wide cost center. This includes any internal costs that are directly related to development and exploration activities, but does not include any costs related to production, general corporate overhead or similar activities. Proceeds received from property disposals are credited against accumulated cost except when the sale represents a significant disposal of reserves, in which case a gain or loss is recognized. The sum of net capitalized costs and estimated future development and dismantlement costs for each cost center is depleted on the equivalent unit-of-production method, based on proved oil and gas reserves. Excluded from amounts subject to depletion are costs associated with unproved properties.

U.S. ENERGY CORP.

Notes to Cendensed Consolidated Financial Statemnts (Unaudited)

(Continued)

Under the full cost method, net capitalized costs are limited to the lower of unamortized cost reduced by the related net deferred tax liability and asset retirement obligations or the cost center ceiling. The cost center ceiling is defined as the sum of (i) estimated future net revenue, discounted at 10% per annum, from proved reserves, based on unescalated average prices per barrel of oil and per MMbtu of natural gas at the first day of each month in the 12-month period prior to the end of the reporting period and costs, adjusted for contract provisions, financial derivatives that hedge our oil and gas revenue and asset retirement obligations, (ii) the cost of properties not being amortized, and (iii) the lower of cost or market value of unproved properties included in the cost being amortized, reduced by the (iv) income tax effects related to differences between the book and tax basis of the natural gas and crude oil properties. If the net book value reduced by the related net deferred income tax liability and asset retirement obligations exceeds the cost center ceiling limitation, a non-cash impairment charge is required in the period in which the impairment occurs. At June 30, 2011, the book value of our oil and gas properties did not exceed the cost center ceiling.

Derivative Instruments

The Company uses derivative instruments, typically fixed-rate swaps and costless collars, to manage price risk underlying its oil and gas production. All derivative instruments are recorded in the consolidated balance sheets at fair value. The Company offsets fair value amounts recognized for derivative instruments executed with the same counterparty. Although the Company does not designate any of its derivative instruments as a cash flow hedge, such derivative instruments provide an economic hedge of our exposure to commodity price risk associated with forecasted future oil and gas production. These contracts are accounted for using the mark-to-market accounting method and accordingly, the Company recognizes all unrealized and realized gains and losses related to these contracts currently in earnings and are classified as gain (loss) on derivative instruments, net in our consolidated statements of operations. The Company may also use puts, calls and basis swaps in the future.

The Company’s Board of Directors sets all risk management policies and reviews the status and results of derivative activities, including volumes, types of instruments and counterparties on a quarterly basis. These policies require that derivative instruments be executed only by the Chief Executive Officer or President. The master contracts with approved counterparties identify the Chief Executive Officer and President as the only Company representatives authorized to execute trades. See Note 6, Commodity Price Risk Management, for further discussion.

Revenue Recognition

The Company records oil and natural gas revenue under the sales method of accounting. Under the sales method, we recognize revenues based on the amount of oil or natural gas sold to purchasers, which may differ from the amounts to which we are entitled to based on our interest in the properties. Natural gas balancing obligations as of June 30, 2011 were not significant.

Revenues from real estate operations are reported on a gross revenue basis and are recorded at the time the service is provided.

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Notes to Cendensed Consolidated Financial Statemnts (Unaudited)

(Continued)

Recent Accounting Pronouncements

In May 2011, the FASB issued Accounting Standards Update 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs ("ASU 2011-04"). The amendments in ASU 2011-04 generally represent clarification of Topic 820, but also include instances where a particular principle or requirement for measuring fair value or disclosing information about fair value measurements has changed. ASU 2011-04 results in common principles and requirements for measuring fair value and for disclosing information about fair value measurements in accordance with U.S. GAAP and International Financial Reporting Standards. The amendments are effective for interim and annual periods beginning after December 15, 2011 and are to be applied prospectively. Early application is not permitted. The Company does not expect the adoption of ASU 2011-04 will have a material impact on its financial condition, results of operations or cash flows.

In June 2011, the Financial Accounting Standards Board (the "FASB") issued Accounting Standards Update 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income ("ASU 2011-05"), which allows an entity the option to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In both choices, an entity is required to present each component of net income along with total net income, each component of other comprehensive income along with a total for other comprehensive income, and a total amount for comprehensive income. ASU 2011-05 eliminates the option to present the components of other comprehensive income as part of the statement of changes in stockholders' equity. The amendments to the Codification in the ASU do not change the items that must be reported in other comprehensive income or when an item of other comprehensive income must be reclassified to net income and are effective for fiscal years, and interim periods within those years, beginning after December 15, 2011. The adoption of ASU 2011-05 will not have a material impact on the Company's financial condition, results of operations or cash flows.

3) Properties and Equipment

Land, buildings, improvements, machinery and equipment are carried at cost. Depreciation of buildings, improvements, machinery and equipment is provided principally by the straight-line method over estimated useful lives ranging from 3 to 45 years.

U.S. ENERGY CORP.

Notes to Cendensed Consolidated Financial Statemnts (Unaudited)

(Continued)

Components of Property and Equipment as of June 30, 2011 and December 31, 2010 are as follows:

U.S. Energy Corp.
Components of Properties & Equipment

	(In thousands)	
	June 30, 2011	December 31, 2010
Oil & Gas properties		
Unevaluated	$ 25,303	$ 17,926
Wells in progress	5,325	3,694
Evaluated	78,537	63,317
	109,165	84,937
Less accumulated depreciation		
depletion and amortization	(20,469)	(14,563)
Net book value	88,696	70,374
Mining properties	20,771	21,077
Building, land and equipment	14,561	14,564
Less accumulated depreciation	(5,492)	(5,228)
Net book value	9,069	9,336
Totals	$ 118,536	$ 100,787

U.S. ENERGY CORP.

Notes to Cendensed Consolidated Financial Statemnts (Unaudited)

(Continued)

Oil and Gas Activities

Full Cost Pool - Full cost pool capitalized costs are amortized over the life of production of proven properties. Capitalized costs at June 30, 2011 and December 31, 2010 which were not included in the amortized cost pool were $30.6 million and $21.6 million, respectively. These costs consist of exploratory wells in progress, seismic costs that are being analyzed for potential drilling locations as well as land costs related to unproved properties. No capitalized costs related to unproved properties are included in the amortization base at June 30, 2011 and December 31, 2010. It is anticipated that these costs will be added to the full cost amortization pool in the next two years as properties are proved, drilled or abandoned.

Ceiling Test Analysis - We perform a quarterly ceiling test for each of our oil and gas cost centers. There was only one such cost center in 2011. The reserves used in the ceiling test and the ceiling test itself incorporate assumptions regarding pricing and discount rates over which management has no influence in the determination of present value. In arriving at the ceiling test for the quarter ended June 30, 2011, we used $90.09 per barrel for oil and $4.209 per MMbtu for natural gas (and adjusted for property specific gravity, quality, local markets and distance from markets) to compute the future cash flows of our producing properties. The discount factor used was 10%.

At June 30, 2011 and 2010, the ceiling was in excess of the net capitalized costs as adjusted for related deferred income taxes and no impairment was required. Management will continue to review our unproved properties based on market conditions and other changes and if appropriate, unproved property amounts may be reclassified to the amortized base of properties within the full cost pool.

Wells in Progress - Wells in progress represent the costs associated with unproved wells that have not reached total depth or have not been completed as of period end. They are classified as wells in progress and withheld from the depletion calculation. The costs for these wells are then transferred to proved property when the wells reach total depth and are cased and the costs become subject to depletion and the ceiling test calculation in future periods.

Mineral Properties

We capitalize all costs incidental to the acquisition of mineral properties. Mineral exploration costs are expensed as incurred. When exploration work indicates that a mineral property can be economically developed as a result of establishing proved and probable reserves, costs for the development of the mineral property as well as capital purchases and capital construction are capitalized and amortized using units of production over the estimated recoverable proved and probable reserves. Costs and expenses related to general corporate overhead are expensed as incurred. All capitalized costs are charged to operations if we subsequently determine that the property is not economical due to permanent decreases in market prices of commodities, excessive production costs or depletion of the mineral resource.

Mineral properties at June 30, 2011 and December 31, 2010 reflect capitalized costs associated with our Mt. Emmons molybdenum property near Crested Butte, Colorado. On April 21, 2011, Thompson Creek Metals Company USA (“TCM”) terminated its option agreement with the Company to develop the Mount Emmons molybdenum deposit. In notifying the Company, TCM cited more immediate development priorities in its portfolio of assets including the expansion of the Endako Project, its newly acquired Mt. Milligan Project and the Berg Project. When TCM terminated the option agreement with the Company, TCM forfeited $354,000 in funds held in escrow for future development expenditures which is reflected in accounts receivable at June 30, 2011.

U.S. ENERGY CORP.

Notes to Cendensed Consolidated Financial Statemnts (Unaudited)

(Continued)

Our carrying balance in the Mt. Emmons property at June 30, 2011 and December 31, 2010 is as follows:

	(In thousands)	
	June 30, 2011	December 31, 2010
Costs associated with Mount Emmons beginning of year	$ 21,077	$ 21,969
Development costs during the six months	48	108
Option payment from Thompson Creek	(354)	(1,000)
Costs at the end of the period	$ 20,771	$ 21,077

4) Assets Held for Sale

In accordance with property, plant, and equipment authoritative guidance, assets are classified as held for sale when the Company commits to a plan to sell the assets and there is reasonable certainty that the sale will take place within one year. Upon classification as held for sale, long-lived assets are no longer depreciated or depleted, and a measurement for impairment is performed to determine if there is any excess of carrying value over fair value less costs to sell. Subsequent changes to estimated fair value less the cost to sell will impact the measurement of assets held for sale if the fair value is determined to be less than the carrying value of the assets.

In January 2011, we made the decision to sell our Remington Village multifamily project in Gillette, Wyoming and plan to use the proceeds to further the development of our oil and gas business. At December 31, 2010, we recorded a $1.5 million impairment to adjust the carrying value of the multifamily project to the approximate appraised value. At June 30, 2011, management has determined that no further impairment is needed. As of June 30, 2011, the accompanying condensed consolidated balance sheets present $21.0 million in book value of assets held for sale, net of accumulated depreciation, and $10.2 million in liabilities held for sale. Because Remington Village has been classified as an asset held for sale, the scheduled depreciation of $473,000 was not recorded during the first six months of 2011. Remington is pledged as collateral on a $10.0 million note. At such time as Remington is sold, the debt balance will be retired.

