SECURITIES & EXCHANGE COMMISSION EDGAR FILING

US ENERGY CORP

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark One)

☑ Annual report pursuant to section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year Ended December 31, 2011

☐ Transition report pursuant to section 13 or 15(d) of the Securities Exchange Act of 1934 for the transition period from _____ to _____

Commission File Number 000-6814

U.S. ENERGY CORP.

(Exact Name of Company as Specified in its Charter)

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

Securities registered pursuant to Section 12(b) of the Act:
None

Securities registered pursuant to Section 12(g) of the Act:
Common Stock, $0.01 par value
(Title of Class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES ☐ NO ☑

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. YES ☐ NO ☑

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§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 ☑ NO ❑

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

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

Large accelerated filer ❑ Accelerated filer ☑ Non-accelerated filer ❑
Smaller reporting company ❑

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES ❑ NO ☑

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and ask price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter (June 30, 2011): $109,762,000.

Class	Outstanding at March 9, 2012
Common stock, $.01 par value	27,449,075

Documents incorporated by reference: Certain information required by Items 10, 11, 12, 13, and 14 of Part III is incorporated by reference from portions of the registrant's definitive proxy statement relating to its 2012 annual meeting of stockholders to be filed within 120 days after December 31, 2011.

TABLE OF CONTENTS

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

The information discussed in this Annual Report includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical facts are forward-looking statements.

Examples of forward-looking statements in this Annual Report include:

- planned capital expenditures for oil and gas exploration;
- cash expected to be available for continued work programs;
- recovered volumes and values of oil and gas approximating third-party estimates of oil and gas reserves;
- anticipated increases in oil and gas production;
- drilling and completion activities in the Williston Basin in North Dakota and the Eagle Ford shale in Texas and other areas;
- timing for drilling of additional wells;
- expected spacing and the number of wells to be drilled with our industry partners including Brigham Exploration Company (“Brigham”), Zavanna, LLC (“Zavanna”), and Murex Petroleum Corporation (“Murex”), in the Bakken/Three Forks formations, Crimson Exploration Operating, Inc. (“Crimson”), in the Eagle Ford shale, and Houston Energy, L.P. (“Houston Energy”), Southern Resources Company (“Southern Resources”), PetroQuest Energy, LLC (“PetroQuest”) and Cirque Resources LP (“Cirque”) in other areas;
- when “Pooled Payout” or similar thresholds will be reached for the purposes of our agreements with Brigham and Zavanna;
- expected working and net revenue interests, and costs of wells, relating to the drilling programs with our partners;
- actual decline rates for producing wells in the Bakken/Three Forks and Eagle Ford formations;
- submission of a plan of operations to the U.S. Forest Service and approval of such plan in connection with the Mt. Emmons molybdenum project (“Mt. Emmons Project”) and the expected length of time to permit and develop the Mt. Emmons Project;
- expected time to receive a return on investment from the geothermal prospects;
- future cash flows and borrowings;
- pursuit of potential acquisition opportunities;
- anticipated business activities in the Gillette, Wyoming area and their impact on our multi-family housing complex;
- our expected financial position;
- other plans and objectives for future operations.

These forward-looking statements are identified by their use of terms and phrases such as “may,” “expect,” “estimate,” “project,” “plan,” “believe,” “intend,” “achievable,” “anticipate,” “will,” “continue,” “potential,” “should,” “could,” “up to,” and similar terms and phrases. Though we believe that the expectations reflected in these statements are reasonable, they involve certain assumptions, risks and uncertainties. Results could differ materially from those anticipated in these statements as a result of numerous factors, including, among others:

For oil and gas:

- our ability to obtain sufficient cash flow from operations, borrowing and/or other sources to fully develop our undeveloped acreage positions;

- volatility in oil and natural gas prices, including potentially depressed natural gas prices and/or declines in oil prices, which would have a negative impact on operating cash flow and could require ceiling test write-downs on our oil and gas assets, and which could adversely impact the borrowing base available under our credit facility with BNP Paribas;

- the possibility that the oil and gas industry may be subject to new adverse regulatory or legislative actions (including changes to existing tax rules and regulations and changes in environmental regulation);

- the general risks of exploration and development activities, including the failure to find oil and natural gas in sufficient commercial quantities to provide a reasonable expectation of a return on investment;

- future oil and natural gas production rates, and/or the ultimate recoverability of reserves, falling below estimates;

- the ability to replace oil and natural gas reserves as they deplete from production;

- environmental risks;

- availability of pipeline capacity and other means of transporting crude oil and natural gas production;

- competition in leasing new acreage and for drilling programs with operating companies, resulting in less favorable terms or fewer opportunities being available;

- higher drilling and completion costs related to competition for drilling and completion services and shortages of labor and materials;

- unanticipated weather events resulting in possible delays of drilling and completions and the interruption of anticipated production streams of hydrocarbons, which could impact expenses and revenues, respectively; and

- unanticipated downhole mechanical problems, which could result in higher than expected drilling and completion expenses and/or the loss of the wellbore or a portion thereof.

For the molybdenum property:

- the ability to obtain permits required to initiate mining and processing operations;

- completion of a feasibility study based on a comprehensive mine plan, which indicates that the property warrants construction and operation of mine and processing facilities, taking into account projected capital expenditures and operating costs in the context of molybdenum price trends;

- the ability to fund the capital expenditures required to build the mine and its infrastructure, and the related processing facilities, after all permits and a favorable feasibility study have been received;

- the ability to find a suitable joint venture partner or raise sufficient capital for the project;

- continued compliance with current environmental regulations and the possibility of new legislation or environmental regulations adverse to the mining industry;
- molybdenum prices and operating costs staying within the parameters established by the feasibility study;
- successfully managing the substantial operating risks attendant to a large scale mining and processing operations; and
- compliance and operating costs associated with the wastewater treatment plant.

For real estate:

- insufficient demand for apartments in our multi-family apartment project in Gillette, Wyoming ("Remington Village Apartments") which could impact our ability to sell the property; and
- inability of the Company to receive the anticipated sales price for Remington Village Apartments.

Finally, our future results will depend upon various other risks and uncertainties, including, but not limited to, those detailed in the section entitled "Risk Factors" in this Annual Report. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements made above and elsewhere in this Annual Report. Other than as required under securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations, or otherwise.

PART I

Item 1 – Business

Overview

U.S. Energy Corp. ("U.S. Energy", "USE", "Company", "we" or "us"), is a Wyoming corporation organized in 1966. We are an independent energy company focused on the acquisition and development of oil and gas producing properties in the continental United States and other mineral properties. Our oil and gas business is currently focused in the Rocky Mountain region (specifically the Williston Basin of North Dakota and Montana), Louisiana, and Texas. 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.

We currently explore for and produce oil and gas through a non-operator business model. However, in the future we may expand our activities to include operations. As a non-operator, we rely on our operating partners to propose, permit, drill, complete and produce the oil and gas wells. Before a well is drilled, the operator provides all oil and gas interest owners in the designated well the opportunity to participate in the drilling and completion costs and revenues of the well on a pro-rata basis. Our operating partners also produce, transport, market and account for all oil and gas production.

We are also involved in: (i) the exploration for and development of minerals (molybdenum) through our ownership of the Mt. Emmons Project located in west central Colorado, which is a long-term development mining project, (ii) geothermal resources through Standard Steam Trust LLC ("SST") and

(iii) Remington Village Apartments, a multi-family housing project serving the residential market in Gillette, Wyoming, which is generating positive cash flow and is held as a property held for sale at December 31, 2011. We do not intend to make more investments in the real estate housing sector.

Industry Segments/Principal Products

At December 31, 2011, we have two operating segments: Oil and Gas and Maintenance of Mineral Properties (including molybdenum and geothermal).

Office Location and Website

Our principal executive office is located at 877 North 8th West, Riverton, Wyoming 82501, telephone 307-856-9271.

Our website is www.usnrg.com. We make available on this website, through a direct link to the Securities and Exchange Commission's website at http://www.sec.gov, free of charge, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and Forms 3, 4 and 5 relating to stock ownership of our directors and executive officers. You may also find information related to our corporate governance, board committees and code of ethics on our website. Our website and the information contained on or connected to our website are not incorporated by reference herein and our web address is included only as an inactive textual reference.

Business

Oil and Gas

We participate in oil and gas projects primarily as a non-operating working interest owner through exploration and development agreements with various oil and gas exploration and production companies. Our working interest varies by project. These projects may result in numerous wells being drilled over the next three to five years. We are also actively pursuing potential acquisitions of exploration, development or production-stage oil and gas properties or companies.

At December 31, 2011 we had:

- Estimated proved reserves of 3,195,361 BOE (86% oil and 14% natural gas), with a standardized measure value of $63.2 million and a PV10 of $72.5 million, representing increases of 63%, 42%, and 39% over our reserves, standardized measure and PV10, respectively, as of December 31, 2010.
- Gross and net leases of 122,815 and 34,871 acres, respectively. At March 1, 2012, our leases covered 122,815 gross and 29,921 net acres.
- Forty-one gross (12.79 net) producing wells (42 gross and 13.06 net at March 1, 2012).
- 1,212 BOE/D average for 2011.

PV10 (defined in "Glossary of Oil and Gas Terms") is widely used in the oil and gas industry and is considered by institutional investors and professional analysts when comparing companies. However, PV10 data is not an alternative to the standardized measure of discounted future net cash flows, which is calculated under GAAP and includes the effects of income taxes. The following table reconciles PV10 to the standardized measure of discounted future net cash flows as of the dates indicated, which are presented in Note F to the our consolidated financial statements.

	(In thousands) At December 31,		
	2011	2010	2009
Standardized measure of discounted net cash flows	$ 62,191	$ 44,653	$ 19,984
Future income tax expense (discounted)	10,346	7,420	5,776
PV-10	$ 72,537	$ 52,073	$ 25,760

Activities with Operating Partners in Oil and Gas

The Company holds a geographically and geologically diverse portfolio of oil-weighted prospects in varying stages of exploration and development. Prospect stages range from prospect origination, including geologic and geophysical mapping, leasing, exploration drilling and development. The Company engages in the prospect stages either for its own account or with prospective partners to enlarge the oil and gas lease ownership base.

Each of the operators of our principal prospects has a substantial technical staff. We believe that these arrangements allow us to deliver value to shareholders without having to build the full staff of geologists, engineers and land personnel required to work on diverse projects involving horizontal drilling in North Dakota (Brigham, Zavanna and Murex) and South Texas (Crimson), and conventional exploration in Gulf Coast prospects (Houston Energy, PetroQuest and Southern Resources). However, consistent with industry practice with smaller independent oil and gas companies, we also utilize specialized consultants with local expertise as needed.

The Company currently has oil and gas projects with operating partners in the following areas:

Williston Basin, North Dakota

With Brigham Exploration Company. On August 24, 2009, we entered into a Drilling Participation Agreement (the "DPA") with a wholly-owned subsidiary of Brigham to jointly explore for oil and gas in up to 19,200 gross acres in a portion of Brigham's Rough Rider prospect in Williams and McKenzie Counties, North Dakota. Under the DPA, we earned working interests, out of Brigham's interests, in fifteen 1,280-acre spacing units in Brigham's Rough Rider project area by participating in the drilling of one initial well on each unit of acreage. Accordingly, we have earned the rights to drill up to 30 gross wells in the Bakken formation and an additional 30 gross wells in the Three Forks formation, for a total of 60 gross wells, based on current spacing rules in North Dakota. If the spacing is ultimately increased to four wells per 1,280 acre spacing unit, the potential number of drilling locations could increase to 120 gross wells.

The leases in the units are a combination of fee and state leases. In some areas, the rights may be depth limited to the Bakken and the upper part of the Three Fork formations under the terms of the leases obtained by Brigham from third parties, while other leases may have rights to all depths. Working interests earned vary according to Brigham's initial working interest, after-payout provisions and the provisions governing each stage of the program.

Our earn-in rights were staged in three groups of units and were earned upon paying our share of all drilling and completion costs, or plugging and abandonment costs (if applicable), for all the initial wells (one for each unit) in each group. The numbers of initial wells (and units in the groups) consist of: six in the First Group; four in the Second Group; and five in the Third Group. For information on the wells drilled through the date this Annual Report was filed, see "Item 2 – Properties – Oil and Natural Gas"

below. At the date this Annual Report was filed, we have drilled and completed all 15 wells in the initial phase of the DPA and have completed 5 additional gross infill wells.

Brigham is the operator for all the units covered by the DPA, and is compensated for services pursuant to an industry standard operating agreement, except that the customary non-consent provisions have been revised as to the drilling of subsequent wells (see below).

First Group: We earned 65% of Brigham's initial working interest in six initial wells drilled in the 1,280 acre units; our working interest ranges from 61.46% to 29.58% (48.55% to 23.80% net revenue interest ("NRI")), for an average 49.54% working interest.

When we have received production revenues (less property and production taxes) from all six of the initial wells in this First Group equal to our costs on a pooled basis ("Pooled Payout"), our working interest will be reduced to 42.25% of Brigham's initial working interest in the initial wells, and the NRI will decrease to a range of 31.56% to 15.47%, for an average 25.45% NRI. At December 31, 2011, we estimate that the Pooled Payout for the First Group of wells will occur in the first quarter of 2013.

We earned 36% of Brigham's initial working interest in all of the acreage in the applicable unit. Brigham will have no back in rights on any subsequent drilling locations in these units (or in any of the units we earned in the Second and Third Groups). All working interest ownership in each initial well, and all of the subsequent wells, will be subject to proportionate reduction for third party leasehold rights. At December 31, 2011, three subsequent wells had been drilled in the First Group.

Second Group: In 2010, we participated in the drilling and completion of the four wells in the Second Group. Brigham provided us notice that it would be taking 50% of the working interest available to it, and we elected to take the remaining 50% of the working interest available to Brigham. The four wells were all producing in 2011; our working interests range from 48.03% to 21.02% (NRIs range from 37.80% to 16.29%).

We have earned working interest rights in all the acreage in these four units. For future wells drilled in these units, we will hold 36% of Brigham's initial working interest (without back in rights), subject to proportionate reduction for third party leasehold rights. After Pooled Payout on the Second Group's four wells, we will assign to Brigham 35% of our working interest in the initial wells in each spacing unit, and the NRI will decrease to a range of 24.26% to 10.61%. We anticipate that Pooled Payout for the Second Group will be reached in third quarter of 2012.

Third Group: On January 11, 2010, Brigham provided us notice that it would be taking 50% of the working interest available to it. In accordance with the DPA, we elected to take the remaining 50% of the working interest available to Brigham. All five wells in this group were drilled and producing at December 31, 2010, one was producing, one was being drilled, one was being completed, and two were awaiting completion work. Working (and net revenue) interests range from 41.76% (32.96% NRI) to 20.01% (15.81% NRI).

We have earned 36% of Brigham's initial working interest in all the acreage in the units in this Third Group (which will not be subject to back in rights), proportionately reduced for third party leasehold rights. After payout on a per initial well basis ("Unpooled Payout"), we will assign 27.7% of our working interest in each initial well to Brigham, resulting in NRIs of 23.83% to 11.49%). We expect Unpooled Payout to be reached on these initial wells between mid-2014 and late 2019.

Effective December 15, 2011, the Company sold an undivided 75% of its undeveloped acres in the Rough Rider prospect to Brigham for $13.7 million. Under the terms of the agreement, the Company retained the remaining 25% of its interest in the undeveloped acreage and its original working interest in its 20 developed wells in the Rough Rider prospect. After the sale, our working interest in the undeveloped acreage in the Rough Rider Prospect ranges from 3.41% to 9.90%. In addition, Brigham also agreed to commence drilling operations for at least three gross wells in the Rough Rider acreage in each of 2012 and 2013. Drilling plans beyond 2013 are not known at this time.

Non-Participation in Subsequent Wells. Under the form of operating agreement which governs operations for each of the 15 units, after the applicable initial well was drilled, we have the right to elect not to participate in the drilling or completion in subsequent wells proposed to be drilled in a unit. If the Company or Brigham should make an election not to participate, the non-participating party will assign all its rights in the proposed well to the participating entity for no consideration. However, our working interest rights in all acreage remaining in the unit would not be affected by the assignment.

With Zavanna, LLC. In December 2010, we signed two agreements with Zavanna (a private oil and gas company based in Denver, Colorado), and other parties. The Company paid $10,987,000 in cash to acquire 35% of Zavanna's working interests in oil and gas leases covering approximately 6,050 net acres in McKenzie County, North Dakota. The total net acres subject to the agreement has increased to 6,500 as a result of subsequent acquisitions from third parties.

The acquired acreage is in two prospects – the Yellowstone Prospect and the SE HR Prospect. We expect this program will result in 27 gross 1,280 acre spacing units with the potential for 108 gross Bakken and 108 gross Three Forks wells, based on an assumed four wells per formation in each spacing unit.

Our interests in all the acreage in both prospects is subject to reduction by a 30% reversionary working interest under each prospect upon expiration of the "Project Payout Period" or "Project Payout," as those terms are defined in the agreements, whichever occurs first. Project Payout will occur when we have received proceeds from the sale of production (or from the sale of all or part of the acreage to third parties) equal to 130% of: the $10,987,000 paid on execution of the agreements, plus all drilling and completion costs (including dry hole costs) and surface gathering facilities for all wells drilled on the acreage (and on any additional acreage acquired in the two Areas of Mutual Interest contemplated by the agreements). This acreage is referred to collectively as the "Project Payout Properties."

However, if Project Payout does not occur within the Project Payout Period, the reduction due to operation of the reversionary working interest will take effect on all acreage other than the Project Payout Properties (i.e., that acreage on which wells not have commenced drilling, including all infill locations in drilling units where the Project Payout Properties are located). The Project Payout Period for the Yellowstone Project is from the spud date of the initial well drilled in the prospect to July 15, 2014 and the Project Payout Period for the SE HR Prospect is from the spud date of the initial well drilled in the prospect to March 31, 2014. After expiration of the Project Payout Period, all costs and expenses related to the Project Payout Properties will continue to be included in the Project Payout calculation until Project Payout occurs.

On January 24, 2012 (but effective as of December 1, 2011), the Company sold an undivided 75% of its undeveloped acreage in the SE HR Prospect and the Yellowstone Prospect to GeoResources, Inc. (56.25%) and Yuma Exploration and Production Company, Inc. (18.75%) for a total of $16.7 million. Under the terms of the agreement, the Company retained the remaining 25% of its interest in the undeveloped acreage and its original working interest in its 10 developed wells in the SE HR and Yellowstone prospects (including the two wells drilled with Murex Petroleum Corporation discussed

below). Our working interest in the remaining locations will be approximately 8.75% and net revenue interests in new wells after the sale are expected to be in the range of 6.7375% to 7.0%, proportionately reduced depending on Zavanna's actual working interest percentages.

At the date of this Annual Report, we have drilled nine gross wells with Zavanna. Four of these wells have been completed and are producing and five more wells have been drilled to depth and are awaiting completion. We have an average working interest of 27.1% and an average net revenue interest of 20.9% in these nine wells. The current drilling schedule anticipates that one additional well will be drilled per month through June 2012.

With Murex Petroleum Corporation. The Company also participated in drilling two wells operated by Murex Petroleum Corporation ('Murex") in the Yellowstone acreage block. During 2011, two gross wells were drilled and completed and put into production. The Amy Michelle 16-23 #1H well was drilled and completed with 15 fracture stimulation stages using a sliding sleeve. We have an approximate 8.9% WI and 6.9% NRI in this well. Additionally, the David Roger 18-19H well has been drilled and completed with 38 fracture stimulation stages. We have any approximate 3.21% WI and 2.47% NRI in this well.

For further information on the wells drilled in North Dakota through the date of this Annual Report, see "Item 2 – Properties – Oil and Natural Gas" below.

Texas and Louisiana

With Crimson Exploration Inc. On February 22, 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 (the "Leona River prospect"). Under the terms of the agreement, the Company has 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 on a heads up basis with no carry by the Company. The prospect is an Eagle Ford shale oil window target in Zavala County, Texas. Crimson is the operator of the prospect. The KM Ranch #1H well was drilled to a total depth of approximately 12,500 feet (~6,000 ft. vertical, ~6,500 ft. horizontal) by Crimson at the Leona River prospect. It was completed in the second quarter of 2011 and had an announced initial gross production rate of 418 BOE/D from 11 fracture stimulation stages. The KM Ranch #2H well in the Leona River prospect was also recently drilled to depth and it is anticipated that completion operations will commence in March 2012.

In June 2011, the Company entered into a second participation agreement with Crimson to acquire an interest in an Eagle Ford oil prospect and associated leases located in Zavala and Dimmit Counties, Texas (the "Booth Tortuga prospect"). Under the terms of this second agreement with Crimson, we have acquired 30% of Crimson's working interest (an approximate 22.5% net revenue interest) in approximately 7,186 gross acres (2,156 net). All of the leases are currently held by production and produce approximately 115 gross BOE/D (20 net BOE/D) from the Austin Chalk formation. We estimate that under current spacing there is a potential for up to 44 gross (13.5 net) Eagle Ford drilling locations on the acreage. All drilling and leasing on this prospect will be on a heads up basis. Crimson also operates this prospect. The initial well at the Booth Tortuga prospect, the Beeler #1H well, has been completed with 20 fracture stimulation stages and initial well flow back operations have commenced. The operator plans to evaluate initial well results over the course of the coming weeks.

Currently, our total acreage in the Leona River prospect and the Booth Tortuga prospect is approximately 11,861 gross acres (3,558.5 net). Based upon assumed 120 acre spacing units, there is the potential for up to 98 gross and 29.6 net Eagle Ford drilling locations. Looking forward, the Company continues to seek additional leasing opportunities in the Eagle Ford oil window jointly with Crimson.

With Houston Energy L.P. The Company has an interest in two producing wells with Houston Energy; we have a 7.65% WI (6.23% NRI) in one well and a 25% WI (17.63% NRI) in the other. During December 2011 our average aggregate daily production from the two wells was 11 BOE/D.

With PetroQuest Energy, Inc. The Company has an interest in three natural gas and oil producing wells with PetroQuest in coastal Louisiana, with working interests of 11.9% (8.32% NRI), 50.0% (36.0% NRI) and 17.0% (12.75% NRI). During December 2011, our average aggregate daily production from these three wells was 116 BOE/D. PetroQuest operates all of the wells.

With Southern Resources Company. Our agreement with Southern Resources covers a 13.5% working interest (9.86% NRI) in 1,282 gross (173 net) acres in Hardin County, Texas. The Company earned a working interest in all the acreage by participating in the initial test well and paying $135,000 in seismic, land acquisition and legal costs. The Company agreed to carry the seller in an 18.75% working interest to the casing point decision ("CPD") in the initial test well, and a 12.5% carried working interest in the second test well to the CPD. Subsequent wells will be paid for proportionally to all parties' working interests. Mueller Exploration, Inc. will operate all of the wells.

During September 2011, we drilled our first well in the program, reaching a total depth of 11,265 feet on October 17, 2011 and encountering what we believe are two prospective pay zones, the EY3 and EY4 channel sandstones. Preliminary production testing on the EY4, the deepest prospective zone, indicates an estimated production rate of approximately 80 BOE/D and 624 MCF/D. The well is scheduled to commence production in March 2012. Once the EY4 zone is depleted, the operator plans to move up hole to test the EY3 zone, which was the primary objective. The Company's net cost in this well at December 31, 2011 is $755,000. Based on the initial results of this well, we believe there may be the opportunity to drill up to three additional conventional wells on this acreage.

With Yuma Exploration and Production Company, Inc. On October 27, 2011, the Company entered into an agreement with Yuma Exploration and Production Company, Inc. to sell its interest in the Livingston prospect in Louisiana for $1.0 million. The Company owned a 4.79% working interest in the prospect, which included one gross producing well (approximately 5 BOE/day net) and one additional gross development well that was being completed at the time of the sale. Our total investment in the prospect was approximately $2.0 million including seismic, drilling, leasehold acquisition and other development costs.

For further information on the wells drilled in Texas and Louisiana through the date of this Annual Report, see "Item 2 – Properties – Oil and Natural Gas" below.

California

With Cirque Resources LP. Under an October 2010 agreement with Cirque (a private exploration and development company based in Denver, Colorado), the Company paid $2,498,000 to Cirque 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 in Kern County, California. Of the amount paid, $1,620,000 was an advance against our 40% working interest for the initial well, including 33% of Cirque's 60% working interest share for the well.

The primary target in the prospect was the Miocene formation on the flank of the Elk Hills anticline in Kern County, California. The Tupman 16X-13 well (initial well) was drilled by Cirque and reached its total depth of 13,403 feet during the last week of December 2011. The Stevens Sands objective target was encountered and had hydrocarbon shows, but did not have sufficient porosity or permeability to be deemed productive. The Company has agreed with the operator's recommendation to plug and abandon the well. The Company's net cost in this well through December 31, 2011 was $2.1 million. Cirque is evaluating deeper objectives on the acreage block, but no further drilling is anticipated at this time.

Operated Oil and Gas Activities

Montana Acreage Play

In 2010 and 2011, the Company acquired a 100% working interest in approximately 24,960 gross mineral acres (18,714 net mineral acres) of undeveloped leasehold interests in oil and gas leases in Northeast Montana for approximately $1.2 million. The Company is the operator of this acreage, which is believed to have conventional, Bakken and Three Forks resource potential. The Company may enlist the participation of industry partners, but no arrangements with other companies have been negotiated to date, and no wells have been drilled on our acreage.

Apache and Buffalo Creek Prospects (Southeast Colorado)

On January 26, 2011 we paid $87,000 to buy an 80% working interest in leases covering 2,994 net mineral acres in southeast Colorado, for their joint development with the sellers, who retained 20% of the working interest (and, only as to the acreage in the Buffalo Creek acreage, the positive difference between an 80% NRI and landowners' royalties). In addition, we paid all the drilling costs of the initial well to the casing point. In June 2011, we drilled the initial well at a net cost of $417,000. This well was determined to be non-productive and has been plugged and abandoned. No further drilling is anticipated at this time.

Forward Plan

In 2012 and beyond, the Company intends to seek additional opportunities in the oil and natural gas sector, including but not limited to further acquisition of assets, participation with current and new industry partners in their exploration and development projects, acquisition of operating companies, and the purchase and exploration of new acreage positions.

Credit Facility

On July 30, 2010, we established a Senior Secured Revolving Credit Facility (the "Credit Facility") through our wholly-owned subsidiary, Energy One LLC, which allows us to borrow up to a maximum of $75 million (with a current borrowing base of $28.0 million) from a syndicate of banks, financial institutions and other entities, including BNP Paribas ("BNPP," and, together with other members of the syndicate, the "Lenders"). This arrangement is available only for our oil and gas segment, and provides us with the flexibility of investing and funding drilling/completion work. We expect our borrowings to be serviced with cash flow and/or equity financing.

BNPP is the administrative agent for the Facility, which is governed by a Credit Agreement, a Mortgage, a Deed of Trust, an Assignment of As-Extracted Collateral, a Security Agreement, a Fixture Filing and Financing Statement and a Guaranty and Pledge Agreement, or the Guaranty. We refer to these documents together as the Facility Documents. The following summarizes the principal provisions of the Credit Facility as set forth in the Facility Documents.

The Company has unconditionally and irrevocably guaranteed Energy One's performance of its obligations under the Credit Agreement, including without limitation Energy One's payment of all borrowings and related fees thereunder.

From time to time until expiration of the Facility (July 30, 2014), if Energy One is in compliance with the Facility Documents, Energy One may borrow, pay, and re-borrow from the Lenders, up to an amount equal to the borrowing base. The borrowing base is re-determined semi-annually (or more often at the request of BNPP or Energy One), based on updated reserve reports prepared by the Company's independent consulting engineers. Any proposed increase in the borrowing base will require approval by all Lenders, and any proposed borrowing base decrease will require approval by Lenders holding not less than two-thirds of the outstanding loans and loan commitments. On September 6, 2011, the borrowing base increased to $28.0 million (from $22.5 million) as a result of a redetermination using our June 30, 2011 financial statements, production reports and reserve reports.

Interest is payable quarterly at the greater of the prime rate, the federal funds effective rate (plus 0.5%), and the adjusted LIBO rate for the three prior months (plus 1%), plus, in any event, an additional 1.25% to 3.25%, depending on the amount of the loan relative to the borrowing base. Interest rates on outstanding loans are adjustable each day by BNPP as administrative agent. Energy One may prepay principal at any time without premium or penalty, but all outstanding principal will be due on July 30, 2014. If there is a decrease in the borrowing base, outstanding principal will be due over the five months following the determination.

Energy One is required to comply with customary affirmative and negative covenants under the Credit Agreement. Under the agreement, our (i) "Interest Coverage Ratio" (the ratio of EBITDAX to Interest Expense, as those terms are defined in the agreement) may not be less than 3.0 to 1; (ii) the ratio of Total Debt, as defined in the agreement, to EBITDAX may not be greater than 3.5 to 1; and (iii) the Current Ratio (the ratio of current assets plus unused Lender commitments under the Borrowing Base to current liabilities) must be at least 1.0 to 1.0. EBITDAX is defined in the Credit Agreement as consolidated net income plus non-cash charges. Compliance with these covenants is measured at various times as provided in the Credit Agreement. As of December 31, 2011, Energy One was in compliance with all the covenants under the Credit Facility.

At December 31, 2011, Energy One had $12.0 million in debt outstanding under the Credit Facility. On January 27, 2012, we used a portion of the proceeds from the sale of 75% of our undeveloped interests in the Brigham and Zavanna acreage to retire the outstanding balance on the Credit Facility.

Activities other than Oil and Gas

Molybdenum

The Company re-acquired the Mt. Emmons Project located near Crested Butte, Colorado on February 28, 2006. The Mt. Emmons Project includes a total of 160 fee acres, 25 patented and approximately 1,353 unpatented mining and mill site claims, which together approximate 9,920 acres, or over 15 square miles. For further information, see "Item 2 – Properties – Molybdenum Mt. Emmons Project" below.

Renewable Energy — Geothermal

At December 31, 2011 we owned a minority ownership interest, 22.4%, in Standard Steam Trust LLC ("SST"), a geothermal limited liability company. Our investment in SST does not obligate us to fund any future cash calls, but if we elect not to fund cash calls, we will suffer dilution. We did not participate in

any cash calls in 2010 and 2011, which diluted our ownership. We do not currently expect to fund any future cash call, and as a result, we may experience further dilution of our ownership of SST.

Asset Held for Sale - Remington Village

In 2008, we completed construction of Remington Village Apartments, a nine-building, 216-unit multifamily apartment complex in Gillette, Wyoming for a total all-in cost of $24.5 million. The occupancy rate was 82% during December 2011. Impairments of $1.5 million and $3.1 million were recorded to reflect the difference between the cost of the property and its estimated fair market value at December 31, 2010 and 2011. Although the property produces positive cash flow from its operations, the return from oil and gas investments is expected to yield a higher return. The Company therefore plans to sell this property to continue growing its oil and gas business. The property is collateralized with a $10 million conventional note with a local bank, First Interstate Bank. For further information, see “Item 2 – Properties – Real Estate below.

Item 1A - Risk Factors

The following risk factors should be carefully considered in evaluating the information in this Annual Report.

Risks Involving Our Business

Global financial stress and the credit crisis could adversely affect our business.

The continuing credit crisis and related turmoil in the global financial system may have a material impact on our ability to finance the purchase and/or exploitation of oil and gas properties. The availability of credit to our industry partners may also affect their ability to generate new exploration and development prospects, to meet their obligations to us, and/or on their liquidity, which could result in operational delays or even their failure to make required payments. Additionally, volatility in oil prices, particularly a significant and sustained drop in current oil prices, could have a negative impact on our financial position, results of operations, and cash flows.

The development of oil and gas properties involves substantial risks that may result in a total loss of investment.

The business of exploring for and developing natural gas and oil properties involves a high degree of business and financial risk, and thus a significant risk of loss of initial investment even a combination of experience, knowledge and careful evaluation may not be able to overcome. The cost of drilling, completing and operating wells is often uncertain. Factors which can delay or prevent drilling or production, or otherwise impact expected results, include but are not limited to:

- unexpected drilling conditions;
- inability to obtain required permits from State and Federal agencies;
- inability to obtain, or limitations on, easements from land owners;
- adverse weather;
- high pressure or irregularities in geologic formations;
- equipment failures;
- title problems;
- fires, explosions, blowouts, cratering, pollution and other environmental risks or accidents;
- changes in government regulations;
- reductions in commodity prices;

- pipeline ruptures; and
- unavailability or high cost of equipment and field services and labor.

A productive well may become uneconomic in the event that unusual quantities of water or other non-commercial substances are encountered in the well bore, which impair or prevent production. We may participate in wells that are unproductive or, though productive, won't produce in economic quantities.

In addition, initial 24-hour or other limited-duration production rates announced regarding our oil and gas properties are not indicative of future production rates. Such stated rates on our wells should not be used as an indication of future production rates.

Dry holes and other unsuccessful or uneconomic exploration, exploitation and development activities adversely affect our cash flow, profitability and financial condition, and can adversely affect our reserves.

Our business may be impacted by adverse commodity prices.

In the past three years, oil prices have ranged from a high of $113.39 per barrel to a low of $34.03 per barrel. Global markets, in reaction to the recession, and perceived upticks or downticks in future global supply, have caused these large fluctuations, and significant future changes are likely. Natural gas prices have also been volatile, reaching a ten year high during July 2008 on the City Gate at $12.48 per Mcf, but have since fallen as low as $3.67 per Mcf. Declines in the prices we receive for our oil and natural gas production adversely affect many aspects of our business, including our financial condition, revenues, results of operations, liquidity, rate of growth and the carrying value of our oil and natural gas properties, all of which depend primarily or in part upon those prices. Declines in the prices we receive for our oil and natural gas also adversely affect our ability to finance capital expenditures, make acquisitions, raise capital and satisfy our financial obligations. In addition, declines in prices reduce the amount of oil and natural gas that we can produce economically and, as a result, adversely affect our quantities of proved reserves. Among other things, a reduction in our reserves can limit the capital available to us, as the maximum amount of available borrowing under our revolving credit facility is, and the availability of other sources of capital likely will be, based to a significant degree on the estimated quantities of those reserves.

Mineral prices also change significantly over time. Molybdenum prices have declined from a ten-year high of $38.00 per pound in June 2005 to a ten-year low average price of $8.03 per pound in April 2009. The average price at December 31, 2011 was $13.37 per pound, compared to $16.23 per pound at year end 2010. Price improvement in 2012 will be dependent on continued demand, but demand could weaken if industrial consumption sags due to economic constraints in key global markets. Lower molybdenum prices would adversely affect the feasibility of developing the Mt. Emmons project.

The Williston Basin oil price differential could have adverse impacts on our revenues.

Generally, crude oil produced from the Bakken formation in North Dakota is high quality (36 to 44 degrees API, which is comparable to West Texas Intermediate Crude). However, due to takeaway constraints, oil prices in the Williston Basin generally have been from $8.00 to $10.00 less per barrel than prices for other areas in the United States, and recently as much as $22.00 less per barrel. This discount, or differential, may widen in the future, which would reduce the price we would receive for our production.

Drilling and completion costs for the wells we drill in the Williston Basin are comparable to other areas where there is no price differential. As a result of this reverse leverage effect, a significant, prolonged downturn in oil prices on a national basis could result in a ceiling limitation write-down of the

oil and gas properties we hold. Such a price downturn also could reduce cash flow from the Williston Basin properties and adversely impact our ability to participate fully in drilling with Brigham and Zavanna. Our production in other areas could also be affected by adverse changes in differentials. In addition, changes in differentials could make it more difficult for us to effectively hedge our exposure to changes in commodity prices.

We will require funding in addition to working capital at December 31, 2011 .

We were able to maintain adequate working capital in 2011 primarily through borrowing from BNP Paribas and revenues from operations. Working capital at December 31, 2011 was $16.2 million, an amount sufficient to continue substantial exploration and development work on our oil and gas properties, but not enough to take full advantage of the opportunities we now have or to be in position to pursue new opportunities. In 2012, we could spend up to $46 million for work on existing programs.

Our exploration and development agreements contain customary industry non-consent provisions. Pursuant to these provisions, if a well is proposed to be drilled or completed but a working interest owner doesn't participate, the resulting revenues (which otherwise would go to the non-participant) flow to the participants until they receive from 150% to 300% of the capital they provided to cover the non-participant's share. In order to be in position to avoid non-consent penalties, and make opportunistic investments in new assets, we will continually evaluate various options to obtain additional capital, including loans under the Credit Facility and sales of one or more of a portion of our non-producing oil and gas assets, equity securities and the apartment complex in Gillette, Wyoming.

Beyond 2012, we may have capital needs from time to time in excess of funds on hand. The minerals business presents the opportunity for significant returns on investment, but achievement of such returns is subject to high risk. As examples:

- Initial results from one or more of the oil and gas programs could be marginal but warrant investing in more wells. Dry holes, over-budget exploration costs, low commodity prices, or any combination of these or other adverse factors, could result in production revenues below projections, thus adversely impacting cash expected to be available for continued work in a program, its ultimate returns falling below projections, and a reduction in cash available for investment in other programs.

- We are paying the annual costs (approximately $1.8 million) to operate and maintain the water treatment plant at the Mt. Emmons Project, and these costs could increase in the future.

These types of events could require a reassessment of priorities and therefore potential re-allocations of existing capital and could also mandate obtaining new capital. There can be no assurance that we will be able to complete any financing transaction on acceptable terms or at all. For example, our ability to borrow under the Credit Agreement may be limited if we are unable, or run a significant risk of becoming unable, to comply with the financial covenants that we are required to satisfy under the agreement. In addition, the borrowing base under the agreement is subject to redetermination periodically and from time to time in the Lenders' discretion. Borrowing base reductions may occur as a result of unfavorable changes in commodity prices, asset sales, performance issues or other events. In addition to reducing the capital available to finance our operations, a reduction in the borrowing base could cause us to be required to repay amounts outstanding under the Credit Agreement in excess of the reduced borrowing base, and the funds necessary to do so may not be available at that time. Other sources of external debt or equity financing may not be available when needed on acceptable terms or at all, especially during periods in which financial market conditions are unfavorable. Also, sales of equity securities would be dilutive to existing shareholders.

Competition may limit our opportunities in the oil and gas business.

The oil and natural gas business is very competitive. We compete with many public and private exploration and development companies in finding investment opportunities. We also compete with oil and gas operators in acquiring acreage positions. Our principal competitors are small to mid-size companies with in-house petroleum exploration and drilling expertise. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. They may be willing and able to pay more for oil and natural gas properties than our financial resources permit, and may be able to define, evaluate, bid for and purchase a greater number of properties. In addition, there is substantial competition in the oil and natural gas industry for investment capital, and we may not be able to compete successfully in raising additional capital if needed.

Successful exploitation of the Williston Basin and the Eagle Ford Shale is subject to risks related to horizontal drilling and completion techniques.

