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

(Mark One)

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

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 þ

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 þ

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 þ NO ¨

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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 þ 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 þ

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 þ 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 þ

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.

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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,” ar 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;

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- 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;

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- 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 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

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(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.

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	(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"

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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.

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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

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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.

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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.

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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.

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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

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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;

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- 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

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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.

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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.

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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.

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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

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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.

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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.

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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.

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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.

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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

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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

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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

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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.

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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

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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.

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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.

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	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.

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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%.

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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.

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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.

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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 (MoS_2). 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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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

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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:

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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.

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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.

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	(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	27,238,869	26,763,995	21,604,959	23,274,978	22,189,828

outstanding

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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 a 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
	20,739	21,077

Undeveloped mining properties		
	$ 140,242	$ 106,014

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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:

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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.

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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.

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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.

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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:

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	(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, 2011	2010	Increase (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)
	(848)	(1,881)	1,033

Risk management activities			
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)

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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.

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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
	12,130	5,066

Depreciation, depletion and amortization						
Impairment		1,540			1,468	
		31,408			19,620	
Operating loss	$	(4,232	)	$	(9,271	)

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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

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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, 2010	Year Ended December 31, 2009	Increase (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

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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.

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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.

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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").

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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.

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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

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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.

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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.

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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.

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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

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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.

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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.

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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.

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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

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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.

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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

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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.

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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.

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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.

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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.

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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.

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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, 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.

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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.

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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.

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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.

U.S. ENERGY CORP.
NOTESTO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2011, 2010,and 2009

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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.

U.S. ENERGY CORP.
NOTESTO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2011, 2010,and 2009
(Continued)

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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

U.S. ENERGY CORP.
NOTESTO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2011, 2010,and 2009
(Continued)

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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.

U.S. ENERGY CORP.
NOTESTO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2011, 2010,and 2009
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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.

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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.

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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.

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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.

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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

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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.

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(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

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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

Total

	Less Than 12 Months		12 Months or Greater			
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

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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

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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.

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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

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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	16,68	