Operations related to Remington Village are shown in discontinued operations on the accompanying condensed consolidated statements of operations.

5) Asset Retirement Obligations

We record the fair value of the reclamation liability on our inactive mining properties and our operating oil and gas properties as of the date that the liability is incurred. We review the liability each quarter and determine if a change in estimate is required as well as accrete the discounted liability on a quarterly basis for the future liability. Final determinations are made during the fourth quarter of each year. We deduct any actual funds expended for reclamation during the quarter in which it occurs.

U.S. ENERGY CORP.

Notes to Cendensed Consolidated Financial Statemnts (Unaudited)

(Continued)

The following is a reconciliation of the total liability for asset retirement obligations:

	(In thousands) June 30, 2011	December 31, 2010
Beginning asset retirement obligation	$ 303	$ 211
Accretion of discount	10	17
Liabilities incurred	134	75
Ending asset retirement obligation	$ 447	$ 303
Mining properties	$ 144	$ 139
Oil & Gas Wells	303	164
Ending asset retirement obligation	$ 447	$ 303

6) Commodity Price Risk Management

Through our wholly-owned affiliate Energy One, we have entered into three commodity derivative contracts ("economic hedges") with BNP Paribas ("BNP"), a costless collar and two fixed price swaps, as described below. The three derivative contracts are priced using West Texas Intermediate ("WTI") quoted prices. The Company is a guarantor of Energy One under the economic hedges. The objective of utilizing the economic hedges is to reduce the effect of price changes on a portion of our future oil production, achieve more predictable cash flows in an environment of volatile oil and gas prices and to manage our exposure to commodity price risk. The use of these derivative instruments limits the downside risk of adverse price movements. However, there is a risk that such use may limit our ability to benefit from favorable price movements. Energy One may, from time to time, add incremental derivatives to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of its existing positions. The Company does not engage in speculative derivative activities or derivative trading activities nor does it use derivatives with leveraged features.

Energy One's commodity derivative contracts as of June 30, 2011 are summarized below:

Settlement Period	Counterparty	Basis	Quantity (Bbl/d)	Strike Price
Crude Oil Costless Collars				
10/01/10 - 09/30/11	BNP Paribas	WTI	200	Put: $ 75.00

				Call:	$ 83.25
Crude Oil Swaps					
10/01/10 - 09/30/11	BNP Paribas	WTI	200	Fixed:	$ 79.05
01/01/11 - 12/31/11	BNP Paribas	WTI	200	Fixed:	$ 89.60

U.S. ENERGY CORP.

Notes to Cendensed Consolidated Financial Statemnts (Unaudited)

(Continued)

The following table details the fair value of the derivatives recorded in the applicable condensed consolidated balance sheet, by category:

Underlying Commodity	Location on Balance Sheet	Fair Value at June 30, 2011
Crude oil costless collar	Current Liability	$ 245
Crude oil swap #1	Current Liability	314
Crude oil swap #2	Current Liability	268
		$ 827

Unrealized gains and losses resulting from derivatives are recorded at fair value on the condensed consolidated balance sheet and changes in fair value are recognized in the unrealized gain (loss) on risk management activities line on the condensed consolidated statement of operations. Realized gains and losses resulting from the contract settlement of derivatives are recorded in the commodity price risk management activities line on the condensed consolidated statement of income. There were no realized gains or losses recorded for the three and six months ending June 30, 2010.

7) Fair Value

We follow fair value measurement authoritative guidance for all assets and liabilities measured at fair value. That guidance establishes a fair value hierarchy that prioritizes the inputs the Company uses to measure fair value based on the significance level of the following inputs:

- Level 1 - Unadjusted quoted prices are available in active markets for identical assets or liabilities.
- Level 2 - Pricing inputs, other than quoted prices within Level 1, which are either directly or indirectly observable.
- Level 3 - Pricing inputs that are unobservable requiring the Company to use valuation methodologies that result in management's best estimate of fair value.

Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the nonfinancial assets and liabilities and their placement in the fair value hierarchy levels. As of June 30, 2011, we held $1.1 million of investments in government securities and marketable securities. The fair value of our commodity risk management liabilities and other accrued liabilities are determined using discounted cash flow methodologies based on inputs that are not readily available in public markets. The fair values of our property held for sale is determined based on anticipated future cash flows, cost and comparables to the extent they are available, less selling costs. The fair values of our other accrued liabilities that are reflected on the balance sheet are detailed below. The other accrued liabilities are the long term portion of the executive retirement program.

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U.S. ENERGY CORP.

Notes to Cendensed Consolidated Financial Statemnts (Unaudited)

(Continued)

		(In thousands) Fair Value Measurements at June 30, 2011 Using		
Description	June 30 2011	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Available for sale securities	$ 1,106	$ 1,106	$ --	$ --
Assets held for sale	20,979	--	--	20,979
Total assets	$ 22,085	$ 1,106	$ --	$ 20,979
Commodity risk management liability	$ 827	$ --	$ 827	$ --
Liabilities held for sale	226	--	226	--
Other accrued liabilities	895	--	--	895
Total	$ 1,948	$ --	$ 1,053	$ 895

The following table summarizes, by major security type, the fair value and any unrealized gain of our available for sale securities. The unrealized gain is recorded on the condensed consolidated balance sheets as other comprehensive income, a component of shareholders' equity. Other accrued liabilities increased by approximately $48,000 to $895,000 at June 30, 2011 as a result of accretion of the liability.

	(In thousands)		
June 30, 2011	Less Than 12 Months	12 Months or Greater	Total

Description of Securities	Fair Value	Unrealized Gain	Fair Value	Unrealized Gain	Fair Value	Unrealized Gain
Available for sale securities	$ 937	$ 579	$ --	$ --	$ 937	$ 579
Total	$ 937	$ 579	$ --	$ --	$ 937	$ 579

Our other financial instruments include cash and cash equivalents, accounts receivable, accounts payable, other current liabilities and long-term debt. The carrying amount of cash and cash equivalents, accounts receivable, accounts payable and other current liabilities approximate fair value because of their immediate or short-term maturities. The carrying value of our debt approximates its fair market value since interest rates have remained generally unchanged from the issuance of the debt. The fair value and carrying value of our debt was $13.6 million as of June 30, 2011.

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Notes to Cendensed Consolidated Financial Statemnts (Unaudited)

(Continued)

8) Debt

At June 30, 2011, our debt consists of debt related to our oil and gas reserves, the purchase of land near our Mt. Emmons molybdenum property and debt on our multifamily housing project. The oil and gas debt bears an interest rate of 2.70% per annum and the land debt bears an interest rate of 6.0% per annum.

The $3.0 million in oil and gas debt is for a term of six months and is due on August 18, 2011, but can be continued at our election if we remain in compliance with the covenants under the Senior Credit Facility through July 30, 2014. Our intent is to extend this debt and therefore have classified it as a long-term liability. As of June 30, 2011, Energy One was in compliance with all the covenants under the Senior Credit Facility.

The land debt is due in three equal annual payments of $200,000 plus accrued interest. The next payment is due on January 2, 2012.

On May 5, 2011 we borrowed $10.0 million from a commercial bank. The note is secured by the Company's multi-family property in Gillette, Wyoming. The note has a term of five years and has an interest rate of 5.50% per annum. The proceeds of the note are being used to facilitate our general business obligations. The note replaces the $10.0 million line of credit that we had with the same commercial bank. When Remington is sold, the proceeds from the sale will first be applied to the retirement of the $10.0 million debt balance and the remainder applied to general corporate overhead and project development. Therefore, the debt is shown as a current liability in liabilities held for sale.

9) Shareholders' Equity

Common Stock

During the six months ended June 30, 2011, the Company issued 170,781 shares of common stock. These shares consist of (a) 40,000 shares issued to officers of the Company pursuant to the 2001 Stock Compensation Plan; (b) 32,896 shares issued as a result of warrants being exercised by directors of the Company and (c) 97,885 shares as a result of the exercise of options by employees of the Company.

The following table details the changes in common stock during the six months ended June 30, 2011:

(Amounts in thousands, except for share amounts)

	Common Stock Shares	Amount	Additional Paid-In Capital
Balance December 31, 2010	27,068,610	$ 271	$ 121,062
2001 stock compensation	40,000	--	252

plan			
Exercise of employee stock options	97,885	1	(226)
Exercise of outside director warrants	32,896	--	39
Expense of employee options vesting	--	--	505
Expense of outside director warrants vesting	--	--	(16)
Balance June 30, 2011	27,239,391	$ 272	$ 121,616

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Notes to Cendensed Consolidated Financial Statemnts (Unaudited)

(Continued)

Stock Option Plans

The Board of Directors adopted, and the shareholders approved, the U.S. Energy Corp. 2001 Incentive Stock Option Plan (the "2001 ISOP") for the benefit of the Company's employees. The 2001 ISOP reserves for issuance shares of the Company’s common stock equal to 25% of the Company’s shares of common stock issued and outstanding at any time. The 2001 ISOP has a term of 10 years, and expires on December 6, 2011. Any options issued prior to that date will survive to their expiration date which cannot exceed a ten year period from date of grant and will be subject to vesting and forfeiture provisions at date of grant.

During the three and six months ended June 30, 2011, we recognized $254,000 and $505,000, respectively, in compensation expense related to employee options. We will recognize an additional $444,000 in expense over the remaining vesting period of the outstanding options of 0.47 years. We compute the fair values of options granted using the Black-Scholes pricing model. As a result of the exercise of 368,136 options held by officers and employees, 97,885 shares of common stock were issued during the six months ended June 30, 2011.

Warrants to Others

From time to time we issue stock purchase warrants to non-employees for services. During the six months ended June 30, 2011, we issued 20,000 warrants to independent directors. The warrants were issued at the closing price of $4.19 on the date of grant, vest over a three year period and expire ten years from the date of grant or one year after the Board member no longer serves on the Board. The warrants were valued under Black-Scholes using a risk free interest rate of 1.765%, expected life of 6 years and expected volatility of 59.64%.