Operations in the Williston Basin and the Eagle Ford Shale involve utilizing the latest drilling and completion techniques to generate the highest possible cumulative recoveries and therefore generate the highest possible returns. Risks that are encountered while drilling include, but are not limited to, landing the well bore in the desired drilling zone, staying in the zone while drilling horizontally through the shale formation, running casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore.

Completion risks include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations, and successfully cleaning out the well bore after completion of the final fracture stimulation stage. Ultimately, the success of these latest drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period.

The drilling and completion of a well in the Williston Basin or the Eagle Ford frequently costs between $7.5 million and $11.5 million on a gross basis, which is significantly more expensive than a typical onshore conventional well. Accordingly, unsuccessful exploration or development activity affecting even a small number of wells could have a significant impact on our results of operations. Costs other than drilling and completion costs can also be significant for Williston Basin, Eagle Ford and other wells. For example, we incurred approximately $3.1 million in workover costs relating to a single Williston Basin well in 2011, and these costs substantially exceeded our estimates.

The results of the drilling programs in the Williston Basin and the Eagle Ford Shale are subject to more uncertainties than drilling in more established formations in other areas.

Williston Basin

Although numerous wells have been drilled and completed in the Bakken and Three Forks formations in the Williston Basin with horizontal wells and completion techniques that have proven to be successful in other shale formations, the industry's drilling and production history in the formations generally remains somewhat limited. The ultimate success of these drilling and completion strategies and techniques will be better evaluated over time as more wells are drilled and longer term production profiles are established.

In addition, based on reported decline rates in these formations, estimated average monthly rates of production may decline by approximately 70% during the first twelve months of production. However, actual decline rates may be significantly different than expected. Due to the limited horizontal production data for wells targeting the Bakken and Three Forks formations, drilling and production results are more uncertain than those encountered in other formations and areas with longer histories. Good results from wells we have participated in may not be replicated in additional wells, even in the same drilling unit. In addition, increases in the number of wells drilled per spacing unit could impact per-well performance.

Through the date of this Annual Report, one of the wells we have drilled with Brigham was completed in the Three Forks formation, and the rest have been completed in the Bakken formation. Brigham (and other operators) have reported successful completion of Three Forks wells in other parts of the Williston Basin. The Three Forks, underlying the Bakken, is an unconventional carbonate formation (sand and porous rock) which is prospective for oil and gas. It is believed to be separate from the Bakken. However, the Three Forks has been explored to a lesser extent than the Bakken in many areas of the basin, and its characteristics are not as well defined. Accordingly, we may encounter more uncertainty in drilling Three Forks wells compared with drilling Bakken wells.

The foregoing considerations also apply to our opportunities to drill the same formations with Zavanna.

Eagle Ford Shale

The Eagle Ford Shale, covering 14 counties in South Texas, is now a very active area for exploration and development, involving large companies (such as Shell, ConocoPhillips, and Chesapeake Energy) as well as a host of mid-size to small independents. However, like the Bakken, since the data base is still evolving, the Eagle Ford characteristics are not well defined and thus can present more uncertainty than more mature drilling areas.

If our access to oil and gas markets is restricted, it could negatively impact our production and revenues. Securing access to takeaway capacity may be particularly difficult in less developed regions of the Williston Basin.

Market conditions or limited availability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. In particular, access to adequate gathering systems or pipeline takeaway capacity is limited in the Williston Basin. In order to secure takeaway capacity, our operators may be forced to enter into arrangements that are not as favorable to operators as those in other areas.

As of the date of this Annual Report, all of the wells we have drilled with Brigham have produced oil and natural gas (generally an initial ratio of about 85% oil and 15% gas). Oil sales commence immediately after completion work is finished, but natural gas is flared (burned off) until the well can be hooked up to a transmission line. Installation of a gathering system can take from 90 to 120 days, or longer, depending on well location, weather conditions, and availability of service providers. As of the date of this Annual Report, all but two of our wells with Brigham are selling gas. We may encounter the same operating issues in the drilling program with Zavanna.

If continued drilling in the Williston Basin, and other areas such as the Eagle Ford, proves to be successful, the amount of oil and natural gas being produced by us and others could exceed the capacity of the various gathering and intrastate or interstate transportation pipelines currently available in these areas. If this occurs, it will be necessary for new pipelines and gathering systems to be built. Because of the current economic climate, certain pipeline projects that are planned for the Williston Basin and other areas may not occur for lack of financing. In such event, we might have to shut in our wells until a pipeline connection is available, sell natural gas production at significantly lower prices than we would otherwise receive and/or flare the gas we produce.

We may not be able to drill wells on a substantial portion of our Williston Basin and Eagle Ford Shale acreage.

We may not be able to participate in all or even a substantial portion of the many locations we have earned through the Drilling Participation Agreement with Brigham, and available to us through the Zavanna program, or the drilling locations available in the Crimson Participation Agreement. The extent of our participation will depend on drilling and completion results, commodity prices, the availability and cost of capital relative to ongoing revenues from completed wells, applicable spacing rules and other factors.

Lower oil and natural gas prices may cause us to record ceiling limitation write-downs, which would reduce stockholders' equity.

We use the full cost method of accounting to account for our oil and natural gas investments. Accordingly, we capitalize the cost to acquire, explore for and develop these properties. Under full cost accounting rules, the net capitalized cost of oil and gas properties may not exceed a "ceiling limit" that is based upon the present value of estimated future net revenues from proved reserves, discounted at 10%, plus the lower of the cost or fair market value of unproved properties. If net capitalized costs exceed the ceiling limit, we must charge the amount of the excess to earnings (called a "ceiling limitation write-down"). The risk of a ceiling test write-down increases when oil and gas prices are depressed or if we have substantial downward revisions in estimated proved reserves.

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 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 unevaluated 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 costs, adjusted for contract provisions, any financial derivatives that hedge our oil and gas revenue and asset retirement obligations, and unescalated oil and gas prices during the period, (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, less (iv) income tax effects related to tax assets directly attributable to 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.

Full cost pool capitalized costs are amortized over the life of production of proven properties. Capitalized costs at December 31, 2011 and 2010, which were not included in the amortized cost pool, were $20.0 million and $21.6 million, respectively. These costs consist of wells in progress, costs for seismic analysis of potential drilling locations, and land costs, all related to unproved properties.

We perform a quarterly and annual ceiling test for each of our oil and gas cost centers. At December 31, 2011 and 2010, there was one such cost center (the United States). The ceiling test incorporates assumptions regarding pricing and discount rates over which we have no influence in the determination of present value. In arriving at the ceiling test for the year ended December 31, 2011, we used $96.19 per barrel for oil and $4.12 per MMbtu for natural gas to compute the future cash flows of each of the producing properties at that date. The discount factor used was 10%.

Capitalized costs for oil and gas properties did not exceed the ceiling test limit in 2011. During 2009, we recorded a non-cash write down of $1.5 million. We may be required to recognize additional pre-tax non-cash impairment charges (write-downs) in future reporting periods depending on the results of oil and gas operations and/or market prices for oil, and to a lesser extent natural gas.

We do not currently operate most of our drilling locations, and, therefore, we will not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of these non-operated assets.

We are the operator of our Montana acreage in Daniels County, and our acreage in southeastern Colorado. However, we do not operate or expect to be the operator of any of the prospects we hold with industry partners.

Allowing others to operate limits our ability to exercise influence over the operations of the drilling programs. In the usual case in the oil and gas industry, new work is proposed by the operator and often is approved by most of the non-operating parties. If the work is approved by the holders of a majority of the working interest, but we disagree with the proposal and do not (or are unable to) participate, we will forfeit our share of revenues from the well until the participants receive 150% to 300% of their investment. In some cases, we could lose all of our interest in the well. We would avoid a penalty of this kind only if a majority of the working interest owners agree with us and the proposal does not proceed.

The success and timing of our drilling and development activities on properties operated by others depend upon a number of factors outside of our control, including:

- the nature and timing of the operator's drilling and other activities;
- the timing and amount of required capital expenditures;
- the operator's geological and engineering expertise and financial resources;
- the approval of other participants in drilling wells; and
- the operator's selection of suitable technology.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or the relevant underlying assumptions will materially affect the quantity and present value of our reserves.

Oil and gas reserve reports are prepared by independent consultants to estimate the quantities of hydrocarbons that can be economically recovered from proved properties, utilizing current commodity prices and taking into account expected capital and other expenditures. These reports also estimate the future net present value of the reserves, and are used for internal planning purposes and for testing the carrying value of the properties on our balance sheet.

The reserve data included in this Annual Report represent estimates only. Estimating quantities of proved oil and natural gas reserves is a complex process. It requires interpretations of available technical data and various estimates, including estimates based upon assumptions relating to economic factors, such as future commodity prices, production costs, severance and excise taxes, availability of capital, estimates of required capital expenditures and workover and remedial costs, and the assumed effect of governmental regulation. The assumptions underlying our estimates of our proved reserves could prove to be inaccurate, and any significant inaccuracy could materially affect, among other things, future estimates of the reserves, the economically recoverable quantities of oil and natural gas attributable to the properties, the classifications of reserves based on risk of recovery, and estimates of our future net cash flows.

At December 31, 2011, 56% of our estimated proved reserves were producing, 13% were proved developed non-producing and 31% were proved undeveloped. Estimation of proved undeveloped reserves and proved developed non-producing reserves is almost always based on analogy to existing wells, volumetric analysis or probabilistic methods, in contrast to the performance data used to estimate producing reserves. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Revenues from estimated proved developed non-producing and proved undeveloped reserves will not be realized until sometime in the future, if at all.

You should not assume that the present values referred to in this report represent the current market value of our estimated oil and natural gas reserves. The timing and success of the production and the expenses related to the development of oil and natural gas properties, each of which is subject to numerous risks and uncertainties, will affect the timing and amount of actual future net cash flows from our proved reserves and their present value. In addition, our PV10 estimates are based on costs as of the date of the estimates and assume fixed commodity prices. Actual future prices and costs may be materially higher or lower than the prices and costs used in the estimate.

Further, the effect of derivative instruments is not reflected in these assumed prices; we have three such instruments in place at December 31, 2011. Also, the use of a 10% discount factor to calculate PV10 may not necessarily represent the most appropriate discount factor given actual interest rates and risks to which our business or the oil and natural gas industry in general are subject.

The use of hedging arrangements in oil and gas production could result in financial losses or reduce income.

We use derivative instruments, typically fixed-rate swaps and costless collars, to manage price risk underlying our oil and gas production. The fair value of our derivative instruments will be marked to market at the end of each quarter and the resulting unrealized gains or losses due to changes in the fair value of our derivative instrument will be recognized in current earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative contracts for such period. If the actual amount of production is higher than we estimated, we will have greater commodity price exposure than we intended. If the actual amount of production is lower than the notional amount that is subject to our derivative instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- the counter-party to the derivative instrument defaults on its contract obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- the steps we take to monitor our derivative financial instruments do not detect and prevent transactions that are inconsistent with our risk management strategies.

In addition, depending on the type of derivative arrangements we enter into, the agreements could limit the benefit we would receive from increases in oil prices. It cannot be assumed that the hedging transactions we have entered into, or will enter into, will adequately protect us from fluctuations in commodity prices.

Additionally, the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, among other things, imposes restrictions on the use and trading of certain derivatives, including energy derivatives. The nature and scope of those restrictions will be determined in significant part through implementing regulations to be adopted by the SEC, the Commodities Futures Trading Commission and other regulators. If, as a result of the Dodd-Frank Act or its implementing regulations, capital or margin requirements or other limitations relating to our commodity derivative activities are imposed, this could have an adverse effect on our ability to implement our hedging strategy. In particular, a requirement to post cash collateral in connection with our derivative positions, which are currently collateralized on a non-cash basis by our oil and natural gas properties and other assets, would likely make it impracticable to implement our current hedging strategy. In addition, requirements and limitations imposed on our derivative counterparties could increase the costs of pursuing our hedging strategy.

We may incur losses as a result of title deficiencies in oil and gas leases.

Typically, operators obtain a preliminary title opinion prior to drilling. We rely on our operating partners to provide us with ownership of the interests we pay for. To date, our operators have generally provided preliminary title opinions prior to drilling. However, from time to time, our operators may not retain attorneys to examine title, even on a preliminary basis, before starting drilling operations. If curative title work is recommended to provide marketability of title (and assurance of payment from production), but is not successfully completed, a loss may be incurred from drilling a productive well because the operator (and therefore the Company) would not own the interest.

Insurance may be insufficient to cover future liabilities.

Our business is focused in three areas, each of which presents potential liability exposure: Oil and gas exploration and development; permitting and limited exploration of the Mt. Emmons molybdenum property; and a residential multi-family housing complex in Gillette, Wyoming. We also have potential exposure in connection with our corporate aircraft and general liability and property damage associated with the ownership of other corporate assets. In the past, we relied primarily on the operators of our oil and gas and mineral properties to obtain and maintain liability insurance for our working interest in the properties. In some cases, we may continue to rely on those operators' insurance coverage policies depending on the coverage. However, since June 2011, we have established our own insurance policies for our oil and gas operations that are broader in scope and coverage and are in our control. We also maintain insurance policies for the liability of and damage to our multifamily housing complex, corporate aircraft and general corporate assets.

We also have separate policies for the Mt. Emmons properties and liability and environmental exposures for the water treatment plant operations at the Mount Emmons project. These policies provide coverage for bodily injury and property damage as well as costs to remediate events adversely impacting the environment. See "Insurance" below.

We would be liable for claims in excess of coverage. If uncovered liabilities are substantial, payment thereof could adversely impact the Company's cash on hand, resulting in possible curtailment of operations. Moreover, some liabilities are not insurable at a reasonable cost or at all.

We do not have independent reports on the value of some of our mineral properties.

We have not yet completed a feasibility study on the Mt. Emmons Project. A feasibility study would establish the potential economic viability of the molybdenum property based on a reassessment of historical and additional drilling and sampling data, the design and costs to build and operate a mine and mill, the cost of capital, and other factors. A feasibility study conducted by professional consulting and engineering firms will determine if the deposits contain proved reserves (i.e., amounts of minerals in sufficient grades that can be extracted profitably under current commodity pricing assumptions and estimated development and operating costs).

The timing and cost to obtain reports for the Mt. Emmons molybdenum property cannot be predicted. However, when such reports are obtained, they may not support our internal valuations of the properties, and additionally may not be sufficient to attract new partners or investment capital.

Oil and gas and mineral operations are subject to environmental and other regulations that can materially adversely affect the timing and cost of operations.

Oil and gas exploration and production are subject to certain federal, state and local laws and regulations relating to a variety of issues, including environmental quality and pollution control. These laws and regulations increase costs and may prevent or delay the commencement or continuance of operations. Specifically, the industry generally is subject to regulations regarding the acquisition of permits before drilling, the spacing of wells, unitization and pooling of properties, habitat and endangered species protection, reclamation and remediation, restrictions on drilling activities in restricted areas, emissions into the environment, water discharges, and storage and disposition of hazardous wastes. In addition, state laws require wells and facility sites to be abandoned and reclaimed to the satisfaction of state authorities. Such laws and regulations have been frequently changed in the past, and we are unable to predict the ultimate cost of compliance as a result of future changes. The adoption or enforcement of stricter regulations, if enacted, could have a significant impact on our operating costs.

Our business activities in mining are also regulated by government agencies. Among other things, permits are required to explore for minerals, operate mines and build and operate processing plants. The regulations under which permits are issued change from time to time to reflect changes in public policy or scientific understanding of issues. If the economics of a project cannot withstand the cost of complying with changed regulations, we might decide not to move forward with the project.

In addition, we must comply with numerous environmental laws and regulations with respect to our mining activities, including the National Environmental Policy Act, or NEPA, the Clean Air Act, the Clean Water Act, and the Resource Conservation and Recovery Act, or RCRA. Other laws impose reclamation obligations on abandoned mining properties, in addition to or in conjunction with federal statutes. Environmental regulatory programs create potential liability for operators, and may result in requirements to perform environmental investigations or corrective actions under federal and state laws and federal and state Superfund requirements.

Under these laws and regulations, we could be liable for personal injuries, property and natural resource damages, releases or discharges of hazardous materials, well reclamation costs, oil spill clean-up costs, other remediation and clean-up costs, plugging and abandonment costs, governmental sanctions, and other environmental damages. Some environmental laws and regulations impose strict liability. Strict liability means that in some situations we could be exposed to liability for clean-up costs and other damages as a result of conduct that was lawful at the time it occurred or for the conduct of prior operators of properties we have acquired or other third parties, including, in some circumstances, operators of properties in which we have an interest and parties that provide transportation services for us. Similarly, some environmental laws and regulations impose joint and several liability, meaning that we could be held responsible for more than our share of a particular reclamation or other obligation, and potentially the entire obligation, where other parties were involved in the activity giving rise to the liability.

Changes in applicable laws and regulations could increase our costs, reduce demand for our production, impede our ability to conduct operations or have other adverse effects on our business.

Future changes in the laws and regulations to which we are subject may make it more difficult or expensive to conduct our operations and may have other adverse effects on us. For example, many of our activities involve the use of hydraulic fracturing, which is a process that creates a fracture extending from the well bore in a rock formation to enable oil or natural gas to move more easily through the rock pores to a production well. Fractures are typically created through the injection of water and chemicals into the rock formation. Legislative and regulatory efforts at the federal level and in some states have been made to impose new or more burdensome permitting, disclosure and safety requirements for hydraulic fracturing, and in some cases to prohibit hydraulic fracturing altogether in certain areas. These proposals, if adopted, could increase our costs and make it more difficult, or impossible, to pursue some of our development projects. For example, in the 111th Congress, companion bills were introduced in the United States Senate and House of Representatives. These bills would have repealed the exemption for hydraulic fracturing from the federal Safe Drinking Water Act, which would have had the effect of allowing the EPA to promulgate regulations requiring permits and imposing new restrictions on hydraulic fracturing under the federal Safe Drinking Water Act. This could, in turn, require state regulatory agencies in states with programs delegated under the Safe Drinking Water Act to impose additional requirements on hydraulic fracturing operations. In addition, the bills would have required persons using hydraulic fracturing, such as us, to disclose the chemical constituents, but not the proprietary formulas, of their fracturing fluids to a regulatory agency, which would make the information public via the internet, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. If legislation similar to that introduced in the 111th Congress becomes law, it could

establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business. Compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the potential impact on our business that may arise if the federal or state legislation is enacted into law. In addition, in March 2010, the EPA announced its intention to conduct a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health. Preliminary results of the study are expected in 2012. Thus, even if the pending legislation is not adopted, the EPA study, depending on its results, could spur further initiatives to regulate hydraulic fracturing under the Safe Drinking Water Act.

Similarly, the Colorado Department of Public Health and Environment is considering regulatory changes that could translate into more stringent discharge permit limits for the Mt. Emmons Project. These changes, if adopted, could increase the costs of operating the water treatment plant and managing stormwater at the site, or they could possibly require physical modifications to the water treatment plant and other facilities.

In addition, the adoption of laws and regulations, and international accords to which the United States is a party, relating to climate change and the emission of greenhouse gasses, or GHGs, could affect our oil and natural gas business segment. The emergence of trends such as a worldwide increase in hybrid power motor vehicle sales, and/or decreased personal motor vehicle use by individuals, in response to regulatory changes and/or perceived negative impacts on the climate from GHGs could result in lower world-wide consumption of, and prices for, crude oil. As part of state-level efforts to reduce these emissions, operating restrictions on emissions by drilling rigs and completion equipment could be enacted, leading to an increase in drilling and completion costs. The Environmental Protection Agency, or EPA, has issued a notice of finding and determination that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, which allows the EPA to begin regulating emissions of GHGs under existing provisions of the Clean Air Act. The EPA has begun to implement GHG-related reporting and permitting rules. Similarly, the U.S. Congress has considered, and may in the future consider, “cap and trade” legislation that would establish an economy-wide cap on emissions of GHGs in the United States and would require most sources of GHG emissions to obtain GHG emission “allowances” corresponding to their annual emissions of GHGs. Any laws or regulations that may be adopted to restrict or reduce emissions of GHGs would likely require us to incur increased operating costs and could have an adverse effect on demand for our production.

Additionally, President Obama’s 2013 fiscal year budget includes proposals that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could defer or eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

Seasonal weather conditions adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and natural gas operations in the Williston Basin and the Gulf Coast are adversely affected by seasonal weather conditions. In the Williston Basin, drilling and other oil and natural gas activities cannot be conducted as effectively during the winter months, and this can materially increase our

operating and capital costs. Gulf Coast operations are also subject to the risk of adverse weather events, including hurricanes.

Shortages of equipment, services and qualified personnel could reduce our cash flow and adversely affect results of operations.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices and activity levels in new regions, causing periodic shortages. These problems can be particularly severe in certain regions such as the Williston Basin. During periods of high oil and gas prices, the demand for drilling rigs and equipment has increased along with increased activity levels, and this may result in shortages of equipment. In addition, there is currently a shortage of hydraulic fracturing capacity in many of the areas in which we operate. Higher oil and natural gas prices generally stimulate increased demand and result in increased prices for drilling rigs, crews and associated supplies, oilfield equipment and services, and personnel in our exploration, production and midstream operations. These types of shortages and subsequent price increases could significantly decrease our profit margin, cash flow and operating results and/or restrict or delay our ability to drill those wells and conduct those operations that we currently have planned and budgeted, causing us to miss our forecasts and projections.

The exploration and future development of our Mt. Emmons Project is highly speculative, involves substantial expenditures, and may be non-productive.

Mineral exploration and development, including the exploration and development of our Mt. Emmons Project, involves a high degree of risk. Exploration projects are frequently unsuccessful and few prospects that are explored are ultimately developed into producing mines. We cannot assure you that our exploration or development efforts at Mt. Emmons will be successful. Substantial expenditures are required to determine if the project has economically mineable mineralization, and our ability to fund these expenditures will be driven substantially by the market price for molybdenum. It could take several years to obtain the necessary governmental approvals and permits to establish proven and probable mineral reserves and to develop and construct mining and processing facilities. Because of these uncertainties, it cannot be assumed that our efforts at Mt. Emmons will result in the discovery of economic mineral reserves or our ability to develop the project into a producing mine.

Development of the Mt. Emmons Project is subject to numerous environmental and permitting risks

The Mt. Emmons Project is located on fee property within the boundary of U.S. Forest Service (“USFS”) land. Although mining of the mineral resource will occur on the fee property, associated ancillary activities will occur on USFS land. The Company submitted an initial plan of operations to the USFS in 2010. The Company also plans to submit on or before April 30, 2013 a full mine plan of operations to satisfy the requirements of the conditional water rights decree. Under the procedures mandated by the National Environmental Protection Act (“NEPA”), the USFS will prepare an environmental analysis in the form of an environmental assessment to evaluate the predicted environmental and socio-economic impacts of the proposed mine plan. The NEPA process provides for public review and comment of the proposed plan.

The USFS is the lead regulatory agency in the NEPA process, and coordinates with the various federal and state agencies in the review and approval of the mine plan of operations. Various Colorado state agencies will have primary jurisdiction over certain areas. For example, enforcement of the Clean Water Act in Colorado is delegated to the Colorado Department of Public Health and Environment. A water discharge permit under the Colorado Discharge Pollutant System, (“CDPS”), is required before the

USFS can approve the plan of operations. We currently have CDPS permits for the discharge from the water treatment plant and for stormwater discharges associated with the Mt. Emmons Project.

In addition, the Colorado Division of Reclamation, Mining and Safety issues mining and reclamation permits for mining activities pursuant to the Colorado Mined Land Reclamation Act, and otherwise exercises supervisory authority over mining in the state. As part of obtaining a permit to mine, we will be required to submit a detailed reclamation plan for the eventual mine closure, which must be reviewed and approved by the agency. In addition, we will be required to provide financial assurance that the reclamation plan will be achieved (by bonding and/or insurance) before the mining permit will be issued.

Obtaining and maintaining the various permits for the mining operations at the Mt. Emmons Project will be complex, time-consuming, and expensive, and is subject to ongoing litigation. Changes in a mine's design, production rates, quality of material mined, and many other matters, often require submission of the proposed changes for agency approval prior to implementation. In addition, changes in operating conditions beyond our control, or changes in agency policy and federal and state laws, could further affect the successful permitting of the mine operations and the costs of complying with environmental permits and related requirements. The timing, cost, and ultimate success of our future development efforts and mining operations cannot be predicted.

We depend on key personnel.

Our employees have experience in dealing with the acquisition of and financing of mineral properties, but we have a limited technical staff and executive group. From time to time we rely on third party consultants for professional geophysical and geological advice in oil and gas matters. The loss of key employees could adversely impact our business, as finding replacements could be difficult as a result of competition for experienced personnel in the minerals industry.

Risks Related to Our Stock

We have authorization to issue shares of preferred stock with greater rights than our common stock.

Although we have no current plans, arrangements, understandings or agreements to do so, our articles of incorporation authorize the board of directors to issue one or more series of preferred stock and set the terms of the stock without seeking approval from holders of the common stock. Preferred stock that is issued may have preferential rights over the common stock in terms of dividends, liquidation rights and voting rights.

Future equity transactions and exercises of outstanding options or warrants could result in dilution.

From time to time, we have sold restricted stock and warrants and convertible debt to investors in private placements conducted by broker-dealers, or in negotiated transactions. Because the stock was issued without registration under the Securities Act of 1933, it was sold at a discount to market prices. We have also issued stock in public offerings. These transactions caused dilution to existing shareholders. Also, from time to time, options and warrants are issued to employees, directors and third parties as incentives, with exercise prices equal to market prices at dates of issuance. Exercise of in-the-money options and warrants would result in dilution to existing shareholders. Future issuances of equity securities, or securities convertible into equity securities, would also have a dilutive effect on existing shareholders. In addition, the perception that such issuances may occur could adversely affect the market price of our common stock.

We do not intend to declare dividends on our common stock.

We paid a one-time special cash dividend of $0.10 per share on our common stock in July 2007. However, we do not intend to declare dividends in the foreseeable future. Accordingly, stockholders must look solely to increases in the price of our common stock to realize a gain on their investment, and this may not occur.

The Company could implement take-over defense mechanisms that could discourage some advantageous transactions.

Although our shareholder rights plan expired in 2011, certain provisions of the Company's governing documents and applicable law could have anti-takeover effects. For example, the Company is subject to a number of provisions of the Wyoming Management Stability Act, an anti-takeover statute, and has a classified, or "staggered" board. In addition, the Company could implement additional anti-takeover defenses in the future. These existing or future defenses could prevent or discourage a potential transaction in which shareholders would receive a takeover price in excess of then-current market values, even if a majority of the shareholders support such a transaction.

Our stock price likely will continue to be volatile.

Our stock is traded on the Nasdaq Capital Market. In the two years ended December 31, 2011, the stock has traded as high as $7.06 per share and as low as $2.05 per share. The principal factors which have contributed and/or in the future could contribute to this volatility include:

- price swings in the oil and gas commodities markets;
- price and volume fluctuations in the stock market generally;
- relatively small amounts of stock trading on any given day;
- fluctuations in our financial operating results;
- industry trends;
- legislative and regulatory changes; and
- global economic uncertainty.

The stock market has recently experienced significant price and volume fluctuations, as have commodity prices. These fluctuations have particularly affected the market prices of securities of oil and gas companies like ours. These market fluctuations could adversely affect the market price of our stock.

Item 1 B - Unresolved Staff Comments.

None.

Item 2 – Properties

Oil and Natural Gas

The following table sets forth our net proved reserves as of the dates indicated. Our reserve estimates as of December 31, 2009, 2010 and 2011 are based on reserve reports prepared by Ryder Scott Company, L.P., or Ryder Scott, Cawley, Gillespie & Associates, Inc., or CGA, and Netherland, Sewell & Associates, Inc., or NSAI. Ryder Scott, CGA and NSAI are nationally recognized independent petroleum engineering firms. Ryder Scott is a Texas Registered Engineering Firm (F-1580). Our primary contact at Ryder Scott is Mr. James F. Latham, Senior Vice President. Mr. Latham is a State of Texas Licensed

Professional Engineer (License #49586). CGA is a Texas Registered Engineering Firm (F-693). Our primary contact at CGA is Mr. W. Todd Brooker, Senior Vice President. Mr. Brooker is a State of Texas Licensed Professional Engineer (License # 83462). NSAI is a Texas Registered Engineering Firm (F-2699). Our primary contact at NSAI is Mr. Richard B. Talley, Jr., Vice President. Mr. Talley is a State of Texas Licensed Professional Engineer (License # 102425). Ryder Scott prepared the estimates related to our Gulf Coast Basin, including Louisiana and Texas properties. CGA prepared the estimates for our North Dakota properties and NSAI prepared the estimates for our Austin Chalk and Eagle Ford properties in Texas. The reserve estimates were based upon the review (by the relevant contracted engineering firm(s)) of the production histories and other geological, economic, ownership and engineering data, as provided by us and the corresponding operators to them. Copies of these reports are filed as exhibits to this Annual Report.

We do not have in-house geophysical or reserve engineering expertise. We therefore primarily rely on the operators of our producing wells who provide production data to our contract reserve engineers.

Summary of Oil and Gas Reserves as of Fiscal Year End (1)

	December 31,		
	2011	**2010**	**2009**
Net proved reserves			
Oil (Bbls)			
Developed	1,884,068	1,362,733	811,789
Undeveloped	853,930	183,713	--
Total	2,737,998	1,546,446	811,789
Natural gas (Mcf)			
Developed	1,973,453	1,996,490	1,502,296
Undeveloped	760,595	139,286	--
Total	2,734,048	2,135,776	1,502,296
Plant Products (Bbls)			
Developed	1,688	52,532	24,031
Undeveloped	--	--	--
Total	1,688	52,532	24,031
Total proved reserves (BOE)	3,195,361	1,954,941	1,086,203

(1) Reserve estimates are based on 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. Reserve estimates as of December 31, 2011 are based on prices of $96.19 per barrel of oil and $4.12 per MMbtu of natural gas, in each case adjusted for regional price differentials and other factors.

As of December 31, 2011, our proved reserves totaled 3,195,361 BOE (69% developed and 31% undeveloped), comprised of 2,737,998 Bbls of oil (86% of the total), 2,734,048 Mcf of natural gas (14% of the total) and 1,688 Bbls of natural gas liquid. See the "Glossary of Oil and Gas Terms" for an explanation of these and other terms. You should not place undue reliance on estimates of proved reserves. See "Risk Factors - Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or the relevant underlying assumptions will materially affect the quantity and present value of our reserves". A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are reservoir simulation, decline curve analysis, volumetrics, material balance, advance production type curve matching, petrophysics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields.

Proved Undeveloped Reserves

As of December 31, 2011, we had 980,696 BOE of proved undeveloped reserves, which is an increase of 773,769 BOE, or 474%, compared with 206,927 BOE of proved undeveloped reserves at December 31, 2010. We invested approximately $4.6 million to convert 79,198 BOE of proved undeveloped reserves to proved developed reserves in 2011 in our Bakken/Three Forks property. As of December 31, 2011, we have no proved undeveloped reserves that have been on the books in excess of five years and we have recorded no material proved undeveloped locations that were more than one direct offset from an existing producing well. As of December 31, 2011, estimated future development costs relating to proved undeveloped reserves are projected to be approximately $35.9 million over the next five years.

On January 25, 2012, we sold an undivided 75% of our undeveloped acreage in the SE HR and Yellowstone Prospects. If applied retrospectively to our December 31, 2011 reserves, this sale reduced our proved developed reserves by 41,048 BOE (due to acceleration of a reversionary interest at payout related to the producing wells), reduced our proved undeveloped reserves by 509,534 BOE, reduced our estimated future development costs by $21.4 million and increased our PV-10 by approximately $468,000.

Oil and Gas Production, Production Prices, and Production Costs

The following table sets forth certain information regarding our net production volumes, average sales prices realized and certain expenses associated with sales of oil and natural gas for the periods indicated. We urge you to read this information in conjunction with the information contained in our financial statements and related notes included in this Annual Report. The information set forth below is not necessarily indicative of future results.

	December 31,		
	2011	2010	2009
Production Volume			
Oil (Bbls)	300,325	303,433	80,461
Natural gas (Mcf)	736,261	757,905	467,691
Natural gas liquids (Bbls)	19,325	19,104	5,987
BOE	442,360	448,855	164,397
Daily Average Production Volume			
Oil (Bbls/d)	823	831	220
Natural gas (Mcf/d)	2,017	2,076	1,281
Natural gas Liquids (Bbls/d)	53	52	16
BOE/d	1,212	1,230	450
Oil Price per Bbl Produced			
Realized Price	$ 87.80	$ 72.11	$ 66.22
Natural Gas Price per Mcf Produced			
Realized Price	$ 4.85	$ 4.96	$ 4.30
Natural Gas Liquids Price per Bbl Produced			
Realized Price	$ 52.88	$ 47.53	$ 40.25
Average Sale Price per BOE (1)	$ 69.98	$ 59.15	$ 46.11
Expense per BOE			
Production costs (2)	$ 19.10	$ 6.81	$ 2.40
Depletion, depreciation and amortization	$ 31.64	$ 23.64	$ 21.72

(1) Amounts shown are based on oil and natural gas sales, divided by sales volumes. Natural gas produced but flared is not included.

(2) Production costs are comprised of oil and natural gas production expenses (excluding ad valorem and severance taxes), and are computed using production costs as determined under ASC 932-235-55.

Drilling and Other Exploratory and Development Activities

The following table sets forth information with respect to development and exploration wells we completed from January 1, 2009 through December 31, 2011. The number of gross wells is the total number of wells we participated in, regardless of our ownership interest in the wells.

	Years Ended December 31,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	1.0000	0.2491	--	--	--	--
Non-productive	--	--	--	--	--	--
	1.0000	0.2491	--	--	--	--
Exploratory:						
Productive	12.0000	2.9817	8.0000	2.9409	8.0000	3.3286
Non-productive	4.0000	0.7954	5.0000	0.3902	2.0000	0.5833
	16.0000	3.7771	13.0000	3.3311	10.0000	3.9119
Total	17.0000	4.0262	13.0000	3.3311	10.0000	3.9119

The information above should not be considered indicative of future drilling performance, nor should it be assumed that there is any correlation between the number of productive wells drilled and the amount of oil and natural gas that may ultimately be recovered. See "Management's Discussion and Analysis of Financial Condition and Results of Operation – General Overview."

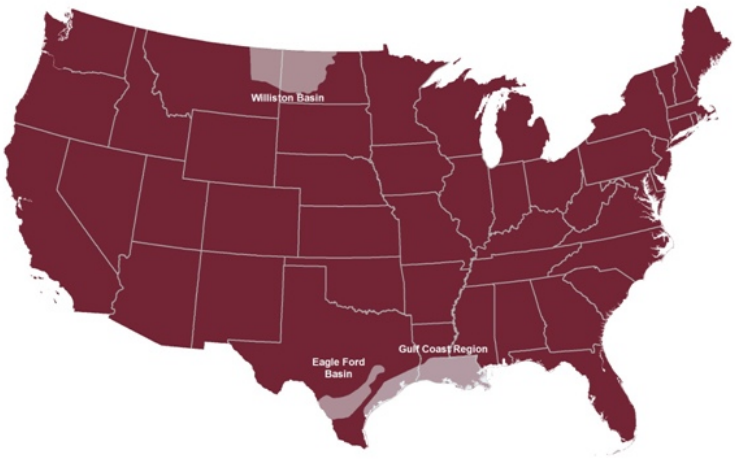
Oil and Natural Gas Properties, Wells, Operations and Acreage

The following table details our working interests in producing wells as of December 31, 2011. A well with multiple completions in the same bore hole is considered one well. Wells are classified as oil or natural gas wells according to the predominant production stream, except that a well with multiple completions is considered an oil well if one or more is an oil completion.

	Gross Producing Wells	Net Producing Wells	Average Working Interest [1]
Oil	37.00	11.92	32.21514%
Natural Gas	4.00	0.87	21.63750%
Total [1]	41.00	12.79	31.18317%

(1) The average working interest for the twenty-three Williston Basin wells producing at December 31, 2011 is 35.19%; the remaining eighteen wells (Texas and Louisiana) have an average working interest of 26.07%.

The following map reflects where our oil and gas wells are generally located:



Acreage

The following table summarizes our estimated developed and undeveloped leasehold acreage as of December 31, 2011.

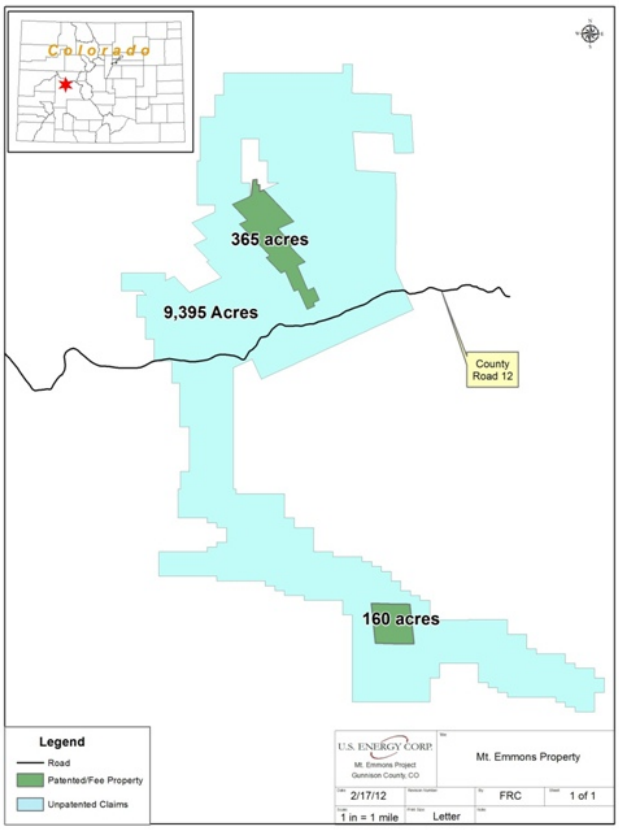
	Developed		Undeveloped		Total	
AREA	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Williston Basin						
Rough Rider Prospect	19,200	1,175	--	--	19,200	1,175
Yellowstone and SEHR Prospects	6,400	1,186	29,440	5,414	35,840	6,600
Wolverine Prospect, Daniels County, MT	--	--	29,664	18,690	29,664	18,690
Southeast Texas and Louisiana	4,414	978	12,734	845	17,148	1,823
Eagle Ford/Austin Chalk						
Leona River Prospect	--	--	4,675	1,402	4,675	1,402
Booth Tortuga Prospect	--	--	9,110	2,733	9,110	2,733
San Joaquin Basin	--	--	7,178	2,448	7,178	2,448
TOTAL	**30,014**	**3,339**	**92,801**	**31,532**	**122,815**	**34,871**

Present Activities

As of March 1, 2012, we were in the process of drilling and/or completing 6 gross wells in the Williston Basin and the Eagle Ford, and 3 gross wells were drilled and waiting on completion.