During the three months ended June 30, 2011, we recorded $13,000 in expense for warrants issued to third parties. Due to an adjustment made during the first quarter of 2011 to the expected forfeiture rate of the outstanding, unvested warrants, we recorded a credit to expense of $16,000 for warrants issued to third parties during the six months ended June 30, 2011. We will recognize an additional $76,000 in expense over the vesting period of the outstanding warrants. During the six months ended June 30, 2011, we issued 32,896 shares of common stock to directors of the Company as the result of the exercise of 95,000 outstanding warrants.

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Notes to Cendensed Consolidated Financial Statemnts (Unaudited)

(Continued)

The following table represents the activity in employee stock options and non-employee stock purchase warrants for the six months ended June 30, 2011:

	June 30, 2011			
	Employee Stock Options		Stock Purchase Warrants	
	Options	Weighted Average Exercise Price	Warrants	Weighted Average Exercise Price
Outstanding balance at December 31, 2010	3,011,647	$3.87	320,000	$2.95
Granted	-	$-	20,000	$4.19
Forfeited	-	$-	(20,000)	$2.52
Expired	-	$-	-	$-
Exercised	(368,136)	$3.94	(95,000)	$2.99
Outstanding at June 30, 2011	2,643,511	$3.86	225,000	$3.08
Exercisable at June 30, 2011	2,246,012	$3.87	185,001	$2.93
Weighted Average Remaining Contractual Life - Years		4.94		3.22
Aggregate intrinsic value of options / warrants outstanding		$1,932,000		$275,000

10) Income Taxes

The Company uses the asset and liability method of accounting for deferred income taxes. Deferred tax assets and liabilities are determined based on the temporary differences between the financial statement and tax basis of assets and liabilities. Deferred tax assets or liabilities at the end of each period are determined using the tax rate in effect at that time.

The deferred income tax liability for an oil and gas exploration company is dependent on many variables such as estimating the economic lives of depleting oil and gas reserves and commodity prices. Accordingly, the liability is subject to continual recalculation, revision of the numerous estimates required, and may change significantly in the event of such things as major acquisitions, divestitures, product price changes, changes in reserve estimates, changes in reserve lives, and changes in tax rates or tax laws.

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Notes to Cendensed Consolidated Financial Statemnts (Unaudited)

(Continued)

11) Segment Information

As of June 30, 2011, we had two reportable segments: Oil and Gas and Maintenance of Mineral Properties. A summary of results of operations for the six months ended June 30, 2011, and 2010, and total assets as of June 30, 2011 and December 31, 2010 by segment are as follows:

	(In thousands)			
	For the three months ended June 30,		For the six months ended June 30,	
	2011	2010	2011	2010
Revenues:				
Oil and gas	$ 8,148	$ 6,218	$ 13,031	$ 13,927
Total revenues:	8,148	6,218	13,031	13,927
Operating expenses:				
Oil and gas	5,075	3,894	11,939	7,279
Mineral properties	535	454	1,007	860
Total operating expenses:	5,610	4,348	12,946	8,139
Interest expense				
Oil and gas	20	--	29	--
Mineral properties	9	12	18	24
Total interest expense:	29	12	47	24
Operating (loss) income				
Oil and gas	3,053	2,324	1,063	6,648
Mineral properties	(544)	(466)	(1,025)	(884)
Operating (loss) income from identified segments	2,509	1,858	38	5,764
General and administrative expenses	(2,138)	(2,167)	(4,549)	(4,835)
Add back interest expense	29	12	47	24
	(61)	121	(129)	1,211

Other revenues and expenses:				
(Loss) income before income taxes				
and discontinued operations	$ 339	$ (176)	$ (4,593)	$ 2,164
Depreciation depletion and amortization expense:				
Oil and gas	$ 3,120	$ 2,396	$ 5,905	$ 4,651
Mineral properties	25	18	51	36
Corporate	124	94	250	248
Total depreciation expense	$ 3,269	$ 2,508	$ 6,206	$ 4,935

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Notes to Cendensed Consolidated Financial Statemnts (Unaudited)

(Continued)

	(In thousands)	
	June 30, 2011	December 31, 2010
Assets by segment		
Oil and Gas properties	$ 93,610	$ 75,639
Mineral properties	21,230	20,800
Corporate assets	43,995	59,577
Total assets	$ 158,835	$ 156,016

12) Equity Income in Unconsolidated Investment

We recorded an equity loss from our unconsolidated investment in Standard Steam, LLC (“SST”) during the three and six months ended June 30, 2011, of $65,000 and $129,000, respectively.

13) Subsequent Events

None.

ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is Management's Discussion and Analysis of significant factors that have affected liquidity, capital resources and results of operations during the three and six months ended June 30, 2011 and 2010. The following also updates information as to our financial condition provided in our 2010 Annual Report on Form 10-K. Statements in the following discussion may be forward-looking and involve risk and uncertainty. The following discussion should also be read in conjunction with our condensed financial statements and notes thereto.

General Overview

We are an independent energy company focused on the acquisition and development of oil and gas producing properties in the continental United States. Our business is currently focused in the Rocky Mountain region (specifically the Williston Basin of North Dakota and Montana), Texas, Louisiana and California, however, we do not intend to limit our focus to these geographic areas. We continue to focus on increasing production, reserves, revenues and cash flow from operations while managing our level of debt. Our liquidity and access to financing under our Senior Secured Credit Facility (see Liquidity and Capital Resources below) allows us to seek additional oil and gas opportunities in the U.S.

We currently explore for and produce oil and gas through a non-operator business model; however, we operated our Colorado oil and gas property for our own account and plan to expand our operations to other areas. As a non-operator, we rely on our operating partners to propose, permit and manage wells. Before a well is drilled, the operator is required to provide all oil and gas interest owners in the designated well unit the opportunity to participate in the drilling costs and revenues of the well on a pro-rata basis. After the well is completed, our operating partners also transport, market and account for all production.

We are also involved in the exploration for and development of minerals (molybdenum) through our ownership of the Mt. Emmons Molybdenum Project in Colorado and other mineral and energy opportunities. Gross capitalized dollar amounts invested in each of these areas at June 30, 2011 and December 31, 2010 were as follows:

	(In thousands)	
	June 30, 2011	December 31, 2010
Unevaluated oil and gas properties	$ 30,628	$ 21,620
Evaluated oil and gas properties	78,537	63,317
Undeveloped mining properties	20,771	21,077
Investment in geothermal properties	2,705	2,834
	$ 132,641	$ 108,848

Oil and Gas Activities

We participate in oil and gas projects primarily as a non-operating working interest owner and have active agreements with several oil and gas exploration and production companies. Our working interest varies by project, but typically ranges from approximately 5% to 65%. These projects may result in numerous wells being drilled over the next three to five years. We are also actively pursuing the potential of acquiring additional exploration, development or production stage oil and gas properties or companies.

Williston Basin, North Dakota

With Brigham Oil & Gas, L.P. We participate in fifteen 1,280 acre drilling units with Brigham Oil & Gas, L.P. From August 24, 2009 to June 30, 2011, we have drilled and completed 15 gross initial Bakken Formation wells (6.26 net), 2 gross Bakken formation infill wells (0.63 net) and 1 gross Three Forks formation well (0.17 net) under the Drilling Participation Agreement with Brigham Oil & Gas, L.P. ("Brigham") a Delaware limited partnership, that is wholly-owned by Brigham Exploration Company (a Delaware corporation). Two additional gross infill wells (0.35 net) are expected to be drilled during the balance of 2011. Brigham operates all of the wells.

During the first six months of 2011, the Company completed 4 gross wells (1.37 net) and finished drilling one well that was in progress at December 31, 2011 with net costs of $5.3 million for the period.

Brigham recently announced that the interpretation of the micro-seismic data from the 18 square mile data set accumulated during the Brad Olson 9-16 #2H fracture stimulation indicates that frac wings appear to extend laterally approximately 500' on either side of the wellbore, or 1,000' in total, per well. Based on a one mile wide spacing unit, results from the micro-seismic monitoring appear to support development of at least four wells per producing horizon per 1,280 acre spacing unit, or approximately eight total Bakken and Three Forks wells per spacing unit. If the state of North Dakota allows four wells per formation in each spacing unit, the Company could ultimately drill 60 gross Bakken formation and 60 gross Three Forks formation wells for a total of 120 gross wells with Brigham (including wells already drilled).

With Zavanna, LLC. In December 2010, we acquired approximately 6,200 net acres in the Williston Basin from Zavanna, LLC for approximately $11.0 million. The acreage is in two parcels – the Yellowstone Prospect and the SE HR Prospect. We expect this program will result in 31 gross 1,280 acre spacing units (with various working interests of up to 35%), with the potential of 93 gross Bakken and 93 gross Three Forks wells (including wells already drilled). Through June 30, 2011, we have acquired an additional 138 net acres in the Yellowstone Prospect from third parties for $218,000.

During the first six months of 2011, we drilled 4 gross wells (1.0 net) with Zavanna, LLC. We expect that these wells will be completed in the third quarter of 2011. Our net investment in these wells as of June 30, 2011 was $3.5 million. Zavanna, LLC operates all of these wells.

With Murex Petroleum Corporation. During the first six months of 2011, we drilled and completed 1 gross well (0.09 net) with Murex Petroleum Corporation. Additionally, we have funded the drilling costs for a second well (0.03 net) that is expected to be drilled in the third or fourth quarter of 2011. Our net investment in these wells as of June 30, 2011 was $832,000. Murex Petroleum Corporation operates these wells.

U.S. Gulf Coast (Onshore) and Permian Basin, Texas

We participate with several different operators in the U.S. Gulf Coast (onshore) and the Permian Basin of Texas. At June 30, 2011, we had 6 gross producing wells (1.16 net) in this region.

During the first six months of 2011, we drilled 3 gross wells (0.52 net) in the U.S. Gulf Coast. One gross well (0.17 net) was successfully completed and is currently producing. Our net investment is this well through June 30, 2011 is $783,000. Two gross wells (0.35 net) were deemed to be non-productive and have been plugged and abandoned. Net costs to the Company as of June 30, 2011 for the abandoned wells were $928,000.

San Joaquin Basin, California

Under an October 2010 agreement with Cirque Resources LP ("Cirque") (a private exploration and development company based in Denver, Colorado), we paid $2.5 million to Cirque in 2010 to purchase a 40% working interest (32% NRI) in Cirque's leases on 6,120 net mineral acres (2,448 acres net to our interest), in the San Joaquin Basin. Of the amount paid, $1.6 million is an advance against our 40% working interest for the initial well, including 33% of Cirque's 60% working interest share for the well. Cirque's lease assignments to us, are held in escrow, until the end of the well's drilling phase; once we have paid all the drilling costs (our working interest and Cirque's carry), the assignments will be recorded and released to us.

Completion and all other costs and expenses for the initial well and for all subsequent wells and any midstream projects (gathering, compressors, and processing/treatment facilities) will be paid by participants in proportion to their working interests. If successful, we estimate that our share of total completion costs for the initial well to be in the range of $640,000. Cirque is the operator for all operations on the prospect. We expect drilling to commence in the fourth quarter of 2011.

Eagle Ford Shale, South Texas

In February 2011, we entered into a participation agreement with Crimson Exploration Inc. ("Crimson") to acquire a 30% working interest in an oil prospect and associated leases located in Zavala County, Texas. Under the terms of the agreement, we have earned a 30% working interest (22.5% net revenue interest) in approximately 4,675 gross contiguous acres (1,402.5 net mineral acres) through a combination of a cash payment and commitment well carry. All future drilling and leasing will be paid by the participants in proportion to their respective working interests.

In June 2011, we entered into a second participation agreement with Crimson to acquire a 30% working interest in another oil prospect and associated leases located in Zavala and Dimmit Counties, Texas. Under the terms of this agreement, we acquired a 30% working interest (22.5% net revenue interest) in approximately 7,186 acres (2,156 acres net to the Company). The leases are currently held by production and produce approximately 200 gross BOE/D (46 net BOE/D) from the Austin Chalk formation.

The prospects are both Eagle Ford shale oil window targets and both will be operated by Crimson. The initial well on the first prospect was spud during the second quarter of 2011. The initial well on the second prospect is expected to spud in October 2011. If successful, the wells will be put on production and monitored for several months to evaluate well performance, which will allow Crimson and the Company to properly plan and budget for additional drilling in 2012.

These acquisitions bring our total acreage in the Eagle Ford oil window to approximately 11,861 gross acres (3,558 acres net to the Company). It is estimated under current spacing that there is a potential for up to 70 gross (21.3 net) drilling locations on the combined acreage. Looking forward, the Company plans to seek additional leasing opportunities in the Eagle Ford oil window jointly with Crimson.

Anadarko Basin, Southeast Colorado

On January 31, 2011, we entered into an acquisition, exploration and development agreement with a private party in an oil and gas prospect located in Southeast Colorado. Under the terms of the agreement, we acquired an 80% working interest in approximately 3,000 net acres for cash and a commitment to carry the seller for their 20% working interest to casing point in the initial well.

The initial well was spud in June 2011 and was in progress at June 30, 2011. Subsequent to June 30, 2011, the well was determined to be non-productive and has been plugged and abandoned. Our net cost in this well at June 30, 2011 was $324,000.

Liquidity and Capital Resources

At June 30, 2011, we had $7.8 million in cash and cash equivalents and $1.1 million in U.S. Treasuries with longer than 90-day maturities from date of purchase for a total of $8.9 million. Our working capital (current assets minus current liabilities) was $20.0 million. As discussed below in Capital Resources and Capital Requirements, we project that our capital resources at June 30, 2011 will be sufficient to fund operations and capital projects through the balance of 2011.

The principal recurring trend which affects the Company is variable prices for commodities producible from our oil, gas and mineral properties. The extent and grade of discovered oil, gas and minerals can mitigate or aggravate the impact of price swings. As commodities experience lower values in the market place, it is typically less expensive to acquire properties and hold them until prices rise to levels which either allow the properties to be sold or placed into production with joint venture partners or for our own account. Availability of exploration drilling and completion equipment and crews fluctuates with the market prices for oil and natural gas. When prices are low there is typically less exploration activity and the cost of drilling and completing wells is generally reduced. Conversely, when prices are high there is generally more exploration activity and the cost of drilling and completing wells generally increases.

Cash flows during the six months ended June 30, 2011:

Operations provided $2.0 million, Investing Activities consumed $13.2 million, Financing Activities provided $12.8 million and Discontinued Operations provided $235,000 for a net increase in cash of $1.9 million during the six months ended June 30, 2011. During the six months ended June 30, 2010, Operations provided $7.0 million, Investing Activities consumed $35.3 million, Financing Activities provided $503,000 and Discontinued Operations provided $535,000, for a net decrease of $27.3 million.

Operating Activities:

- Cash provided by operations for the six month period ended June 30, 2011 decreased to $2.0 million as compared to cash provided in operations of $7.0 million for the same period of the prior year. This $5.0 million decrease year over year in cash from operating activities is predominantly a result of $3.4 million higher lease operating expenses and a realized loss of $1.6 million in risk management activities.

  - For a complete discussion of cash provided by Operations please refer to Results of Operations below.

Investing Activities:

- Investing activities consumed cash through the acquisition and development of oil and gas properties in the amount of $29.8 million during the first six months of 2011 (including payment of $5.7 million which was included in accounts payable at December 31, 2010). Other uses of cash for investing activities in the period were: the acquisition of property and equipment in the amount of $44,000, a change in restricted investments in the amount of $206,000, and the development of mining properties in the amount of $48,000.

- Investing activities provided cash during the first six months of 2011 through the redemption of $16.8 million of treasury investments which were used to fund the purchase of oil and gas properties and advance drilling programs on existing prospects; $147,000 in proceeds from the sale of property and equipment; and $11,000 from the sale of marketable securities.

Financing Activities:

- Financing activities consumed $186,000 during the first six months of 2011 from the exercise of employee options and non-employee warrants (the Company received $39,000 in proceeds from the exercise of warrants by a director and paid taxes of $225,000 as a result of the cashless exercise of options by employees). Additionally, the Company paid $61,000 on its outstanding debt.

- Financing activities provided $13.0 million during the first six months of 2011 from a combination of the borrowing of $3.0 million under our Senior Credit Facility with BNP and the borrowing of $10.0 million from a commercial bank.

Following is a discussion regarding our projected Capital Resources and Capital Requirements for the balance of 2011. For longer-range projections of capital resources and requirements, please refer to the Company's Annual Report on Form 10-K for the year ended December 31, 2010.

Capital Resources

Potential primary sources of future liquidity include the following:

Oil and Gas Production

At June 30, 2011, we had twenty-five gross producing wells (8.3 net). During the six months ended June 30, 2011, we received an average of $2.3 million per month from these producing wells with an average operating cost of $285,000 per month (excluding workover costs) and production taxes of $225,000, for average cash flows of $1.8 million per month from oil and gas production before non-cash depletion expense. We anticipate that cash flows from oil and gas operations will increase through the balance of 2011 as the wells being drilled with Brigham Oil & Gas, L.P. ("Brigham"), Zavanna, LLC ("Zavanna"), Crimson and others, begin to produce. However, decreases in the price of oil and natural gas, increased operating costs, declines in production rates, unsuccessful development activities and other factors could decrease these average monthly cash flow amounts.

Normal production declines and the back-in after payout provision granted Brigham on the 15 initial wells drilled with Brigham will decrease the amount of cash flow we receive. We anticipate drilling more Bakken and Three Forks wells with Brigham and Zavanna in the future and will continue to search for additional drilling opportunities to replace these oil reserves and cash flows.

The ultimate amount of net cash that will be derived from the production of oil and gas will be determined primarily by the price of oil and gas, the amount of production and production costs. The ultimate life of producing wells will likewise be impacted by market prices and costs of production. We plan to continue in the oil and gas exploration business.

Factors that could affect cash flow from oil and gas production include:

- Lower market prices for oil and gas
- Higher drilling and completion costs
- Higher lease operating expenses
- Steeper decline rates than currently anticipated
- Mechanical and geological problems with the wells

Cash on Hand

At June 30, 2011, we had $7.8 million in cash and cash equivalents and $1.1 million in U.S. Treasuries. We invest cash in interest bearing accounts, with the majority invested in U.S. Government Treasuries. During the past two years, this investment policy has insured the preservation of principal with a nominal yield.

BNP Paribas Senior Credit Facility

On July 30, 2010, we established a senior credit facility to borrow up to $75 million from a syndicate of banks, financial institutions and other entities, including BNP. The Facility may be used to further our short and mid-terms goals of increasing our investment in oil and gas. As a result of establishing this credit facility we formed a wholly owned subsidiary, Energy One LLC ("Energy One"), to own the majority of our oil and gas properties as well as the BNP senior credit facility.

From time to time until the expiration of the credit facility (July 30, 2014) if Energy One is in compliance with the Facility Documents, Energy One may borrow, pay, and re-borrow funds from the Lenders, up to an amount equal to the Borrowing Base. On March 28, 2011, the Borrowing Base increased to $22.5 million (from $18.5 million) as a result of a redetermination using our December 31, 2010 financial statements, production reports and reserve reports. As of June 30, 2011, Energy One was in compliance with all the covenants under the Senior Credit Facility.

The Borrowing Base is redetermined semi-annually, taking into account updated reserve reports. Any proposed increase in the Borrowing Base will require approval by all Lenders in the syndicate, and any proposed Borrowing Base decrease will require approval by Lenders holding not less than two-thirds of outstanding loans and loan commitments.

On February 18, 2011 we borrowed $3.0 million under the Credit Facility to fund a portion of our initial participation in the Eagle Ford Shale oil prospect in Zavala County, Texas with Crimson.

Equity Market

We filed a registration statement with the Securities and Exchange Commission on October 20, 2009 which became effective on November 6, 2009. The registration statement provides for the sale of up to $100 million of the Company's common stock from time to time. During the fourth quarter of 2009, we sold 5 million shares of our common stock for $5.25 per share or $26.3 million, $24.3 million net of offering costs. Additional capital may be raised under the registration statement to fund future oil and gas acquisitions and development drilling and other general purposes.