Molybdenum – Mt. Emmons Project

The Mt. Emmons Project is located near Crested Butte, Colorado and includes a total of 160 fee acres, 25 patented and approximately 1,353 unpatented mining and mill site claims, which together approximate 9,920 acres, or over 15 square miles of claims and fee lands. The Mt. Emmons Project is located in Gunnison County, Colorado. The property is accessed by vehicle traffic on Gunnison County Road 12.



We own both surface and mineral rights at the Mt. Emmons Project in fee pursuant to mineral patents issued by the federal government. All fee property requires the payment of property taxes to Gunnison County. Unpatented mining and mill site claims require the payment of an annual maintenance fee of $140 per claim to the Bureau of Land Management; the total amount paid for claim maintenance fees in 2011 was $191,000.

The breakdown of the property is as follows:

	Acres	Number of Claims
Patented Claims / Fee Land	365	25
Unpatented Claims	6,075	664
Mill Site Claims	3,320	664
Fee Property	160	n/a
	9,920	1,353

On April 21, 2011, Thompson Creek Metals Company USA ("Thompson Creek" or "TCM") terminated the August 10, 2008 Exploration, Development and Mine Operating Agreement ("the Agreement") with the Company. TCM advised the Company that the termination was the result of TCM desiring to concentrate efforts on other mineral resource projects with a shorter projected time line for commencing production. Although TCM had spent approximately $14.4 million in option payments and work expenditures on the property through April 21, 2011, TCM had not earned an interest in the property at termination and currently has no interest in the property.

History of the Mt. Emmons Project

We leased various patented and unpatented mining claims on the Mt. Emmons Project to Amax, Inc. ("Amax") in 1974. In the late 1970s, Amax delineated a large deposit of molybdenum on the properties, reportedly containing approximately 155 million tons of mineralized material averaging 0.44% molybdenum disulfide (MoS2). In 1981, Amax constructed a water treatment plant at the Mt. Emmons Project to treat water flowing from the old Keystone mine workings and for potential use in milling operations. By 1983, Amax had reportedly spent an estimated $150 million in the acquisition of the property, securing water rights, extensive exploration, ore body delineation, mine planning, metallurgical testing and other activities involving the mineral deposit. Amax was merged into Cyprus Minerals in 1992 to form Cyprus Amax. Phelps Dodge ("PD") then acquired Mt. Emmons Project in 1999 through its acquisition of Cyprus Amax. Thereafter, PD acquired additional conditional water rights and patents to certain mineral claims.

The exploration work conducted in the late 1970s by Amax as discussed in Cyprus Amax's Patent Claim Application to the Bureau of Land Management dated December 23, 1992, defined the initial mineralized material at the Mt. Emmons Project as follows: "Molybdenite is present in randomly distributed veinlets (i.e. stockwork veining) and in some larger veins that are up to two feet wide. This mineralized zone is found in metamorphosed sedimentary rocks and in Tertiary igneous complex which acted as the source of the mineralization."

There are also a number of existing mine adits located on the property. Historic work completed by Amax in the 1970s and early 1980s included 2,400 feet of new drift with 18 underground diamond drill stations to facilitate underground drilling (consisting of 168 diamond drill holes for a total of 157,037 feet of core drilling). The majority of the drilling was concentrated within 3,000 feet north and south; 3,000 feet east and west and 2,000 vertical feet defining the area of mineralized material. A bulk sample was collected from this area and sent off site for metallurgical testing.

In its 1992 patent application, Cyprus Amax stated that the size and grade of the Mt. Emmons deposit was determined to approximate 220 million tons of mineralized material grading 0.366% molybdenite. In a letter dated April 2, 2004, the BLM estimated that there were about 23 million tons of mineralized material containing 0.689% molybdenite, and that about 267 million pounds of molybdenum trioxide was recoverable. This letter covered only the high-grade mineralization which is only a portion of the total mineral deposit delineated to date. The analysis set forth in the letter was based upon a price of $4.61 per pound for molybdic oxide and was used by the BLM in determining that nine claims satisfied the patenting requirement that the mining claims contain a valuable mineral that could be mined profitably.

We note that the statements made by the predecessor owners of the Mt. Emmons Project regarding “recoverable” minerals and “mineralized material” were based on costs, permitting requirements and commodity prices then prevailing. We believe these estimates to be relevant, but they should not be relied upon. Substantial additional exploration and drilling efforts and a full feasibility study will be required, using current and expected capital costs, and operating expenses, to estimate the viability of the project. It will be possible to classify some, or none, of the mineralized resources as “reserves” or “recoverable” only after a full feasibility study, based on a specific mine plan, has been completed.

In December 2008, an additional 160 acres of fee land in the vicinity of the claims was purchased by the Company and TCM for $4 million ($2 million in January 2009, $400,000 annually for five years). On December 6, 2011, TCM notified the Company that it wishes to sell its interest in the property. The Company has 18 months to decide whether to purchase TCM’s interest and the property and close such purchase.

In July 2011 the Company acquired 109 additional mill site claims, totaling approximately 545 additional acres.

Geology

The sedimentary sequence in the Mt. Emmons area spans from the late Cretaceous to the early Tertiary periods. The oldest formation is the Mancos, a 4,000 foot sequence of shales with some interbedding limestone and siltstones. The Mancos Formation is not exposed on Mt. Emmons, but may be seen in valley bottoms a few miles to the north, south, and east. All of the Mancos Formation encountered in the vicinity of the Mt. Emmons mineralization has been strongly metamorphosed and attempts to correlate internal divisions of the unit have not been made. The overlying Mesaverde Formation, also of the late Cretaceous age, consists of a massive repetitive sequence of alternating sandstones, siltstones, shales and minor coals. Coal seams were not observed in any of the diamond drill holes, or in any of the underground drifts. On Mt. Emmons the Mesaverde Formation varies from 1,100 to 1,700 feet thick. The variability in thickness of the Mesaverde Formation is mainly due to post-depositional erosion. The Ohio Creek Formation, dominantly a coarse sandstone with local chert pebble conglomerate and well-defined shale to siltstone beds, overlies the Mesaverde Formation. The Ohio Creek Formation is of early Tertiary (Paleocene) age and remains fairly consistent at 400 feet thick on Mt. Emmons. Capping Mt. Emmons is the Wasatch Formation, also of early Tertiary (Paleocene to Eocene) age.

On a more regional scale, within the Ruby Range the Wasatch Formation may reach 1,700 feet in thickness. However, on Mt. Emmons specifically, all but the basal 600 to 700 feet has been eroded. The Wasatch Formation is composed of alternating sequences of immature shales, siltstones, arkosic sandstones, and volcanic pebble conglomerates. The Mt. Emmons stock has intruded the Mancos and Mesaverde sediments, strongly metamorphosing both formations to hornfels up to 1,500 feet outward from the igneous body.

Sedimentary rocks on Mt. Emmons generally dip 15 – 20 degrees to the southeast, south, and southwest as is consistent with the locations of the Oh-Be-Joyful anticline and Coal Creek syncline.

During crystallization of the Red Lady Complex, hydrothermal fluids collected near the top of the magma column. These fluids were released after a period of intense fracturing in the solid upper portions of the Red Lady Complex and the surrounding country rock. This release of fluids was responsible for the formation of the major part of the Mt. Emmons molybdenum mineralized zone and the associated alteration zones. Hydrothermal alteration associated with the Mt. Emmons stock occurs in several distinct overlapping zones. Altered rocks include sedimentary rocks of the Mancos, Mesaverde, Ohio Creek and Wasatch Formations, the rhyodacite porphyry sills, and rocks of the Mt. Emmons stock.

Water Treatment Plant; Site Facilities

PD's 2006 re-conveyance of the property to the Company also included the transfer of ownership and operational responsibility of the mine water treatment plant located on the property. The water treatment permit issued under the Colorado Discharge Permit System was assigned to us by the Colorado Department of Health and Environment. We are responsible for all operating and maintenance costs. We also are evaluating using the plant in milling operations.

The water treatment plant was constructed by Amax in 1981 (at a cost of approximately $15 million) to treat mine discharge water from the historic Keystone Mine which produced lead and zinc. A certified water treatment plant operations contractor with four licensed and/or trained employees operates the water treatment plant on a continuous basis, treating water discharged from the Keystone Mine. The plant utilizes a standard lime pH adjustment to precipitate heavy metals from the water. Mine water is then filtered and discharged in accordance with the requirements of the CDPS permit for the plant, and solids are dewatered and mixed with cement for proper disposal in accordance with state and federal law. We also maintain coverage under the CDPS General Permit for Stormwater Discharges associated with the Metal Mining Industry. This permit provides authorization to discharge stormwater from the Mt. Emmons Project subject to the general requirements of the permit itself, which are applicable to all active and inactive metal mining operations in Colorado, and a site-specific stormwater management plan.

Additional equipment used in the operation of the water treatment plant includes large front-end loaders, forklifts, specialized snow removal equipment and pickup trucks.

Several capital upgrades to onsite facilities have been made since 2006. Current facilities include a core and office building, five ancillary pump houses and underground pipelines and utilities, which move water from five water storage ponds to the water treatment plant. Surface access is maintained to the four underground adits and the ancillary pump houses.

Historical Capital Expenditures by Prior Owners, and Related Information

Amax reportedly spent approximately $150 million in exploration and related activities on the Mt. Emmons Project, which included construction of the water treatment plant. Since the Company reacquired the property in 2006, an additional $22.7 million has been spent on the development of the property. In addition, our annual operating cost for the water treatment plant is approximately $1.8 million. The total costs associated with future drilling and the development of the project has not yet been determined.

We are using grid electric power to operate the water treatment plant and other facilities from the local electric utility serving Gunnison County. We have been granted conditional water rights from the State of Colorado for operation and development of the project. The Company is reviewing and evaluating potential future power and water needs, however no definitive development project plans have been finalized or approved at this time.

Additional drilling may need to be conducted to further delineate the depth, grades and volume of mineralized materials before we can determine if there are reserves present in the project (presently in the advanced exploration stage). The timetable for completing drilling, and the permitting and construction of the mine and milling facilities, is dependent upon several factors, including local, state and federal regulations and availability of capital, which is driven substantially by the market price for molybdenum.

Activities in 2010 - 2011 and Plans for 2012

The Company submitted an initial plan of operations to the USFS on March 30, 2010. During 2011, the Company continued work on the mine plan of operations to satisfy the requirements of the conditional water rights decree, which the Company is planning to submit on or before April 30, 2013.

Information About Molybdenum Markets

The metallurgical market for molybdenum is characterized by cyclical and volatile prices, little product differentiation and strong competition. In the market, prices are influenced by production costs of domestic and foreign competitors, worldwide economic conditions, world supply/demand balances, inventory levels, the U.S. Dollar exchange rate and other factors. Molybdenum prices also are affected by the demand for end-use products in, for example, the construction, transportation and durable goods markets. A substantial portion the of world's molybdenum supply is produced as a by-product of copper mining. Today, by-product production is estimated to account for approximately 60% of global molybdenum production.

Annual Metal Week Dealer Oxide mean prices averaged $15.48 in 2011, compared to $15.90 in 2010.

Real Estate

Remington Village Apartments - Gillette, Wyoming.

We own Remington Village Apartments, a nine building multifamily apartment complex, with 216 units on 10.15 acres located in Gillette, Wyoming. The apartments are a mix of one, two, and three bedroom units, with a clubhouse and family amenities for the complex. This project is held by our wholly-owned subsidiary Remington Village, LLC.

Occupancy averaged 87% in 2011. For the year, we realized average monthly revenues of approximately $174,000. The occupancy rate was 80% at December 31, 2009, 89% at December 31, 2010 and 82% at December 31, 2011. The decrease in occupancy rate from 2010 to 2011 was due to the national economic downturn and reduced activities in the oil and gas sector in Wyoming and competition with available single family housing. On May 5, 2011, we borrowed $10.0 million from a commercial bank. The note is secured by the Remington Village Apartments. 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.

Impairments of $3.1 million and $1.5 million were recorded at December 31, 2011 and 2010, respectively, on the property to reflect the difference between the cost of the property and its estimated fair market value. Although the property produces positive cash flow from its operations, the return from oil and gas investments is expected to yield a higher return. The Company plans to sell this property in 2012 and redirect the sale proceeds to growing its oil and gas business.

Fremont County, Wyoming

U.S. Energy owns a 14-acre tract in Riverton, Wyoming, with a two-story 30,400 square foot office building. The first floor is rented to non-affiliates and government agencies; the second floor is occupied by the Company. In addition, we own three city lots covering 13.84 acres adjacent to our corporate office building. When the real estate market recovers we intend to sell this property without development. The timing of sale is not known. We also own a 10,000 square foot aircraft hangar on land leased from the City of Riverton with 7,000 square feet of associated offices and facilities and two vacant lots covering 13.2 acres in Fremont County, Wyoming.

Sold Uranium Properties – Possible Future Revenues

In 2007, we sold all of our uranium assets for cash and stock of the purchaser. Included in the sold assets were the Shootaring Canyon uranium mill in Utah and unpatented uranium claims in Wyoming, Colorado, Arizona and Utah. Pursuant to the asset purchase agreement, we may also receive from the purchaser:

- $20,000,000 cash when the Shootaring Canyon Mill has been operating at 60% or more of its design capacity of 750 short tons per day for 60 consecutive days.
- $7,500,000 cash on the first delivery (after commercial production has occurred) of mineralized material from any of the claims we sold to a commercial mill (excluding existing ore stockpiles on the properties).
- From and after commercial production occurs at the Shootaring Canyon Mill, a production payment royalty (up to but not more than $12,500,000) equal to five percent of (i) the gross value of uranium and vanadium products produced at and sold from the mill; or (ii) mill fees received by the purchaser from third parties for custom milling or tolling arrangements, as applicable. If production is sold to an affiliate of the purchaser, partner, or joint venturer, gross value shall be determined by reference to mining industry publications or data.

The timing of any potential future receipt of funds from any of these contingencies is not known.

Royalty on Uranium Claims

We hold a 4% net profits interest on unpatented mining claims on Rio Tinto's Jackpot uranium property located on Green Mountain in Wyoming.

Research and Development

No research and development expenditures have been incurred, either on the Company's account or sponsored by a customer of the Company, during the past three fiscal years.

Marketing, Major Customers and Delivery Commitments

Markets for oil and natural gas are volatile and are subject to wide fluctuations depending on numerous factors beyond our control, including seasonality, economic conditions, foreign imports, political conditions in other energy producing countries, OPEC market actions, and domestic government regulations and policies. All of our production is marketed by our industry partners for our benefit and is sold to competing buyers, including large oil refining companies and independent marketers. Substantially all of our production is sold pursuant to agreements with pricing based on prevailing commodity prices, subject to adjustment for regional differentials and similar factors. We had no material delivery commitments as of December 31, 2011.

Competition

The oil and natural gas business is highly competitive in the search for and acquisition of additional reserves and in the sale of oil and natural gas. Our competitors principally consist of major and intermediate sized integrated oil and natural gas companies, independent oil and natural gas companies and individual producers and operators. In particular, we compete for property acquisitions and for the equipment and labor required to operate and develop our properties. These competitors may be able to pay more for properties and may be able to define, evaluate, bid for and purchase a greater number of properties than we can. Ultimately, our future success will depend on our ability to develop or acquire additional reserves at costs that allow us to remain competitive.

Environmental

Our operations are subject to various federal, state and local laws and regulations regarding the discharge of materials into the environment or otherwise relating to the protection of the environment, including NEPA, the Clean Air Act, Federal Water Pollution Control Act of 1972 (the “Clean Water Act”), the Oil Pollution Act of 1990, RCRA, and the Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA” or the Superfund Law). Regulations applicable to our operations have been changed frequently in the past and, in general, these changes have imposed more stringent requirements that increase operating costs and/or require capital expenditures to remain in compliance. Failure to comply with these requirements can result in civil and/or criminal penalties and liability for non-compliance, clean-up costs and other environmental damages. It also is possible that unanticipated developments or changes in the law could require us to make environmental expenditures significantly greater than those we currently expect.

With respect to proposed mining operations at the Mt. Emmons Project, Colorado’s mine permitting statute, the Abandoned Mine Reclamation Act, and industrial development and siting laws and regulations, also may affect the project. We believe we are in compliance in all material respects with existing environmental regulations. Based on an inspection in December 2010, the Colorado Department of Public Health and Environment advised us in March 2011 that the CPDS permits for the site may be modified to: (i) require additional monitoring to determine whether or not stormwater discharges from the site are in full compliance with permit requirements, and (ii) impose more stringent requirements when the permits are up for renewal in 2013. To date, the Colorado Department of Public Health and Environment has not followed-up on its advisory with any specific directives or permit modifications. Nevertheless, we have voluntarily implemented a stormwater and surface water quality monitoring program to better assess site conditions and compliance with permit requirements. For information on the approximate reclamation costs (decommissioning, decontamination and other reclamation efforts for which we are primarily responsible or potentially responsible) related to the Mt. Emmons Project, see the consolidated financial statements included in Part II of this Annual Report.

We may generate wastes, including “solid” wastes and “hazardous” wastes that are subject to regulation under RCRA and comparable state statutes, although certain mining and oil and natural gas exploration and production wastes currently are exempt from regulation as hazardous wastes under RCRA. EPA has limited the disposal options for certain wastes that are designated as hazardous wastes. Moreover, certain wastes generated by our mining and oil and natural gas operations that currently are exempt from regulation as hazardous wastes may in the future be designated as hazardous wastes and, as a result, become subject to more rigorous and costly management, disposal and remediation requirements.

Gas and oil operations are also subject to various federal, state and local governmental and environmental regulations, including regulations governing natural gas and oil production, federal and state regulations for environmental quality and pollution control, and state limits on allowable rates of production by well. These regulations may affect the amount of natural gas and oil available for sale, the availability of adequate pipeline and other regulated transportation and processing facilities, and other matters. State and federal regulations generally are intended to prevent waste of natural gas and oil, protect rights to produce natural gas and oil between owners in a common reservoir, control the amount produced by assigning allowable rates of production and control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies. From time to time, various proposals are made by regulatory agencies and legislative bodies to change existing requirements or to add new requirements. Regulatory changes can adversely impact the permitting and exploration and development of mineral and oil and gas properties including the availability of capital.

Although all of our currently producing oil and gas properties are operated by third parties, the activities on the properties are still subject to environmental protection regulations. Operators are required to obtain drilling permits, restrict substances that can be released into the environment, and require remedial work to mitigate pollution from operations (such as pollution from operations), close and cover disposal pits, and plug abandoned wells. Violations by the operator could result in substantial liabilities, and we would have to pay our share. Based on the current regulatory environment in those states where we have oil and natural gas investments and rules and regulations currently in effect, we do not expect to make any material capital expenditures for environmental control facilities.

Failure to comply with applicable regulations could result in substantial fines, environmental remediation orders and/or potential shut down of a project until compliance is achieved. Failure to timely obtain required permits to start operations at a project could cause delay and/or the failure of the project resulting in a potential write-off of the investments made.

Insurance

The Company has the following insurance coverage:

General

We have liability insurance coverage in amounts we deem sufficient for our business operations, consisting of property loss insurance on all major assets equal to the approximate replacement value of the assets and additional liability and control of well insurance for our oil and gas drilling programs. Payment of substantial liabilities in excess of coverage could require diversion of internal capital away from regular business, which could result in curtailment of projected future operations.

Mt. Emmons Project

The Company is responsible for all costs to operate the water treatment plant at the Mt. Emmons Project. We maintain an insurance policy for our benefit in the amounts of $1 million per event, $2 million aggregate general liability, $1 million automobile liability, $10 million environmental impairment liability, and $10 million excess liability (an upper limit on the coverage other than environmental).

We believe the above insurance is sufficient in the current permitting-exploration stage of the Mt. Emmons Project. Additional insurance will be obtained as the level of activity in exploration and development expands.

Corporate Aircraft

The Company maintains a $20 million per event liability policy on its corporate aircraft. We also maintain a $4 million physical damage insurance policy on the aircraft which approximates its replacement value.

Remington Village

We have a policy covering $1 million each event, $2 million general aggregate liability and a $9 million of excess liability policy. The deductibles are $1,000 ($5,000 retained limited) per event. We maintain $20.4 million of coverage for the real property written on a Special Form/Replacement Cost basis.

Employees

As of December 31, 2011, we had 19 full-time employees.

Mining Claim Holdings

Title

Approximately 25 of the Mt. Emmons Project mining claims are patented claims; however, the majority of claims are unpatented.

Unpatented claims are located upon federal and public land pursuant to procedures established by the General Mining Law, which governs mining claims and related activities on federal public lands. Requirements for the location of a valid mining claim on public land depend on the type of claim being staked, but generally include discovery of valuable minerals, erecting a discovery monument and posting thereon a location notice, marking the boundaries of the claim with monuments, and filing a certificate of location with the county in which the claim is located and with the U.S. Bureau of Land Management (“BLM”). If the statutes and regulations for the location of a mining claim are complied with, the locator obtains a valid possessory right to the contained minerals. To preserve an otherwise valid claim, a claimant must also pay certain rental fees annually to the federal government and make certain additional filings with the county and the BLM. Failure to pay such fees or make the required filing may render the mining claim void or voidable.

Because mining claims are self-initiated and self-maintained, they possess some unique vulnerability not associated with other types of property interests. It is impossible to ascertain the validity of unpatented mining claims solely from public records and it can be difficult or impossible to confirm that all of the requisite steps have been followed for location and maintenance of a claim. If the validity of an unpatented mining claim is challenged by the government, the claimant has the burden of proving the economic feasibility of mining minerals located thereon. However, we believe that all of our Mt. Emmons Project mining claims are valid and in good standing.

Proposed Federal Legislation

The U.S. Congress from time to time has considered proposed revisions to the General Mining Law, including as recently as 2009. If these proposed revisions are enacted, payment of royalties on production of minerals from federal lands could be required as well as additional procedural measures, new requirements for reclamation of mined land, and other environmental control measures. The effect of any revision of the General Mining Law on operations cannot be determined until enactment. However, it is possible that revisions would materially increase the carrying and operating costs of mineral properties located on federal unpatented mining claims.

Item 3 – Legal Proceedings

Material legal proceedings pending at December 31, 2011 and developments in those proceedings from that date to the date of this Annual Report are summarized below.

Water Rights Litigation –Mt. Emmons Project

On July 25, 2008, we filed an Application for Finding of Reasonable Diligence with the Colorado Water Court ("Water Diligence Application") concerning the conditional water rights associated with the Mt. Emmons Project (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 Decree, or within six years of the final determination of the 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 (by denial of certiorari) 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 United States Forest Service ("USFS") regulations and did not satisfy certain "reality check" limitations contained in the Decree. On September 24, 2010, we filed a response to the motion for summary judgment responding that the plan of operations complied with USFS and BLM regulations and satisfied the reality check limitations. The U.S. Department of Justice also filed a response on behalf of the USFS and BLM asserting that the Court cannot second guess the USFS's determination that the plan of operations satisfied USFS and BLM regulations.

On November 24, 2010 the District Court Judge denied the Opposers's 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 Project

On March 8, 2008, High Country Citizens' Alliance ("HCCA") filed a request for hearing before the Colorado Mine Land Reclamation Board ("Board") of the approval of a "Notice of Intent to Conduct Prospecting" ("NOI") for the Mt. Emmons Project, which was approved by the Division of Reclamation, Mining and Safety of the Colorado Department of Natural Resources ("DRMS") on January 3, 2008. The approved NOI provides 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 1970s. On May 14, 2008, the MLRB denied HCCA's request for hearing and also denied its 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 MLRB'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 have both filed the responsive pleadings in addition to motions to dismiss the HCCA complaint.

On February 24, 2011, the District Court issued an order dismissing all of HCCA's claims concerning the appeal of the NOI holding that: (i) HCCA does not have standing to request judicial review on the merits of the DRMS's approval of the NOI and (ii) HCCA does not have standing to request a declaratory order. This decision upholds the Board's May 14, 2008 decision denying HCCA's request for hearing and its 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.

Appeal of Modification – Notice of intent to Conduct Prospecting for the Mt. Emmons Project

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 Board 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 Board on a 4-1 vote upheld DRMS's approval of MD-03 and its 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 District Court; this appeal is currently pending.

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 itself 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 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 anticipate filing with the court documents to change Energy One's status to an additional plaintiff.

Item 4 – Mine Safety Disclosures.

Not applicable.

PART II

Item 5 - Market for Registrant's Common Equity, Related Stockholder Matters, and Issuer Purchase of Equity Securities

Market Information

Shares of USE common stock are traded on the over-the-counter market, and prices are reported on a "last sale" basis on the Nasdaq Capital Market of the National Association of Securities Dealers Automated Quotation System ("Nasdaq"). Quarterly high and low sale prices follow:

	High	Low
Calendar year ended December 31, 2011		
First quarter ended 03/31/11	$ 6.60	$ 5.17
Second quarter ended 06/30/11	6.49	3.88
Third quarter ended 09/30/11	4.57	2.20
Fourth quarter ended 12/31/11	3.40	2.05
Calendar year ended December 31, 2010		
First quarter ended 03/31/10	$ 6.76	$ 5.14
Second quarter ended 06/30/10	7.06	4.67
Third quarter ended 09/30/10	5.43	4.01
Fourth quarter ended 12/31/10	6.17	4.37

Holders

At March 9, 2012 the closing market price was $3.34 per share. There were approximately 1,234 shareholders of record, with 27,409,908 shares of common stock issued and outstanding at December 31, 2011.

We paid a one-time special $0.10 per share cash dividend to common shareholders of record on July 6, 2007. There are no contractual restrictions on our present or future ability to pay cash dividends.

Issuance of Securities in 2011

During the twelve months ended December 31, 2011, USE issued a total of 341,298 shares. A brief discussion of the issuance of the shares follows:

Registered Securities

During the twelve months ended December 31, 2011, we issued 124,444 shares of common stock as a result of the exercise of options which had been issued to employees and 42,896 shares as a result of the exercise of warrants issued to outside directors. We also issued 98,958 shares pursuant to the terms of our ESOP. The ESOP funding represents the minimum required amount during the twelve months ended December 31, 2011.

The Company has an active registration statement for $100 million. During December 2009 we raised $26.2 million under this registration statement by issuing 5 million shares. A balance of $73.8 million is available under the registration statement which may be used in the future.

Unregistered Securities

During the twelve months ended December 31, 2011, we issued 75,000 shares pursuant to the 2001 Stock Award Plan; 20,000 shares to the CEO, COO and General Counsel and 15,000 shares to the former CFO prior to his retirement

Equity Plan Compensation Information - Information about Compensation Plans as of December 31, 2011

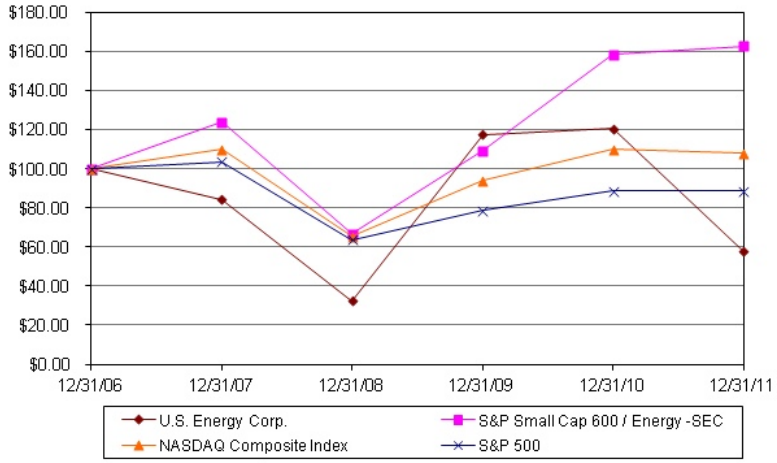
Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensaiton plans (excluding securities reflected in column (a)) (c)
Equity Compensation plans approved by security holders			
2001 Incentive Stock Option Plan	2,318,399	$ 3.94	--
2001 Stock Compensation Plan	(1)	(1)	(1)
2008 Stock Option plan for U.S. Energy Corp. Independent Directors and Advisory board members	110,000	$ 3.05	164,099
Equity compensation plans not approved by security holders	--	$ --	--
Total	2,428,399	$ 3.90	164,099

(1) Officers of the Company are eligible to receive 5,000 shares of common stock at the beginning of each calendar quarter or 20,000 shares per year each under this plan. The Company pays the taxes on these shares as the Officers have agreed to not pledge, sell or in any other way leverage these shares. The shareholders of the Company approved this plan.

Stock Performance Graph

The following graph compares the cumulative return on a $100 investment in our common stock for the five years ended December 31, 2011, to that of the cumulative return on a $100 investment in the S&P 500, the NASDAQ Market Index, and the S&P Small Cap 600 Energy Index. In calculating the cumulative return, we assumed reinvestment of the $0.10 per share cash dividend paid in July 2007. The indices are included for comparative purpose only. This graph is not "soliciting material," is not deemed filed with the SEC and is not to be incorporated by reference in any of our filings under the Securities Act of 1933 or the Exchange Act, whether made before or after the date the Annual Report was filed and irrespective of any general incorporation language in any such filing.

COMPARISON OF CUMULATIVE TOTAL RETURN AMONG U.S. ENERGY CORP., THE S&P 500, THE NASDAQ MARKET INDEX, AND THE S&P SMALL CAP 600 ENERGY INDEX



ITEM 6. SELECTED FINANCIAL DATA

The selected financial data is derived from and should be read with the financial statements included in this Report.

	(In thousands) December 31,				
	2011	2010	2009	2008	2007
Current assets	$ 37,136	$ 50,562	$ 85,300	$ 95,882	$ 94,500
Current liabilities	20,937	18,763	8,672	19,983	8,093
Working capital	16,199	31,799	53,428	75,899	86,407
Total assets	162,439	156,016	146,723	142,631	131,404
Long-term obligations [1]	13,532	1,150	973	1,870	1,283
Shareholders' equity	126,781	130,688	129,133	111,833	115,100

[1] Includes $510,000 of accrued reclamation costs on properties at December 31, 2011, $303,000, at December 31, 2010, $211,000, at December 31, 2009, $144,000, at December 31, 2008, and $133,000 at December 31, 2007.

	(In thousands except per share data) For the years ended December 31,				
	2011	2010	2009	2008	2007
Operating revenues	$ 30,110	$ 24,667	$ 7,581	$ 691	$ 1,174
Loss from continuing operations	(6,064)	(2,867)	(9,935)	(10,296)	(14,539)
Other income & expenses	131	1,549	(1,331)	(17)	108,824
Gain (loss) before minority interest, income taxes and discontinued operations	(5,933)	(1,318)	(11,266)	(10,313)	94,285
Minority interest in (income) loss of consolidated subsidiaries	--	--	--	--	(3,551)
Benefit from (provision for) income taxes	3,755	1,860	2,562	3,326	(32,367)
Discontinued operations, net of tax	(2,629)	(1,314)	526	5,599	(2,004)
Net (loss) income	$ (4,807)	$ (772)	$ (8,178)	$ (1,388)	$ 56,363
Per share financial data					
Operating revenues	$ 1.11	$ 0.92	$ 0.35	$ 0.03	$ 0.06
Loss from continuing operations	(0.22)	(0.11)	(0.46)	(0.44)	(0.71)
Other income & expenses	--	0.06	(0.06)	--	5.32
Gain (loss) before minority interest, income taxes and discontinued operations	(0.22)	(0.05)	(0.52)	(0.44)	4.61
Minority interest in income of consolidated subsidiaries	--	--	--	--	(0.17)
Benefit from (provision for) income taxes	0.14	0.07	0.12	0.14	(1.58)
Discontinued operations, net of tax	(0.10)	(0.05)	0.02	0.24	(0.10)
Net (loss) income per share basic	$ (0.18)	$ (0.03)	$ (0.38)	$ (0.06)	$ 2.76
Net (loss) income per share diluted	$ (0.18)	$ (0.03)	$ (0.38)	$ (0.06)	$ 2.54
Basic shares outstanding	27,238,869	26,763,995	21,604,959	23,274,978	20,469,846
Diluted shares outstanding	27,238,869	26,763,995	21,604,959	23,274,978	22,189,828

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

Forward Looking Statements

Statements in this discussion about expectations, plans and future events or conditions are forward looking statements. Actual future results, including oil and natural gas production growth, financing sources, and environmental and capital expenditures, could be materially different depending on a number of factors, such as: commodity prices, political or regulatory events, and other matters. Please see "Cautionary Statement Regarding Forward-Looking Statements" and Item 1A in this Report, which should be carefully considered in reading this section.

General Overview

In 2008, U.S. Energy Corp. ("U.S. Energy", "USE", the "Company", "we" or "us") began investing in oil and gas properties and expending the amount of capital necessary to place them into production with the intent of generating recurring cash flows, revenues and net income. Prior to 2008 the Company invested in mineral properties and sold them prior to placing them into production.

Our primary objective is to acquire and develop 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 and Louisiana, however, we do not intend to limit our focus to these geographic areas. We continue to focus on increasing production, reserves, revenue and cash flow from operations while managing our level of debt. Our liquidity and access to financing under our Credit Facility allows us to seek additional oil and gas opportunities in the U.S.

We explore for and produce oil and gas primarily through a non-operator business model; however, we operated our Colorado oil and gas property for our own account and may 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 spud, 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 project in Colorado. Gross capitalized dollar amounts invested in each of these areas at December 31, 2011 and December 31, 2010 were as follows:

	(In thousands)	
	December 31, 2011	December 31, 2010
Unproved oil and gas properites	$ 20,007	$ 21,620
Proved oil and gas properties	99,496	63,317
Undeveloped mining properties	20,739	21,077
	$ 140,242	$ 106,014

Oil & Gas Activities

In 2011, we had the following financial and operational results:

Revenue growth. In 2011, we recognized record revenues from oil and natural gas production of $31.0 million as compared to $26.5 million during the year ended December 31, 2010.

Reserve growth. As a result of our drilling programs discussed below, our proved reserves increased 63% to 3,195,361 BOE at December 31, 2011, replacing 280% of 2011 production.

Production. Our 2011 annual production was 442,360 BOE, or 1,212 BOE/d, as compared to 448,855 BOE, or 1,230 BOE/d in 2010.

Financial flexibility. In the third quarter of 2011, the borrowing base under the Credit Facility was redetermined and was increased from $22.5 million to $28.0 million. The commitment amount of the bank group remained unchanged at $75.0 million. At the end of 2011, we had $12.0 million outstanding under our credit facility. Subsequent to year end, we used a portion of the proceeds from the sale of 75% of our undeveloped acreage in the Yellowstone and SEHR prospects in the Williston Basin to repay the outstanding balance under the Credit Facility. See “Capital Resources - BNP Paribas Reserve Lending Facility” below.

Commodity prices. Our average realized oil price in 2011 was $87.80 per Bbl (excluding the impact of our economic hedges), or $15.69 higher than in 2010. Our average natural gas price realized during 2011 was $4.85 per Mcf, $0.11 per Mcf lower than the 2010 price of $4.96. Commodity prices are affected by changes in market demand, overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. Our financial results are significantly dependent on commodity prices, particularly oil prices, which are beyond our control and have been and are expected to remain volatile.

Through our wholly-owned affiliate Energy One LLC (“Energy One”), from time to time, we enter into commodity derivative contracts (“hedges”) with BNP Paribas, typically costless collars and fixed price swaps. U.S. Energy is a guarantor of Energy One’s obligations under the hedges. The objective of the hedging program 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, such use may limit our ability to benefit from favorable price movements. Energy One may 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.

Drilling programs. Our success is largely dependent on the results of our drilling programs. During the year ended December 31, 2011, we drilled 20 gross wells (4.10 net wells) comprised of: (a) twelve gross wells (2.65 net wells) in the Williston Basin, (b) seven gross wells (1.05 net wells) in the Gulf Coast and Texas drilling programs, and (c) one gross well (0.40 net wells) in the San Joaquin Basin of California. At December 31, 2011, 8 of these gross wells (1.76 net wells) were awaiting completion; 7 gross wells (1.62 net wells) in the Williston Basin and 1 gross well (0.14 net wells) in the onshore Gulf Coast area. Each of our programs is more fully described below:

Williston Basin, North Dakota

With Brigham Oil & Gas, L.P. We participate in fifteen 1,280 acre drilling units in the Rough Rider prospect with Brigham. From August 24, 2009 to December 31, 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 (0.18 net) under a Drilling Participation Agreement with Brigham. Two additional gross infill wells (0.35 net) were in progress at December 31, 2011 and were completed in the first quarter of 2012. Brigham operates all of the wells.

Under the Drilling Participation Agreement in 2011, the Company completed 4 gross wells (1.37 net) and drilled and completed one gross well (0.25 net) and drilled two gross wells (0.35 net) that were awaiting completion at December 31, 2011 with net capital costs related to these wells of $20.7 million for the period.

On December 15, 2011, the Company sold an undivided 75% of its undeveloped acres in the Rough Rider prospect to Brigham for $13.7 million. Under the terms of the agreement, the Company retained the remaining 25% of its interest in the undeveloped acreage and its original working interest in its 20 developed wells in the Rough Rider prospect. After the sale, our working interest in the undeveloped acreage in the Rough Rider Prospect ranges from 3.41% to 9.90%. In addition, Brigham also agreed to commence drilling operations for at least three gross wells in the Rough Rider acreage in each of 2012 and 2013. Drilling plans beyond 2013 are not known at this time.

In February 2011, Brigham announced that its interpretation of micro-seismic data from an 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 four Bakken and four 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 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 27 gross 1,280 acre spacing units (with various working interests of up to 35%), with the potential for 108 gross Bakken and 108 gross Three Forks wells (including wells already drilled) based on an assumed 4 wells per formation per unit. Through December 31, 2011, we acquired approximately 400 additional net acres in the Yellowstone Prospect from third parties for $329,000.

During 2011, we drilled 8 gross wells (2.18 net) with Zavanna. Three gross wells (0.90 net) were completed in 2011 and the remaining 5 gross wells (1.27 net) are expected to be completed in the first and second quarters of 2012. Our net investment in these wells as of December 31, 2011 was $17.5 million. Zavanna operates all of these wells.

Subsequent to December 31, 2011, but effective December 1, 2011, we sold an undivided 75% of its undeveloped acreage in the SE HR Prospect and the Yellowstone Prospect to GeoResources, Inc. (56.25%) and Yuma Exploration and Production Company, Inc. (18.75%) for $16.7 million (see note P, Subsequent Events, to the accompanying financial statements). Our working interest in the remaining locations will be approximately 8.75% and net revenue interests in new wells after the sale are expected to be in the range of 6.7375% to 7.0%, proportionately reduced depending on Zavanna's actual working interest percentages.

With Murex Petroleum Corporation. During 2011, we drilled and completed 2 gross wells (0.12 net) with Murex Petroleum Corporation. Our net investment in these wells as of December 31, 2011 was $1.2 million. 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 December 31, 2011, we had 5 gross producing wells (1.12 net) in this region.

During 2011, we drilled 4 gross wells (0.57 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 December 31, 2011 is $746,000. Three gross wells (0.40 net) were deemed to be non-productive and have been plugged and abandoned. Net costs to the Company as of December 31, 2011 for the abandoned wells were $1.0 million. One gross well (0.13 net) was in progress at December 31, 2011.

On October 27, 2011, we entered into an agreement with Yuma Exploration and Production Company, Inc. to sell our interest in the Livingston prospect in Louisiana for $1.0 million. We owned a 4.79% working interest in the prospect which included one gross producing well (0.05 net) (approximately 5 BOE/day net) and one additional gross development well (0.05 net) that was being completed at the time of the sale. Our total investment in the prospect was approximately $1.9 million including seismic, drilling, leasehold acquisition and other development costs.

San Joaquin Basin, California

Under an October 2010 agreement with Cirque, 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 was an advance against our 40% working interest for the initial well, including 33% of Cirque's 60% working interest share for the well. Cirque drilled this exploratory well in the fourth quarter of 2011 and determined it to be non-productive. Our net investment in this well as of December 31, 2011 was $2.1 million, including the $1.6 million advance that was paid in 2010. No further drilling is anticipated at this time.

Eagle Ford Shale, South Texas

In 2011, we entered into two participation agreements with Crimson to acquire an interest in oil prospects in Zavala and Dimmit Counties, Texas. Under the first agreement, we acquired a 30% working interest in the Leona River 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.

Under the second agreement, we acquired a 30% working interest in the Booth/Tortuga 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 115 gross BOE/D (20 net BOE/D) from the Austin Chalk formation.

Subsequent infill acquisitions bring our total acreage in the Eagle Ford oil window to approximately 13,785 gross acres (4,136 acres net to the Company). It is estimated under current spacing that there is a potential for up to 114 gross (34 net) drilling locations on the combined acreage.

The prospects are both Eagle Ford shale oil window targets and are operated by Crimson. The initial well on the first prospect (0.30 net) was drilled during the second and third quarters of 2011 and is now producing. Our net investment in this well at December 31, 2011 was $3.0 million. The initial well on the second prospect (0.30 net) was drilled in the fourth quarter of 2011 and completed in the first quarter of 2012. Our net investment in this well as of December 31, 2011 was $1.2 million.

Anadarko Basin, Southeast Colorado

On January 31, 2011, we entered into an acquisition, exploration and development agreement with a private party relating to 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 determined to be non-productive and has been plugged and abandoned. Our net cost in this well at December 31, 2011 was $417,000. No additional drilling is expected on this prospect.

Other

Minerals (molybdenum). The Mt. Emmons Project is located near Crested Butte, Colorado and includes a total of 160 fee acres, 25 patented and approximately 1,353 unpatented mining and mill site claims, which together approximate 9,920 acres, or over 15 square miles of claims and fee lands. Historical records filed by predecessor owners of the Mt. Emmons project with the Bureau of Land Management (BLM) in the 1990's for the application of patented mineral claims, referenced identification of mineral resources of approximately 220 million tons of 0.366% molybdic disulfide (MoS2) mineralization. A high grade section of the mineralization containing roughly 23 million tons at a grade of 0.689% MoS2 was also reported. No assurance can be given that these quantities of MoS2 exist or that the Company will be successful in permitting the property. Our net investment in this property at December 31, 2011 was $20.7 million.

Geothermal. We own a 22.4% interest in SST, a geothermal limited partnership. We recorded an equity loss from SST in 2011 of $173,000. Equity losses from the investment in SST are expected until such time as additional SST properties are sold, equity losses reduce the investment to zero or we sell the investment. Our net investment in this partnership at December 31, 2011 was $2.6 million. We have notified SST that we do not intend to fund any cash calls, which decision will result in a dilution of our ownership in SST if future cash calls are made.

Real estate – asset held for sale. We will continue to receive cash flows, revenues and net profits from our multifamily housing development in northeastern Wyoming until its sale. We do not plan to build or acquire any additional multifamily housing projects.

The principal factors affecting the Company are the success of its oil and gas exploration activities, commodity prices, drilling and completion costs, lease operating expenses, decline rates of our wells, mechanical and geological issues with our wells, the grade of mineral deposits, permitting and costs associated with exploration and development of the prospects.

Results of Operations

Year Ended December 31, 2011 Compared with the Year ended December 31, 2010

During the year ended December 31, 2011, we recorded a loss of $4.8 million or $0.18 per share basic and diluted, as compared to a loss of $772,000, or $0.03 per share, during the year ended December 31, 2010. The decrease in net earnings for 2011 as compared to 2010 is primarily due to (a) $5.5 million higher lease operating expenses in 2011 which included approximately $3.1 million in proportionate workover costs on one well, (b) $3.4 million higher oil and gas depletion expense, (c) a $3.1 million impairment in 2011 on the discontinued operations of our Remington Village project as compared to at $1.5 million impairment in 2010, (d) a 2010 equity gain of $1.0 million related to our investment in SST as compared to an equity loss of $211,000 in 2011, (e) $85,000 higher costs related to the operation of the Mt. Emmons water treatment plant and (f) $401,000 higher mineral holding costs for Mt. Emmons. These decreases in net earnings after taxes were offset by (a) $4.4 million higher revenues from oil and gas sales during 2011, (b) a deferred tax benefit of $3.8 million during the year ended December 31, 2011 as compared to a deferred tax benefit of $1.9 million during the year ended December 31, 2010, (c) $848,000 in realized and unrealized loss on risk management activities in 2011 as compared to a realized and unrealized loss of $1.9 million in the same period of 2010, (d) $712,000 lower general and administrative expenses and (e) $91,000 higher income from the sale of marketable securities.

We recognized $30.1 million in revenues during the year ended December 31, 2011 as compared to revenues of $24.7 million during same period in the prior year. Components of the change in operating revenues and results of operations for the year ended December 31, 2011 as compared to the year ended December 31, 2010 are as follows:

Oil and Gas Operations. Oil and gas operations produced net operating income of $4.6 million during the year ended December 31, 2011 as compared to net operating income of $8.0 million from oil and gas operations during the year ended December 31, 2010. The decrease in earnings from oil and gas operations is primarily due to $5.5 million higher lease operating expenses in 2011 which included approximately $3.1 million in proportionate workover costs on one well and $3.4 million higher oil and gas depreciation, depletion and amortization expense. This is partially offset by an increase in oil and gas revenues of $4.4 million and $848,000 in realized and unrealized loss on risk management activities in 2011 as compared to a realized and unrealized loss of $1.9 million in the same period of 2010. The following table details the results of operations from the oil and gas sector for the years ended December 31, 2011 and 2010:

	(In thousands) For the years ending	
	December 31, 2011	December 31, 2010
Oil and gas revenues	$ 30,958	$ 26,548
Realized (loss) from risk management activities	(1,974)	(156)
Unrealized gain (loss) from risk management activities	1,126	(1,725)
	30,110	24,667
Operating expenses	11,552	6,073
Depreciation, depletion and amortization	13,997	10,610
	25,549	16,683
Operating income	$ 4,561	$ 7,984

The following table summarizes production volumes, average sales prices and operating revenues for the years ended December 31, 2011 and 2010:

	Year Ended December 31,		Increase
	2011	2010	(Decrease)
Production volumes			
Oil (Bbls)	300,329	303,433	(3,104)
Natural gas (Mcf)	736,261	757,905	(21,644)
Natural gas liquids (Bbls)	19,325	19,104	221
Average sales prices			
Oil (per Bbl)	$ 87.80	$ 72.11	$ 15.69
Natural gas (per Mcf)	4.85	4.96	(0.11)
Natural gas liquids (per Bbl)	52.88	47.53	5.36
Operating revenues (in thousands)			
Oil	$ 26,368	$ 21,881	$ 4,487
Natural gas	3,568	3,759	(191)
Natural gas liquids	1,022	908	114
Total operating revenue	30,958	26,548	4,410
Lease operating expense	(8,450)	(3,056)	(5,394)
Production taxes	(3,102)	(3,017)	(85)
Risk management activities	(848)	(1,881)	1,033
Impairment	-	-	-
Income before depreciation, depletion and amortization	18,558	18,594	(36)
Depreciation, depletion and amortization	(13,997)	(10,610)	(3,387)
Income	$ 4,561	$ 7,984	$ (3,423)

During the year ended December 31, 2011, we produced approximately 442,360 barrels of oil equivalent (BOE), or an average of 1,212 BOE/day as compared to 448,855 BOE and 1,230 BOE/day during the year ended December 31, 2010. 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.

Our average net realized price for the year ended December 31, 2011, was $69.98 per BOE compared with $59.15 per BOE for the same period in 2010. The increase in our equivalent realized price for production corresponds with stronger oil prices in 2011 when compared with 2010.

Lease operating expense of $8.4 million for the year ended December 31, 2011 was comprised of $4.7 million in lease operating expense and $3.7 million in workover expense. Of the $3.7 million in workover expense, $3.1 million was related to one well. While there can be no assurance that we will not experience these types of workover costs in the future, we do not expect these high workover costs to occur regularly.

Our depletion, depreciation, and amortization (DD&A) rate for the year ended December 31, 2011 increased 34% percent to $31.64 per BOE compared to $23.64 per BOE for the same period in 2010. We have been impacted by higher DD&A rates related to our Williston Basin wells due to increases in drilling and completion costs for wells in this region. Our DD&A rate can also fluctuate as a result of impairments, divestitures, changes in the mix of our production, the underlying proved reserve volumes and estimated costs to drill and complete proved undeveloped reserves.

Mt. Emmons and Water Treatment Plant Operations. We recorded $1.9 million in costs and expenses for the water treatment plant and $486,000 for holding costs of the Mt. Emmons molybdenum property during the year ended December 31, 2011. During the year ended December 30, 2010, we recorded $1.8 million in operating costs related to the water treatment plant and $85,000 in holding costs. The increase in holding costs is directly as a result of Thompson Creek electing to terminate its agreement with us. As a result, we paid the majority of the holding costs related to Mt. Emmons in 2011 while Thompson Creek paid the majority of these costs in 2010. These costs are expected to be higher in 2012 because we will bear the increased share of the costs for the full year.

General and Administrative. General and administrative expenses decreased by $712,000 during the year ended December 31, 2011 as compared to general and administrative expenses for the year ended December 31, 2010. Lower general and administrative costs in 2011 are primarily a result of $916,000 lower accrued bonus compensation and were partially offset by $217,000 in higher bank fees related to our note on Remington Village and the Credit Facility.

Other income and expenses. During the year ended December 31, 2011, we had an equity loss of $211,000 related to our investment in SST. During the year ended December 31, 2010, as a result of the sale of two of SST's geothermal properties, we recorded an equity gain of $1.0 million from our investment in SST. Equity losses from the investment in SST are expected to continue until such time as additional SST properties are sold, equity losses reduce the investment to zero or we sell the investment.

We recorded a gain on sale of marketable securities of $529,000 during the year ended December 31, 2011 related to the sale of shares of Sutter Gold Mining, Inc. During the year ended December 31, 2010, we recorded a gain on sale of marketable securities of $438,000 related to the sale of shares of Sutter Gold Mining, Inc. and Kobex Resources, Inc.

We recorded a gain on sale of assets of $137,000 during the year ended December 31, 2011 primarily related to the sale of equipment. During the year ended December 31, 2010, we recorded a gain on sale of assets of $115,000. The gain was primarily related to the sale of an office building that we previously held as rental property.

Interest income decreased from $112,000 during the year ended December 31, 2010 to $40,000 during the year ended December 31, 2011. The decrease is a result of lower amounts of cash invested in interest bearing instruments and lower interest received on those investments.

Interest expense of $326,000 during the year ended December 31, 2011 was related primarily to the borrowings under the Credit Facility of $266,000 and $36,000 for the financing of a property purchased near the Mt. Emmons project.

Discontinued operations. We recorded a loss of $2.6 million, net of taxes from the discontinued operations of Remington Village during the year ended December 31, 2011 and a loss of $1.3 million, net of taxes for the year ended December 31, 2010. The decrease in income is primarily a result of a $3.1 million impairment recorded at December 31, 2011 as compared to an impairment of $1.5 million recorded at December 31, 2010, $323,000 higher interest expense in 2011 as compared to 2010 and $370,000 lower net tax affected operating income in the period ended December 31, 2011 as compared to the same period of 2010. This is partially offset by $946,000 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 a net loss after taxes of $4.8 million, or $0.18 per share basic and diluted, during the year ended December 31, 2011 as compared to a net loss after taxes of $772,000, or $0.03 per share basic and diluted, during the year ended December 31, 2010.

Year Ended December 31, 2010 Compared with the Year ended December 31, 2009

We recorded a net loss after taxes of $772,000 or $0.03 per share basic and diluted, for the year ended December 31, 2010 as compared to a net loss after taxes of $8.2 million, or $0.38 per share, during the year ended December 31, 2009.

We recognized $27.2 million in revenues during the year ended December 31, 2010 as compared to revenues of $10.3 million during same period in the prior year. Tabular representation of the increases in revenues as well as the income (loss) from operations for the years ended December 31, 2010 and 2009 was as follows:

	(In thousands) For the years ending December 31,	
	2010	2009
Revenues	$ 29,057	$ 10,349
Realized (loss) from risk management activities	(156)	--
Unrealized gain from risk management activities	(1,725)	--
	27,176	10,349
Operating expenses	17,738	13,086
Depreciation, depletion and amortization	12,130	5,066
Impairment	1,540	1,468
	31,408	19,620
Operating loss	$ (4,232)	$ (9,271)

The significant increase in revenues of $16.8 million for the year ended December 31, 2010 as compared to those revenues recorded during the prior year was primarily a result of production of oil and gas in the Williston Basin. The increased expenses were a result of the increases in lease operating, work over, and depletion costs recognized during the year ended December 31, 2010. During the year ended December 31, 2009, we recorded an impairment of $1.5 million on the oil and gas operations due to depressed gas prices and dry hole costs which had been capitalized. As a result of increased oil and gas prices during 2010 and additional reserves to amortize the full cost pool, no impairment of our oil and gas assets was required during the year ended December 31, 2010.

Oil and gas operations produced net operating income of $8.0 million during the year ended December 31, 2010 as compared to net operating income of $1.5 million from oil and gas operations during the year ended December 31, 2009. The following table details the results of operations from the oil and gas sector for the years ended December 31, 2010 and 2009:

	(In thousands) For the years ending December 31,	
	2010	2009
Oil and gas revenues	$ 26,548	$ 7,581
Realized (loss) from risk management activities	(156)	--
Unrealized gain (loss) from risk management activities	(1,725)	--
	24,667	7,581
Operating expenses	6,073	1,085
Depreciation, depletion and amortization	10,610	3,571
Impairment	--	1,468
	16,683	6,124
Operating income	$ 7,984	$ 1,457

The following table summarizes production volumes, average sales prices and operating revenues for the years ended December 31, 2010 and 2009:

	Year Ended December 31,		Increase
	2010	2009	(Decrease)
Production volumes			
Oil (Bbls)	303,433	80,461	222,972
Natural gas (Mcf)	757,905	467,691	290,214
Natural gas liquids (Bbls)	19,104	5,987	13,117
Average sales prices			
Oil (per Bbl)	$ 72.11	$ 66.22	$ 5.89
Natural gas (per Mcf)	4.96	4.30	0.66
Natural gas liquids (per Bbl)	47.53	40.25	7.28
Operating revenues (in thousands)			
Oil	$ 21,881	$ 5,328	$ 16,553
Natural gas	3,759	2,012	1,747
Natural gas liquids	908	241	667
Total operating revenue	26,548	7,581	18,967
Lease operating expense	(3,056)	(394)	(2,662)
Production taxes	(3,017)	(691)	(2,326)
Risk management activities	(1,881)	-	(1,881)
Impairment	-	(1,468)	1,468
Income before depreciation, depletion and amortization	18,594	5,028	13,566
Depreciation, depletion and amortization	(10,610)	(3,571)	(7,039)
Income	$ 7,984	$ 1,457	$ 6,527

Portions of our natural gas production are sent to gas processing plants to profitably extract from the gas various NGLs 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 NGLs and the remaining natural gas. In the table above, our share of processing costs are classified in lease operating expenses.

A breakdown of the 2010 and 2009 income from operations from commercial real estate is contained in the following table:

	(In thousands) For the years ending	
	December 31, 2010	December 31, 2009
Real estate revenues	$ 2,509	$ 2,768
Operating expenses	1,271	1,059
Interest expense	--	19
Depreciation, depletion and amortization	1,063	1,045
Impairment	1,540	--
	3,874	2,123
Operating income	$ (1,365)	$ 645

The decline in revenues for the year ended December 31, 2010 as compared to the prior year resulted from lower average rental rates, discounts provided and occupancy rates during the year ended December 31, 2010. Occupancy rates were approximately 80% at December 31, 2009 and 89% at December 31, 2010. Operating expenses increased as a result of the multifamily housing project reaching maturity which added additional expenses relating to grounds maintenance and ongoing maintenance of apartment units when property damage occurs or tenants move out. The property was appraised at December 31, 2010 and reflected a value of $21.0 million, resulting in a $1.5 million impairment.

Mt. Emmons Molybdenum Project. The Company pays all costs associated with the water treatment plant at the Mt. Emmons project and thereby recorded $1.8 million in costs and expenses for that facility and $85,000 in holding costs relating to the Mt. Emmons project during the year ended December 31, 2010. During the year ended December 31, 2009, we expended $1.6 million in operating costs related to the water treatment plant and $323,000 in holding costs for the Mt. Emmons project.

General and Administrative. General and administrative expenses decreased by $460,000 during the year ended December 31, 2010 as compared to general and administrative expenses for the year ended December 31, 2009.

Other income and expenses. As a result of the sale of two of SST's geothermal properties, we recorded an equity gain of $1.0 million from our investment in SST during the year ended December 31, 2010. We recorded an equity loss of $1.4 million for the year ended December 31, 2009. Equity losses from the investment in SST are expected to continue until such time as additional SST properties are sold, equity losses reduce the investment to zero or we sell the investment.

We recorded a gain on sale of marketable securities of $438,000 during the year ended December 31, 2010. The gain was related to the sale of shares of Sutter Gold Mining, Inc. and Kobex Resources, Inc. No similar gains were recorded in the prior year.

We recorded a gain on sale of assets of $115,000 during the year ended December 31, 2010. The gain was primarily related to the sale of an office building that we previously held as rental property. We recorded a loss on sale of assets of $43,000 during the year ended December 31, 2009.

Interest income decreased from $314,000 during the year ended December 31, 2009 to $112,000 during the year ended December 31, 2010. The decrease is a result of lower amounts of cash invested in interest bearing instruments and lower interest received on those investments.

Interest expense of $70,000 during the year ended December 31, 2010 was related primarily to the financing of a property purchased with Thompson Creek near the Mt. Emmons project. During the year ended December 31, 2009 we recorded interest expense of $98,000. The increase over the amount recorded in the year ended December 31, 2010 was primarily due to the construction loan for Remington Village which was fully repaid in January 2009.

We therefore recorded a net loss after taxes of $772,000, or $0.03 per share basic and diluted, during the year ended December 31, 2010 as compared to a net loss after taxes of $8.2 million, or $0.38 per share basic and diluted, during the year ended December 31, 2009.

Overview of Liquidity and Capital Resources

We maintained a strong liquidity position throughout the year ended December 31, 2011, notwithstanding significant investment in our oil and gas properties. The Company generated $2.5 million in cash flow from operations while maintaining strong liquidity ratios and cash balances. The following table sets forth key liquidity measures for the year ended December 31, 2011 as compared to the year ended December 31, 2010:

	(In thousands)	
	December 31, 2011	December 31, 2010
Current ratio[1]	1.77 to 1	2.69 to 1
Working capital[2]	$ 16,199	$ 31,799
Total debt	$ 12,400	$ 600
Total cash and marketable securities less debt	$ 640	$ 24,419
Total stockholders' equity	$ 126,787	$ 130,688
Total debt to equity	0.10 to 1	0.00 to 1

[1]Current assets divided by current liabilities
[2]Current assets less current liabilities

Capital Resources

We anticipate that cash flows from operations and proceeds from asset divestitures, such as the sale of 75% of our undeveloped Zavanna program acres to GeoResources and Yuma in January 2012, will fund the majority of our 2012 capital program. We plan to use our credit facility to fund the remaining portion of our capital program. Given the magnitude of the commitments associated with our existing inventory or potential drilling projects, our funding requirements could increase significantly in 2012 and beyond. As a result, we may consider accessing the capital markets, selling assets, entering into joint ventures and other financing alternatives as we determine the best options to fund our annual capital programs. All of our sources of liquidity can be impacted by the general condition of the broad economy and by significant fluctuations in oil and gas prices, operating costs and volumes produced. We have no control over the market prices for oil, natural gas, or NGLs, although we are able to influence the amount of our net realized revenues related to our oil and gas sales through the use of derivative contracts. Potential primary sources of future liquidity include the following:

Cash on Hand. At December 31, 2011, we had $12.9 million in cash and cash equivalents.

Oil and Gas Production. The Company's current sources of cash are expected to be provided by successful oil and gas wells. The ultimate amount of cash resources derived from the production of oil and gas will be determined by production volumes, the price of oil and gas, exploration and production costs. We plan to continue to explore for and develop oil and gas properties and may also acquire existing production.

To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we utilize derivative instruments to economically hedge future sales prices on a portion of our oil production. Our current strategy is to economically hedge up to 50% of our proved developed producing (PDP) volumes. The use of certain types of derivative instruments may prevent us from realizing the benefit of upward price movements. See "Item 1A. Risk Factors - *The use of hedging arrangements in oil and gas production could result in financial losses or reduce income."*

The following table is a summary of our estimated reserves as of December 31, 2011:

Estimated net proved reserves:	Bakken / Three Forks	Gulf Coast / Texas	Total
Producing:			
Oil (bbls)	1,466,406	60,934	1,527,340
Gas (Mcf)	996,647	648,200	1,644,847
NGL (bbls)	--	219	219
Developed non-producing:			
Oil (bbls)	326,093	30,635	356,728
Gas (Mcf)	239,606	89,000	328,606
NGL (bbls)	--	1,469	1,469
Undeveloped:			--
Oil (bbls)	853,930	--	853,930
Gas (Mcf)	760,595	--	760,595
NGL (bbls)	--	--	--
Total (BOE)	2,979,237	216,124	3,195,361
Future net income before income taxes	$ 130,426	$ 8,322	$ 138,748
PV-10	$ 66,154	$ 6,383	$ 72,537

Estimated proved reserves (on a BOE basis) at December 31, 2011 increased by 1,240,420 BOE or approximately 63% over estimated proved reserves at December 31, 2010. Most of the increase is related to our successful Williston Basin drilling program.

The reserve estimates are calculated by independent engineering firms in accordance with SEC rules. Estimated future net cash flows before income taxes are discounted at 10%. This value is not intended to represent the current market value of the reserves. Reserve estimates are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, oil and gas prices, and other factors.

Estimates of reserve volumes and future net cash flows are based on the average of first day of month prices during the year ended December 31, 2011 ($96.19 per barrel of oil and $4.12 per MMbtu of gas). Future estimated production taxes and ad valorem taxes, capital costs and operating costs are deducted from estimated future cash flows, and the result is discounted at an annual rate of 10% to determine "present value" ("PV10").

PV10 is widely used in the oil and gas industry, and is followed by institutional investors and professional analysts, to compare companies. However, the PV10 data is not an alternative to the standardized measure of discounted future net cash flows calculated under GAAP and in accordance with ASC 932-235-55, which includes the effects of income taxes. The following table provides a reconciliation of Estimated Future Net Revenues Discounted at 10% to the Standardized Measure of Discounted Future Net Cash Flows as shown in Note F to the Company's Consolidated Financial Statements.

	(In thousands) At December 31,		
	2011	2010	2009
Standardized measure of discounted net cash flows	$ 62,191	$ 44,653	$ 19,984
Future income tax expense (discounted)	10,346	7,420	5,776
PV-10	$ 72,537	$ 52,073	$ 25,760

BNP Paribas Reserve Credit Facility. On July 30, 2010, we established the Credit Facility, pursuant to which we may borrow up to $75 million (subject to a borrowing base as described below) from a syndicate of banks, financial institutions and other entities, including BNP. The Credit Facility may be used to further our short and mid-terms goals of increasing our investment in oil and gas. 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, which was originally established at $12 million. On September 6, 2011, the borrowing base was increased from $22.5 million to $28.0 million. The commitment amount of the bank group remained unchanged at $75.0 million. We believe that the current commitment amount is sufficient to meet our current liquidity and operating needs. To date, we have experienced no issues drawing upon the Credit Facility. We monitor the credit environment closely and have frequent discussions with the lending group. 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 of the Lenders, and any proposed borrowing base decrease will require approval by Lenders holding not less than two-thirds of outstanding loans and loan commitments. The borrowing base could be reduced as a result of lower commodity prices or divestitures of producing properties.

At December 31, 2011, we had $12.0 million outstanding under the Credit Facility. Subsequent to year end, we used a portion of the proceeds from the sale of 75% of our undeveloped acreage in the Yellowstone and SEHR prospects in the Williston Basin to repay the outstanding balance under the facility. As of January 27, 2011 we had no borrowings outstanding under the facility.

We are subject to customary covenants under our credit facility, including requirements to maintain certain financial ratios, which include debt to earnings, taxes, depreciation and amortization of less than 3.5 to 1.0 and a current ratio (as defined in the Credit Agreement) of not less than 1.0. During the year ended December 31, 2011 we were in compliance with all the covenants under the Credit Facility.

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. 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.

Asset Held for Sale – Remington Village. Until the Remington Village property is sold, we will continue to receive rental receipts from the property. The property averaged an occupancy rate of 87% during 2011 and was 82% occupied as of December 31, 2011. Occupancy is dependent on the regional economy, including local coal mining operations, which have been affected by the global recession. The property generated positive cash flow from operations of $1.0 million during 2011 and is projected to remain in that range during 2012. To maintain these levels of cash flow, occupancy rates will have to average 87% with costs and expenses similar to those experienced in 2011.

On May 5, 2011, we borrowed $10.0 million from a commercial bank against Remington Village. The note is amortized over 20 years with a balloon payment at the end of five years and has an interest rate of 5.50% per annum. The proceeds of the note are being used to fund our general business obligations.

Mt. Emmons Molybdenum Project. The Mt. Emmons Project is located near Crested Butte, Colorado and includes a total of 160 fee acres, 25 patented and approximately 1,353 unpatented mining and mill site claims, which together approximate 9,920 acres, or over 15 square miles of claims and fee lands.

See “Properties—Molybdenum—Mt. Emmons Project” for a description of the project. If permitted and placed into production, the project could provide the Company with long term capital resources.

Future Receipts of Royalties and Contractual Commitments from Uranium Properties. We retained a 4% net profits royalty on a portion of the Green Mountain uranium property in Wyoming which is owned by Rio Tinto, Inc. No assurance can be given as to when or if the property will be placed into production. Any royalty due will be based on the market price of uranium concentrates and the cost of producing those concentrates.

Pursuant to the terms of the 2007 sale of our uranium properties to sxr Uranium One Inc., we are entitled to receive $20 million when commercial production begins at the Utah uranium mill which the Company sold; $7.5 million when the first delivery of ore from any property sold by USE to sxr Uranium One Inc. to any commercial mill, after commercial production commences, from any of the uranium properties we sold; and a production royalty on the mill of up to $12.5 million. No assurance can be given as to if or when these events and payments will occur.

Capital Requirements

Our direct capital requirements during 2012 relate to 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, payment of debt obligations, operating and capital improvement costs of the water treatment plant at the Mt. Emmons project, operations at Remington Village until its sale and general and administrative costs. We intend to finance our 2012 capital expenditure plan primarily from the sources described above under “Capital Resources”. We may be required to reduce or defer part of our 2012 capital expenditures plan if we are unable to obtain sufficient financing from these sources. We regularly review our capital expenditure budget to assess changes in current and projected cash flows, acquisition opportunities, debt requirements and other factors.

Oil and Gas Exploration and Development. Expenditures for exploration and development of oil and gas properties and acquisitions are the primary use of our capital resources. We expect to spud approximately 27 gross and 4.7 net wells with capital expenditures of approximately $43.3 million in our 2012 oil and gas drilling program. We have allocated an estimated $18.4 million to be spent in the Williston Basin of North Dakota in the Rough Rider and Yellowstone/SEHR programs with Brigham and Zavanna, respectively. The remaining $24.9 million in capital expenditure is budgeted to be spent on

exploration initiatives in the Eagle Ford Basin with Crimson. Amounts budgeted for each regional drilling program is contingent upon timing, well costs and success. If our Eagle Ford drilling initiatives are not initially successful, funds allocated for those drilling programs 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. The Company is responsible for all costs associated with the Mt. Emmons project, which includes operation of a water treatment plant. Annual water treatment plant operating costs during 2012 are projected to be approximately $1.8 million. Additionally, we have budgeted $866,000 for mining claims fees, permitting and water treatment plant capital improvements which are expected to improve the plant's efficiency and reduce costs.

In January 2009, an additional 160 acres of fee land in the vicinity of the claims was purchased by the Company and TCM for $4 million ($2 million in January 2009, $400,000 annually for five years). On December 6, 2011, TCM notified the Company that it wishes to sell its interest in the property. The Company has 18 months to decide whether to purchase TCM's interest in the property, at TCM's cost, and close such purchase.

Real Estate. Until it is sold, we will incur operating expenses at Remington Village. Cash operating expenses are projected to be $1.1 million for 2012. In addition, we have budgeted $300,000 for capital improvements at Remington Village. The property is pledged as collateral for the $10 million commercial real estate note. In 2011 we made the decision sell the property and use the proceeds to further our oil and gas exploration and development projects.

Insurance. We have liability insurance coverage in amounts deemed 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.

Reclamation Costs. We have reclamation obligations of $361,000 related to our oil and gas wells and $149,000 related to the Mt. Emmons molybdenum property. One depleted oil and gas well in Louisiana is expected to be plugged and abandoned in 2012 at a projected net cost to the Company of $46,000. No additional reclamation is expected to be performed during the year ended December 31, 2012 unless a well, or wells, are abandoned due to unexpected operational challenges. Reclamation will only begin after the wells no longer produce oil or gas in economic quantities. 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, upon closure of the proposed mine at the Mt. Emmons project, is to eliminate long-term liabilities associated with the property.

Overview of Cash Flow Activities

The following tables summarize the provision and use of cash in Operations, Investing Activities and Financing Activities for the years ended December 31, 2011, 2010 and 2009:

	(In thousands) For the years ending December 31,		
	2011	2010	2009
Cash provided by operations	$ 2,567	$ 11,395	$ 980
Cash provided by (used in) investing activities	(17,775)	(39,835)	17,283
Cash provided by financing activities	21,558	94	5,267

	(In thousands) For the years ending December 31,		
	2011	2010	2009
Net increase (decrease) in cash and cash equivalents	$ 7,062	$ (27,591)	$ 24,969
Net (redemption) investment in U.S. Treasury investments	(17,843)	(4,293)	(29,277)
Net change in cash and U.S. Treasuries	$ (10,781)	$ (31,884)	$ (4,308)

Investments of surplus cash were held in U.S. Treasuries with maturity dates in excess of 90 days and were therefore classified as Held to Maturity Marketable Securities for financial presentation purposes under Generally Accepted Accounting Practices (“GAAP”) in the United States of America. The proceeds were used as needed to fund operations and capital projects, and accordingly are presented in the above table with cash and cash equivalents to clarify the net change in ready liquid assets. A description of the provision of and use of cash in Operations, Investing Activities and Financing Activities for the year ended December 31, 2011 follows:

Operating Activities. Cash provided by operations for the year ended December 31, 2011 decreased to $2.6 million as compared to $11.4 million for the same period of the prior year. This $8.8 million year over year decrease in cash from operating activities is predominantly a result of $5.4 million higher lease operating expenses and a $3.4 million reduction in accounts payable for the year ended December 31, 2011 as compared to the year ended December 31, 2010. The remainder of the changes in cash provided by operations is part of the complete discussion of cash provided by operations in “Results of Operations” above.

Investing Activities. Investing activities consumed $50.3 million in cash through the acquisition and development of oil and gas properties during the year ended December 31, 2011 (including $2.1 million in accounts payable at December 31, 2011). Other uses of cash for investing activities in the period were the acquisition and development of mining properties in the amount of $221,000, the acquisition of property and equipment in the amount of $42,000 and an $11,000 change in restricted investments.

Investing activities provided cash during the year ended December 31, 2011 through the maturity or redemption of $17.8 million of treasury investments which were used to fund the purchase of oil and gas properties and advance drilling programs on existing prospects, $846,000 from the proceeds on the sale of shares of Sutter Gold Mining, Inc., $354,000 from the last payment received on the Mt. Emmons property from Thompson Creek, and $147,000 in proceeds from the sale of property and equipment.

Financing Activities. Financing activities consumed $11.5 million during the year ended December 31, 2011 through $11.4 million in repayments of debt and $146,000 net from the exercise of employee options and non-employee director warrants (the Company received $95,000 in proceeds from the exercise of options by employees and warrants by a director and paid taxes of $241,000 as a result of the cashless exercise of options by employees).

Financing activities provided $33.1 million during the year ended December 31, 2011 from a combination of the borrowing of $23.0 million under the Credit Facility and the borrowing of $10.0 million from a commercial bank.

Critical Accounting Policies

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 Company's 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 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.

Full cost pool capitalized costs are amortized over the life of production of proven properties. Capitalized costs at December 31, 2011 and December 31, 2010 which were not included in the amortized cost pool were $20.0 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 and are related to unproved properties. No capitalized costs related to unproved properties are included in the amortization base at December 31, 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.

Ceiling Test. We perform a quarterly ceiling test for each of our oil and gas cost centers, of which in 2011 and 2010 there was only one. The ceiling test incorporates 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 year ended December 31, 2011, the Company used $96.19 per barrel for oil and $4.12 per MMbtu for natural gas to compute the future cash flows of the Company's producing property. The discount factor used was 10%.

At December 31, 2011, the ceiling was in excess of the net capitalized costs as adjusted for related deferred income taxes and no impairment was required. Furthermore, as of year-end there were no unproved properties that were considered to be impaired and reclassified to properties being amortized. Management will continue to review its 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.

Derivative Instruments. We use derivative instruments, typically fixed-rate swaps and costless collars, to manage price risk underlying its 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 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, 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. The master contracts with approved counterparties identify the CEO and President as Company representatives authorized to execute trades. See Note D, Commodity Price Risk Management, for further discussion.

Proved Reserves. Our estimates of proved reserves are based on quantities of oil and gas reserves which current engineering data indicates are recoverable from known reservoirs under existing economic and operating conditions. Estimates of proved reserves are key elements in determining our depletion expense and our full cost ceiling limitation. Estimates of proved reserves are inherently imprecise because of uncertainties in projecting rates of production and timing of developmental expenditures, interpretations of geological, geophysical, engineering and production data and the quality and quantity of available data. Changing economic conditions also may affect our estimates of proved reserves due to changes in developmental costs and changes in commodity prices that may impact reservoir economics. We utilize independent reserve engineers to estimate our proved reserves annually.

On December 29, 2008, the SEC issued a revision to Staff Accounting Bulletin 113 ("SAB 113") which established guidelines related to modernizing accounting and disclosure requirements for oil and natural gas companies. The revised disclosure requirements include provisions that permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. The revised rules also allow companies the option to disclose probable and possible reserves in addition to the existing requirement to disclose proved reserves. The revised disclosure requirements also require companies to report the independence and qualifications of third party preparers of reserves and file reports when a third party is relied upon to prepare reserves estimates. A significant change to the rules involves the pricing at which reserves are measured. The revised rules utilize a 12-month average price using first of the month pricing during the 12-month period prior to the ending date of the balance sheet to report oil and natural gas reserves rather

than year-end prices. In addition, the 12-month average is used to measure ceiling test impairments and to compute depreciation, depletion and amortization. The revised rules became effective for reserve estimation at December 31, 2009 with first reporting for calendar year companies in their 2009 annual reports.

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 December 31, 2011 and December 31, 2010 reflect capitalized costs associated with the Mt. Emmons project near Crested Butte, Colorado. We review our investment in the Mt. Emmons project annually to determine if an impairment has occurred to the carrying value of the property. With the reduction of the book value of Mt. Emmons by $3.4 million as a result of option payments by TCM and, taking into account the decrease in the market price for Molybdenum Oxide from $16.60 per pound at December 31, 2010 to $13.25 per pound at December 31, 2010, we have determined that no impairment is needed to the book value of the property.

Assets Held for Sale. 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.

Use of Estimates. The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions. These estimates and assumptions affect the reported amounts of assets and liabilities and 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. Actual results could differ from those estimates. 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.

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.

Revenue Recognition. We record 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 based on our interest in the properties. Gas balancing obligations as of December 31, 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.

Stock Based Compensation. We measure the cost of employee services received in exchange for all equity awards granted, including stock options, based on the fair market value of the award as of the grant date.

We recognize the cost of the equity awards over the period during which an employee is required to provide service in exchange for the award, usually the vesting period. As share-based compensation expense is recognized based on awards ultimately expected to vest, the expense has been reduced for estimated forfeitures based on historical forfeiture rates.

Income Taxes. We recognize deferred income tax assets and liabilities for the expected future income tax consequences, based on enacted tax laws, of temporary differences between the financial reporting and tax bases of assets, liabilities and carry forwards.

We recognize deferred tax assets for the expected future effects of all deductible temporary differences, loss carry forwards and tax credit carry forwards. Deferred tax assets are reduced, if deemed necessary, by a valuation allowance for any tax benefits which, based on current circumstances, are not expected to be realized. Management believes it is more likely than not that such tax benefits will be realized and a valuation allowance has not been provided.

Future Operations

We intend to acquire new oil and gas properties and pursue new business opportunities. Long term, we intend to be prepared to pay the holding and development costs associated with the Mt. Emmons project.

Effects of Changes in Prices

Natural resource operations are significantly affected by changes in commodity prices. As prices for a particular mineral increase, values for that mineral 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 those natural resources, but could make sales of such properties more difficult. Operational impacts of changes in mineral commodity prices are common in the natural resource business. Historical and current prices for the Company's two main natural resource participation interests follow:

Oil and Gas. The ten year Cushing, OK WTI spot price for oil reached a high of $145.31 per barrel during July 2008 and a ten year low of $18.02 per barrel during January of 2002. As of December 31, 2011 the Cushing, OK WTI spot price for oil was $98.83 per barrel.

The ten year U.S. Natural Gas City Gate Price reached a high of $12.48 per Mcf in July of 2008 and the ten year low was $3.67 per Mcf in August 2002. The price per Mcf at December 31, 2011 was $5.03.