Asset Held for Sale – Remington Village

Until the property is sold, we will continue to receive rental receipts. The property averaged an occupancy rate of 90% during 2010 and was 85% occupied as of June 30, 2011. Occupancy is dependent on the regional economy including coal mining operations, oil and gas exploration and construction of a power generating plant in the area. The property generated average positive cash flow of $97,000 per month during the first six months of 2011 and cash flow is projected to remain in that range during the balance of 2011.

On May 5, 2011 we borrowed $10.0 million from a commercial bank. The note is secured by the Company's multi-family property in Gillette, Wyoming. The note has a term of five years and has an interest rate of 5.50% per annum. The proceeds of the note are being used to facilitate our general business obligations. The note replaces the $10.0 million line of credit that we had with the same commercial bank.

Capital Requirements

Our direct capital requirements during the balance of 2011 are the funding of our drilling programs, additional oil and gas exploration and development projects, acquisition of prospective oil and gas properties and/or existing production, operating and capital improvement costs of the water treatment plant at the Mt. Emmons project and ongoing permitting activities for the project, operations at Remington Village until it is sold and general and administrative costs. We intend to finance our 2011 capital expenditure plan primarily from the sources described above under "Capital Resources". We may be required to reduce or defer part of our 2011 capital expenditures plan if we are unable to obtain sufficient financing from these sources.

Oil and Gas Exploration and Development

We continue to expect capital expenditures of approximately $45 to $50 million in our 2011 oil and gas drilling program (through June 30, 2011, we have spent approximately $24.2 million of this budgeted amount). Of the original budget, we have allocated an estimated $33.5 to $35 million to be spent in the Williston Basin of North Dakota in the Rough Rider and Yellowstone/SEHR programs with Brigham Exploration and Zavanna LLC, respectively. The remaining $12.5 to $15 million in capital expenditure is budgeted to be spent on exploration and acquisition initiatives in the San Joaquin Basin of California, in Texas and Louisiana (primarily onshore Gulf Coast) and our operated Montana prospect. Amounts budgeted for each regional drilling program is contingent upon timing, well costs and success. If our non-Bakken drilling initiatives in California are not initially successful, funds allocated for this drilling program will be allocated to other drilling initiatives in due course. The actual number of gross and net wells could vary in each of these cases.

Mt. Emmons Molybdenum Project

On April 21, 2011, Thompson Creek Metals Company USA ("TCM") terminated its option agreement with U.S. Energy to develop the Mount Emmons project. Prior to that date, TCM funded the costs related to the property. Going forward, these costs will be our responsibility. We anticipate that our expenditures to continue the baseline data collection studies and activities under the Plan of Operations for the balance of 2011 will be approximately $500,000.

We are also responsible for all costs associated with operating the water treatment plant at the Mt. Emmons project. Operating costs during the balance of 2011 are projected to be approximately $1.2 million. Additionally, we have budgeted $200,000 for capital improvements in the plant which are expected to improve its efficiency.

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In 2009, U.S. Energy and TCM purchased a 160 acre parcel of property near the Mt. Emmons project. Under the terms of the purchase agreement the Company is obligated to make annual payments to the prior owner in the amount of $200,000 beginning in January 2010 through January 2014 with 6% interest per annum on the unpaid balance. In addition to the retirement of the debt, we will be responsible for one half of the holding and operating costs of the acreage which are expected to be minimal. TCM may elect to sell to us its 50% interest in the 160 acre parcel discussed above. In the event that TCM does elect to sell its interest in the property, it is anticipated that our cost to purchase this interest will be approximately $1.4 million. If we do acquire TCM's interest in this property, our annual note payments will increase to three payments of $400,000 plus 6% interest per annum on the unpaid balance.

Real Estate

Cash operating expenses at Remington Village are projected to be approximately $85,000 per month until Remington Village is sold. We do not anticipate any major capital expenditures on the property.

Geothermal and Alternative Energy Projects

At June 30, 2011, our net investment was $2.7 million which reflected a 22.8% minority ownership position in a geothermal partnership. We are not obligated to fund cash calls but will suffer further dilution if we do not fund.

Insurance

We have liability insurance coverage in amounts we deem sufficient and in line with industry standards for the location, stage, and type of operations in oil and gas, mineral property development (the Mt. Emmons molybdenum project), and the Remington Village housing complex. Payment of substantial liabilities in excess of coverage could require diversion of internal capital away from regular business, which could result in diminished operations. We have property loss insurance on all major assets equal to the approximate replacement value of the assets. We have also purchased additional liability and control of well insurance for our oil and gas drilling programs.

Asset Retirement Obligations/Reclamation Costs

We have reclamation obligations with an estimated present value of $303,000 related to our oil and gas wells and $144,000 related to the Mt. Emmons molybdenum property. As of June 30, 2011, no reclamation is expected to be performed on the existing wells during the year ended December 31, 2011. Reclamation will only begin after the wells no longer produce oil or gas in economic quantities. The earliest projected reclamation will begin in 2013 in the Gulf Coast unless wells in other areas are abandoned due to operational challenges. As the Mt. Emmons project is developed, the reclamation liability is expected to increase. It is not anticipated that this reclamation work will occur in the near term. Our objective, after the proposed mine is fully produced and reclaimed, is to eliminate long-term liabilities associated with the property.

Results of Operations

Three Months Ended June 30, 2011 compared to 2010

During the three months ended June 30, 2011, we recorded a net loss after taxes of $75,000 as compared to a net loss after taxes of $131,000 during the same period of 2010. The decrease in net earnings for 2011 as compared to 2010 is primarily due to (a) $457,000 higher lease operating expense, (b) $724,000 higher oil and gas depreciation, depletion and amortization, (c) a deferred tax expense of $618,000 in the quarter ended June 30, 2011 as compared to a deferred tax benefit of $17,000 during the quarter ended June 30, 2010 and (d) a 2010 equity gain of $179,000 related to our investment in Standard Steam Trust as compared to an equity loss of $65,000 during the quarter ended June 30, 2011. These decreases in net earnings after taxes were offset by (a) $1.1 million in realized and unrealized gain on risk management activities in the second quarter of 2011, (b) $29,000 lower general and administrative expenses and (c) $807,000 higher revenues from oil and gas sales in 2011.

Operating Revenues - We recognized $8.1 million in net revenues during the quarter ended June 30, 2011 as compared to revenues of $6.2 million during the same period in the prior year. The components of the change are as follows:

Oil and Gas Operations - Oil and gas operations produced operating income of $3.1 million during the quarter ended June 30, 2011 as compared to operating income of $2.3 million from oil and gas operations during the quarter ended June 30, 2010. The increase in earnings from oil and gas operations is primarily due to (a) an $807,000 increase in revenues due to higher commodity prices during 2011 compared to 2010 and (b) $1.0 million in realized loss and $2.1 million in unrealized gain on risk management activities in 2011. This is partially offset by $457,000 higher lease operating expenses and $724,000 higher depletion expense in 2011. The following table details the results of operations from the oil and gas sector for the quarters ended June 30, 2011 and 2010:

	(In thousands) For the three months ending		Increase
	June 30, 2011	June 30, 2010	(Decrease)
Oil and gas revenues	$ 7,025	$ 6,218	$ 807
Realized (loss) from risk management activities	(1,015)	--	(1,015)
Unrealized gain from risk management activities	2,138	--	2,138
	8,148	6,218	1,930
Operating expenses	1,955	1,498	457
Depreciation, depletion and amortization	3,120	2,396	724
	5,075	3,894	1,181
Direct operating income	$ 3,073	$ 2,324	$ 749

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The following table summarizes production volumes, average sales prices and operating revenues for the quarters ended June 30, 2011 and 2010:

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Increase (Decrease)
Production volumes			
Oil (Bbls)	56,109	72,601	(16,492)
Natural gas (Mcf)	238,825	157,775	81,050
Natural gas liquids (Bbls)	6,500	3,159	3,341
Average sales prices, before economic hedging			
Oil (per Bbl)	$ 99.77	$ 71.98	$ 27.79
Natural gas (per Mcf)	4.46	5.16	(0.70)
Natural gas liquids (per Bbl)	55.85	56.35	(0.50)
Operating revenues (in thousands)			
Oil	$ 5,598	$ 5,226	$ 372
Natural gas	1,064	814	250
Natural gas liquids	363	178	185
Total operating revenue	7,025	6,218	807
Lease operating expense	(1,289)	(664)	(625)
Production taxes	(667)	(834)	167
Risk management activities	1,123	--	1,123
Impairment	--	--	--
Direct operating income before depreciation, depletion and amortization	6,192	4,720	1,472
Depreciation, depletion and amortization	(3,120)	(2,396)	(724)
Direct operating income	$ 3,072	$ 2,324	$ 748

During the three months ended June 30, 2011, we produced approximately 102,413 barrels of oil equivalent (BOE), or an average of 1,125 BOE/day. Portions of our natural gas production are sent to gas processing plants to profitably extract from the gas various natural gas liquids (“NGL”) that are sold separately from the remaining natural gas. We sell some of our processed gas before processing and some after processing but in both cases receive revenues based on a share of post-processing proceeds from plant sales of the extracted NGL and the remaining natural gas. In the table above, our share of processing costs are classified in lease operating expenses. Natural gas and natural gas liquids volumes were higher in the period ending June 30, 2011 primarily due to production from the ALMI #8 and SL 20183 #1 (LL Bean) Gulf Coast wells that were completed in August 2010 and May 2011, respectively. Oil volumes were lower in the period ending June 30, 2011 primarily due to weather related production issues in the Williston Basin.

During the balance of 2011 we will complete wells that were drilled during the first and second quarters of 2011 and drill and complete new wells. We anticipate our production rates increasing as a result of these activities. In particular, we expect that oil volumes will increase as we drill and complete oil wells in the Williston Basin and other areas. However, natural gas and natural gas liquids volumes are expected to decrease as production declines from the producing wells. The net increase in production is projected to add additional cash flows from operations and improve net earnings from our oil and gas operations. Extensive work over costs on existing wells, cost over runs on projected drilling projects or unsuccessful wells or other development activities would have a negative effect on both cash flows and earnings from the oil and gas segment.