Higher oil and gas prices should positively impact our revenues going forward while lower oil and gas prices will have a negative impact not only on revenues, cash flows and profitability but also may impact ultimate reserve calculations for our wells. There is no assurance that our projected 2012 investments in oil and gas properties will be profitable.

Molybdenum. The ten year high for dealer molybdenum oxide was $38.00 per pound in June of 2005 and the ten year low was $8.03 per pound in April of 2009. The mean price of molybdenum oxide at December 31, 2011 and December 31, 2010 was $13.37 per pound and $16.60 per pound, respectively. The price of molybdenum will have a direct impact on the development of Mt. Emmons project.

Contractual Obligations

We had three principal categories of contractual obligations at December 31, 2011: Debt to third parties of $22.3 million, executive retirement obligations of $946,000 and asset retirement obligations of $510,000. The debt consists of debt to a commercial bank secured by the Remington Village Apartments, debt related to our oil and gas reserves and debt for 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 3.07% per annum and the land debt bears an interest rate of 6.0% per annum. The debt to the commercial bank is amortized over 20 years with a balloon payment due at the end of five years on May 5, 2016. The balloon payment at maturity is $8.8 million. The oil and gas debt at December 31, 2011 of $12.0 million was for a term of six months with principal and accrued interest due in April 2012 (and could be continued, at our election, if we remain in compliance with the covenants under the Credit Facility through July 30, 2014). We repaid this $12.0 million in debt in January 2012 and there are no borrowings outstanding under the Credit Facility as of the filing date of this report. The $400,000 land debt is due in two equal annual payments of $200,000, plus accrued interest. The next payment is due on January 2, 2013. 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 as of December 31, 2011. This table reflects the debt obligation on the Remington Village Apartments pursuant to the 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	$ 22,304	$ 481	$ 13,153	$ 8,670	$ --
Executive retirement	946	125	327	163	331
Asset retirement obligation	510	46	23	14	427
Totals	$ 23,760	$ 652	$ 13,503	$ 8,847	$ 758

Item 7A – 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. A 10% fluctuation in the price received for oil and natural gas production would have an approximate $3.0 million impact on our 2011 annual revenues.

To mitigate some of our commodity risk, we use derivative instruments, typically fixed-rate swaps and costless collars, to manage price risk. 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, such use may limit our ability to benefit from favorable price movements. We 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 existing positions.

Through our wholly-owned affiliate Energy One, we have entered into commodity derivative contracts ("economic hedges") with BNP Paribas, as described below. The 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 December 31, 2011 are summarized below:

Settlement Period	Counterparty	Basis	Quantity (Bbl/d)	Strike Price		
Crude Oil Costless Collar						
10/01/11 - 09/30/12	BNP Parabis	WTI	400	Put:	$	80.00
				Call:	$	99.00
Crude Oil Costless Collar						
01/01/12 - 12/31/12	BNP Parabis	WTI	200	Put:	$	90.00
				Call:	$	106.50

The following table reflects commodity derivative contracts entered into subsequent to December 31, 2011:

Settlement Period	Counterparty	Basis	Quantity (Bbl/d)	Strike Price		
Crude Oil Costless Collar						
10/01/12 - 09/30/13	BNP Parabis	WTI	200	Put:	$	95.00
				Call:	$	116.60

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

	As of December 31, 2011 (in thousands)			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
Crude oil costless collars	Current Asset	$ 3	Current Liability	$ 601

These contracts are accounted for using the mark-to-market accounting method and accordingly, USE recognizes 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. The net loss realized by us related to these instruments was $2.0 million, $156,000 and $0 for the years ended December 31, 2011, 2010 and 2009, respectively.

Interest Rate Risk. At December 31, 2011, we had long-term debt of $12.4 million, of which $400,000 was at a fixed rate of 6.0% and $12.0 million was at a variable rate pursuant to our Credit Facility. The interest rate that we pay on amounts borrowed under the Credit Facility is derived from the Eurodollar rate and a margin that is applied to the Eurodollar rate. The margin that we pay is based upon the percentage of our available borrowing base that we utilize at the beginning of the quarter. At December 31, 2011, the borrowing base for the Credit Facility was $28.0 million. At December 31, 2011 we had utilized $12.0 million, or 43%, of the borrowing base. At this level of utilization, the Credit Facility requires us to pay a margin of 2.50%. Our all-in interest rate at December 31, 2011 was 3.07%. A 10% increase in the Eurodollar rate would equal approximately six basis points. Such an increase in the Eurodollar rate would change our annual interest expense by approximately $17,000, assuming amounts borrowed under our Credit Facility equaled our total potential borrowing base of $28.0 million as of December 31, 2011.

Item 8 – Financial Statements

Financial statements meeting the requirements of Regulation S-X are included below.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
U.S. Energy Corp.

We have audited the accompanying consolidated balance sheets of U.S. Energy Corp. and subsidiaries as of December 31, 2011 and 2010, and the related consolidated statements of operations, shareholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of U.S. Energy Corp. and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), U.S. Energy Corp.'s and subsidiaries' internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 14, 2012 expressed an unqualified opinion on the effectiveness of U.S. Energy Corp.'s internal control over financial reporting.

HEIN *& ASSOCIATES LLP*

Denver, Colorado
March 14, 2012

U.S. ENERGY CORP.
CONSOLIDATED BALANCE SHEETS
ASSETS
(In thousands, except shares)

	December 31, 2011	December 31, 2010
Current assets:		
Cash and cash equivalents	$ 12,874	$ 5,812
Marketable securities		
Held to maturity - treasuries	--	17,843
Available for sale securities	166	1,364
Accounts receivable		
Trade	5,496	3,890
Reimbursable project costs	--	114
Income taxes	113	104
Commodity risk management asset	3	--
Assets held for sale	18,132	20,979
Other current assets	352	456
Total current assets	37,136	50,562
Investment	2,623	2,834
Properties and equipment		
Oil & gas properties under full cost method,		
net of $28,561 and $14,563 accumulated		
depletion, depreciation and amortization	90,942	70,374
Undeveloped mining claims	20,739	21,077
Property, plant and equipment, net	9,196	9,336
Net properties and equipment	120,877	100,787
Other assets	1,803	1,833
Total assets	$ 162,439	$ 156,016

The accompanying notes are an integral part of these statements.

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

	December 31, 2011	December 31, 2010
Current liabilities:		
Accounts payable	$ 9,370	$ 14,830
Accrued compensation	501	1,669
Commodity risk management liability	601	1,725
Current portion of debt	200	200
Liabilities held for sale	10,241	323
Other current liabilities	24	16
Total current liabilities	20,937	18,763
Long-term debt, net of current portion	12,200	400
Deferred tax liability	1,189	5,015
Asset retirement obligations	510	303
Other accrued liabilities	822	847
Commitment and contigencies (Note N)	--	--
Shareholders' equity		
Common stock, $.01 par value; unlimited shares authorized; 27,409,908 and 27,068,610 shares issued, respectively	274	271
Additional paid-in capital	122,523	121,062
Accumulated surplus	3,906	8,713
Unrealized gain on marketable securities	78	642
Total shareholders' equity	126,781	130,688
Total liabilities and shareholders' equity	$ 162,439	$ 156,016

The accompanying notes are an integral part of these statements.

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

	Years ended December 31,		
	2011	2010	2009
Operating revenues:			
Oil, gas, and NGL production revenue	$ 30,958	$ 26,548	$ 7,581
Realized (loss) on risk management activities	(1,974)	(156)	--
Unrealized gain/(loss)on risk management activities	1,126	(1,725)	--
	30,110	24,667	7,581
Operating expenses:			
Oil and gas	11,552	6,073	3,611
Oil and gas depreciation, depletion and amortization	13,997	10,610	1,045
Impairment of oil and gas properties	--	--	1,468
Water treatment plant	1,878	1,793	1,636
Mineral holding costs	486	85	323
General and administrative	8,261	8,973	9,433
	36,174	27,534	17,516
Loss from operations	(6,064)	(2,867)	(9,935)
Other income and expenses:			
Gain/(loss) on the sale of assets	137	115	(43)
Equity (loss)/gain in unconsolidated investment	(211)	1,014	(1,374)
Gain on sale of marketable securities	529	438	--
Miscellaneous income and (expenses)	(38)	(60)	(130)
Interest income	40	112	314
Interest expense	(326)	(70)	(98)
	131	1,549	(1,331)
Loss before income taxes and discontinued operations	(5,933)	(1,318)	(11,266)

The accompanying notes are an integral part of these statements.

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

	Years ended December 31,		
	2011	2010	2009
Income taxes:			
Current benefit from (provision for)	--	104	210
Deferred benefit from (provision for)	3,755	1,756	2,352
	3,755	1,860	2,562
(Loss) income from continuing operations	(2,178)	542	(8,704)
Discontinued operations:			
Discontinued operations, net of taxes	434	226	526
Impairment on discontinued operations	(3,063)	(1,540)	--
	(2,629)	(1,314)	526
Net loss	$ (4,807)	$ (772)	$ (8,178)
Net loss per share			
(Loss) income from continuing operations, basic	$ (0.08)	$ 0.02	$ (0.40)
(Loss) income from discontinued operations, basic	(0.10)	(0.05)	0.02
Net (loss) income, basic	$ (0.18)	$ (0.03)	$ (0.38)
(Loss) income from continuing operations, diluted	$ (0.08)	$ 0.02	$ (0.40)
(Loss) income from discontinued operations, diluted	(0.10)	(0.05)	0.02
Net loss, basic and diluted	$ (0.18)	$ (0.03)	$ (0.38)
Weighted average shares outstanding			
Basic	27,238,869	26,763,995	21,604,959
Diluted	27,238,869	26,763,995	21,604,959

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP
STATEMENT OF SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME
(In thousands except share data)

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Retained Earnings	Unrealized Gain (Loss) on Marketable Securities	Total Shareholders' Equity
Balance January 1, 2009	21,935,129	$ 219	$ 93,951	$ 17,663	$ --	$ 111,833
Net loss available to common shareholders	--	--	--	(8,178)	--	(8,178)
Unrecognized gain on marketable securities	--	--	--	--	602	602
Unrealized tax effect on the unrealized gain	--	--	--	--	(216)	(216)
Comprehensive (loss)						(7,792)
Issuance of common stock	5,000,000	50	24,267	--	--	24,317
Funding of ESOP	36,583	--	217	--	--	217
Issuance of common stock 2001 stock compensation plan	80,000	1	185	--	--	186
Issuance of common stock from stock warrants	71,088	1	232	--	--	233
Issuance of common stock from stock options	1,984	--	5	--	--	5
Vesting of stock options issued to employees	--	--	1,430	--	--	1,430
Vesting of stock warrants to outside contractor	--	--	9	--	--	9
Vesting of stock options issued to outside directors	--	--	56	--	--	56
Excess tax benefit on the exercise stock options and warrants	--	--	38	--	--	38
Common stock buy back program	(706,071)	(7)	(1,392)	--	--	(1,399)
Balance December 31, 2009	26,418,713	264	118,998	9,485	386	129,133

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP
STATEMENT OF SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME
(continued)
(In thousands except share data)

	Common Stock		Additional Paid-In Capital	Retained Earnings	Unrealized Gain (Loss) on Marketable Securities	Total Shareholders' Equity
	Shares	Amount				
Balance December 31, 2009	26,418,713	264	118,998	9,485	386	129,133
Net loss	--	--	--	(772)	--	(772)
Unrecognized gain on marketable securities	--	--	--	--	400	400
Unrealized tax effect on the unrealized gain	--	--	--	--	(144)	(144)
Comprehensive (loss)						(516)
Funding of ESOP	42,802	--	260	--	--	260
Issuance of common stock 2001 stock compensation plan	80,000	1	429	--	--	430
Issuance of common stock from stock options	275,728	3	(455)	--	--	(452)
Issuance of common stock from stock warrants	251,367	3	743	--	--	746
Vesting of stock options	--	--	1,021	--	--	1,021
Vesting of stock warrants	--	--	66	--	--	66
Balance December 31, 2010	27,068,610	271	121,062	8,713	642	130,688

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP
STATEMENT OF SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME
(continued)
(In thousands except share data)

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Retained Earnings	Unrealized Gain (Loss) on Marketable Securities	Total Shareholders' Equity
Balance December 31, 2010	27,068,610	271	121,062	8,713	642	130,688
Net loss	--	--	--	(4,807)	--	(4,807)
Recognized gain on marketable securities	--	--	--	--	(850)	(850)
Unrecognized gain on marketable securities	--	--	--	--	(30)	(30)
Unrealized tax effect on the unrealized gain	--	--	--	--	316	316
Comprehensive (loss)						(5,371)
Funding of ESOP	98,958	1	287	--	--	288
Issuance of common stock 2001 stock compensation plan	75,000	1	369	--	--	370
Issuance of common stock from stock options	124,444	1	(209)	--	--	(208)
Issuance of common stock from stock warrants	42,896	--	61	--	--	61
Vesting of stock options	--	--	947	--	--	947
Vesting of stock warrants	--	--	6	--	--	6
Balance December 31, 2011	27,409,908	$ 274	$ 122,523	$ 3,906	$ 78	$ 126,781

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	(In thousands) For the years ended December 31,		
	2011	2010	2009
Cash flows from operating activities:			
Net (loss)	$ (4,807)	$ (772)	$ (8,178)
Loss (income) from discontinued operations includes non-cash impairment of $3,063, $1,540, and $0	2,629	1,314	(526)
(Loss) income from continuing operations	(2,178)	542	(8,704)
Adjustments to reconcile net (loss) income to net cash provided by operations			
Depreciation, depletion & amortization	14,593	11,184	4,135
Change in fair value of commodity price risk management activities, net	(1,126)	1,725	--
Accretion of discount on treasury investment	--	(78)	(183)
Impairment of oil and gas properties	--	--	1,468
Gain on sale of marketable securities	(529)	(438)	--
Equity (gain)/loss from Standard Steam	211	(1,014)	1,374
Net change in deferred income taxes	(3,990)	(1,533)	(2,207)
(Gain) on sale of assets	(137)	(115)	43
Noncash compensation	1,604	1,710	1,935
Noncash services	6	66	65
Net changes in assets and liabilities			
Accounts receivable	(1,493)	(174)	(2,858)
Income tax receivable	(9)	249	5,543
Other current assets	148	(386)	(192)
Accounts payable	(3,368)	(498)	71
Accrued compensation expense	(1,194)	6	1,000
Other liabilities	29	149	(510)
Net cash provided by operating activities	2,567	11,395	980
Cash flows from investing activities:			
Net redemption of treasury investments	17,843	4,293	29,277
Cash distributions from (investment in) Standard Steam	--	1,138	(877)
Acquisition & development of real estate	--	--	(3)
Acquisition & development of oil & gas properties	(50,265)	(45,933)	(17,498)
Acquisition & development of mining properties	(221)	(123)	(1)
Mining property option payment	354	1,000	2,000
Acquisition of property and equipment	(42)	(624)	(277)
Proceeds from sale of oil and gas properties	13,574	--	--
Proceeds from sale of marketable securities	846	602	--
Proceeds from sale of property and equipment	147	142	11
Net change in restricted investments	(11)	(330)	4,651
Net cash (used in) provided by investing activities:	(17,775)	(39,835)	17,283

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	(In thousands) For the years ended December 31,		
	2011	2010	2009
Cash flows financing activities:			
Issuance of common stock	(146)	294	24,516
Tax benefit from the exercise of stock options	--	--	38
Proceeds from new debt	33,069	--	--
Repayments of debt	(11,365)	(200)	(17,888)
Stock buyback program	--	--	(1,399)
Net cash provided by financing activities	21,558	94	5,267
Net cash provided by operating activities of discontinued operations	767	779	1,572
Net cash used in investing activities of discontinued operations	(55)	(24)	(133)
Net increase (decrease) in cash and cash equivalents	7,062	(27,591)	24,969
Cash and cash equivalents at beginning of period	5,812	33,403	8,434
Cash and cash equivalents at end of period	$ 12,874	$ 5,812	$ 33,403
Supplemental disclosures:			
Income tax received	$ --	$ (353)	$ (5,753)
Interest paid	$ 290	$ 22	$ 39
Non-cash investing and financing activities:			
Unrealized gain	$ 78	$ 642	$ 386
Acquisition and development of oil and gas properties through accounts payable	$ 2,092	$ 8,983	$ 5,522
Acquisition and development of oil and gas through asset retirement obligations	$ 186	$ 75	$ 58

The accompanying notes are an integral part of these statements.

Table of Contents

A. BUSINESS ORGANIZATION AND OPERATIONS

U.S. Energy Corp. was incorporated in the State of Wyoming on January 26, 1966. U.S. Energy Corp. ("USE") engages in the acquisition, exploration and development of oil and gas properties and the exploration, holding, sale and/or development of mineral properties. Principal asset interests at December 31, 2011 are in oil and gas, molybdenum, real estate and minority ownership in a geothermal partnership.

B. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP 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.

Principles of Consolidation

The financial statements of USE as of December 31, 2011 and 2010 include the accounts of USE and its wholly owned subsidiaries Energy One, LLC (“Energy One”) and Remington Village, LLC (“Remington Village”). The consolidated financial statements as of December 31, 2009 include USE and Remington Village. All inter-company balances and transactions have been eliminated in consolidation. The financial statements as of December 31, 2011, 2010 and 2009 reflect USE’s ownership in a geothermal partnership, Standard Steam Trust LLC (“SST”) which is accounted for using the equity method. At December 31, 2011 USE’s ownership interest in SST was 22.4%.

Cash and Cash Equivalents

USE considers all highly liquid investments with original maturities of three months or less to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value due to the short-term nature of these instruments. USE maintains its cash and cash equivalents in bank deposit accounts which exceed federally insured limits. USE has not experienced any losses in such accounts and believes the accounts are not exposed to any significant credit risk on cash and cash equivalents.

Marketable Securities

USE categorizes its marketable securities as available-for-sale or held-to-maturity. Increases or decreases in the fair value which are considered temporary are recorded within equity as comprehensive income or losses. Gains or losses as a result of sale are recorded in operations when realized. As of December 31, 2011 and 2010 USE had unrealized gains in the marketable securities before tax effect of $122,000 and $1.0 million, respectively.

Table of Contents

Accounts Receivable

USE determines any required allowance by considering a number of factors including the length of time trade and other accounts receivable are past due and our previous loss history. USE provides reserves for account receivable balances when they become uncollectable. Payments subsequently received on such reserved receivables are credited to the allowance for doubtful accounts. During the years ended December 31, 2011 and 2010, USE recorded $56,000 and $76,000, respectively, in bad debt expense related to its multifamily housing project. The balance of accounts receivable at December 31, 2011 and 2010 are for the sale of oil and gas and have been collected subsequent to the balance sheet date. No reserve for uncollectable receivables was booked during the year ended December 31, 2011 or 2010.

Restricted Investments

USE accounts for cash deposits held as collateral for reclamation obligations as restricted investments. Maturities or release dates less than twelve months from the end of the reported accounting period are reported as current assets while maturities or release dates in excess of twelve months from report dates are reported as long term assets.

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. Following is a breakdown of the lives over which assets are depreciated:

Machinery and Equipment:	
Office Equipment	3 to 5 years
Aircraft	15 years
Field Tools and Hand Equipment	5 to 7 years
Vehicles and Trucks	3 to 7 years
Heavy Equipment	7 to 10 years
Buildings and Improvements:	
Service Buildings	20 years
Corporate Headquarter Building	45 years

Table of Contents

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

	(In thousands)	
	December 31, 2011	December 31, 2010
Oil & Gas properties		
Unproved	$ 17,098	$ 17,926
Wells in progress	2,909	3,694
Proved	99,496	63,317
	119,503	84,937
Less accumulated depreciation		
depletion and amortization	(28,561)	(14,563)
Net book value	90,942	70,374
Mining properties	20,739	21,077
Building, land and equipment	14,984	14,564
Less accumulated depreciation	(5,788)	(5,228)
Net book value	9,196	9,336
Totals	$ 120,877	$ 100,787

Oil and Gas Properties

USE 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 unevaluated properties.

Full Cost Pool – Full cost pool capitalized costs are amortized over the life of production of proven properties. Capitalized costs at December 31, 2011 and 2010 which were not included in the amortized cost pool were $20.0 million and $21.6 million, respectively. These costs consist of unproved wells in progress, seismic costs that are being analyzed for potential drilling locations as well as land costs and are related to unproved properties. No capitalized costs related to unproved properties are included in the amortization base at December 31, 2011 and 2010. It is anticipated that these costs will be added to the full cost amortization pool within the next two years as properties are evaluated, drilled or abandoned.

Ceiling Test Analysis – 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 USE's 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, less (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.

USE performs a quarterly ceiling test for each of its 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 and over which management has no influence in the determination of present value. In arriving at the ceiling test for the year ended December 31, 2011, USE used $96.19 per barrel for oil and $4.12 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 USE's producing properties. At December 31, 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. We 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 been completed as of period end. They are classified as wells in progress and withheld from the depletion calculation and the ceiling test. The costs for these wells are then transferred to evaluated 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

USE capitalizes 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 USE subsequently determines that the property is not economical due to permanent decreases in market prices of commodities, excessive production costs or depletion of the mineral resource.

Table of Contents

Mineral properties at December 31, 2011 and 2010 reflect capitalized costs associated with USE's Mt. Emmons molybdenum property near Crested Butte, Colorado. USE's carrying balance in the Mt. Emmons property at December 31, 2011 and 2010 is as follows:

	(In thousands)	
	December 31, 2011	December 31, 2010
Costs associated with Mount Emmons beginning of year	$ 21,077	$ 21,969
Development costs during the nine months	16	108
Option payment from Thompson Creek	(354)	(1,000)
Costs at the end of the period	$ 20,739	$ 21,077

Long-Lived Assets

USE evaluates its long-lived assets for impairment when events or changes in circumstances indicate that the related carrying amount may not be recoverable. Impairment calculations are generally based on market appraisals. If estimated future cash flows, on an undiscounted basis, are less than the carrying amount of the related asset, an asset impairment is considered to exist. Changes in significant assumptions underlying future cash flow estimates may have a material effect on USE's financial position and results of operations.

Assets Held for Sale

In accordance with authoritative accounting guidance regarding property plant and equipment, 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. Operations related to Remington Village are shown in discontinued operations on the accompanying consolidated statements of operations. For additional discussion on assets held for sale, please refer to Note H – Assets Held for Sale.

Table of Contents

Derivative Instruments

USE uses derivative instruments, typically fixed-rate swaps and costless collars to manage price risk underlying its oil and gas production. USE may also use puts, calls and basis swaps in the future. All derivative instruments are recorded in the consolidated balance sheets at fair value. USE offsets fair value amounts recognized for derivative instruments executed with the same counterparty. Although USE 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, USE 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.

USE'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.

Fair Value of Financial Instruments

The carrying amount of cash equivalents, receivables, other current assets, accounts payable and accrued expenses approximate fair value because of the short-term nature of those instruments. The recorded amounts for short-term and long-term debt approximate the fair market value due to the variable nature of the interest rates on the short-term debt, and the fact that interest rates remain generally unchanged from issuance of the long-term debt.

Asset Retirement Obligations

USE accounts for its asset retirement obligations under FASB ASC 410-20, " *Asset Retirement Obligations*." USE records the fair value of the reclamation liability on its inactive mining properties and its operating oil and gas properties as of the date that the liability is incurred. USE reviews the liability each quarter and determines if a change in estimate is required as well as accretes the discounted liability on a quarterly basis for the future liability. Final determinations are made during the fourth quarter of each year. USE deducts any actual funds expended for reclamation during the quarter in which it occurs.

Table of Contents

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

	(In thousands)	
	December 31, 2011	December 31, 2010
Beginning asset retirement obligation	$ 303	$ 211
Accretion of discount	23	17
Liabilities incurred	187	75
Liabilities sold	(3)	--
Ending asset retirement obligation	$ 510	$ 303
Mining properties	$ 149	$ 139
Oil & Gas wells	361	164
Ending asset retirement obligation	$ 510	$ 303

Revenue Recognition

USE derives revenue primarily from the sale of produced oil, gas, and NGLs. The Company reports revenue as the gross amount received before taking into account production taxes and transportation costs, which are reported separately as expenses and are included in oil and gas production expense in the accompanying statements of operations. USE records natural gas and oil revenue under the sales method of accounting. Revenue is recorded in the month that the production is delivered to the purchaser. Payment is generally received between 30 and 90 days after the date of production. At the end of each month, we estimate the amount of production delivered to the purchaser and the price we will receive. USE uses its knowledge of its properties, their historical performance, market prices, and other factors as the basis for these estimates.

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

Stock Based Compensation

USE measures the cost of employee services received in exchange for all equity awards granted including stock options based on the fair market value of the award as of the grant date. USE computes the fair values of its options granted to employees using the Black Scholes pricing model. No options were granted in 2011, 2010 or 2009.

USE recognizes the cost of the equity awards over the period during which an employee is required to provide service in exchange for the award, usually the vesting period. As share-based compensation expense is recognized based on awards ultimately expected to vest, the expense has been reduced for estimated forfeitures based on historical forfeiture rates.

Income Taxes

USE recognizes deferred income tax assets and liabilities for the expected future income tax consequences, based on enacted tax laws, of temporary differences between the financial reporting and tax bases of assets, liabilities and carry forwards.

Additionally, USE recognizes deferred tax assets for the expected future effects of all deductible temporary differences, loss carry forwards and tax credit carry forwards. Deferred tax assets are reduced, if deemed necessary, by a valuation allowance for any tax benefits which, based on current circumstances, are not expected to be realized. Management believes it is more likely than not that such tax benefits will be realized and a valuation allowance has not been provided.

Net Income (Loss) Per Share

Basic earnings per share are computed based on the weighted average number of common shares outstanding. Common shares held by the ESOP are included in the computation of earnings per share. Total shares held by the ESOP at December 31, 2011, 2010, and 2009 were 684,643, 685,382, and 642,913, respectively. Diluted earnings per share is computed based on the weighted average number of common shares outstanding adjusted for the incremental shares attributed to outstanding options and warrants to purchase common stock, if dilutive. Using the treasury stock method, potential common shares relating to options and warrants are excluded from the computation of diluted loss per share for the years ending December 31, 2011, 2010 and 2009 because they were anti dilutive. Dilutive options and warrants totaled 486,371, 994,067 and 282,504 at December 31, 2011, 2010 and 2009, respectively.

Recent Accounting Pronouncements

In May 2011, the Financial Accounting Standards Board (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 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.

USE has reviewed other current outstanding statements from the FASB and does not believe that any of those statements will have a material adverse affect on the financial statements of USE when adopted.

C. FAIR VALUE

We follow authoritative guidance regarding fair value measurements 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 December 31, 2011, we held $166,000 of investments in marketable securities. The fair value of our commodity risk management assets and other accrued liabilities are determined using a market approach based on several factors, including observable transactions for the same or similar commodity options using the NYMEX futures index, and are designated as Level 2 within the valuation hierarchy. The fair value of our property held for sale is determined based on anticipated future cash flows, costs and comparables to the extent they are available, less estimated selling costs. The fair values of our other accrued liabilities that are reflected on the balance sheet are detailed below. Other accrued liabilities increased to $822,000 at December 31, 2011 as a net result of accretion of the liability and the commencement of payments from the retirement plan. The other accrued liabilities are the long term portion of the executive retirement program.

Table of Contents

(In thousands)

Description	December 31, 2011	Fair Value Measurements at December 31, 2011 Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Commodity risk management assets	$ 3	$ --	$ 3	$ --
Available for sale securities	166	166	--	--
Assets held for sale	18,132	--	--	18,132
Total assets	$ 18,301	$ 166	$ 3	$ 18,132
Commodity risk management liability	$ 601	$ --	$ 601	$ --
Other accrued liabilities	822	--	--	822
Total	$ 1,423	$ --	$ 601	$ 822

(In thousands)

Description	December 31 2010	Fair Value Measurements at December 31, 2010 Using: 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	$ 1,364	$ 1,364	$ --	$ --
Assets held for sale	20,979	--	--	20,979
Total assets	$ 22,343	$ 1,364	$ --	$ 20,979
Commodity risk management liability	$ 1,725	$ --	$ 1,725	$ --
Other accrued liabilities	762	--	--	762
Total	$ 2,487	$ --	$ 1,725	$ 762

Table of Contents

The following table summarizes the change in the fair value of our Level 3 Fair Value measurements for the year ended December 31, 2011.

Change in Level 3 Fair Value Measurements

Description	December 31, 2010	Revision of Value	December 31, 2011
Assets held for sale	$ 20,979	$ (2,847)	$ 18,132

Description	December 31, 2010	Additions and Payments	December 31, 2011
Other accrued liabilities	$ 762	$ 59	$ 821

The following table summarizes, by major security type, the fair value and unrealized gain of our investments. The unrealized gain is recorded on the consolidated balance sheet as other comprehensive income, a component of stockholders' equity.

(In thousands)

December 31, 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	$ 166	$ 122	$ --	$ --	$ 166	$ 122
Total	$ 166	$ 122	$ --	$ --	$ 166	$ 122

December 31, 2010

	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	$ 1,364	$ 1,003	$ --	$ --	$ 1,364	$ 1,003
Total	$ 1,364	$ 1,003	$ --	$ --	$ 1,364	$ 1,003

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 $22.3 million as of December 31, 2011.

D. COMMODITY PRICE RISK MANAGEMENT

Through our wholly-owned affiliate Energy One, we have entered into commodity derivative contracts ("economic hedges") with BNP Paribas ("BNP"), as described below. The derivative contracts are priced using West Texas Intermediate ("WTI") quoted prices. The Company is a guarantor of Energy One's obligations 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, 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 December 31, 2011 are summarized below:

Settlement Period	Counterparty	Basis	Quantity (Bbl/d)	Strike Price	
Crude Oil Costless Collar					
10/01/11 - 09/30/12	BNP Parabis	WTI	400	Put: $	80.00
				Call: $	99.00
Crude Oil Costless Collar					
01/01/12 - 12/31/12	BNP Parabis	WTI	200	Put: $	90.00
				Call: $	106.50

The following table reflects commodity derivative contracts entered into subsequent to December 31, 2011:

Settlement Period	Counterparty	Basis	Quantity (Bbl/d)	Strike Price		
Crude Oil Costless Collar						
10/01/12 - 09/30/13	BNP Parabis	WTI	200	Put:	$	95.00
				Call:	$	116.60

Table of Contents

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

	As of December 31, 2011 (in thousands)			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
Crude oil costless collars	Current Asset	$ 3	Current Liability	$ 601

	As of December 31, 2010 (in thousands)			
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
Crude oil costless collars	Current Asset	$ --	Current Liability	$ 1,725

Unrealized gains and losses resulting from derivatives are recorded at fair value on the consolidated balance sheet and changes in fair value are recognized in the unrealized gain (loss) on risk management activities line on the consolidated statement of operations. Realized gains and losses resulting from the contract settlement of derivatives are recognized in the commodity price risk management activities line on the consolidated statement of operations. During the year ended December 31, 2011 we had a recognized loss of $2.0 million from the contract settlements of derivatives and an unrealized gain of $1.1 million.

E. MINERAL PROPERTY TRANSACTIONS

Oil and Gas Exploration

USE participates in oil and gas projects as a non-operating working interest owner and has 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.

Eagle Ford Shale Acquisitions

During 2011 we entered into two participation agreements with Crimson Exploration Inc. (“Crimson”) to acquire a 30% working interest in oil prospects and associated leases located in Zavala and Dimmit Counties, Texas. Under the terms of the agreements, the Company has earned a 30% working interest (22.5% net revenue interest) through a combination of a cash payment and commitment well carry. During the year, the Company participated in the drilling of two wells in the prospects and expects to continue exploration and development in 2012. One well was completed in 2011 and the remaining well was in progress at December 31, 2011.

Bakken/Three Forks Shale Sale

On December 15, 2011, the Company sold an undivided 75% of its undeveloped acres in the Rough Rider prospect to Brigham for $13.7 million. Under the terms of the agreement, the Company retained the remaining 25% of its interest in the undeveloped acreage and its original working interest in its 20 developed wells in the Rough Rider prospect. After the sale, our working interest in the undeveloped acreage in the Rough Rider Prospect ranges from 3.41% to 9.90%. In addition, Brigham also agreed to commence drilling operations for at least three gross wells in the Rough Rider acreage for each calendar year of 2012 and 2013.

Gulf Coast Sale

On October 27, 2011, the Company entered into an agreement with Yuma Exploration and Production Company, Inc. to sell its interest in the Livingston prospect in Louisiana for $1.0 million. The Company owned a 4.79% working interest in the prospect which included one gross producing well (approximately 5 BOE/day net) and one additional gross development well that was being completed at the time of the sale. Our total investment in the prospect was approximately $2.0 million including seismic, drilling, leasehold acquisition and other development costs.

Mount Emmons Molybdenum Properties

Mineral properties at December 31, 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 its 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.

Costs to operate the water treatment plant and maintain the property are being paid solely by USE.

F. SUPPLEMENTAL FINANCIAL INFORMATION ON OIL AND NATURAL GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES

Capitalized Costs

The following table presents information regarding USE's net costs incurred in the purchase of proved and unproved properties, and in exploration and development activities:

	(In thousands) Year Ended December 31,	
	2011	2010
Oil & Gas properties		
Unproved oil and gas properties	$ 17,098	$ 17,926
Wells in progress	2,909	3,694
Proved oil and gas properties	99,496	63,317
Total capitalized costs	$ 119,503	$ 84,937

Table of Contents

USE's DD&A per equivalent BOE was $31.64 in 2011, $23.64 in 2010 and $21.72 in 2009.

Undeveloped properties as of December 31, 2011 include costs incurred in the following years:

	(In thousands)			
	Acquisitions	Exploration	Exploration	Total
2010	$ 8,131	$ --	$ --	$ 8,131
2011	8,967	2,909	--	11,876
Total	$ 17,098	$ 2,909	$ --	$ 20,007

Costs Incurred

Costs incurred in oil and natural gas property acquisition, exploration and development activities are summarized below:

	(In thousands) For the years ending December 31,		
	2011	2010	2009
Property acquisition costs:			
Proved	$ 1,288	$ --	$ --
Unproved	10,679	14,237	560
Exploration costs	32,787	35,899	21,107
Development costs	4,550	4,846	--
Total capitalized costs	$ 49,304	$ 54,982	$ 2,1667

Results of Operations

Results of operations from oil and natural gas producing activities are presented below:

	(In thousands) For the years ending December 31,		
	2011	2010	2009
Oil and gas revenues	$ 30,958	$ 26,548	$ 7,581
Realized (loss) from risk management activities	(1,974)	(156)	--
Unrealized gain (loss) from risk management activities	1,126	(1,725)	--
	30,110	24,667	7,581
Operating expenses	11,552	6,073	1,085
Depreciation, depletion and amortization	13,997	10,610	3,571
Impairment	--	--	1,468
	25,549	16,683	6,124
Operating income	$ 4,561	$ 7,984	$ 1,457

Table of Contents

Oil and Natural Gas Reserves (Unaudited)

Proved reserves are estimated quantities of oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are reserves that can reasonably be expected to be recovered through existing wells with existing equipment and operating methods.

Proved oil and natural gas reserve quantities at December 31, 2011 and the related discounted future net cash flows before income taxes are based on the estimates prepared by Cawley, Gillespie & Associates, Inc., Ryder Scott Company, L.P and Netherland, Sewell & Associates, Inc. The reserve reports for the periods ended December 31, 2010 and 2009 were prepared by Cawley, Gillespie & Associates, Inc., Ryder Scott Company, L.P. Such estimates have been prepared in accordance with guidelines established by the Securities and Exchange Commission.

USE's net ownership interests in estimated quantities of proved oil and natural gas reserves and changes in net proved reserves, all of which are located in the continental United States, are summarized below:

December 31, 2011	Oil (BBLS)	Natural Gas or NGL (MCFE)
Beginning of year	1,546,446	2,450,968
Revisions of previous quantity estimates	4,913	(864,513)
Extensions, discoveries and improved recoveries	1,516,797	2,004,535
Purchase of reserves in place	48,615	49,065
Sales of reserves in place	(78,477)	(43,716)
Production	(300,325)	(852,211)
End of Year	2,737,969	2,744,128
Proved developed reserves at end of year	1,884,068	1,983,581

December 31, 2010	Oil (BBLS)	Natural Gas or NGL (MCFE)
Beginning of year	811,789	1,646,482
Revisions of previous quantity estimates	(55,450)	(234,852)
Extensions, discoveries and improved recoveries	1,093,540	1,911,867
Sales of reserves in place	--	--
Production	(303,433)	(872,529)
End of Year	1,546,446	2,450,968
Proved developed reserves at end of year	1,362,733	2,311,682

Table of Contents

Standardized Measure (Unaudited)

The standardized measure of discounted future net cash flows relating to USE's ownership interests in proved oil and natural gas reserves as of year-end is shown below:

	(In thousands) Year Ended December 31,		
	2011	2010	2009
Future cash inflows	$ 259,533	$ 124,629	$ 51,024
Future costs:			
Production	(77,813)	(36,299)	(14,025)
Development	(42,972)	(6,774)	(104)
Future income tax expense	(19,790)	(11,622)	(8,273)
Future net cash flows	118,958	69,934	28,622
10% discount factor	(56,767)	(25,281)	(8,638)
Standardized measure of discounted future net cash flows	$ 62,191	$ 44,653	$ 19,984

Future cash flows are computed by applying 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 to year-end quantities of proved oil and natural gas reserves. Prices used in computing year end 2011, 2010 and 2009 future cash flows were $96.19/barrel, $79.43/barrel and $61.18/barrel, respectively, for oil and $4.12/MMbtu, $4.38/MMbtu and $3.87/MMbtu for natural gas, respectively, in each case adjusted for regional price differentials and other factors. Future operating expenses and development costs are computed primarily by USE's petroleum engineers by estimating the expenditures to be incurred in developing and producing USE's proved oil and natural gas reserves at the end of the year, based on year end costs and assuming continuation of existing economic conditions.

Future income taxes are based on year-end statutory rates, adjusted for the tax basis of oil and gas properties and available applicable tax assets. A discount factor of 10% was used to reflect the timing of future net cash flows. The standardized measure of discounted future net cash flows is not intended to represent the replacement cost or fair market value of USE's oil and natural gas properties. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs, and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

Table of Contents

Change in Standardized Measure (Unaudited)

Changes in standardized measure of future net cash flows relating to proved oil and natural gas reserves are summarized below:

	(In thousands) Year Ended December 31,		
	2011	2010	2009
Balance at beginning of period	$ 44,653	$ 19,984	$ 3,318
Sales of oil and gas, net of production costs	(19,406)	(20,476)	(6,496)
Net change in prices and production costs	1,401	3,895	297
Extensions and discoveries	26,574	40,011	26,721
Purchase of reserves in place	3,082	--	--
Sale of reserves in place	(1,947)	--	--
Revisions of previous quantity estimates	(3,158)	(2,519)	1,586
Development costs incurred during year	14,930	--	--
Previously estimated development costs incurred	(2,719)	--	--
Net change in income taxes	(4,270)	(2,138)	(4,385)
Accretion of discount	5,207	2,576	531
Changes in production rates, timing and other	(2,156)	3,320	(1,588)
Balance at end of period	$ 62,191	$ 44,653	$ 19,984

Sales of oil and natural gas, net of oil and natural gas operating expenses, are based on historical pretax results. Extensions and discoveries and the changes due to revisions in standardized variables are reported on a pretax discounted basis.

G. GEOTHERMAL

During the year ended December 31, 2011, USE's minority interest investment in Standard Steam Trust, LLC ("SST"), a Denver, Colorado based private geothermal resource acquisition and development company, decreased. Due to not funding cash calls from SST during 2011, USE's ownership interest decreased from 22.8% to 22.4%.

H. ASSETS HELD FOR SALE

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, 2011 and 2010, we recorded impairments of $3.1 million and $1.5 million, respectively, to adjust the carrying value of the multifamily project to the estimated fair value as of the evaluation date. As of December 31, 2011, Remington is classified as an asset held for sale with a net book value of $18.1 million and a $10.2 million liability held for sale. Because Remington Village has been classified as an asset held for sale, the scheduled depreciation of $946,000 was not recorded during 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.

Table of Contents

The Company's real estate operations for the years ending December 31, 2010 and 2009 respectively were reported as an operating segment. For the year ended December 31, 2011, these operations have been reclassified as discontinued operations in the current financial statements. Results of discontinued operations for the years ended December 31, were as follows:

	(In thousands) For the years ending December 31,		
	2011	2010	2009
Revenues	$ 2,147	$ 2,411	$ 2,630
Operating expenses	1,468	2,062	1,840
Impairment	3,063	1,540	--
	4,531	3,602	1,840
(Loss) income before income taxes	(2,384)	(1,191)	790
Income tax benefit from (provision for)	(245)	(123)	(264)
Net (loss) income from discontinued operations	$ (2,629)	$ (1,314)	$ 526

The following assets and liabilities have been segregated and included in the Assets Held for Sale and Liabilities Held for Sale, as appropriate, in the consolidated balance sheets as of December 31, 2011 and 2010, respectively, and represent the assets and liabilities of the multifamily housing project.

	(In thousands)	
	December 31, 2011	December 31, 2010
Cash and cash equivalents	$ 170	$ 198
Accounts receivable	13	43
Prepaid expenses	99	--
Property, plant and equipment, net	17,730	20,738
Restricted investment	120	--
Assets of discontinued operations held for sale	$ 18,132	$ 20,979
Accounts payable	$ 117	$ 86
Accrued and other liabilities	220	237
Long term debt	9,904	--
Assets of discontinued operations held for sale	$ 10,241	$ 323

Table of Contents

I. BNP RESERVE CREDIT FACILITY

On July 30, 2010, USE established a Senior Secured Revolving Credit Facility (the "Facility") to borrow up to $75 million from BNP Paribas ("BNP"). At present, BNP is the only lender under the Facility. In the future, the facility may include other members of a lending syndicate (the "Lenders") as provided for in the Facility. BNP also is the administrative agent for the Facility, which is governed by the following documents: Credit Agreement; Mortgage, Deed of Trust, Assignment of As-Extracted Collateral, Security Agreement, Fixture Filing and Financing Statement (the "Mortgage"); and Guaranty and Pledge Agreement (the "Guaranty"), which are referred to below together as the "Facility Documents." The following summarizes the principal provisions of the Facility as set forth in the Facility Documents. The summary is qualified by reference to the complete text of the documents.

USE's wholly-owned subsidiary, Energy One LLC ("Energy One"), is the borrower under the Facility. USE has assigned to Energy One all of its rights, title and interest in certain oil and gas properties and equipment related thereto, rights under various operating agreements, proceeds from sale of production and from sale or other disposition of the properties. USE also has unconditionally and irrevocably guaranteed Energy One's performance of its obligations under the Credit Agreement, including without limitation Energy One's payment of all borrowings and related fees thereunder.

From time to time until expiration of the 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, which was initially established at $12 million. The Borrowing Base is redetermined semi-annually, taking into account updated reserve reports prepared by USE's independent consulting engineers. Any proposed increase in the Borrowing Base will require approval by all Lenders in the syndicate (presently only BNP), and any proposed Borrowing Base decrease will require approval by Lenders holding not less than two-thirds of outstanding loans and loan commitments.

Interest is payable quarterly at the greater of the Prime Rate, the Federal Funds Effective Rate (plus 0.5%), and the adjusted LIBO rate for the three prior months, plus, an additional 2.25% to 3.25%, depending on the amount of the loan relative to the Borrowing Base. Interest rates on outstanding loans are adjustable each day by BNP as administrative agent. Energy One may prepay principal at any time without premium or penalty, but all outstanding principal will be due on July 30, 2014. If there is a decrease in the Borrowing Base, the excess of outstanding loans over the Borrowing Base will be due over the six months following the redetermination. We pay BNP a Facility fee each time the Borrowing Base is increased.

In addition, on a quarterly basis, Energy One will pay BNP, for the account of each Lender (as applicable), a commitment fee of 0.50% of the unused amount of each Lender's unused amount of its Facility lending commitment, computed daily until July 30, 2014.

Energy One is required to comply with customary affirmative covenants and with certain negative covenants. The principal negative financial covenants (measured at various times as provided in the Credit Agreement) do not permit (i) Interest Coverage Ratio (Interest Expense to EBITDAX) to be less than 3.0 to 1; (ii) Total Debt to EBITDAX to be greater than 3.5 to 1; and (iii) Current Ratio (current assets plus unused lender commitments under the Borrowing Base) to be less than 1.0 to 1.0. EBITDAX is defined in the Credit Agreement as Consolidated Net Income, plus non-cash charges. At all times during the year ended December 31, 2011 Energy One was in compliance with all the affirmative and negative covenants.

Table of Contents

If Energy One fails to pay interest or principal when due, or fails to comply with the covenants in the Credit Agreement (after a reasonable cure period, if applicable), BNP as Administrative Agent may (and shall, if requested by the Majority Lenders (Lenders holding not less than 2/3rds of the outstanding loan principal), declare the loans immediately due, and foreclose on Energy One's assets and enforce USE's guaranty.

As of December 31, 2011, the Borrowing Base was $28.0 million and we had borrowed $12.0 million from the Facility. Subsequent to December 31, 2011, Energy One used a portion of the proceeds from the sale of 75% of its undeveloped acreage in the Yellowstone and SEHR prospects in the Williston Basin to repay its outstanding balance under the senior credit facility. As of March 14, 2012, no borrowings were outstanding under this facility.

J. OTHER LIABILITIES AND DEBT

As of December 31, 2011 and 2010, USE had current and long term liabilities associated with the following funding commitments:

	(In thousands)	
	December 31, 2011	December 31, 2010
Other liabilities and debt:		
Other liabilities		
Deferred rent	$ 14	$ 16
Employee health insurance self funding	10	--
	$ 24	$ 16
Other long term liabilities:		
Accrued executive retirement costs	$ 822	$ 762
Debt:		
Credit Facility - collateralized by		
oil and gas reserves, at 3.07%	$ 12,000	$ --
Long term Debt		
Real estate note - collateralized by		
property, interest at 5.5%	9,904	--
Real estate note - collateralized by		
property, interest at 6%	400	600
	22,304	600
Less current portion	(481)	(200)
Totals	$ 21,823	$ 400

Table of Contents

In December 2008, USE and TCM jointly purchased land for $4 million ($2 million in January 2009, $400,000 annually for five years). USE is responsible for one-half the purchase price. As of December 31, 2011, USE has paid $1.6 million leaving $400,000 to be paid at the rate of $200,000 per year through 2013. On December 6, 2011, TCM notified the Company that it wishes to sell its interest in the property. The Company has 18 months to decide whether to purchase TCM's 50% interest in the property, at cost, and close such purchase.

On May 5, 2011 USE borrowed $10.0 million from a commercial bank against Remington Village. At the date of filing of this annual report $9.9 million is due on the note. The note is secured by the Company's multi-family property in Gillette, WY. The note is amortized over 20 years with a balloon payment at the end of five years with an interest rate of 5.50% per annum. Proceeds of the note were used to fund general business obligations. When Remington Village is sold, the proceeds from the sale will first be applied to the retirement of the debt and the remainder applied to general corporate overhead and project development. Therefore, the debt is included in current liabilities held for sale.

	(In thousands) Payments due by period					
	Total	2012	2013	2014	2015	2016 and thereafter
Credit facility	$ 12,000	$ 12,000	$ --	$ --	$ --	$ --
Real estate note - 5.5%	9,904	281	312	326	345	8,640
Real estate note - 6.0%	400	200	200	--	--	--
Total	$ 22,304	$ 12,481	$ 512	$ 326	$ 345	$ 8,640

K. INCOME TAXES

The provision for income taxes is composed of the following:

	(In thousands) Years ended December 31,		
	2011	2010	2009
Current income tax expense (benefit)			
Federal	$ --	$ (104)	$ (210)
State	--	--	--
	$ --	$ (104)	$ (210)
Deferred income tax expense (benefit)			
Federal	$ (3,316)	$ (1,543)	$ (1,794)
State	(195)	(91)	(275)
	$ (3,511)	$ (1,634)	$ (2,069)

Table of Contents

The effective income tax rate differs from the U.S. Federal Statutory income tax rate due to the following:

	(In thousands) Years ended December 31,		
	2011	2010	2009
Federal statutory income tax rate	$ (2,828)	$ (853)	$ (3,555)
State income taxes, net of federal benefit	(166)	(50)	(209)
Incentive stock options	246	258	404
percent depletion carryover	(807)	(1,067)	(128)
Other	44	(26)	1,209
	$ (3,511)	$ (1,738)	$ (2,279)

The components of deferred tax assets and liabilities as of December 31, 2011 and 2010 are as follows:

	(In thousands)		
	December 31, 2011	December 31, 2010	December 31, 2009
Deferred tax assets:			
Net operating loss	$ 2,547	$ 1,857	$ 2,078
Derivative instruments	215	621	--
Asset retirement obligation	184	109	40
Stock based compensation	288	287	629
Deferred compensation	357	372	534
Alternative minimum tax credit	706	706	810
Contribution carryover	28	27	19
Equity investments	37	362	--
Percentage depletion carryover	1,924	1,198	128
	$ 6,286	$ 5,539	$ 4,238
Deferred tax liabilities:			
Property and equipment	$ (7,385)	$ (10,149)	$ (10,700)
Marketable securities	(44)	(361)	--
	$ (7,429)	$ (10,510)	$ (10,700)
Net deferred tax assets (liabilities)	$ (1,143)	$ (4,971)	$ (6,462)
Less: Valuation Allowance	--	--	--
Deferred tax liability	$ (1,143)	$ (4,971)	$ (6,462)

Table of Contents

During the year ended December 31, 2011, deferred tax assets increased $747,000 and deferred tax liabilities decreased by $3.1 million. The change in net deferred tax liabilities was a decrease of $3.8 million compared to the previous year. This decrease is comprised of a deferred tax benefit of $3.5 million and a reduction to other comprehensive income of $316,000 resulting from the future tax impact of unrealized gain on marketable securities.

USE has net operating loss carryovers as of December 31, 2011 of $8.8 million for federal income tax purposes and $6.2 million for financial reporting purposes. The difference of $2.6 million relates to tax deductions for compensation expense for financial reporting purposes for which the benefit will not be recognized until the related deductions reduce taxes payable. The net operating loss carryovers may be carried back two years and forward twenty years from the year the net operating loss was generated. The net operating losses may be used to offset taxable income through 2031. In addition, USE has alternative minimum tax credit carry-forwards of $706,000 which are available to offset future federal income taxes over an indefinite period.

The statute of limitations is closed for the tax years through 2006. USE agreed to extend the statute of limitations for the 2007 tax year until July 2012.

USE adopted the applicable provisions of ASC 740 to recognize, measure, and disclose uncertain tax positions in the financial statements. Under ASC 740, tax positions must meet a “more-likely-than-not” recognition threshold to be recognized. During the year ended December 31, 2011, no adjustments were recognized for uncertain tax positions. USE recognizes interest and penalties related to uncertain tax positions in income tax expense (benefit). No interest or penalties related to uncertain tax positions have been accrued.

Table of Contents

L. SEGMENTS AND MAJOR CUSTOMERS

During the years ended December 31, 2011, 2010, and 2009, USE, for financial reporting purposes, operated two business segments, the exploration for and sale of oil and gas, and mining. USE's operating segments are reflected in the tables below:

	(In thousands) For the years ended December 31,		
	2011	2010	2009
Revenues:			
Oil and gas	$ 30,110	$ 24,667	$ 7,581
Total revenues:	30,110	24,667	7,581
Operating expenses:			
Oil and gas	25,549	16,683	6,124
Mineral properties	2,364	1,878	1,959
Total operating expenses:	27,913	18,561	8,083
Interest expense			
Oil and gas	268	--	--
Mineral properties	36	48	60
Total interest expense:	304	48	60
Operating (loss) income			
Oil and gas	$ 4,293	$ 7,984	$ 1,457
Mineral properties	(2,400)	(1,926)	(2,019)
Operating income (loss) from identified segments	1,893	6,058	(562)
General and administrative expenses	(8,261)	(8,973)	(9,433)
Add back interest expense	304	48	60
Other revenues and expenses:	131	1,549	(1,331)
(Loss) income before income taxes and discontinued operations	$ (5,933)	$ (1,318)	$ (11,266)
Depreciation depletion and amortization expense:			
Oil and gas	$ 13,997	$ 10,610	$ 1,045
Mineral properties	102	77	54
Corporate	494	380	396
Total depreciation expense	$ 14,593	$ 11,067	$ 1,495

Table of Contents

	(In thousands) December 31,		
	2011	2010	2009
Assets by segment			
Oil and Gas	$ 109,141	$ 75,639	$ 30,016
Mineral	20,755	20,800	21,998
Corporate	32,543	59,577	94,709
Total assets	$ 162,439	$ 156,016	$ 146,723

M. SHAREHOLDERS' EQUITY

Stock Option Plans

The Board of Directors adopted the U.S. Energy Corp. 1989 Stock Option Plan for the benefit of USE's employees. The Option Plan, as amended and renamed the 1998 Incentive Stock Option Plan ("1998 ISOP"), reserved 3,250,000 shares of USE's $.01 par value common stock for issuance under the 1998 ISOP. Options which expired without exercise were available for reissue until the 1998 ISOP was replaced by the 2001 ISOP. All options issued under the 1998 ISOP have been exercised or have expired and the 1998 ISOP terminated on January 9, 2011.

In December 2001, the Board of Directors adopted (and the shareholders subsequently approved) the U.S. Energy Corp. 2001 Incentive Stock Option Plan (the "2001 ISOP") for the benefit of USE's employees. The 2001 ISOP (amended by approval of the shareholders in 2004 and 2007) reserved for issuance 25% of USE's shares of common stock issued and outstanding at any time. The 2001 ISOP had a term of 10 years and expired on December 6, 2011. Options issued under the 2001 ISOP remain exercisable until their expiration date under the terms of the 2001 ISOP.

A summary of the Employee Stock Option Plans activity in all plans for the year ended December 31, 2011, 2010 and 2009 is as follows:

	Year ended December 31,					
	2011		2010		2009	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
Outstanding at beginning of the period	3,011,647	$ 3.87	3,711,114	$ 3.64	3,717,098	$ 3.63
Granted	--	$ --	--	$ --	--	$ --
Forfeited	--	$ --	--	$ --	--	$ --
Expired	(200,000)	$ 3.90	--	$ --	(4,000)	$ 2.46
Exercised	(493,248)	$ 3.51	(699,467)	$ 2.63	(1,984)	$ 2.52
Outstanding at period end	2,318,399	$ 3.94	3,011,647	$ 3.87	3,711,114	$ 3.64
Exercisable at period end	2,108,399	$ 3.84	2,404,148	$ 3.78	2,614,453	$ 3.43
Weighted average fair value of options granted during the period		$ --		$ --		$ --

During the year ended December 31, 2011, a total of 493,248 options were exercised by employees by the payment of $34,000 in cash and the surrender of 368,804 shares valued at $1.9 million. In the year ended December 31, 2010, 699,467 options were exercised by the payment of $63,000 in cash and surrender of 325,195 shares valued at $1.8 million. In the year ended December 31, 2009, 1,984 options were exercised by the payment of $5,000.

Option related compensation expense is recognized over the vesting period of the options and is calculated using the Black Scholes option pricing model. USE initially assumed no forfeitures, but has subsequently reduced the cumulative expense based on historical forfeiture. Total future expense for the option plan is $2,000 to be recognized in 2012.

The following table summarizes information about employee stock options outstanding and exercisable at December 31, 2011:

Grant Price Range	Options Outstanding at December 31, 2011	Weighted average remaining contractual life in years	Weighted average exercise price	Options exercisable at December 31, 2011	Weighted average exercise price
$ 2.46	389,319	2.50	$ 2.46	389,319	$ 2.46
$ 2.47 - $2.52	450,312	6.67	$ 2.52	450,312	$ 2.52
$ 2.53 - $3.86	273,768	3.79	$ 3.86	273,768	$ 3.86
$ 3.91 - $4.97	1,205,000	5.34	$ 4.97	995,000	$ 4.97
	2,318,399	4.94	$ 3.94	2,108,399	$ 3.84

The following table sets forth the number of options available for grant as well as the intrinsic value of the options outstanding and exercisable:

	2011	2010	2009
Available for future grant	--	3,765,506	3,327,780
Intrinsic value of option exercised	$ 888,000	$ 1,956,000	$ 14,000
Aggregate intrinsic value of options outstanding	$ 351,000	$ 6,660,000	$ 8,514,000
Aggregate intrinsic value of options exercisable	$ 351,000	$ 5,526,000	$ 6,543,000

Employee Stock Ownership Plan

The Board of Directors of USE adopted the U.S. Energy Corp. 1989 Employee Stock Ownership Plan ("ESOP") in 1989, for the benefit of all USE's employees. Employees become eligible to participate in the ESOP after one year of service which must consist of at least 1,000 hours worked. After the employee becomes a participant in the plan, he or she must have a minimum of 1,000 hours of service in each plan year to be considered for allocations of funding from USE. Employees become 20% vested after three years of service and increase their vesting by 20% each year thereafter until such time as they are fully vested after eight years of service.

Table of Contents

An employee's total compensation paid, which is subject to federal income tax, up to an annual limit of $245,000 for the years ended December 31, 2011, 2010 and 2009, is the basis for computing how much of the total annual funding is contributed into his or her personal account. An employee's compensation divided by the total eligible compensation paid to all plan participants is the percentage that each participant receives on an annual basis. USE funds 10% of all eligible compensation annually in the form of common stock and may fund up to an additional 15% to the plan in common stock. As of December 31, 2011, all shares of USE's stock that have been contributed to the ESOP have been allocated. The estimated fair value of shares that are not vested is approximately $37,000.

During the year ended December 31, 2011, the Board of Directors of USE approved a contribution of 98,958 shares to the ESOP at the price of $2.91 for a total expense of $287,000. This compares to contributions to the ESOP during the year ended December 31, 2010 and 2009 of 42,802 and 36,583 shares to the ESOP at prices of $6.08 and $5.93 per share, respectively. The expense for the contributions during the years ended December 31, 2010 and 2009 were $260,000 and $217,000, respectively.

Warrants to Others

As of December 31, 2011, there were 210,000 warrants outstanding to purchase shares of USE's common stock. Of the total outstanding warrants, 183,334 were exercisable. USE values these warrants using the Black-Scholes option pricing model and expenses that value over various terms based on the nature of the award. Activity for the periods ended December 31, 2011, 2010 and 2009 for warrants is presented in the following table:

	Year ended December 31,					
	2011		2010		2009	
	Warrants	Weighted Average Exercise Price	Warrants	Weighted Average Exercise Price	Warrants	Weighted Average Exercise Price
Outstanding at beginning of the period	320,000	$ 2.95	581,367	$ 2.91	1,036,387	$ 3.43
Granted	20,000	$ 4.19	10,000	$ 5.04	--	$ --
Forfeited	(20,000)	$ 2.52	(20,000)	$ 2.52	--	$ --
Expired	(5,000)	$ 3.90	--	$ --	(383,932)	$ 4.26
Exercised	(105,000)	$ 2.92	(251,367)	$ 2.97	(71,088)	$ 3.27
Outstanding at period end	210,000	$ 3.10	320,000	$ 2.95	581,367	$ 2.91
Exercisable at period end	183,334	$ 2.91	276,667	$ 2.93	494,701	$ 2.98
Weighted average fair value of options granted during the period		$ 2.34		$ 2.99		$ --

During the year ended December 31, 2011, a total of 105,000 warrants were exercised by the payment of $62,000 in cash and the surrender of 62,104 shares valued at $245,000. In the year ended December 31, 2010, 251,367 warrants were exercised by the payment of $746,000 in cash. In the year ended December 31, 2009, 71,088 warrants were exercised by the payment of $232,000 in cash.

The following table summarizes information about non-employee warrants outstanding and exercisable at December 31, 2011:

Grant Price Range	Warrants Outstanding at December 31, 2011	Weighted average remaining contractual life in years	Weighted average exercise price	Warrants exercisable at December 31, 2011	Weighted average exercise price
$ 2.46	50,000	0.48	$ 2.46	50,000	$ 2.46
$ 2.47 - $2.52	80,000	3.61	$ 2.52	80,000	$ 2.52
$ 2.53 - $3.86	50,000	0.48	$ 3.86	50,000	$ 3.86
$ 3.87 - $4.19	20,000	9.48	$ 4.19	3,334	$ 4.19
$ 3.91 - $5.04	10,000	8.48	$ 5.04	--	$ 5.04
	210,000	2.91	$ 3.10	183,334	$ 2.91

These warrants are held by current and former directors of USE.

USE has computed the fair values of its options and warrants using the Black Scholes pricing model and the following weighted average assumptions:

	Year Ended December 31,		
	2011	2010	2009
Risk-free interest rate	1.77%	2.24%	--
Expected lives (years)	6.0	6.0	--
Expected volatility	59.64%	63.79%	--
Expected dividend yield	--	--	--

N. COMMITMENTS, CONTINGENCIES AND OTHER

Legal Proceedings

From time to time, we are party to certain legal actions and claims arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on our financial position or results of operations. Following are currently pending legal matters:

Water Rights Litigation –Mt. Emmons Project

On July 25, 2008, we filed an Application for Finding of Reasonable Diligence with the Colorado Water Court ("Water Diligence Application") concerning the conditional water rights associated with the Mt. Emmons Project (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 Decree, or within six years of the final determination of the 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 (by denial of certiorari) 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 ("HCAA"), 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 United States Forest Service ("USFS") regulations and did not satisfy certain "reality check" limitations contained in the Decree. On September 24, 2010, we filed a response to the motion for summary judgment responding that the plan of operations complied with USFS and BLM regulations and satisfied the reality check limitations. The U.S. Department of Justice also filed a response on behalf of the USFS and BLM asserting that the Court cannot second guess the USFS's determination that the plan of operations satisfied USFS and BLM regulations.

On November 24, 2010 the District Court Judge denied the Opposers's 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 Project

On March 8, 2008, HCCA filed a request for hearing before the Colorado Mine Land Reclamation Board ("Board") of the approval of a "Notice of Intent to Conduct Prospecting" ("NOI") for the Mt. Emmons Project, which was approved by the Division of Reclamation, Mining and Safety of the Colorado Department of Natural Resources ("DRMS") on January 3, 2008. The approved NOI provides 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 1970s. On May 14, 2008, the MLRB denied HCCA's request for hearing and also denied its 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 MLRB'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 have both filed the responsive pleadings in addition to motions to dismiss the HCCA complaint.

On February 24, 2011, the District Court issued an order dismissing all of HCCA's claims concerning the appeal of the NOI holding that: (i) HCCA does not have standing to request judicial review on the merits of the DRMS's approval of the NOI and (ii) HCCA does not have standing to request a declaratory order. This decision upholds the Board's May 14, 2008 decision denying HCCA's request for hearing and its 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.

Appeal of Modification – Notice of intent to Conduct Prospecting for the Mt. Emmons Project

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 Board 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 Board on a vote 4-1 vote upheld DRMS's approval of MD-03 and its 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, which is currently pending.

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 itself 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 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 anticipate filing with the court documents to change Energy One's status to an additional plaintiff.

Table of Contents

Mining Permits

The Mount Emmons molybdenum property is located on fee property within the boundary of U.S. Forest Service ("USFS") land. Although mining of the mineral resource will occur on the fee property, associated ancillary activities will occur on USFS land. USE submitted an initial plan of operations in accordance with 36 C.F.R. Sec. 228.4(d) on March 31, 2010. An additional plan of operations will be submitted to the USFS for the USFS approval prior to April 30, 2013, which approval is required before initial construction and mining and processing may occur. Under the procedures mandated by National Environmental Protection Act ("NEPA"), the USFS will prepare an environmental analysis in the form of an Environmental Assessment and/or and Environmental Impact Statement to evaluate the predicted environmental and social economic impacts of the proposed development and mining of the Mount Emmons molybdenum property. The NEPA process provides for public review and comment of the proposed plan.

Obtaining and maintaining the various permits for the mining operations at Mount Emmons will be complex, time-consuming, and expensive. Changes in a mine's design, production rates, quality of material mined, and many other matters, often require submission of the proposed changes for agency approval prior to implementation. In addition, changes in operating conditions beyond our control, or changes in agency policy and Federal and State law, could further affect the successful permitting of the mine operations.

Although USE is confident that the plan of operations for Mount Emmons will ultimately be approved by the USFS, this cannot be guaranteed. Moreover, the timing and cost, and ultimate success of the mining operation, cannot be predicted.

401(K) Plan

The Board of Directors of USE adopted the U.S. Energy Corp. 401(K) Plan ("401(K)") in 2004. USE matches 50% of an employee's salary deferrals up to a maximum contribution per employee of $4,000 annually. USE expensed $57,000, $49,000, and $48,000 for the years ended December 31, 2011, 2010 and 2009, respectively related to these contributions.

Executive Officer Compensation

In December 2001, the Board of Directors adopted (and the shareholders subsequently approved) the 2001 Stock Award Plan to compensate its executive officers. The Stock Award Plan was amended on June 22, 2007 by a vote of the shareholders. Under the Plan, 20,000 shares may be issued annually to each officer during his employment. During the years ended December 31, 2011, 2010 and 2009, USE collectively issued 75,000, 80,000, and 80,000 shares of stock to these officers, respectively. While in USE's employ, the officers have agreed not to sell, pledge or otherwise dispose of or encumber the shares granted under the 2001 Stock Award Plan. In consideration of this agreement USE has agreed to pay all taxes due on the shares granted to the officers.

USE committed to pay the surviving spouse of the former Chairman and Founder, who passed away on September 4, 2006, one years' full salary and 50% of that amount annually for an additional four years thereafter. During the three years ended December 31, 2011, 2010, and 2009, USE paid $57,000, $85,000, and 85,000, respectively. The Board of Directors also approved payment of 50% of the then existing wages to USE's former General Counsel for a period of five years. USE has paid $85,000 annually under this agreement beginning at date of retirement, January 12, 2007, to January 12, 2012.

On October 20, 2005, the Board of Directors of USE adopted an Executive Retirement Policy for the then Chairman/CEO President/COO and CFO/Treasurer/V.P. Finance. Under the terms of the Retirement Plan, the retired executive will receive payments equaling 50% of the greater of (i) the amount of compensation the Executive Officer received as base cash pay on his/her final regular pay check or (ii) the average annual pay rate, less all bonuses, he/she received over the last five years of his/her employment with Company. To be eligible for this benefit, the executive officer must serve in one of the designated executive offices for 15 years, reach the age of 60 and be an employee of USE on December 31, 2010. Through each executive's employment contract USE has also agreed to pay for health insurance for the executive and his spouse from date of retirement, after age 60, until the executive is eligible for Medicare. During 2007, the Board of Directors voted unanimously to fund the retirement benefit for the then active officers who qualified under the plan. The funding is held in a separate trust account that is managed by an independent trustee and is subject only to the claims of creditors in the event of insolvency of USE. At December 31, 2011, USE had funded the executive retirement account with the amount calculated by a third party actuary, of $929,000 recorded as Other Long Term Assets. Additional amounts will be deposited annually until each executive's 60th birthday. As of June 30, 2011 the former CFO/Treasurer/V.P. Finance retired. During the year ended December 31, 2011 the former CFO/Treasurer/V.P. Finance received payments totaling $50,000 from the Retirement Plan. At December 31, 2011, there were two officers who were included in the Retirement Plan and three that may qualify for the health insurance benefit.

Compensation expense for executives under the retirement plan for the year ended December 31, 2011, 2010 and 2009 was $72,000, $314,000, and $192,000, respectively. The total accrued liability for executive retirement under all plans at December 31, 2011, 2010 and 2009 was $947,000, $1.0 million, and $915,000, respectively.

USE has also established a mandatory retirement age of 70 unless the board specifically requests the services of an employee or officer beyond that age. Certain officers and one employee have agreements for payment of severance in the event of a change of control of USE.

Operating Leases

USE is the lessor of portions of the office buildings and building improvements that it owns. USE occupies the majority of its main office building. The leases are accounted for as operating leases and provide for minimum monthly receipts of $8,000 through December 31, 2012. Rental income under the agreements was $101,000, $98,000, and $138,000 for the years ended December 31, 2011, 2010 and 2009, respectively. Future minimum receipts for non-cancelable operating leases are $108,000 for the year ended December 31, 2012.

Table of Contents

O. SELECTED QUARTERLY FINANCIAL DATA (Unaudited)

	(In thousands except per share data) Three Months Ended			
	December 31, 2011	September 30, 2011	June 30, 2011	March 31, 2011
Operating revenues	$ 7,107	$ 9,972	$ 8,148	$ 4,883
Operating income (loss)	$ (2,475)	$ 875	$ 400	$ (4,864)
Income (loss) before income tax and discontinued operations	$ (2,362)	$ 1,022	$ 339	$ (4,932)
Benefit from (provision for) income taxes	$ 2,671	$ (892)	$ (618)	$ 2,594
Discontinued operations, net of tax	$ (3,100)	$ 138	$ 204	$ 129
Net income (loss)	$ (2,791)	$ 268	$ (75)	$ (2,209)
Income (loss) per share, basic				
Continuing operations	$ 0.01	$ --	$ (0.01)	$ (0.08)
Discontinued operations	(0.12)	0.01	0.01	--
	$ (0.11)	$ 0.01	$ --	$ (0.08)
Basic weighted average shares outstanding	27,288,470	27,259,174	27,220,049	27,186,438
Income (loss) per share, diluted				
Continuing operations	$ 0.01	$ --	$ (0.01)	$ (0.08)
Discontinued operations	(0.12)	0.01	0.01	--
	$ (0.11)	$ 0.01	$ --	$ (0.08)
Diluted weighted average shares outstanding	27,288,470	27,862,098	27,866,544	27,186,438

Table of Contents

	(In thousands except per share data) Three Months Ended			
	December 31, 2010	September 30, 2010	June 30, 2010	March 31, 2010
Operating revenues	$ 5,023	$ 5,717	$ 6,218	$ 7,709
Operating income (loss)	$ (2,862)	$ (958)	$ (297)	$ 1,250
Income (loss) before income tax and discontinued operations	$ (2,359)	$ (950)	$ (176)	$ 2,340
Benefit from (provision for) income taxes	$ 1,975	$ 634	$ 17	$ (888)
Discontinued operations, net of tax	$ (1,549)	$ 81	$ 28	$ 75
Net income (loss)	$ (1,933)	$ (235)	$ (131)	$ 1,527
Income (loss) per share, basic				
Continuing operations	$ (0.02)	$ (0.01)	$ --	$ 0.06
Discontinued operations	(0.05)	--	--	--
	$ (0.07)	$ (0.01)	$ --	$ 0.06
Basic weighted average shares outstanding	26,973,834	26,855,513	26,734,636	26,487,162
Income (loss) per share, diluted				
Continuing operations	$ (0.02)	$ (0.01)	$ --	$ 0.05
Discontinued operations	(0.05)	--	--	--
	$ (0.07)	$ (0.01)	$ --	$ 0.05
Diluted weighted average shares outstanding	26,973,834	26,855,513	26,734,636	27,785,572

Table of Contents

	(In thousands except per share data) Three Months Ended			
	December 31, 2009	September 30, 2009	June 30, 2009	March 31, 2009
Operating revenues	$ 5,462	$ 691	$ 754	$ 674
Operating income (loss)	$ (1,370)	$ (2,476)	$ (2,441)	$ (3,648)
Income (loss) before income tax and discontinued operations	$ (2,254)	$ (2,823)	$ (2,479)	$ (3,710)
Benefit from (provision for) income taxes	$ 1,011	$ 941	$ (590)	$ 1,200
Discontinued operations, net of tax	$ 41	$ 138	$ 184	$ 163
Net income (loss)	$ (1,202)	$ (1,744)	$ (2,885)	$ (2,347)
Loss per share, basic				
Continuing operations	$ (0.05)	$ (0.09)	$ (0.14)	$ (0.12)
Discontinued operations	--	0.01	0.01	0.01
	$ (0.05)	$ (0.08)	$ (0.13)	$ (0.11)
Basic weighted average shares outstanding	22,195,694	21,288,841	21,311,266	21,654,519
Loss per share, diluted				
Continuing operations	$ (0.05)	$ (0.09)	$ (0.14)	$ (0.11)
Discontinued operations	--	0.01	0.01	--
	$ (0.05)	$ (0.08)	$ (0.13)	$ (0.11)
Diluted weighted average shares outstanding	22,195,694	21,288,841	21,311,266	21,654,519

P. SUBSEQUENT EVENTS

Yellowstone and SE HR Prospect Undeveloped Acreage Sale. On January 24, 2012 (but effective December 1, 2011), the Company sold an undivided 75% of its undeveloped acreage in the SE HR Prospect and the Yellowstone Prospect to GeoResources, Inc. (56.25%) and Yuma Exploration and Production Company, Inc. (18.75%) for $16.7 million. Under the terms of the agreement, the Company retained the remaining 25% of its interest in the undeveloped acreage and its original working interest in its 10 developed wells in the SE HR and Yellowstone prospects (including the two wells drilled with Murex Petroleum Corporation discussed below). Our working interest in the remaining locations will be approximately 8.75% and net revenue interests in new wells after the sale are expected to be in the range of 6.7375% to 7.0%, proportionately reduced depending on Zavanna's actual working interest percentages.

Item 9 – Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None

Item 9A. Controls and Procedures

Effectiveness of Disclosure Controls and Procedures

We are required to maintain disclosure controls and procedures (as defined by Rules 13a-15(e) and 15d-15(e) under the Exchange Act) that are designed to ensure that required information is recorded, processed, summarized and reported within the required timeframe, as specified in the rules set forth by the SEC. Our disclosure controls and procedures are also designed to ensure that information required to be disclosed is accumulated and communicated to management, including our Chief Executive Officer and Principal Accounting Officer, to allow timely decisions regarding required disclosures.

Our management, with the participation of our Chief Executive Officer and Principal Accounting Officer, has evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2011 and, based on this evaluation, our Chief Executive Officer and Principal Accounting Officer have concluded that our disclosure controls and procedures were effective as of December 31, 2011.

Management's Annual Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Internal control over financial reporting is a process designed by, or under the supervision of, our Chief Executive Officer and Principal Accounting Officer, and effected by our Board, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of USE; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets that could have a material effect on our financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Forward looking statements regarding the effectiveness of internal controls during future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2011. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on our assessment, we believe that, as of December 31, 2011, our internal control over financial reporting was effective based on those criteria.

Our internal control over financial reporting as of December 31, 2011, has been audited by Hein & Associates LLP, the independent registered public accounting firm who also audited our consolidated financial statements. Hein & Associates LLP's report on our internal control over financial reporting appears on page 123 of this Annual Report.

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 December 31, 2011 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
U.S. Energy Corp.

We have audited U.S. Energy Corp.'s (the "Company") internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. U.S. Energy Corp.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that *(a)* pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; *(b)* provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and *(c)* provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, U.S. Energy Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of U.S. Energy Corp. and subsidiaries and the related consolidated statement of operations, shareholders' equity and comprehensive income, and cash flows for the year ended December 31, 2011 of U.S. Energy Corp. and our report dated March 14, 2012 expressed an unqualified opinion.

***HEIN** & ASSOCIATES LLP*
Denver, Colorado
March 14, 2012

Item 9B – Other Information

None

PART III

In the event a definitive proxy statement containing the information being incorporated by reference into this Part III is not filed within 120 days of December 31, 2011, we will file such information under cover of a Form 10-K/A.

Item 10 – Directors, Executive Officers and Corporate Governance

The information required by Item 10 with respect to directors and certain executive officers is incorporated herein by reference to our Proxy Statement for the Meeting of Shareholders to be held on June 29, 2012, under the captions “Proposal 1: Election of Directors”, “Filing of Reports under Section 16(a)”, and “Business Experience of Directors, Nominees and Officers”.

USE has adopted a Code of Ethics. A copy of the Code of Ethics will be provided to any person without charge upon written request addressed to Steven R. Youngbauer, Secretary, 877 North 8th West, Riverton, Wyoming 82501.

Information Concerning Executive Officers Who Are Not Directors

Steven R. Youngbauer is not a director of USE. Mr. Youngbauer (age 62) has been General Counsel and Corporate Secretary for USE since January 23, 2007. He serves at the will of the board of directors. There are no understandings between Mr. Youngbauer and any other person pursuant to which he was named an officer or General Counsel. He has no family relationships with any of the other executive officer or directors of USE. During the past five years, Mr. Youngbauer has not been involved in any Reg. S-K Item 401(f) proceeding.

Item 11 - Executive Compensation

The information required by Item 11 is incorporated herein by reference to the Proxy Statement for the Meeting of Shareholders to be held on June 29, 2012, under the captions “Executive Compensation” and “Non-Employee Director Compensation”.

Item 12 - Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by Item 12 is incorporated herein by reference to the Proxy Statement for the Meeting of Shareholders to be held on June 29, 2012, under the caption "Principal Holders of Voting Securities" and “Ownership by Officers and Directors”.

Item 13 - Certain Relationships and Related Transactions, and Director Independence

The information required by Item 13 is incorporated herein by reference to the Proxy Statement for the Meeting of Shareholders to be held on June 29, 2012, under the caption “Certain Relationships and Related Transactions.”

Item 14 - Principal Accounting Fees and Services

The information required by Item 14 is incorporated herein by reference to the Proxy Statement for the Meeting of Shareholders to be held on June 29, 2012, under the caption “Principal Accountant Fees and Services”.

Glossary of Oil and Gas Terms

The following are abbreviations and definitions of certain terms commonly used in the oil and gas industry and in this report. The definitions of proved developed reserves, proved reserves and proved undeveloped reserves have been abbreviated from the applicable definitions contained in Rule 4-10(a)(2-4) of Regulation S-X.