Mt. Emmons Molybdenum Property - We are responsible for all costs associated with the water treatment plant at the Mt. Emmons molybdenum property and thereby recorded $498,000 in costs and expenses for that facility and $37,000 in holding costs of the Mt. Emmons molybdenum property during the quarter ended June 30, 2011. During the quarter ended June 30, 2010, we recorded $459,000 in operating costs related to the water treatment plant and a credit of $5,000 in holding costs.

General and Administrative - General and administrative expenses decreased by $29,000 during the quarter ended June 30, 2011 over those experienced during the quarter ended June 30, 2010.

Other income and expenses - We recorded an equity loss of $65,000 from the investment in SST during the quarter ended June 30, 2011 and recorded an equity gain of $179,000 for the quarter ended June 30, 2010 due to the sale of two of SST's geothermal properties. Equity losses from the investment in SST are expected to continue until such time as SST properties are sold, equity losses reduce our investment to zero or we sell the investment.

Gain on the sale of assets increased to $137,000 during the quarter ended June 30, 2011 from $0 during the quarter ended June 30, 2010 as a result of the sale of a corporate aircraft which was no longer needed.

Interest income increased to $10,000 during the quarter ended June 30, 2011 from $2,000 during the quarter ended June 30, 2010.

Interest expense increased to $115,000 during the quarter ended June 30, 2011 from $18,000 during the quarter ended June 30, 2010. The increase in interest expense was related primarily to the $10.0 million borrowed from a commercial bank in May 2011 and the $3.0 million borrowed under our Senior Credit Facility with BNP in February 2011.

Discontinued operations - We recorded income of $204,000, net of taxes from the discontinued operations of Remington Village during the quarter ended June 30, 2011 and income of $28,000, net of taxes for the quarter ended June 30, 2010. The increase in income is primarily a result of $236,000 in scheduled depreciation costs that were not recorded during the second quarter of 2011 as a result of Remington Village being classified as an asset held for sale.

We therefore recorded a net loss after taxes of $75,000, or less than $0.01 per share basic and diluted, during the quarter ended June 30, 2011 as compared to a net loss after taxes of $131,000, or less than $0.01 per share basic and diluted, during the quarter ended June 30, 2010.

Six Months Ended June 30, 2011 compared to 2010

During the six months ended June 30, 2011, we recorded a loss of $2.3 million as compared to a net income of $1.4 million during the same period of 2010. The decrease in net earnings for 2011 as compared to 2010 is primarily due to (a) a $1.6 million loss in realized risk management activities that is partially offset by an $897,000 unrealized gain on risk management activities during the first six months of 2011, (b) $3.4 million higher lease operating expenses in 2011 which included approximately $2.8 million in proportionate workover costs on one well, (c) $1.3 million in higher oil and gas depreciation, depletion and amortization expense (d) a deferred tax benefit of $2.0 million in the six months ended June 30, 2011 as compared to a deferred tax expense of $871,000 during the six months ended June 30, 2010 and (e) a 2010 equity gain of $1.1 million related to our investment in Standard Steam Trust.

Operating Revenues - We recognized $13.0 million in net revenues during the six months ended June 30, 2011 as compared to revenues of $13.9 million during same period in the prior year. Components of the change in operating revenues and results of operations for the six months ended June 30, 2011 as compared to June 30, 2010 are as follows:

Oil and Gas Operations - Oil and gas operations produced net operating income of $1.1 million during the six months ended June 30, 2011 as compared to income of $6.6 million from oil and gas operations during the six months ended June 30, 2010. The decrease in earnings from oil and gas operations is primarily due to (a) $223,000 drop in revenues due to lower production during 2011 compared to 2010, (b) $673,000 in realized and unrealized loss on risk management activities in 2011, (c) $3.4 million higher lease operating expenses in 2011 which included approximately $2.8 million in proportionate workover costs on one well. The following table details the results of operations from the oil and gas sector for the six months ended June 30, 2011 and 2010:

	(In thousands) For the six months ending		
	June 30, 2011	June 30, 2010	Increase (Decrease)
Oil and gas revenues	$ 13,704	$ 13,927	$ (223)
Realized (loss) from risk management activities	(1,570)	--	(1,570)
Unrealized gain from risk management activities	897	--	897
	13,031	13,927	(896)
Operating expenses	6,034	2,628	3,406
Depreciation, depletion and amortization	5,905	4,651	1,254
	11,939	7,279	4,660
Direct operating income	$ 1,092	$ 6,648	$ (5,556)

The following table summarizes production volumes, average sales prices and operating revenues for the six months ended June 30, 2011 and 2010:

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010	Increase (Decrease)
Production volumes			
Oil (Bbls)	123,459	160,927	(37,468)
Natural gas (Mcf)	412,580	317,634	94,946
Natural gas liquids (Bbls)	11,281	6,134	5,147
Average sales prices, before economic hedging			
Oil (per Bbl)	$ 90.77	$ 73.30	$ 17.47
Natural gas (per Mcf)	4.61	5.63	(1.02)
Natural gas liquids (per Bbl)	52.92	55.75	(2.83)
Operating revenues (in thousands)			
Oil	$ 11,206	$ 11,796	$ (590)
Natural gas	1,901	1,789	112
Natural gas liquids	597	342	255
Total operating revenue	13,704	13,927	(223)
Lease operating expense	(4,685)	(868)	(3,817)
Production taxes	(1,349)	(1,760)	411
Risk management activities	(673)	--	(673)
Impairment	--	--	--
Direct operating income before depreciation, depletion and amortization	6,997	11,299	(4,302)
Depreciation, depletion and amortization	(5,905)	(4,651)	(1,254)
Direct operating income	$ 1,092	$ 6,648	$ (5,556)

During the six months ended June 30, 2011, we produced approximately 203,503 barrels of oil equivalent (BOE), or an average of 1,124 BOE/day. Portions of our natural gas production are sent to gas processing plants to profitably extract from the gas various natural gas liquids (“NGL”) that are sold separately from the remaining natural gas. We sell some of our processed gas before processing and some after processing but in both cases receive revenues based on a share of post-processing proceeds from plant sales of the extracted NGL and the remaining natural gas. In the table above, our share of processing costs are classified in lease operating expenses. Natural gas and natural gas liquids volumes were higher in the period ending June 30, 2011 primarily due to production from the ALMI #8 and SL 20183 #1 (LL Bean) Gulf Coast wells that were completed in August 2010 and May 2011, respectively. Oil volumes were lower in the period ending June 30, 2011 primarily due to weather related production issues in the Williston Basin and declines in production from producing wells.

During the balance of 2011 we will complete wells that were drilled during the first six months of 2011 and drill and complete new wells. We anticipate our production rates increasing as a result of these activities. In particular, we expect that oil volumes will increase as we drill and complete oil wells in the Williston Basin and other areas. However, natural gas and natural gas liquids volumes are expected to decrease as production declines from the producing wells. The net increase in production is projected to add additional cash flows from operations and improve net earnings from our oil and gas operations. Extensive work over costs on existing wells, cost over runs on projected drilling projects or unsuccessful wells or other development activities would have a negative effect on both cash flows and earnings from the oil and gas segment.

Mt. Emmons Molybdenum Property - We recorded $927,000 in costs and expenses for the water treatment plant and $80,000 in holding costs of the Mt. Emmons molybdenum property during the six months ended June 30, 2011. During the six months ended June 30, 2010, we expended $808,000 in operating costs related to the water treatment plant and $52,000 in holding costs.

General and Administrative - General and administrative expenses decreased by $286,000 during the six months ended June 30, 2011 over those experienced during the six months ended June 30, 2010. The decrease in general and administrative expenses is primarily due to lower accrued compensation costs.

Other income and expenses - We recorded an equity loss of $129,000 from the investment in SST during the six months ended June 30, 2011. We recorded an equity gain of $1.1 million for the six months ended June 30, 2010 due to the sale of two of SST's geothermal properties. Equity losses from the investment in SST are expected to continue until such time as SST properties are sold, equity losses reduce our investment to zero or we sell the investment.

Gain on the sale of assets increased to $137,000 during the six months ended June 30, 2011 from $115,000 during the six months ended June 30, 2010 as a result of the sale of a corporate aircraft which was no longer needed.

Interest income decreased from $61,000 during the six months ended June 30, 2010 to $30,000 during the six months ended June 30, 2011. The decrease is a result of lower amounts of cash invested in interest bearing instruments during the quarter, and lower interest rates received on those investments.

Interest expense increased to $138,000 during the six months ended June 30, 2011 from $35,000 during the six months ended June 30, 2010. The increase in interest expense was related primarily to the $10.0 million borrowed from a commercial bank in May 2011 and the $3.0 million borrowed under our Senior Credit Facility with BNP in February 2011.

Discontinued operations - We recorded income of $333,000, net of taxes from the discontinued operations of Remington Village during the six months ended June 30, 2011 and income of $103,000, net of taxes for the six months ended June 30, 2010. The increase in income is primarily a result of $473,000 in scheduled depreciation costs that were not recorded during 2011 as a result of Remington Village being classified as an asset held for sale.

We therefore recorded net loss after taxes of $2.3 million, or $0.08 per share basic and diluted, during the six months ended June 30, 2011 as compared to a net income after taxes of $1.4 million, or $0.05 per share basic and diluted respectively, during the six months ended June 30, 2010.

Critical Accounting Policies

For detailed descriptions of our significant accounting policies, please see pages 68 to 71 of our Annual Report on Form 10K for the year ended December 31, 2010.

Oil and Gas Properties - We follow the full cost method in accounting for our oil and gas properties. Under the full cost method, all costs associated with the acquisition, exploration and development of oil and gas properties are capitalized and accumulated in a country-wide cost center. This includes any internal costs that are directly related to development and exploration activities, but does not include any costs related to production, general corporate overhead or similar activities. Proceeds received from property disposals are credited against accumulated cost except when the sale represents a significant disposal of reserves, in which case a gain or loss is recognized. The sum of net capitalized costs and estimated future development and dismantlement costs for each cost center is depleted on the equivalent unit-of-production method, based on proved oil and gas reserves. Excluded from amounts subject to depletion are costs associated with unproved properties.