3-D seismic. The method by which a three dimensional image of the earth’s subsurface is created through the interpretation of reflection seismic data collected over surface grid. 3-D seismic surveys allow for a more detailed understanding of the subsurface than do conventional surveys and contribute significantly to field appraisal, development and production.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bcfe. One billion cubic feet of natural gas equivalent. In reference to natural gas, natural gas equivalents are determined using the ratio of 6 Mcf of natural gas to 1 Bbl of oil, condensate or natural gas liquids.

Boe. A barrel of oil equivalent is determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquid.

Completion. The installation of permanent equipment for the production of oil or natural gas. Completion of the well does not necessarily mean the well will be profitable.

Completion Rate. The number of wells on which production casing has been run for a completion attempt as a percentage of the number of wells drilled.

Developed Acreage. The number of acres, which are allocated or assignable to producing wells or wells capable of production.

Development Well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry Well. A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion of an oil or gas well.

Exploratory Well. A well drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir.

Fault. A break in the rocks along which there has been movement of one side relative to the other side.

Fault Block. A body of rocks bounded by one or more faults.

Gross Acres or Gross Wells. The total acres or wells, as the case may be, in which we have a working interest.

Lease Operating Expenses. The expenses, usually recurring, which pay for operating the wells and equipment on a producing lease.

Mcf. One thousand cubic feet of natural gas.

MMBtu. One million Btu, or British Thermal Units. One British Thermal Unit is the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Net Acres or Net Wells. Gross acres or wells multiplied, in each case, by the percentage working interest we own.

Net Production. Production that we own less royalties and production due others.

Oil. Crude oil, condensate or other liquid hydrocarbons.

Operator. The individual or company responsible for the exploration, development, and production of an oil or gas well or lease.

Pay. The vertical thickness of an oil and gas producing zone. Pay can be measured as either gross pay, including non-productive zones or net pay, including only zones that appear to be productive based upon logs and test data.

PV10. The pre-tax present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with Securities and Exchange Commission guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, and discounted using an annual discount rate of 10%.

Proved Developed Reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved Reserves. The estimated quantities of crude oil, natural gas and natural gas liquids, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved Undeveloped Reserves. Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Royalty. An interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

Standardized Measure. The after-tax present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with Securities and Exchange Commission guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, and discounted using an annual discount rate of 10%.

Trend. A geographical area that has been known to contain certain types of combinations of reservoir rock, sealing rock and trap types containing commercial amounts of hydrocarbons.

Working Interest. An interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and natural gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

PART IV

Item 15 – Exhibits and Financial Statement Schedules

All schedules are omitted because the required information is not applicable or is not present in amounts sufficient to require submission of the schedule or because the information required is included in the Consolidated Financial Statement and Notes thereto.

(b) Exhibits. The following exhibits are filed or furnished with or incorporated by reference into this report on Form 10-K:

3.1**	Restated Articles of Incorporation (incorporated by reference form Exhibit 4.1 to the Company's Registration Statement on Form S-3, [333-162607] filed October 21, 2009)
3.2**	Restated Bylaws, as amended through April 17, 2009 (incorporated by reference from Exhibit 3.2 to the Company's Report on Form 8-K filed April 21, 2009)
4.1(a)**	BNP Paribas Lending Facility – Credit Agreement (incorporated by reference from Exhibit 10.1 to the Company's Form 8-K filed August 2, 2010)
4.1(b)**	BNP Paribas Lending Facility – Mortgage Agreement (incorporated by reference from Exhibit 10.2 to the Company's Form 8-K filed August 2, 2010)
4.1(c)**	BNP Paribas Lending Facility – Guaranty (incorporated by reference from Exhibit 10.3 to the Company's Form 8-K filed August 2, 2010)
10.1**†	USE 2001 Officers' Stock Compensation Plan (incorporated by reference from Exhibit 4.21 to the Company's Annual Report on Form 10-K filed September 13, 2002)
10.2**†	2001 Incentive Stock Option Plan (amended in 2003) (incorporated by reference from Exhibit 4.2 to the Company's Annual Report on Form 10-K filed April 15, 2005)
10.3**	2008 Stock Option Plan for Independent Directors and Advisory Board Members (incorporated by reference from Exhibit 4.3 to the Company's Annual Report on Form 10-K filed March 13, 2009)
10.1**	Form of Production Payment Royalty Agreement (Exhibit A to the Asset Purchase Agreement with sxr Uranium One, Inc.) (incorporated by reference from Exhibit 10.2 to the Company's Report on Form 8-K filed February 23, 2007)
10.4(a)**†	Executive Employment Agreements (expires 4-20-12) (incorporated by reference from Exhibits 10.1, 10.2, 10.3, 10.4 to the Form 8-K filed April 21, 2009)
10.5(a)**†	Executive Employment Agreement – Keith G. Larsen (effective 4-20-12) (incorporated by reference from Exhibit 10.1 to the Form 8-K filed January 17, 2012)
10.5(b)**†	Executive Employment Agreement – Mark J. Larsen (effective 4-20-12) (incorporated by reference from Exhibit 10.2 to the Form 8-K filed January 17, 2012)
10.5(c)**†	Executive Employment Agreement – Steven R. Youngbauer (effective 4-20-12) (incorporated by reference from Exhibit 10.3 to the Form 8-K filed January 17, 2012)

10.6*	Agreement for Purchase of Leasehold Interests in McKenzie and Williams Counties, North Dakota (Brigham Oil & Gas, L.P.)
10.7(a)*	Agreement for Purchase of Leasehold Interests in McKenzie County, North Dakota (Geo Resources, Inc)
10.7(b)*	Amendments (5) to Agreement for Purchase of Leasehold Interest in McKenzie County, North Dakota (Geo Resources, Inc.)
14.0**	Code of Ethics (incorporated by reference from Exhibit 14 to the Company's Annual Report on Form 10-K filed March 30, 2004)
21.1*	Subsidiaries of Registrant
23.0*	Consent of Ryder Scott Company L.P.
23.1*	Consent of Cawley, Gillespie & Associates, Inc
23.2*	Consent of Netherland, Sewell & Associates, Inc.
23.3*	Consent of Independent Registered Accounting Firm (Hein & Associates LLP)
31.1*	Certification under Rule 13a-14(a) Keith G. Larsen
31.2*	Certification under Rule 13a-14(a) Bryon G. Mowry
32.1*	Certification under Rule 13a-14(b) Keith G. Larsen
32.2*	Certification under Rule 13a-14(b) Bryon G. Mowry
99.1*	Reserve Report (Ryder Scott Company L.P.)
99.2*	Reserve Report (Cawley, Gillespie & Associates, Inc.)
99.3*	Reserve Report (Netherland, Sewell & Associates, Inc.)
101.INS	XBRL Instance Document
101.SCH	XBRL Schema Document
101.CAL	XBRL Calculation Linkbase Document
101.LAB	XBRL Label Linkbase Document
101.PRE	XBRL Presentation Linkbase Document

* Filed herewith. ** Previously filed.
† Exhibit constitutes a management contract or compensatory plan or agreement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

U.S. ENERGY CORP. (Registrant)

Date: March 14, 2012 By: /s/ Keith G. Larsen
KEITH G. LARSEN, Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Date: March 14, 2012 By: /s/ Keith G. Larsen
KEITH G. LARSEN, Director, Chairman and CEO

Date: March 14, 2012 By: /s/ Bryon G. Mowry
BRYON G. MOWRY
Principal Accounting Officer

Date: March 14, 2012 By: /s/ Mark J. Larsen
MARK J. LARSEN, President and Director

Date: March 14, 2012 By: /s/ Robert Scott Lorimer
ROBERT SCOTT LORIMER, Director

Date: March 14, 2012 By: /s/ Allen S. Winters
ALLEN S. WINTERS, Director

Date: March 14, 2012 By: /s/ Stephen V. Conrad
STEPHEN V. CONRAD, Director

Date: March 14, 2012 By: /s/ Jerry W. Danni
JERRY W. DANNI, Director

Date: March 14, 2012 By: /s/ Leo A. Heath
LEO A. HEATH, Director

Exhibit 10.6

AGREEMENT FOR PURCHASE OF
LEASEHOLD INTERESTS IN MCKENZIE AND WILLIAMS COUNTIES, NORTH DAKOTA

This Agreement for Purchase of Leasehold Interests in McKenzie and Williams Counties, North Dakota (hereinafter referred to as the “Agreement”) is made and entered into effective as of the 15th day of December, 2011, (“Effective Date”) by and between BRIGHAM OIL & GAS, L.P., a Delaware limited liability company, whose address is 6300 Bridge Point Parkway, Building 2, Suite 500, Austin, Texas 78730 (hereinafter referred to as “Brigham”) and ENERGY ONE LLC , a Wyoming limited liability company, whose address is 877 N. 8th W., Riverton, Wyoming, 82501 (hereinafter referred to as “Energy One”) (Brigham and Energy One are sometimes individually referred to herein as a "Party" and collectively referred to herein as the "Parties").

W I T N E S S E T H:

WHEREAS, pursuant to that certain Drilling Participation Agreement (15 Well Program), dated August 24, 2009, by and between Brigham and U.S. Energy Corp., who assigned to Energy One (being hereinafter referred to as the “Drilling Participation Agreement”), Energy One has acquired interests in the oil, gas and other mineral leases described in Exhibit A hereto (Energy One’s interest in the oil and gas leases described in Exhibit A being hereinafter referred to as the “Subject Leasehold”); and

WHEREAS, pursuant to the terms of the Drilling Participation Agreement, the assignments of interests from Brigham to Energy One and the corresponding joint operating agreements (“JOA”) the wells described in Exhibit B hereto (the “Existing Wells”) have been drilled or are in the process of being drilled; and

WHEREAS, Energy One has agreed to assign to Brigham an undivided seventy-five percent (75%) interest in the Subject Leasehold, save and except Energy One’s interest in the Existing Wells, pursuant to the terms, provisions and conditions set forth in this Agreement;

NOW, THEREFORE, for and in consideration of the mutual covenants contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereto agree as follows:

ARTICLE I.
ASSIGNMENT

Section 1.1. Assignment of Conveyed Interests. Concurrent with the execution of this Agreement, Energy One agrees to convey to Brigham an undivided seventy five percent (75%) interest in the Subject Leasehold, less and except Energy One’s interest in the Existing Wells as described in Section 1.2 below, (hereinafter referred to as the “Conveyed Interests”) utilizing the form of assignment attached hereto as Exhibit C (the “Assignment”). A separate Assignment shall be executed and delivered for the properties located in each of McKenzie and Williams Counties, North Dakota.

Section 1.2. Reservation of Interest in Existing Wells. The Parties recognize and agree that Energy One is reserving all of its interest in the Existing Wells, being its existing interest in the well bore, equipment and fixtures of each Existing Well and its right to the production that is obtained from each such Existing Well (including any re-working or re-drill) from the Subject Leasehold (being hereinafter referred to as “Energy One’s Existing Well Interests”). Energy One’s Existing Well Interests and its retained twenty-five percent (25%) interest in the Subject Leasehold shall continue to be subject to the terms and conditions of the Drilling Participation Agreement, as modified by this Agreement.

ARTICLE II.
CONSIDERATION FOR ASSIGNMENT OF CONVEYED INTERESTS

Section 2.1. Consideration for Assignment of Conveyed Interests. Immediately upon the execution of this Agreement and Energy One’s execution and delivery of the Assignment in

recordable form, Brigham shall pay Energy One by wire transfer thirteen million six hundred ninety-five thousand eight hundred dollars ($13,695,800.00) for the Conveyed Interests.

ARTICLE III.
FUTURE OPERATIONS

Section 3.1. Drilling Proposals. During the calendar years 2012 and 2013 Energy One shall not have the right to propose the drilling, re-drill, or re-working of any wells located within the lands covered by the Subject Leasehold or pooled therewith.

Section 3.2. Permitting Support. Energy One shall support all of Brigham's permitting and other regulatory requests related to the Subject Leasehold and agrees to execute any documentation needed by Brigham to support its permitting and other operations on the lands that are covered by the Subject Leasehold.

Section 3.3. Drilling Commitment. During each of calendar year 2012 and 2013 Brigham agrees to commence or cause to be commenced, drilling operations for at least three wells within pooled units that include Subject Leasehold.

ARTICLE IV.
RELEASE OF LIENS

Section 4.1. Energy One Release of Lines. As soon as possible following the execution of this Agreement, but in any event within fifteen days of the execution of this Agreement, Energy One shall cause all of the mortgages and liens burdening the Conveyed Interests to be properly released of record in the appropriate County records.

Section 4.2. Failure to Obtain Release. Should Energy One fail to cause all of the liens burdening the Conveyed Interests to be released within fifteen days of the execution of this Agreement as provided in Section 4.1 above, at Brigham's election, (a) the consideration paid by Brigham to Energy One in Accordance with Article II shall be immediately reimbursed to Brigham by wire transfer to the account designated by Brigham, (b) Brigham will release the Assignment executed pursuant to Article I hereof and (c) this Agreement shall be null and void from its inception.

ARTICLE V.
MISCELLANEOUS

Section 5.1. Assignments. Any Party hereto may assign all or any part of its interest under the terms of this Agreement. This Agreement shall be binding upon and inure to the benefit of the Parties hereto and their respective successors and assigns. The conveyance or assignment instrument vesting such assignee with all or part of such interests in this Agreement or the Subject Leasehold shall provide that the assignment or conveyance is made subject to the terms and conditions contained in this Agreement.

Section 5.2. Notices. All notices and other communications required or permitted under this Agreement shall be in writing, and unless otherwise specifically provided, shall be delivered personally, or by mail, facsimile, email or delivery service, to the addresses set forth opposite the signatures of the Parties below, and shall be considered delivered upon the date of receipt. Each Party may specify its proper address or any other post office address within the continental limits of the United States by giving notice to other Parties, in the manner provided in this Section, at least ten (10) days prior to the effective date of such change of address. Email communications shall not be considered sufficient notice under this Agreement.

Section 5.3. Merger. This Agreement supersedes any and all prior and existing agreements, whether oral or in writing, between the Parties hereto with respect to the subject matter hereof and contains all of the covenants and agreements between the Parties with respect to the

subject matter hereof. However, except as modified by this Agreement, the Drilling Participation Agreement shall continue in full force and effect in accordance with its own terms.

Section 5.4. Counterparts. This Agreement may be executed in multiple counterparts, each of which shall be binding upon the signing Party or Parties thereto as fully as if all Parties had executed one instrument and all of such counterparts shall constitute one and the same instrument. If counterparts of this Agreement are executed, the signatures of the Parties, as affixed hereto, may be combined in and treated and given effect for all purposes as a single instrument. The Parties agree that each will accept signatures to this Agreement and the Assignment attached as Exhibit C transmitted by facsimile, provided that each Party promptly thereafter provides the other with copies of such documents bearing its original signature.

Section 5.5. Governing Law. THIS AGREEMENT SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF TEXAS, WITHOUT REGARD TO PRINCIPLES OF CONFLICTS OF LAWS, EXCEPT THAT, TO THE EXTENT THAT THE LAW OF NORTH DAKOTA, WHERE THE SUBJECT LEASEHOLD IS LOCATED, NECESSARILY GOVERNS, THE LAW OF NORTH DAKOTA SHALL APPLY. JURISDICTION AND VENUE SHALL BE IN THE COUNTY WHERE THE AFFECTED SUBJECT LEASEHOLD IS LOCATED IN NORTH DAKOTA.

IN WITNESS WHEREOF this Agreement is executed by the Parties on the dates set forth opposite their respective signatures below but is effective for all purposes as of the date first set forth above.

Address:
877 N. 8th W.
Riverton, WY 82501
Fax: (307) 857-3050
Phone: (307) 856-9271
Email: mark@usnrg.com

ENERGY ONE LLC

Dated: 12/14/11

By: /s/ Mark J. Larsen
Name Printed: Mark J. Larsen
Its: President

Address:
6300 Bridge Point Pkwy.
Bldg.2, Suite 500
Austin, Texas 78730
(512) 427-3300
Fax: (512) 427-3400
Email: llangford@bexp3d.com

BRIGHAM OIL & GAS, L.P.
by Brigham, Inc.
its General Partner

Dated: 12-14-11

By: /s/ A. Lance Langford
A. Lance Langford
Its: Executive Vice President – Operations

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The following is a list of exhibits and annexes to the Agreement for Purchase of Leasehold Interests in McKenzie and Williams Counties, North Dakota that were omitted from Exhibit10.6 pursuant to the provisions of Item 601(b)(2) of Regulation S-K. U.S. Energy Corp. agrees to furnish supplementally a copy of any omitted exhibit or annex to the Securities and Exchange Commission upon request.

1.	Exhibit A	Description of the Subject Leasehold
2.	Exhibit B	Existing Wells
3.	Exhibit C	Form of Assignment

Exhibit 10.7(a)

AGREEMENT FOR PURCHASE OF
LEASEHOLD INTERESTS IN MCKENZIE COUNTY, NORTH DAKOTA

This Agreement for Purchase of Leasehold Interests in McKenzie County, North Dakota (hereinafter referred to as the "Agreement") is made and entered into effective as of the 15th day of December, 2011, ("Effective Date") by and between **GeoResources, Inc.**, a Colorado corporation, whose address is 110 Cypress Station Dr., Suite 220, Houston, TX 77090 (hereinafter referred to as "GeoResources") and **Energy One LLC**, a Wyoming limited liability company, whose address is 877 N. 8th W., Riverton, Wyoming, 82501 (hereinafter referred to as "Energy One"). GeoResources and Energy One are sometimes individually referred to herein as a "Party" and collectively referred to herein as the "Parties".

W I T N E S S E T H:

WHEREAS, pursuant to the SE HR Participation Agreement dated December 1, 2010 by and between Zavanna, LLC, Spring Creek Exploration & Production Company, Liberty Resources LLC and Energy One as amended (hereinafter referred to as the "SE HR Participation Agreement"), a true and complete copy of which has previously been provided to GeoResources Inc., Energy One has acquired interests in the oil, gas and other mineral leases described in Exhibit A hereto (Energy One's interest in the oil and gas leases described in Exhibit A being hereinafter referred to as the "SE HR Subject Leasehold"); and

WHEREAS, pursuant to the Yellowstone Participation Agreement dated December 1, 2010 by and between Spring Creek Exploration & Production Company, Liberty Resources LLC, Prairie Petroleum, Inc., Gail Siegal, Administrator CTA Estate of Richard D. Siegal and Energy One as amended (hereinafter referred to as the "Yellowstone Participation Agreement"), a true and complete copy of which has previously been provided to GeoResources Inc., Energy One has acquired interests in the oil, gas and other mineral leases described in Exhibit B hereto (Energy One's interest in the oil and gas leases described in Exhibit B being hereinafter referred to as the "Yellowstone Subject Leasehold"); and

WHEREAS, pursuant to the terms of the SE HR Participation Agreement, the Yellowstone Participation Agreement and the corresponding joint operating agreements ("JOA") the wells described in Exhibit C hereto (the "Existing Wells") have been drilled and completed or were in the process of being drilled by November 30, 2011; and

WHEREAS, Energy One has entered into an agreement with a third party to sell an undivided seventy-five percent (75%) of Energy One's interest in the SE HR Subject Leasehold and the Yellowstone Subject Leasehold, save and except Energy One's interest in the Existing Wells, pursuant to the terms, provisions and conditions set forth in this Agreement.

WHEREAS, if the sale to a third party does not close on or before January 15, 2012, GeoResources desires to purchase an undivided seventy-five percent (75%) of Energy One's interest in the SE HR Subject Leasehold and the Yellowstone Subject Leasehold owned by Energy One, save and except Energy One's interest in the Existing Wells, pursuant to the terms, provisions and conditions set forth in this Agreement;

NOW, THEREFORE, for and in consideration of the mutual covenants contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereto agree as follows:

ARTICLE I.
ASSIGNMENT

Section 1.1. Closing, Assignment of Conveyed Interests and Failure to Close . If Energy One does not close the transaction with the third party on or before January 15, 2012, GeoResources agrees to purchase and close on the property on or before January 20, 2012, subject to adequacy of title. Furthermore, if the third party notifies Energy One of its termination of the third party

Agreement prior the third party closing date, then GeoResources agrees to close this transaction no later than five business days after written notification from Energy One of such termination by the third party, subject to adequacy of title. At closing, Energy One agrees to convey to GeoResources an undivided seventy five percent (75%) of Energy One's interest in the SE HR Subject Leasehold and the Yellowstone Subject Leasehold, less and except Energy One's interest in the Existing Wells as described in Section 1.2 below, (hereinafter referred to as the "Conveyed Interests") utilizing the form of assignment attached hereto as Exhibit D (the "Assignment"). The Assignment is subject to and GeoResources will be bound by, the terms and conditions of the SE HR Participation Agreement, the Yellowstone Participation Agreement and all associated JOA's for the Conveyed Interests. If Energy One closes the transaction with the third party on or before January 15, 2012, this Agreement is null and void by its owns terms without any further action by the Parties and neither Party will have any further obligations pursuant to this Agreement except for the Confidentiality provision in Section 3.5.

Section 1.2. Reservation of Interest in Existing Wells. The Parties recognize and agree that Energy One is reserving all of its interest in the Existing Wells, being its existing interest in the well bore, equipment and fixtures of each Existing Well and its right to the production that is obtained from each such Existing Well (including any re-working or re-drill of such well, within or above the presently drilled horizon) from the SE HR Subject Leasehold and the Yellowstone Subject Leasehold (being hereinafter referred to as "Energy One's Existing Well Interests").

Section 1.3. Effective Date. The effective date of the Assignment shall December 1, 2011.

ARTICLE II.
CONSIDERATION FOR ASSIGNMENT OF CONVEYED INTERESTS

Section 2.1. Consideration for Assignment of Conveyed Interests. Immediately upon Energy One's execution and delivery of the Assignment in recordable form, GeoResources shall pay Energy One by wire transfer sixteen million seven hundred thousand dollars ($16,700,000.00) for the Conveyed Interests.

Section 2.2 Reimbursement of Prepaid Costs. GeoResources also agrees to reimburse Energy One two hundred fifty-one thousand one hundred and fifty-one dollars ($251,150.00), which is 75% of the amount prepaid for surface location construction costs on the Bunning 35-26 #1H , the Kepner 9-4 #1H and the Skogen 17-20 #1H wells, payable at the same time the consideration is paid in Section 2.1 above.

ARTICLE III.
MISCELLANEOUS

Section 3.1. Assignments. Any Party hereto may assign all or any part of its interest under the terms of this Agreement. This Agreement shall be binding upon and inure to the benefit of the Parties hereto and their respective successors and assigns. The conveyance or assignment instrument vesting such assignee with all or part of such interests in this Agreement or the SE HR Subject Leasehold and the Yellowstone Subject Leasehold shall provide that the assignment or conveyance is made subject to the terms and conditions contained in this Agreement.

Section 3.2. Notices. All notices and other communications required or permitted under this Agreement shall be in writing, and unless otherwise specifically provided, shall be delivered personally, or by mail, facsimile, email or delivery service, to the addresses set forth opposite the signatures of the Parties below, and shall be considered delivered upon the date of receipt. Each Party may specify its proper address or any other post office address within the continental limits of the United States by giving notice to other Parties, in the manner provided in this Section, at least ten (10) days prior to the effective date of such change of address. Email communications shall not be considered sufficient notice under this Agreement.

Section 3.3. Counterparts. This Agreement may be executed in multiple counterparts, each of which shall be binding upon the signing Party or Parties thereto as fully as if all Parties had executed one instrument and all of such counterparts shall constitute one and the same instrument. If counterparts of this Agreement are executed, the signatures of the Parties, as affixed hereto, may be combined in and treated and given effect for all purposes as a single instrument. The Parties agree

that each will accept signatures to this Agreement and the Assignment attached as Exhibit D transmitted by facsimile, provided that each Party promptly thereafter provides the other with copies of such documents bearing its original signature.

Section 3.4. Governing Law. THIS AGREEMENT SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF WYOMING, WITHOUT REGARD TO PRINCIPLES OF CONFLICTS OF LAWS, EXCEPT THAT, TO THE EXTENT THAT THE LAW OF NORTH DAKOTA, WHERE THE SUBJECT LEASEHOLD IS LOCATED, NECESSARILY GOVERNS, THE LAW OF NORTH DAKOTA SHALL APPLY. JURISDICTION AND VENUE SHALL BE IN THE COUNTY WHERE THE AFFECTED SUBJECT LEASEHOLD IS LOCATED IN NORTH DAKOTA.

Section 3.5. **Confidentiality**. Sellers and Buyer shall treat this Agreement as confidential, except that disclosure of the existence of this Agreement and/or its provisions may be made (a) to those officers, employees or other authorized agents and representatives and professional consultants of a party hereto to whom disclosure is reasonably necessary in connection with the potential transactions under this Agreement and who shall agree to be bound by the terms of this Section, 3.5 as otherwise consented to in writing by the parties hereto, or (c) if in the opinion of the disclosing party's legal counsel (i) such disclosure is legally required to be made in a judicial, administrative or governmental proceeding pursuant to a valid subpoena or other applicable order; (ii) such disclosure is legally required to be made pursuant to the rules or regulations of a stock exchange or similar trading market applicable to the disclosing party; or (iii) such disclosure is legally required to be made by the rules and regulations of any regulatory authority;

IN WITNESS WHEREOF this Agreement is executed by the Parties on the dates set forth opposite their respective signatures below but is effective for all purposes as of the date first set forth above.

Address:	**Energy One LLC**	
877 N. 8th W.		
Riverton, WY 82501		
Fax: (307) 857-3050		
Phone: (307) 856-9271		
Email: mark@usnrg.com		
Dated: December 15, 2011	By:	/s/ Mark J. Larsen
		Name Printed: Mark J. Larsen
		Its: President
Address:	**GeoResources, Inc.**	
110 Cypress Station Dr., Suite 220		
Houston, TX 77090		
Fax: 281-537-8324		
Phone: 281-537-9920		
Email: Robert@Georesourcesinc.com		
Dated: December 15, 2011	By:	/s/ Robert J. Anderson
		Name Printed: Robert J. Anderson
		Its: Executive Vice President – Engineering & Acquisitions

The following is a list of exhibits to the Agreement for Purchase of Leasehold Interests in McKenzie and Williams Counties, North Dakota that were omitted from Exhibit10.6 pursuant to the provisions of Item 601(b)(2) of Regulation S-K. U.S. Energy Corp. agrees to furnish supplementally a copy of any omitted exhibit or annex to the Securities and Exchange Commission upon request.

1.	Exhibit A	Description of the SE HR Subject Leasehold
2.	Exhibit B	Description of the Yellowstone Subject Leasehold
3.	Exhibit C	SE HR & Yellowstone Existing Wells
4.	Exhibit D	Form of Assignment

Exhibit 10.7(b)

AMENDMENT

This Amendment ("Amendment") of the Agreement for Purchase of Leasehold Interests in McKenzie County, North Dakota, dated December 15, 2011 ("Agreement"),, is made and entered into effective as of the 10th day of January, 2012, by and among **GeoResources, Inc.**, a Colorado corporation, whose address is 110 Cypress Station Dr., Suite 220, Houston, TX 77090 (hereinafter referred to as "GeoResources"), **Yuma Exploration and Production Company, Inc.**, a Delaware corporation, whose address is 1177 West Loop South, Suite 1825, Houston, Texas 77027 (hereinafter referred to as "Yuma") and **Energy One LLC**, a Wyoming limited liability company, whose address is 877 N. 8th W., Riverton, Wyoming, 82501 (hereinafter referred to as "Energy One"). GeoResources, Yuma and Energy One are sometimes individually referred to herein as a "Party" and collectively referred to herein as the "Parties".

W I T N E S S E T H:

WHEREAS, GeoResources desires to assign to Yuma and Yuma desires to receive from GeoResources an undivided 25% interest in the Agreement and also have Energy One assign an undivided 18.75% interest in the Conveyed Interests to Yuma; and

WHEREAS, the Agreement provides that the Assignment is subject to and GeoResources will be bound by, the terms and conditions of the SE HR Participation Agreement, the Yellowstone Participation Agreement and all associated JOA's for the Conveyed Interests; and

WHEREAS, the Agreement also provides that GeoResources shall pay Energy One by wire transfer sixteen million seven hundred thousand dollars ($16,700,000.00) as consideration for the Conveyed Interests; and

WHEREAS, the Agreement also provides that GeoResources shall also reimburse Energy One for prepaid costs including two hundred fifty-one thousand one hundred and fifty dollars ($251,150.00), which is 75% of the amount prepaid for surface location construction costs on the Bunning 35-26 #1H, the Kepner 9-4 #1H and the Skogen 17-20 #1H wells, payable at the same time the consideration is paid above.

NOW, THEREFORE, for and in consideration of the mutual covenants contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereto agree as follows:

1. GeoResources hereby assigns to Yuma an undivided 25% interest in the Agreement to Yuma.

2. Yuma agrees to be bound by the terms and conditions of the Agreement including, but not limited to, the terms and conditions of the SE HR Participation Agreement, the Yellowstone Participation Agreement and all associated JOA's for the Conveyed Interests, copies of which have been provided to Yuma.

3. GeoResources and Yuma agree to pay Energy One the following amounts as consideration for the Conveyed Interest:

    a. GeoResources agrees to pay Energy One $12,525,000.00 for the Conveyed Interest and $188,362.50 as reimbursement for prepaid costs (75% of the total consideration); and

    b. Yuma agrees to pay Energy One $4,175,000.00 for the Conveyed Interest and $62,787.50 as reimbursement for prepaid costs (25% of the total consideration).

4. Energy One agrees to transfer to GeoResources and Yuma, as follows:

    a. To GeoResources or its designee an undivided 56.25% of Energy One's interest in the Conveyed Interests; and

    b. To Yuma or its designee an undivided 18.75% of Energy One's interest in the

Conveyed Interests.

5. Except as otherwise provided in this Amendment, the terms, conditions and provisions of the Agreement remain unchanged and are hereby ratified and reaffirmed and continue in full force and effect.

6. This Amendment may be executed in any number of counterparts; each of which when so executed and delivered shall be deemed an original, and all such counterparts together shall constitute one instrument.

IN WITNESS WHEREOF, this Amendment is executed by the Parties on the dates set forth opposite their respective signatures below, but is effective for all purposes as of the date first set forth above.

GeoResources, Inc.

By: /s/ Robert Anderson
Name Printed: Robert Anderson
Its: Executive VP – Engineering and Acquisitions
Date: 1-10-2012

Address: 110 Cypress Station Dr., Suite 220
Houston, TX 77090
Fax: 281-537-8324
Phone: 281-537-9920
Email: Robert@Georesourcesinc.com

Yuma Exploration and Production Company, Inc.

By: /s/ Michael F. Conlon
Name Printed: Michael F. Conlon
Its: President and Chief Operating Officer
Date: 1/13/2012

Address: 1177 West Loop South, Suite 1825
Houston, Texas 77027
Fax: (713) 968-7021
Phone: (713) 968-7068
Email: mconlon@yumacompanies.com

Energy One LLC

By: /s/ Mark J. Larsen
Name Printed: Mark J. Larsen
Its: President and Manager
Date: 1/16/12

Address: 877 N. 8th W.
Riverton, WY 82501
Fax: (307) 857-3050
Phone: (307) 856-9271
Email: mark@usnrg.com

AMENDMENT #2

This Amendment #2 (“Amendment #2”) of the Agreement for Purchase of Leasehold Interests in McKenzie County, North Dakota, dated December 15, 2011 (“Agreement”), is made and entered into effective as of the 16th day of January, 2012, by and among **GeoResources, Inc.**, a Colorado corporation, whose address is 110 Cypress Station Dr., Suite 220, Houston, TX 77090 (hereinafter referred to as “GeoResources”), **Yuma Exploration and Production Company, Inc.**, a Delaware corporation, whose address is 1177 West Loop South, Suite 1825, Houston, Texas 77027 (hereinafter referred to as “Yuma”) and **Energy One LLC**, a Wyoming limited liability company, whose address is 877 N. 8th W., Riverton, Wyoming, 82501 (hereinafter referred to as “Energy One”). GeoResources, Yuma and Energy One are sometimes individually referred to herein as a "Party" and collectively referred to herein as the "Parties".

W I T N E S S E T H:

WHEREAS, effective January 10, 2012 the Parties amended the Agreement; and

WHEREAS, on January 12, 2012, Energy One funded the January 10, 2012 cash call for the Skogen 17-20 #1H well with Zavanna in the amount of $1,303,832.00; and

WHEREAS, at Closing, GeoResources and Yuma will each acquire an interest in the Skogen 17-20 #1H well effective December 1, 2011, pursuant to the Agreement and Amendment and are responsible for their proportionate share of the January 10, 2012 cash call for this well.

NOW, THEREFORE, for and in consideration of the mutual covenants contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereto agree as follows:

7. GeoResources and Yuma agree to pay Energy One at Closing the following amounts as consideration for their proportionate share of the January 10, 2012 cash call for the Skogen 17-20 #1H well:

c. GeoResources agrees to pay Energy One $733,405.50 as reimbursement for prepaid cash call costs in this well (56.25% of the January 10, 2012 cash call); and

d. Yuma agrees to pay Energy One $244,468.50, as reimbursement for prepaid costs in this well (18.75% of the January 10, 2012 cash call).

8. Except as otherwise provided in this Amendment, the terms, conditions and provisions of the Agreement as heretofore amended, remain unchanged and are hereby ratified and reaffirmed and continue in full force and effect.

9. This Amendment may be executed in any number of counterparts; each of which when so executed and delivered shall be deemed an original, and all such counterparts together shall constitute one instrument.

(THE REMAINDER OF THE PAGE IS BLANK)

IN WITNESS WHEREOF, this Amendment is executed by the Parties on the dates set forth opposite their respective signatures below, but is effective for all purposes as of January 16, 2012.

GeoResources, Inc.

By: /s/ Robert Anderson
Name Printed: Robert Anderson
Its: Executive VP – Engineering and Acquisitions
Date: 1-16-2012

Address: 110 Cypress Station Dr., Suite 220
Houston, TX 77090
Fax: 281-537-8324
Phone: 281-537-9920
Email: Robert@Georesourcesinc.com

Yuma Exploration and Production Company, Inc.

By: /s/ Michael F. Conlon
Name Printed: Michael F. Conlon
Its: President and Chief Operating Officer
Date: 1-16-2012

Address: 1177 West Loop South, Suite 1825
Houston, Texas 77027
Fax: (713) 968-7021
Phone: (713) 968-7068
Email: mconlon@yumacompanies.com

Energy One LLC

By: /s/ Mark J. Larsen
Name Printed: Mark J. Larsen
Its: President and Manager
Date: 1/16/12

Address: 877 N. 8th W.
Riverton, WY 82501
Fax: (307) 857-3050
Phone: (307) 856-9271
Email: mark@usnrg.com

AMENDMENT #3

This Amendment #3 (“Amendment #3”) of the Agreement for Purchase of Leasehold Interests in McKenzie County, North Dakota, dated December 15, 2011 (“Agreement”), is made and entered into effective as of the 18th day of January, 2012, by and among **GeoResources, Inc.**, a Colorado corporation, whose address is 110 Cypress Station Dr., Suite 220, Houston, TX 77090 (hereinafter referred to as “GeoResources”), **Yuma Exploration and Production Company, Inc.**, a Delaware corporation, whose address is 1177 West Loop South, Suite 1825, Houston, Texas 77027 (hereinafter referred to as “Yuma”) and **Energy One LLC**, a Wyoming limited liability company, whose address is 877 N. 8th W., Riverton, Wyoming, 82501 (hereinafter referred to as “Energy One”). GeoResources, Yuma and Energy One are sometimes individually referred to herein as a "Party" and collectively referred to herein as the "Parties".

W I T N E S S E T H:

WHEREAS, the Parties previously amended the Agreement effective January 10, 2012 (“Amendment”) and January16, 2012 (“Amendment #2”); and

WHEREAS, the Parties desire to further amend the Agreement (“Amendment #3”) to extend the Closing to on or before January 25, 2012, unless otherwise mutually extended, which consent shall not be unreasonably withheld.

NOW, THEREFORE, for and in consideration of the mutual covenants contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereto agree as follows:

1. Section 1.1 of Article I. Assignment is amended to change the Closing to on or before on January 25, 2012, unless otherwise mutually extended by the Parties, which consent will not be unreasonably withheld.

2. Except as otherwise provided in this Amendment, the terms, conditions and provisions of the Agreement as heretofore amended, remain unchanged and are hereby ratified and reaffirmed and continue in full force and effect.

3. This Amendment may be executed in any number of counterparts; each of which when so executed and delivered shall be deemed an original, and all such counterparts together shall constitute one instrument.

(THE REMAINDER OF THE PAGE IS BLANK)

IN WITNESS WHEREOF, this Amendment is executed by the Parties on the dates set forth opposite their respective signatures below, but is effective for all purposes as of January 18, 2012.

GeoResources, Inc.

By: /s/ Robert Anderson
Name Printed: Robert Anderson
Its: Executive VP – Engineering and Acquisitions
Date: 18 January 2012

Address: 110 Cypress Station Dr., Suite 220
Houston, TX 77090
Fax: 281-537-8324
Phone: 281-537-9920
Email: Robert@Georesourcesinc.com

Yuma Exploration and Production Company, Inc.

By: /s/ Michael F. Conlon
Name Printed: Michael F. Conlon
Its: President and Chief Operating Officer
Date: Jan 18, 2012

Address: 1177 West Loop South, Suite 1825
Houston, Texas 77027
Fax: (713) 968-7021
Phone: (713) 968-7068
Email: mconlon@yumacompanies.com

Energy One LLC

By: /s/ Mark J. Larsen
Name Printed: Mark J. Larsen
Its: President and Manager
Date: 1/18/12

Address: 877 N. 8th W.
Riverton, WY 82501
Fax: (307) 857-3050
Phone: (307) 856-9271
Email: mark@usnrg.com

AMENDMENT #4

This Amendment #4 (“Amendment #4”) of the Agreement for Purchase of Leasehold Interests in McKenzie County, North Dakota, dated December 15, 2011 (“Agreement”), is made and entered into effective as of the 18th day of January, 2012, by and among **GeoResources, Inc.**, a Colorado corporation, whose address is 110 Cypress Station Dr., Suite 220, Houston, TX 77090 (hereinafter referred to as “GeoResources”), **Yuma Exploration and Production Company, Inc.**, a Delaware corporation, whose address is 1177 West Loop South, Suite 1825, Houston, Texas 77027 (hereinafter referred to as “Yuma”) and **Energy One LLC**, a Wyoming limited liability company, whose address is 877 N. 8th W., Riverton, Wyoming, 82501 (hereinafter referred to as “Energy One”). GeoResources, Yuma and Energy One are sometimes individually referred to herein as a "Party" and collectively referred to herein as the "Parties".

W I T N E S S E T H:

WHEREAS, the Parties previously amended the Agreement effective January 10, 2012 (“Amendment”), January16, 2012 (“Amendment #2”) and January 18, 2012 (“Amendment #3”); and

WHEREAS, the Parties desire to further amend the Agreement (“Amendment #4”) to Close on the Yellowstone Subject Leasehold on January 20, 2012, with the Closing on the SE HR Subject Leasehold to remain on or before January 25, 2012, unless otherwise mutually extended, which consent shall not be unreasonably withheld.

NOW, THEREFORE, for and in consideration of the mutual covenants contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereto agree as follows:

10. Section 1.1 of Article I. Assignment is amended to change the Closing of the Yellowstone Subject Leasehold to January 20, 2012, with the Closing on the SE HR Subject Leasehold to remain on or before on January 25, 2012, unless otherwise mutually extended by the Parties, which consent will not be unreasonably withheld.

11. At the Closing of the Yellowstone Subject Leasehold, GeoResources and Yuma agree to pay Energy One the following amounts as consideration for the Convey Interests:

    a. GeoResources agrees to pay Energy One $5,433,345.00 for the Conveyed Interest and $859,949.44 as reimbursement for prepaid costs (75% of the total consideration); and

    b. Yuma agrees to pay Energy One $1,811,115.00 for the Conveyed Interest and $286,649.81 as reimbursement for prepaid costs (25% of the total consideration).

12. At the Closing of the SE HR Subject Leasehold, GeoResources and Yuma agree to pay Energy One the following amounts as consideration for the Convey Interests:

    a. GeoResources agrees to pay Energy One $7,091,655.00 for the Conveyed Interest and $69,757.25 as reimbursement for prepaid costs (75% of the total consideration); and

    b. Yuma agrees to pay Energy One $2,363,885.00 for the Conveyed Interest and $23,252.42 as reimbursement for prepaid costs (25% of the total consideration).

13. Except as otherwise provided in this Amendment, the terms, conditions and provisions of the Agreement as heretofore amended, remain unchanged and are hereby ratified and reaffirmed and continue in full force and effect.

14. This Amendment may be executed in any number of counterparts; each of which when so executed and delivered shall be deemed an original, and all such counterparts together shall constitute one instrument.

IN WITNESS WHEREOF, this Amendment is executed by the Parties on the dates set forth opposite their respective signatures below, but is effective for all purposes as of January 18, 2012.

GeoResources, Inc.

By: /s/ Robert Anderson
Name Printed: Robert Anderson
Its: Executive VP – Engineering and Acquisitions
Date: 1-20-2012

Address: 110 Cypress Station Dr., Suite 220
Houston, TX 77090
Fax: 281-537-8324
Phone: 281-537-9920
Email: Robert@Georesourcesinc.com

Yuma Exploration and Production Company, Inc.

By: /s/ Michael F. Conlon
Name Printed: Michael F. Conlon
Its: President and Chief Operating Officer
Date: 1-20-2012

Address: 1177 West Loop South, Suite 1825
Houston, Texas 77027
Fax: (713) 968-7021
Phone: (713) 968-7068
Email: mconlon@yumacompanies.com

Energy One LLC

By: /s/ Mark J. Larsen
Name Printed: Mark J. Larsen
Its: President and Manager
Date: 1/20/12

Address: 877 N. 8th W.
Riverton, WY 82501
Fax: (307) 857-3050
Phone: (307) 856-9271
Email: mark@usnrg.com

AMENDMENT #5

This Amendment #5 (“Amendment #5”) of the Agreement for Purchase of Leasehold Interests in McKenzie County, North Dakota, dated December 15, 2011 (“Agreement”), is made and entered into effective as of the 24th day of January, 2012, by and among **GeoResources, Inc.**, a Colorado corporation, whose address is 110 Cypress Station Dr., Suite 220, Houston, TX 77090 (hereinafter referred to as “GeoResources”), **Yuma Exploration and Production Company, Inc.**, a Delaware corporation, whose address is 1177 West Loop South, Suite 1825, Houston, Texas 77027 (hereinafter referred to as “Yuma”) and **Energy One LLC**, a Wyoming limited liability company, whose address is 877 N. 8th W., Riverton, Wyoming, 82501 (hereinafter referred to as “Energy One”). GeoResources, Yuma and Energy One are sometimes individually referred to herein as a "Party" and collectively referred to herein as the "Parties".

W I T N E S S E T H:

WHEREAS, the Parties previously amended the Agreement effective January 10, 2012 (“Amendment”), January16, 2012 (“Amendment #2”), January 18, 2012 (“Amendment #3”) and January 20, 2012 (“Amendment #4”); and

WHEREAS, Energy One has paid two additional cash calls, $95,235.00 for the Barker 25-13 #1H well and $143,430.00 for the Wells 6-7 #1H well; and

WHEREAS, the Parties desire to further amend the Agreement (“Amendment #5”) to revise the closing cost for GeoResources and Yuma.

NOW, THEREFORE, for and in consideration of the mutual covenants contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereto agree as follows:

15. At the Closing of the SE HR Subject Leasehold, GeoResources and Yuma agree to pay Energy One the following amounts as consideration for the Conveyed Interests:

    c. GeoResources agrees to pay Energy One $7,091,655.00 for the Conveyed Interest and $204,006.32 as reimbursement for prepaid costs (75% of the total consideration); and

    d. Yuma agrees to pay Energy One $2,363,885.00 for the Conveyed Interest and $68,002.10 as reimbursement for prepaid costs (25% of the total consideration).

16. Except as otherwise provided in this Amendment, the terms, conditions and provisions of the Agreement as heretofore amended, remain unchanged and are hereby ratified and reaffirmed and continue in full force and effect.

17. This Amendment may be executed in any number of counterparts; each of which when so executed and delivered shall be deemed an original, and all such counterparts together shall constitute one instrument.

REMAINDER OF THE PAGE INTENTIONALLY LEFT BLANK

IN WITNESS WHEREOF, this Amendment is executed by the Parties on the dates set forth opposite their respective signatures below, but is effective for all purposes as of January 24, 2012.

GeoResources, Inc.

By: /s/ Robert Anderson
Name Printed: Robert Anderson
Its: Executive VP – Engineering and Acquisitions
Date: 1-24-2012

Address: 110 Cypress Station Dr., Suite 220
Houston, TX 77090
Fax: 281-537-8324
Phone: 281-537-9920
Email: Robert@Georesourcesinc.com

Yuma Exploration and Production Company, Inc.

By: /s/ Michael F. Conlon
Name Printed: Michael F. Conlon
Its: President and Chief Operating Officer
Date: 1-24-2012

Address: 1177 West Loop South, Suite 1825
Houston, Texas 77027
Fax: (713) 968-7021
Phone: (713) 968-7068
Email: mconlon@yumacompanies.com

Energy One LLC

By: /s/Mark J. Larsen
Name Printed: Mark J. Larsen
Its: President and Manager
Date: 1/24/12

Address: 877 N. 8th W.
Riverton, WY 82501
Fax: (307) 857-3050
Phone: (307) 856-9271
Email: mark@usnrg.com

Exhibit 21.1

U.S. Energy Corp.

Subsidiaries

Remington Village, LLC, a Wyoming Limited Liability Company

Energy One LLC, a Wyoming Limited Liability Company

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 3800 HOUSTON, TEXAS 77002-5235 TELEPHONE (713) 651-9191

EXHIBIT 23.0

CONSENT OF RYDER SCOTT COMPANY, L.P.

We hereby consent to the inclusion in this Annual Report on Form 10-K prepared by U.S. Energy Corp. (the "Company") for the year ending December 31, 2011, and to the incorporation by reference for the year ending December 31, 2009 and 2010, of our reports relating to certain estimated quantities of the Company's proved reserves of oil and gas, future net income and discounted future net income, effective December 31, 2009, 2010 and 2011. We further consent to references to our firm under the headings "Oil and Natural Gas" and "Oil and Natural Gas Reserves (Unaudited)."

We also consent to the incorporation by reference of information from our reports in the Registration Statements on Form S-3 (Nos. 333-162607, 333-151637, 33-137139, 333-135958, 333-134800, and 333-124277) and Form S-8 (Nos. 333-108979, 33-74154 and 333-166638).

\s\ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Houston, Texas
March 14, 2012

EXHIBIT 23.1

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

9601 AMBERGLEN BLVD., SUITE 117306
AUSTIN, TEXAS 78729-1106
512-249-7000

WEST SEVENTH STREET, SUITE 3021000
FORT WORTH, TEXAS 76102-4987
817- 336-2461
www.cgaus.com

LOUISIANA STREET, SUITE 625
HOUSTON, TEXAS 77002-5008
713-651-9944

CONSENT OF CAWLEY, GILLESPIE & ASSOCIATES, INC.

We hereby consent to the inclusion in this Annual Report on Form 10-K prepared by U.S. Energy Corp. (the "Company") for the year ending December 31, 2011, and to the incorporation by reference for the year ending December 31, 2009 and 2010, of our reports relating to certain estimated quantities of the Company's proved reserves of oil and gas, future net income and discounted future net income, effective December 31, 2009, 2010 and 2011. We further consent to references to our firm under the headings "Oil and Natural Gas" and "Oil and Natural Gas Reserves (Unaudited)."

We also consent to the incorporation by reference of information from our Report into the Company's Registration Statements on Form S-3 (Nos. 333-162607, 333-151637, 33-137139, 333-135958, 333-134800, and 333-124277), and Form S-8 (Nos. 333-108979, 33-74154 and 333-166638).

Very truly yours,

W. Todd Brooker, P.E.
Senior Vice President
Cawley, Gillespie & Associates, Inc.
Texas Registered Engineering Firm F-693

STATE OF TEXAS
W. TODD BROOKER
83462
LICENSED
PROFESSIONAL ENGINEER

Austin, Texas
March 12, 2012

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

EXHIBIT 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the inclusion in this Annual Report on Form 10-K prepared by U.S. Energy Corp. (the "Company") for the year ending December 31, 2011, of our reports relating to certain estimated quantities of the Company's proved reserves of oil and gas, future net income and discounted future net income, effective December 31, 2011. We further consent to references to our firm under the headings "Oil and Natural Gas" and "Oil and Natural Gas Reserves (Unaudited)."

We also consent to the incorporation by reference of information from our Report into the Company's Registration Statements on Form S-3 (Nos. 333-162607, 333-151637, 33-137139, 333-135958, 333-134800, and 333-124277), and Form S-8 (Nos. 333-108979, 33-74154 and 333-166638).

NETHERLAND, SEWELL & ASSOCIATES, INC.

/s/ Danny D. Simons, P.E.

By: _____
President and Chief Operating Officer

Houston, Texas
March 14, 2012

EXHIBIT 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement on Form S-8 of U.S. Energy Corp. of our reports dated March 14, 2012, relating to our audits of the consolidated financial statements and internal control over financial reporting, which appear in this Annual Report on Form 10-K of U.S. Energy Corp. for the year ended December 31, 2011.

HEIN *& ASSOCIATES LLP*

Denver, Colorado
March 14, 2012

Exhibit 31.1

CERTIFICATION

I, Keith G. Larsen, certify that:

1. I have reviewed this annual report on Form 10-K of U.S. Energy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

DATED this 14th day of March, 2012.

/s/ Keith G. Larsen
Keith G. Larsen
Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Bryon M Mowry, certify that:

1. I have reviewed this annual report on Form 10-K of U.S. Energy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

DATED this 14th day of March, 2012.

/s/ Bryon G. Mowry
Bryon G. Mowry
Principal Accounting Officer

Exhibit 32.1

Certification of CEO Pursuant to
18 U.S.C. Section 1350,
As Adopted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of U.S. Energy Corp. (the "Company") on Form 10-K for the period ending December 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Keith G. Larsen Chief Executive Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of his knowledge, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Keith G. Larsen
Keith G. Larsen,
Chief Executive Officer
March 14, 2012

This certification accompanies this Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.

A signed original of this written statement required by Section 906 has been provided to U.S. Energy Corp. and will be retained by U.S. Energy Corp. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

Certification of CFO Pursuant to
18 U.S.C. Section 1350,
As Adopted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of U.S. Energy Corp. (the "Company") on Form 10-K for the period ending December 31, 2011 as filed with the Securities and Exchange Commission on hereof (the "Report"), Bryon G. Mowry, Principal Accounting Officer of the Company, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of his knowledge, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

/s/ Bryon G. Mowry
Bryon G. Mowry,
Principal Accounting Officer
March 14, 2012

This certification accompanies this Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.

A signed original of this written statement required by Section 906 has been provided to U.S. Energy Corp. and will be retained by U.S. Energy Corp. and furnished to the Securities and Exchange Commission or its staff upon request.

U.S. Energy Corp.

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold Interests

(SEC Parameters)

As of

December 31, 2011

\s\ James F. Latham

James F. Latham, P.E.
TBPE License No. 49586
Senior Vice President

[SEAL]

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
REGISTERED ENGINEERING FIRM F-1580
(713) 651-0849
1100 LOUISIANA SUITE 3800 HOUSTON, TEXAS 77002-5235
FAX
TELEPHONE (713) 651-9191

February 9, 2012

U.S. Energy Corp.
877 North 8th West
Riverton, Wyoming 82501

Gentlemen:

At your request, Ryder Scott Company (Ryder Scott) has prepared an estimate of the proved reserves, future production and income attributable to certain leasehold interests of U.S. Energy Corp. (USE) as of December 31, 2011. The subject properties are located in the states of Louisiana and Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on February 6, 2012 and presented herein, was prepared for public disclosure by USE in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott account for a portion of USE's total net proved reserves as of December 31, 2011. Based on information provided by USE, the third party estimate conducted by Ryder Scott addresses 1.3 percent of the total proved developed net liquid hydrocarbon reserves and 24.8 percent of the total proved developed net gas reserves of USE. No proved undeveloped reserves attributable to USE were evaluated by Ryder Scott. On a barrels of oil equivalent (BOE) basis, Ryder Scott evaluated 4.6 percent of total proved USE net reserves (6 Mcf per barrel conversion).

The estimated reserves and future net income amounts presented in this report, as of December 31, 2011, are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized below.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
U.S. Energy Corp.
As of December 31, 2011

	Proved		
	Developed		Total
	Producing	Non-Producing	Proved
Net Remaining Reserves			
Oil/Condensate – Barrels	3,434	30,635	34,069
Plant Products – Barrels	219	1,469	1,688
Gas – MMCF	588	89	677
Income Data			
Future Gross Revenue	$ 2,680,947	$ 3,450,559	$ 6,131,506
Deductions	653,813	612,803	1,266,616
Future Net Income (FNI)	$ 2,027,134	$ 2,837,756	$ 4,864,890
Discounted FNI @ 10%	$ 1,748,259	$ 2,160,979	$ 3,909,238

Liquid hydrocarbons are expressed in standard 42 gallon barrels. All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, recompletion costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist, nor does it include any adjustment for cash on hand or undistributed income. Liquid hydrocarbon reserves account for approximately 58 percent and gas reserves account for the remaining 42 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income As of December 31, 2011
Discount Rate Percent	Total Proved
5	$ 4,350,123
15	$ 3,529,956
20	$ 3,202,243
30	$ 2,670,083

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "Petroleum Reserves Definitions" is included as an attachment to this report.

The various proved reserve status categories are defined under the attachment entitled "Petroleum Reserves Definitions" in this report. The proved developed non-producing reserves included herein consist of the shut-in and behind pipe category. Depleted well information has also been included for USE's information.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes included herein do not attribute gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves, and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At USE's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward". The proved reserves included herein were estimated using deterministic methods. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a "high degree of confidence that the quantities will be recovered."

Proved reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

USE's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may

cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which USE owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely than not to be achieved." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods, the volumetric method, or a combination of methods . Approximately 95 percent of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by the volumetric

method, with the remaining 5 percent estimated by performance methods . The volumetric analysis utilized pertinent well and seismic data furnished to Ryder Scott by USE or which we have obtained from public data sources that were available through December, 2011. These methods were used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate. The well data incorporated into our volumetric analysis were considered sufficient for the purpose thereof. Performance methods include, but may not be limited to, decline curve analysis or material balance methods which utilized extrapolations of historical production and pressure data available through December, 2011 in those cases where such data were considered to be definitive.

Approximately 88 percent of the proved developed non-producing reserves included herein were estimated by the volumetric method, and the remaining 12 percent were estimated by material balance methods.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data that cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

USE has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by USE with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by USE. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

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Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those reservoirs that are not currently producing. For behind pipe reserves not yet on production, sales were estimated to commence following depletion of the currently producing intervals or reservoirs. Reserves that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or reserves that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

USE furnished us with the above mentioned average prices in effect on December 31, 2011. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area(s) included in the report. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were either estimated by us based on information furnished by USE, or were provided to us by the operators of certain properties. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by such operators to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the "average realized prices." The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
United States	Oil/Condensate	WTI Cushing	$ 96.19/Bbl	$ 111.24/Bbl
	NGLs	WTI Cushing	$ 96.19/Bbl	$ 53.77/Bbl
	Gas	Henry Hub	$ 4.12/MMBTU	$ 4.15/MCF

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished to us by USE or partners of USE, and were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by USE**.** The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Recompletion costs were furnished to us by USE or partners of USE are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were significant. The estimates of the net abandonment costs furnished by USE or partners of USE were accepted without independent verification.

The proved developed non-producing reserves in this report have been incorporated herein in accordance with USE's plans to develop these reserves as of December 31, 2011. The implementation of USE's development plans as presented to us and incorporated herein is subject to the approval process adopted by USE's management. As the result of our inquiries during the course of preparing this report, USE has informed us that the development activities included herein have been subjected to and received the internal approvals required by USE's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to USE. USE has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, USE has informed us that they are not aware of any legal, regulatory, political or economic obstacles that would significantly alter their plans.

Current costs used by USE were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over seventy years. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to USE. Neither we nor any of our employees have any interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by USE.

USE makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, USE has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Forms S-3 and S-8 of USE of the references to our name as well as to the references to our third party report for USE, which appears in the December 31, 2011 annual report on Form 10-K of USE. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by USE.

We have provided USE with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by USE and the original signed report letter, the original signed report letter shall control and supersede the digital version.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

\s\ James F. Latham

James F. Latham, P.E.
TBPE License No. 49586
Senior Vice President

[SEAL]

JFL (FPR)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. James F. Latham was the primary technical person responsible for overseeing the estimate of the reserves, future production and income.

Latham, an employee of Ryder Scott Company L.P. (Ryder Scott) since 1980, is a Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Latham served in a number of engineering positions with Exxon Company USA (now ExxonMobil). For more information regarding Mr. Latham's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Latham earned a Bachelor of Science degree in Mechanical Engineering from Louisiana Tech University in 1974 and a Master of Science degree in Engineering from Louisiana Tech in 1975. Latham is a licensed Professional Engineer in the State of Texas (1981) and is also a member of the Society of Petroleum Evaluation Engineers and the Society of Petroleum Engineers.

The Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Latham fulfills. As part of his 2011 continuing education hours, Latham attended the 2011 RSC Reserves Conference, which addressed such diverse topics such SEC comment letters, applications of nanotechnology shale resource plays, the so-called "SEC 5-year rule," and particularly SPEE Monograph 3, which deals with the probabilistic analysis of resource plays. Latham attended an additional 12 hours of formalized in-house training during 2011 covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, geoscience and petroleum economics evaluation methods, procedures and software and ethics for consultants. Latham has personally authored and conducts instruction regarding over 20 petroleum engineering software programs, eleven of which comprise Ryder Scott's Reservoir Solutions Software for Microsoft® Excel. Reservoir Solutions Software, published by Ryder Scott, is made available without cost to energy industry professionals, and currently has in excess of 10,000 users located in more than 80 countries worldwide.

Based on his educational background, professional training and more than 32 years of practical experience in the estimation and evaluation of petroleum reserves, Latham has attained the professional qualifications as a Reserves Estimator and as a Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale.

Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

PROVED RESERVES (SEC DEFINITIONS) CONTINUED

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:

(1) completion intervals which are open at the time of the estimate, but which have not started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

CAWLEY, GILLESPIE & ASSOCIATES, INC.

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10 February 2012

Mr. Steven D. Richmond
U.S. Energy Corp.
877 North 8th West
Riverton, WY 82501

Re: Evaluation Summary
U.S. Energy Corp. Interests
Total Proved Reserves
As of December 31, 2011

Pursuant to the Guidelines of the Securities and Exchange Commission for Reporting Corporate Reserves and Future Net Revenue

Dear Mr. Richmond:

As requested, this report was prepared on February 10, 2012 for U.S. Energy Corp. ("USEC") for the purpose of submitting our reserve estimates and economic forecasts attributable to the subject interests. We evaluated 96% of USEC reserves, including Bakken/Three Forks oil properties located in McKenzie/Williams Counties, North Dakota. The evaluation employed an effective date of December 31, 2011, using constant prices and costs, while conforming to Item 1202(a)(8) of Regulation S-K and other rules of the *Securities and Exchange Commission* (SEC).

Composite forecasts for the Total Proved, Proved Developed, Proved Developed Producing, Proved Developed Non-Producing and Proved Undeveloped estimates are presented by category in Tables I-TP, I-PD, I-PDP, I-PDNP and I-PUD, respectively. Table I-PD is the summation of the Proved Developed Producing and Proved Developed Non-Producing estimates. The "II" Tables present estimates of ultimate recovery, gross and net reserves, ownership, revenue, expenses, investments, net income and discounted cash flow at ten (10) percent for the individual properties, which are listed alphabetically by lease name for each category.

The proved reserves and economics by category are summarized as follows:

			Proved		
			Total	Developed	Undeveloped
Net Reserves					
Oil	— bbl		2,646,429	1,792,499	853,930
Gas	— Mcf		1,996,848	1,236,253	760,595
Net Revenue					
Oil	— $		230,973,859	156,467,062	74,506,773
Gas	— $		16,296,113	10,114,524	6,181,589
Net BOE Production	—	BOE	2,979,238	1,998,541	980,696
Ad Valorem Tax	—	$	0	0	0
Operating Expense	—	$	47,311,031	33,280,980	14,030,056
Production Severance Tax	—	$	26,748,043	18,131,182	8,652,856
Investments	—	$	42,749,039	6,876,118	35,872,9
Future Net Cash Flow	—	$	130,425,844	108,293,312	22,132,529
Discounted @ 10% ***(Present Worth)***	**—**	**$**	**66,154,180**	**64,973,578**	**1,180,602**

Of the Proved Developed reserves, **1,632,514 BOE** was attributed to producing zones in existing wells (PDP) and **366,027 BOE** were attributed to zones in existing wells not producing (PDNP). Future revenue was calculated prior to deducting state production taxes and ad valorem taxes. Future net cash flow was calculated after deducting these taxes, future capital costs and operating expenses; however, federal income taxes were not included. The future net cash flow was discounted at an annual rate of ten (10) percent to determine its "present worth" in accordance with SEC guidelines. Present worth indicates the effect of time on the value of money and should not be construed as being the fair market value of the properties.

The oil reserves include oil and condensate. Oil volumes are expressed in barrels (42 U.S. gallons). Gas volumes are expressed in thousands of standard cubic feet (Mcf) at contract temperature and pressure base. The net BOE production is based on one (1) barrel of oil being the equivalent of six (6) Mcf of gas.

All included estimates were calculated only from proved reserves. Probable/possible reserves and any additional values for interest in acreage beyond the location of proved reserves have been excluded from the evaluation.

Hydrocarbon Pricing

The base oil and gas prices calculated for December 31, 2011 were **$96.19/bbl** and **$4.118/MMBTU**, respectively. As specified by the SEC, a company must use a 12-month average price, calculated from the unweighted average of each first-day-of-the-month price within the 12-month period

prior to the end of the reporting period. The oil price is based on WTI-Cushing spot prices (EIA) during 2010 and the gas price is based on Henry Hub spot prices (Platt's Gas Daily) during 2010.

The base prices were adjusted for differentials, which may include local basis differentials, transportation, gas shrinkage, gas heating value (BTU content) and/or crude quality and gravity corrections. After these adjustments, the net realized prices were estimated to be **$87.28/bbl** for oil and **$8.16/MCF** for gas. All economic factors were held constant in accordance with SEC guidelines.

Economic Parameters

Ownership was accepted as furnished and has not been independently confirmed. Oil and gas price differentials, gas shrinkage, ad valorem taxes, lease operating expenses and investments were calculated and prepared by USEC and/or Brigham and were thoroughly reviewed by us for accuracy, completeness, and variance from prior years. Lease operating expenses, price differentials, and gas shrinkage were determined at the well level using 12-month averages estimated from August 2010 through July 2011 statements. Ad valorem tax percentages were determined at the well level by comparing 2010 taxes paid to 2010 total revenue. No ad valorem taxes are paid in North Dakota.

SEC Conformance and Regulations

The reserve classifications and the economic considerations used herein conform to the criteria of the SEC as defined in pages one/two of the Appendix. The reserves and economics are predicated on regulatory agency classifications, rules, policies, laws, taxes and royalties currently in effect except as noted herein. The possible effects of changes in legislation or other Federal or State restrictive actions which could affect the reserves and economics have not been considered. However, we do not anticipate nor are we aware of any legislative changes or restrictive regulatory actions that may impact the recovery of reserves.

This evaluation includes 29 proved undeveloped locations, with each targeting the Middle Bakken or Three Forks reservoir in McKenzie/Williams Counties, North Dakota. Each of these drilling locations proposed as part of USEC's development plans conforms to the proved undeveloped standards as set forth by the SEC. In our opinion, USEC and joint venture operators have indicated they have intent to complete this development plan within the next five (5) years. Furthermore, they have demonstrated that they have the proper company staffing, financial backing and prior development success to ensure this five year development plan will be fully executed.

Reserve Estimation Methods

The methods employed in estimating reserves are described in page three (3) of the Appendix. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to offset production, both of which are considered to provide a relatively high degree of accuracy.

Non-producing reserve estimates, for both developed and undeveloped properties, were forecasted using either volumetric, analogy methods, or a combination of both. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and proved undeveloped reserves for US Energy properties, due to the mature nature of their properties targeted for development and an abundance of

subsurface control data. The assumptions, data, methods and procedures used herein are appropriate for the purpose served by this report.

General Discussion

The estimates and forecasts were based upon interpretations of data furnished by USEC and available from our files. All estimates represent our best judgment based on the data available at the time of preparation. Due to inherent uncertainties in future production rates, commodity prices and geologic conditions, it should be realized that the reserve estimates, the reserves actually recovered, the revenue derived therefrom and the actual cost incurred could be more or less than the estimated amounts.

An on-site field inspection of the properties has not been performed nor have the mechanical operation or condition of the wells and their related facilities been examined nor have the wells been tested by Cawley, Gillespie & Associates, Inc. Possible environmental liability related to the properties has not been investigated nor considered. The cost of plugging and the salvage value of equipment at abandonment have not been included.

Cawley, Gillespie & Associates, Inc. is a Texas Registered Engineering Firm (F-693), made up of independent registered professional engineers and geologists that have provided petroleum consulting services to the oil and gas industry for over 50 years. This evaluation was prepared by W. Todd Brooker, Vice President at Cawley, Gillespie & Associates, Inc. and a State of Texas Licensed Professional Engineer (License #83462). We do not own an interest in the properties or US Energy Corp. and are not employed on a contingent basis. We have used all methods and procedures that we consider necessary under the circumstances to prepare this report. Our work-papers and related data utilized in the preparation of these estimates are available in our office.

Yours very truly,

Cawley, Gillespie & Associates, Inc.
Texas Registered Engineering Firm F-693

/s/ W. Todd Brooker (SEAL)

W. Todd Brooker, P. E.
Senior Vice President

APPENDIX
Explanatory Comments for Summary Tables

HEADINGS

Table I
Description of Table Information
Identity of Interest Evaluated
Property Description – Location
Reserve Classification and Development Status
Effective Date of Evaluation

FORECAST

(Columns)

(1) (11) Calendar or Fiscal years/months commencing on effective date.
(2) (3) Gross Production (8/8th) for the years/months which are economical. These are expressed as thousands of barrels (Mbbl) and millions of cubic feet (MMcf) of gas at standard conditions. Total future production, cumulative production to effective date, and ultimate recovery at the effective date are shown following the annual/monthly forecasts. *(Gross MBOE is shown to right of Ultimate Recovery values in light gray font, calculated by dividing the ultimate gross gas production by six (6) then adding to the ultimate gross oil production.)*
(4) (5) Net Production accruable to evaluated interest is calculated by multiplying the revenue interest times the gross production. These values take into account changes in interest and gas shrinkage.
(6) Average (volume weighted) Gross Liquid Price per barrel adjusted for average differential above or below NYMEX, but before deducting production-severance taxes. *(Composite differential in $/bbl shown at left in light gray font)*
(7) Average (volume weighted) Gross Gas Price per Mcf adjusted for average differential above or below NYMEX, but before deducting production-severance taxes. *(Composite differential in $/mcf shown at left in light gray font)*
(8) Revenue derived from oil sales -- column (4) times column (6).
(9) Revenue derived from gas sales -- column (5) times column (7).
(10) Total Revenue -- column (8) plus column (9).
(11) Calendar or Fiscal years/months commencing on effective date.
(12) Net MBOE Production (equivalent net oil production) – Accruable to evaluated interest is calculated by dividing the net gas production by six (6) then adding to the net oil production.
(13) Ad Valorem Taxes.
(14) Average Gross Wells.
(15) Average Net Wells are gross wells times working interest.
(16) Operating Expenses are direct operating expenses to the evaluated working interest.
(17) Production Taxes – Severance Taxes deducted from gross oil and gas revenue.
(18) Investment, if any, includes work-overs, future drilling costs, pumping units, etc. and may be included either tangible or intangible or both.
(19) Future Net Cash Flow is column (10) less columns (13), (16), (17) and (18). The data in column (19) are accumulated in column (20). Federal income taxes have not been considered.
(20) Cumulative Future Net Cash Flow.
(21) Cumulative Cash Flow Discounted @ 10% is calculated by discounting monthly cash flows at the specified annual rates.

MISCELLANEOUS

DCF Profile • The cash flow discounted at six different rates are shown at the bottom of columns (20-21). Interest has been compounded monthly.
Life • The economic life of the appraised property is noted in the lower right-hand corner of the table.
Footnotes • Comments regarding the evaluation may be shown in the lower left-hand footnotes.
Price Deck • A table of oil and gas prices, price caps and escalation rates may be shown in the lower middle footnotes.

APPENDIX

Reserve Definitions and Classifications

The Securities and Exchange Commission, in SX Reg. 210.4-10 dated November 18, 1981, as amended on September 19, 1989 and January 1, 2010, requires adherence to the following definitions of oil and gas reserves:

"(22) **Proved oil and gas reserves**. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations— prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

"(i) The area of a reservoir considered as proved includes: (A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

"(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

"(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

"(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

"(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

"(6) **Developed oil and gas reserves**. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

“(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

“(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

"(31) **Undeveloped oil and gas reserves**. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

“(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

“(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

“(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

"(18) **Probable reserves**. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

"(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

"(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

"(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

"(iv) See also guidelines in paragraphs (17)(iv) and (17)(vi) of this section (below).

"(17) **Possible reserves**. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

"(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

"(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

"(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

"(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

"(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

"(vi) Pursuant to paragraph (22)(iii) of this section (above), where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations."

Instruction 4 of Item 2(b) of Securities and Exchange Commission Regulation S-K was revised January 1, 2010 to state that "a registrant engaged in oil and gas producing activities shall provide the information required by Subpart 1200 of Regulation S–K." This is relevant in that Instruction 2 to paragraph (a)(2) states: "The registrant is *permitted, but not required*, to disclose probable or possible reserves pursuant to paragraphs (a)(2)(iv) through (a)(2)(vii) of this Item."

"(26) **Reserves**. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

"Note to paragraph (26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations)."

APPENDIX

Methods Employed in the Estimation of Reserves

The four methods customarily employed in the estimation of reserves are (1) *production performance*, (2) *material balance*, (3) *volumetric* and (4) *analogy*. Most estimates, although based primarily on one method, utilize other methods depending on the nature and extent of the data available and the characteristics of the reservoirs.

Basic information includes production, pressure, geological and laboratory data. However, a large variation exists in the quality, quantity and types of information available on individual properties. Operators are generally required by regulatory authorities to file monthly production reports and may be required to measure and report periodically such data as well pressures, gas-oil ratios, well tests, etc. As a general rule, an operator has complete discretion in obtaining and/or making available geological and engineering data. The resulting lack of uniformity in data renders impossible the application of identical methods to all properties, and may result in significant differences in the accuracy and reliability of estimates.

A brief discussion of each method, its basis, data requirements, applicability and generalization as to its relative degree of accuracy follows:

Production performance. This method employs graphical analyses of production data on the premise that all factors which have controlled the performance to date will continue to control and that historical trends can be extrapolated to predict future performance. The only information required is production history. Capacity production can usually be analyzed from graphs of rates versus time or cumulative production. This procedure is referred to as "decline curve" analysis. Both capacity and restricted production can, in some cases, be analyzed from graphs of producing rate relationships of the various production components. Reserve estimates obtained by this method are generally considered to have a relatively high degree of accuracy with the degree of accuracy increasing as production history accumulates.

Material balance. This method employs the analysis of the relationship of production and pressure performance on the premise that the reservoir volume and its initial hydrocarbon content are fixed and that this initial hydrocarbon volume and recoveries therefrom can be estimated by analyzing changes in pressure with respect to production relationships. This method requires reliable pressure and temperature data, production data, fluid analyses and knowledge of the nature of the reservoir. The material balance method is applicable to all reservoirs, but the time and expense required for its use is dependent on the nature of the reservoir and its fluids. Reserves for depletion type reservoirs can be estimated from graphs of pressures corrected for compressibility versus cumulative production, requiring only data that are usually available. Estimates for other reservoir types require extensive data and involve complex calculations most suited to computer models which makes this method generally applicable only to reservoirs where there is economic justification for its use. Reserve estimates obtained by this method are generally considered to have a degree of accuracy that is directly related to the complexity of the reservoir and the quality and quantity of data available.

Volumetric. This method employs analyses of physical measurements of rock and fluid properties to calculate the volume of hydrocarbons in-place. The data required are well information sufficient to determine reservoir subsurface datum, thickness, storage volume, fluid content and location. The volumetric method is most applicable to reservoirs which are not susceptible to analysis by production performance or material balance methods. These are most commonly newly developed and/or no-pressure depleting reservoirs. The amount of hydrocarbons in-place that can be recovered is not an integral part of the volumetric calculations but is an estimate inferred by other methods and a knowledge of the nature of the reservoir. Reserve estimates obtained by this method are generally considered to have a low degree of accuracy; but the degree of accuracy can be relatively high where rock quality and subsurface control is good and the nature of the reservoir is uncomplicated.

Analogy. This method which employs experience and judgment to estimate reserves, is based on observations of similar situations and includes consideration of theoretical performance. The analogy method is applicable where the data are insufficient or so inconclusive that reliable reserve estimates cannot be made by other methods. Reserve estimates obtained by this method are generally considered to have a relatively low degree of accuracy.

Much of the information used in the estimation of reserves is itself arrived at by the use of estimates. These estimates are subject to continuing change as additional information becomes available. Reserve estimates which presently appear to be correct may be found to contain substantial errors as time passes and new information is obtained about well and reservoir performance.

NETHERLAND, SEWELL
& ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING - GEOLOGY - GEOPHYSICS – PETROPHYSICS

February 15, 2012

Mr. Steven D. Richmond
U.S. Energy Corp.
877 North 8th West
Riverton, Wyoming 82501

Dear Mr. Richmond:

In accordance with your request, we have estimated the proved developed producing reserves and future revenue, as of December 31, 2011, to the U.S. Energy Corp. (U.S. Energy) interest in certain oil properties located in Leona River and Pearsall Fields, Dimmit and Zavala Counties, Texas. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute approximately 2 percent of all proved reserves owned by U.S. Energy. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for U.S. Energy's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the U.S. Energy interest in these properties, as of December 31, 2011, to be:

	Net Reserves		Future Net Revenue (M$)	
Category	Oil (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	57.5	60.2	3,456.8	2,474.0

The oil reserves shown include crude oil only. Oil volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved developed producing reserves. Our study indicates that there are no proved developed non-producing or proved undeveloped reserves for these properties at this time. No study was made to determine whether probable or possible reserves might be established for these properties. This report does not include any value that could be attributed to interests in undeveloped acreage. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue is U.S. Energy's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for U.S. Energy's share of production taxes and ad valorem taxes and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2011. For oil volumes, the average West Texas

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Intermediate posted price of $92.71 per barrel is adjusted by field for quality, transportation fees, and regional price differentials. For gas volumes, the average Henry Hub spot price of $4.118 per MMBTU is adjusted by field for energy content, transportation fees, and regional price differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $92.71 per barrel of oil and $4.025 per MCF of gas.

Operating costs used in this report are based on operating expense records of Crimson Exploration Inc. (Crimson), the operator of the properties. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Since all properties are nonoperated, headquarters general and administrative overhead expenses of U.S. Energy are not included. Operating costs are held constant throughout the lives of the properties. As requested, our estimates do not include any salvage value for the lease and well equipment or the cost of abandoning the properties.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential gas volume and value imbalances resulting from overdelivery or underdelivery to the U.S. Energy interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on U.S. Energy receiving its net revenue interest share of estimated future gross gas production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from U.S. Energy, Crimson, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting geoscience, performance, and work data are on file in our office. The titles to the properties have not been examined by NSAI, nor has the actual degree or type of interest owned been independently confirmed. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent

petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

/s/ C.H. (Scott) Rees III
By:
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

/s/ Richard B. Talley, Jr.
By:
Richard B. Talley, Jr., P.E. 102425
Vice President

Date Signed: February 15, 2012

LPV:DEG

Please be advised that the digital document you are viewing is provided by Netherland, Sewell & Associates, Inc. (NSAI) as a convenience to our clients. The digital document is intended to be substantively the same as the original signed document maintained by NSAI. The digital document is subject to the parameters, limitations, and conditions stated in the original document. In the event of any differences between the digital document and the original document, the original document shall control and supersede the digital document.

Professional Qualifications of Primary Technical Person

The reserves estimates shown herein have been independently evaluated by Netherland, Sewell & Associates, Inc. (NSAI), a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical person primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein is Mr. Richard B. Talley, Jr. Mr. Talley has been practicing consulting petroleum engineering at NSAI since 2004. Mr. Talley is a Licensed Professional Engineer in the State of Texas (No. 102425) and has over 13 years of practical experience in petroleum engineering, with over 7 years experience in the estimation and evaluation of reserves. He graduated from University of Oklahoma in 1998 with a Bachelor of Science Degree in Mechanical Engineering and from Tulane University in 2001 with a Master of Business Administration Degree. He meets or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology*. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)
b. Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.
b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.
c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.
d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.

f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.