Under the full cost method, net capitalized costs are limited to the lower of unamortized cost reduced by the related net deferred tax liability and asset retirement obligations or the cost center ceiling. The cost center ceiling is defined as the sum of (i) estimated future net revenue, discounted at 10% per annum, from proved reserves, based on unescalated average prices per barrel of oil and per MMbtu of natural gas at the first of each month in the 12-month period prior to the end of the reporting period and costs, adjusted for contract provisions, financial derivatives that hedge the oil and gas revenue and asset retirement obligations, (ii) the cost of properties not being amortized, (iii) the lower of cost or market value of unproved properties included in the cost being amortized less (iv) income tax effects related to tax assets directly attributable to crude oil and natural gas properties. If the net book value reduced by the related net deferred income tax liability and asset retirement obligations exceeds the cost center ceiling limitation, a non-cash impairment charge is required in the period in which the impairment occurs.

Full cost pool capitalized costs are amortized over the life of production of proven properties. Capitalized costs at June 30, 2011 and December 31, 2010 which were not included in the amortized cost pool were $30.6 million and $21.6 million, respectively. These costs consist of wells in progress, seismic costs that are being analyzed for potential drilling locations as well as land costs related to unproved properties. No capitalized costs related to unproved properties are included in the amortization base at June 30, 2011 and December 31, 2010. It is anticipated that these costs will be added to the full cost amortization pool in the next two years as properties are proved, drilled or abandoned.

Given the volatility of oil and gas prices, it is probable that our estimate of discounted future net cash flows from proved oil and gas reserves will change. If oil or natural gas prices decline substantially, even for only a short period of time, or if we have downward revisions to our estimated proved reserves, it is possible that write-downs of oil and gas properties could occur in the future.

Derivative Instruments - We use derivative instruments, typically fixed-rate swaps and costless collars to manage price risk underlying our oil and gas production. We may also use puts, calls and basis swaps in the future. All derivative instruments are recorded in the consolidated balance sheets at fair value. We offset fair value amounts recognized for derivative instruments executed with the same counterparty. Although we do not designate any of our derivative instruments as a cash flow hedge, such derivative instruments provide an economic hedge of our exposure to commodity price risk associated with forecasted future oil and gas production. These contracts are accounted for using the mark-to-market accounting method and accordingly, we recognize all unrealized and realized gains and losses related to these contracts currently in earnings and they are classified as gain (loss) on derivative instruments, net in our consolidated statements of operations.

Our Board of Directors sets all risk management policies and reviews the status and results of derivative activities, including volumes, types of instruments and counterparties on a quarterly basis. These policies require that derivative instruments be executed only by the Chief Executive Officer or President. The master contracts with approved counterparties identify the Chief Executive Officer and the President as the only Company representatives authorized to execute trades. See Note 6, Commodity Price Risk Management, for further discussion.

Mineral Properties - We capitalize all costs incidental to the acquisition of mineral properties. Mineral exploration costs are expensed as incurred. When exploration work indicates that a mineral property can be economically developed as a result of establishing proved and probable reserves, costs for the development of the mineral property as well as capital purchases and capital construction are capitalized and amortized using units of production over the estimated recoverable proved and probable reserves. Costs and expenses related to general corporate overhead are expensed as incurred. All capitalized costs are charged to operations if we subsequently determine that the property is not economical due to permanent decreases in market prices of commodities, excessive production costs or depletion of the mineral resource. Mineral properties at June 30, 2011 and December 31, 2010 reflect capitalized costs associated with the Mt. Emmons molybdenum property near Crested Butte, Colorado.

Asset Retirement Obligations - We account for asset retirement obligations under ASC 410-20. We record the fair value of the reclamation liability on inactive mining properties as of the date that the liability is incurred. We review the liability each quarter and determine if a change in estimate is required as well as accrete the liability on a quarterly basis for the future liability. Final determinations are made during the fourth quarter of each year. We deduct any actual funds expended for reclamation during the quarter in which it occurs.

Future Operations

Management intends to continue seeking investment opportunities in the oil and natural gas sector. Long term, we intend to fund the holding and permitting costs associated with the Mt. Emmons property.

Effects of Changes in Prices

Natural resource operations are significantly affected by changes in commodity prices. As prices for a particular commodity increase, values for prospects for that commodity typically also increase, making acquisitions of such properties more costly and sales potentially more valuable. Conversely, a price decline could enhance acquisitions of properties containing that commodity, but could also make sales of such properties more difficult. Operational impacts of changes in commodity prices are common in the mining and oil and gas industries.

At June 30, 2011, we are receiving revenues from our oil and gas business. Our revenues, cash flows, future rate of growth, results of operations, financial condition and ability to finance projected acquisition of oil and gas producing assets are dependent upon prevailing prices of oil and gas.

Forward Looking Statements

This Form 10-Q contains “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). All statements other than statements of historical facts included in and incorporated by reference into this Form 10-Q are forward-looking statements. These forward-looking statements are subject to certain risks, trends and uncertainties that could cause actual results to differ materially from those projected. Among those risks, trends and uncertainties are those associated with our ability to find oil and natural gas reserves that are economically recoverable, the volatility of oil and natural gas prices, declines in the values of our properties that have resulted in and may in the future result in additional ceiling test write downs, our ability to replace reserves and sustain production, our estimate of the sufficiency of our existing capital sources, our ability to raise additional capital to fund cash requirements for our participation in oil and gas properties and for future acquisitions, the uncertainties involved in estimating quantities of proved oil and natural gas reserves, in prospect development and property acquisitions or dispositions and in projecting future rates of production or future reserves, the timing of development expenditures and drilling of wells, hurricanes and other natural disasters and the operating hazards attendant to the oil and gas and minerals businesses. In particular, careful consideration should be given to cautionary statements made in the Company’s Risk Factors included in our Annual Report on Form 10-K and quarterly reports on Form 10-Q filed with the SEC, all of which are incorporated herein by reference. The Company undertakes no duty to update or revise any forward-looking statements.

When used in this Form 10-Q, the words “will”, “expect,” “anticipate,” “intend,” “plan,” “believe,” “seek,” “estimate” an expressions are intended to identify forward-looking statements, although not all forward-looking statements contain these identifying words. Because these forward-looking statements involve risks and uncertainties, actual results could differ materially from those expressed or implied by these forward-looking statements for a number of important reasons, including those discussed under “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and elsewhere in this Form 10-Q.

Off-Balance Sheet Arrangements

None.

Contractual Obligations

We had three divisions of contractual obligations at June 30, 2011: Debt to third parties of $13.6 million, executive retirement of $1.0 million and asset retirement obligations of $447,000. The debt consists of debt to a commercial bank secured by our multi-family property in Gillette, WY, debt related to our oil and gas reserves and the purchase of land near our Mt. Emmons molybdenum property. The debt to the commercial bank bears an interest rate of 5.5% per annum. The oil and gas debt bears an interest rate of 2.7% per annum and the land debt bears an interest rate of 6.0% per annum. The debt to the commercial bank is for a term of five years and is due on May 5, 2016 and will be paid with sixty monthly installments, with a balloon payment at maturity of $8.8 million. The oil and gas debt is for a term of six months and is due on August 18, 2011. The payment will be $3.0 million plus accrued interest. This debt can be continued at our election if we remain in compliance with the covenants under the Senior Credit Facility. The land debt is due in three equal annual payments of $200,000, plus accrued interest. The next payment is due on January 2, 2012. The executive retirement liability will be paid out over varying periods starting after the actual projected retirement dates of the covered executives. The asset retirement obligations will be retired during the next 34 years. The following table shows the scheduled debt payment, projected executive retirement benefits and asset retirement obligations. This table reflects the debt obligation on the Remington Village apartment complex on terms of the note. However, because the related property is reflected as a current asset held for sale, the note is also classified in the financial statements as a current liability held for sale.

	(In thousands) Payments due by period				
	Total	Less than one Year	One to Three Years	Three to Five Years	More than Five Years
Debt obligations	$ 13,610	$ 3,481	$ 1,353	$ 8,776	$ --
Executive retirement	1,013	118	327	163	405
Asset retirement obligation	447	--	69	14	364
Totals	$ 15,070	$ 3,599	$ 1,749	$ 8,953	$ 769

ITEM 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Risk. Our major market risk exposure is the commodity pricing applicable to our oil and natural gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for oil and spot prices applicable to natural gas. The market prices for oil and natural gas have been highly volatile and are likely to continue to be highly volatile in the future, which will impact our prospective revenues.

To mitigate some of our commodity risk, we use derivative instruments, typically fixed-rate swaps and costless collars, to manage price risk underlying our oil and gas production. We may also use puts, calls and basis swaps in the future. We do not hold or issue derivative instruments for trading purposes. The objective of utilizing the economic hedges is to reduce the effect of price changes on a portion of our future oil production, achieve more predictable cash flows in an environment of volatile oil and gas prices and to manage our exposure to commodity price risk. The use of these derivative instruments limits the downside risk of adverse price movements. However, there is a risk that such use may limit our ability to benefit from favorable price movements. Energy One may, from time to time, add incremental derivatives to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of the its existing positions.

Through our wholly-owned affiliate Energy One, we have entered into three commodity derivative contracts ("economic hedges") with BNP Paribas, a costless collar and two fixed price swaps, as described below. The three derivative contracts are priced using West Texas Intermediate ("WTI") quoted prices. U.S. Energy Corp. is a guarantor of Energy One under the economic hedges.

Energy One's commodity derivative contracts as of June 30, 2011 are summarized below:

Quantity

Settlement Period	Counterparty	Basis	(Bbl/d)	Strike Price	
Crude Oil Costless Collars					
10/01/10 - 09/30/11	BNP Paribas	WTI	200	Put:	$ 75.00
				Call:	$ 83.25
Crude Oil Swaps					
10/01/10 - 09/30/11	BNP Paribas	WTI	200	Fixed:	$ 79.05
01/01/11 - 12/31/11	BNP Paribas	WTI	200	Fixed:	$ 89.60

The following table details the fair value of the derivatives recorded in the applicable condensed consolidated balance sheet, by category:

Underlying Commodity	Location on Balance Sheet	Fair Value at June 30, 2011
Crude oil costless collar	Current Liability	$ 245
Crude oil swap #1	Current Liability	314
Crude oil swap #2	Current Liability	268
		$ 827

These contracts are accounted for using the mark-to-market accounting method and accordingly, we recognize all unrealized and realized gains and losses related to these contracts currently in earnings and such gains and losses are classified as gain (loss) on derivative instruments, net in our consolidated statements of operations.

ITEM 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of June 30 2011, the Company's management, including its Chief Executive Officer and Principal Accounting Officer, completed an evaluation of the effectiveness of the Company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities and Exchange Act of 1934, as amended (the "Exchange Act")). Based on that evaluation the Chief Executive Officer and Principal Accounting Officer concluded:

i. That the Company's disclosure controls and procedures are designed to ensure (a) that information required to be disclosed by the Company in the reports it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms, and (b) that such information is accumulated and communicated to the Company's management, including the Chief Executive Officer and Principal Accounting Officer, as appropriate, to allow timely decisions regarding required disclosure; and

ii. That the Company's disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting that occurred during the quarter ended June 30, 2011 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. Legal Proceedings

Water Right – Mt. Emmons Molybdenum Property

On July 25, 2008, U.S. Energy Corp. (the "Company") filed an Application for Finding of Reasonable Diligence with the Water Court ("Water Diligence Application") concerning the conditional water rights associated with Mt. Emmons (Case No. 2008CW81). The conditional water decree ("Decree") requires the Company to file its proposed plan of operations and associated permits with the Forest Service and BLM within six years of entry of the 2002 Decree, or within six years of the final determination in the Applicant's pending patent application, whichever occurs later. The BLM issued the mineral patents on April 2, 2004. Although the issuance of the patents was appealed, on April 30, 2007, the United States Supreme Court made a final determination upholding BLM's issuance of the mineral patents. The Company filed the Plan of Operations on March 31, 2010.

On August 11, 2010, High Country Citizen's Alliance, Crested Butte Land Trust and Star Mountain Ranch Association, Inc. ("Opposers") filed a Motion for Summary Judgment alleging that the Plan of Operations did not comply with the Forest Service regulations and did not satisfy certain Reality Check Limitations contained in the Water Rights Decree. On September 24, 2010, U.S. Energy filed a Response to the Motion for Summary Judgment responding that the Plan of Operations complied with the Forest Service and BLM's regulations and satisfied the Reality Check Limitations contained in the Water Rights Decree. The U.S. Department of Justice also filed a response on behalf of the Forest Service and BLM that the Court cannot second guess the Forest Service's determination that the Company's Plan of Operations satisfied the Forest Service and BLM's regulations. On November 24, 2010 the District Court Judge denied the Opposers' Motion for Summary Judgment and held that Company had until April 30, 2013 to comply with the Reality Check provision of the Decree, which is six years after the Supreme Court denied certiorari in the judicial proceeding. The question of the adequacy of the Water Diligence Application is pending.

Appeal of Approval of Notice of Intent to Conduct Prospecting for the Mt. Emmons Property

On March 8, 2008, High Country Citizens' Alliance ("HCCA") filed a request for hearing before the Colorado Land Reclamation Board ("Board") of the approval of a Notice of Intent to Conduct Prospecting Notice for the Mt. Emmons molybdenum property ("NOI"), which was approved by the Division of Reclamation, Mining and Safety of the Colorado Department of Natural Resources ("DRMS") on January 3, 2008. The NOI as approved provided for continued exploration of the molybdenum deposit to update, improve and verify, in accordance with current industry standards and legal requirements, mineralization data that was collected by Amax in the late 1970's. On May 14, 2008, the Board denied HCCA's Request for Hearing and also denied their Request for a Declaratory Order. Citing Colorado law, the Board determined that HCCA did not have standing or the right to appeal DRMS's approval of the NOI under Colorado law. On August 28, 2008, HCCA appealed the Board's decision in Denver District Court. Plaintiff: High Country Citizen's Alliance v. Defendants: Colorado Mined Land Reclamation Board, Colorado Division of Reclamation Mining and Safety and U.S. Energy Corp., Case No.: 08CV6156 (District Court, 2d Jud. Dist., City and County of Denver). The Board has filed an answer with the Court. The DRMS and the Company filed the responsive pleadings in addition to motions to dismiss the HCCA complaint.

On February 24, 2011, the Denver, Colorado District Court issued an Order dismissing all of HCCA's claims concerning the appeal of U.S. Energy's NOI holding that: (i) HCCA does not have standing to request judicial review on the merits of the DRMS's approval of U.S. Energy's NOI and (ii) HCCA does not have standing to request a Declaratory Order. This decision upholds MLRB's May 14, 2008 decision denying HCCA's Request for Hearing and their Request for a Declaratory Order because HCCA did not have standing or the right to appeal DRMS's approval of the NOI under Colorado law.

On January 20, 2010 the Company submitted Modification MD-03 ("MD-03") to the NOI. On November 15, 2010 DRMS issued its determination that MD-03 was complete, the activities proposed were prospecting and that MD-03 was approved. On November 19, 2010 HCCA filed an appeal with the MLRB claiming that: (i) the proposed activities were not prospecting, but rather development and mining, (ii) the current financial warranty amount was insufficient to cover the proposed activities and (iii) the permit should be conditioned upon its compliance with other federal and local governmental agency requirements.

On January 12, 2011, the MLRB on a 4-1 vote upheld DRMS's approval of MD-03 and their determination that: (i) the activities proposed by the NOI and MD-03 are prospecting, not development or mining, (ii) the current financial warranty amount is sufficient to cover the proposed activities and (iii) DRMS's decision not to make its approval of MD-03 contingent on permits or licenses that may be required by federal, other state, or local agencies was proper and affirmed that decision. On March 2, 2011, HCCA appealed MLRB's decision on MD-03 to the Denver, Colorado District Court.

Brigham Oil & Gas, L.P.

On June 8, 2011, Brigham Oil & Gas, L.P. ("Brigham") as the Operator of the Williston 25-36 #1H Well, filed an action in the State of North Dakota, County of Williams, in District Court, Northwest Judicial District, Case No. 53-11-CV-00495 to interplead to the court the undistributed suspended funds from this well to protect its self from potential litigation. Brigham became aware of an apparent dispute with respect to ownership of the mineral interest between the ordinary high water mark and the ordinary low water mark of the Missouri River. Brigham has suspended payment of certain proceeds of production related to the minerals in and under this property pending resolution of the apparent dispute. Energy One LLC ("Energy One") is a working interest owner in this well as a result of a Participation Agreement and a Joint Operating Agreement with Brigham and Energy One's legal position is aligned with Brigham. All funds due to Energy One on this well have been distributed to Energy One and there are no undistributed suspended funds held in suspense by Brigham for Energy One. Although initially listed as a defendant in this proceeding, Brigham and Energy One LLC will be filing with the court documents to change Energy One's status to an additional plaintiff.

For information on other legal proceedings in which there have been no new developments, see Item 1, Part II of the Company's Annual Report on Form 10-K filed on March 14, 2011.

ITEM 1A. Risk Factors

There have been no material changes to the risk factors discussed in Part I, "Item 1A - Risk Factors" (pages 18 to 30) in the Company's Annual Report on Form 10-K for the year ended December 31, 2010, which could materially affect the Company's business, financial condition or future results. Additional risks and uncertainties not currently known to the Company or that it currently deems to be immaterial also may materially adversely affect its business, financial condition and/or operating results.

ITEM 2. Unregistered Sales of Equity Securities and Use of Proceeds

During the six months ended June 30, 2011, the Company issued 170,781 shares of its common stock. The shares were issued as restricted securities in reliance on the exemption available to the Company under Section 4(2) of the Securities Act of 1933. These shares were issued as new issuances pursuant to the 2001 stock compensation plan, 40,000 shares; the exercise of warrants by directors, 32,896 shares; and the exercise of options by employees, 97,885 shares.

ITEM 3. Defaults Upon Senior Securities

Not Applicable

ITEM 4. Submission of Matter to a Vote of Security Holders

U.S. Energy Corp. (the "Company") held its annual meeting of shareholders on Friday, June 24, 2011, at 8:30 a.m. Mountain Time in Riverton, Wyoming. The certified results of the matters voted upon at the meeting, which are more fully described in the Company's annual proxy statement, are as set forth below:

The following nominees for directors were elected by a plurality of votes cast to serve until the terms stated in the Company's proxy statement filed on Schedule 14A, with the Securities and Exchange Commission on April 27, 2011 (until the 2014 Annual Meeting of Shareholders and until their successors are elected or appointed and qualified):

Name of Director	Votes For	Withheld
Robert Scott Lorimer	10,007,406	914,588
Jerry Wayne Danni	10,638,574	283,420
Leo A. Heath	10,643,761	278,233

The shareholders voted on an advisory vote on executive compensation ("say-on-pay"):

Votes For	Votes Against	Abstain
9,779,997	527,165	614,832

The shareholders voted on an advisory vote on the frequency of the advisory vote on executive compensation:

1 Year	2 Year	3 Year	Abstain
8,408,205	202,195	2,013,151	298,443

The shareholders also voted on the ratification of appointment of Hein & Associates LLP, as independent auditors for the fiscal year:

Votes For	Votes Against	Abstain
21,093,588	297,627	150,225

ITEM 5. Other Information
Not Applicable

ITEM 6. Exhibits

31.1	Certification of Chief Executive Officer Pursuant to Rule 13a-15(e) / Rule 15d-15(e)
31.2	Certification of Chief Financial Officer Pursuant to Rule 13a-14(a) / Rule 15(e)/15d-15(e)
32.1	Certification of Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as adopted by Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as adopted by Section 906 of the Sarbanes-Oxley Act of 2002

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.

U.S. ENERGY CORP.
(Registrant)

Date: August 8, 2011 By: /s/ Keith G. Larsen
KEITH G. LARSEN
Chairman and CEO

Date: August 8, 2011 By: /s/ Bryon G. Mowry
BRYON G. MOWRY
Principal Accounting Officer