US ENERGY CORP
Form 10-K
March 12, 2010

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, 2009

¨ 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 ¨

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, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ¨ Accelerated filer ¨ Non-accelerated filer þ

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, 2009): $40,215,356.

Class	Outstanding at March 11, 2010
Common stock, $.01 par value	26,499,324

Documents incorporated by reference: None.

TABLE OF CONTENTS

-3-

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 (the "Securities Act") and Section 21E of the Securities Exchange Act of 1934 (the "Exchange Act"). All statements, other than statements of historical facts, are forward-looking statements. Examples of such statements in this Annual Report concern planned capital expenditures for oil and gas exploration; payment or amount of dividends on our common stock in the future; our business strategy and plans to build an asset base that generates recurring revenues; continued earnings swings; 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 and other areas; timing for drilling of additional wells; expected spacing for wells to be drilled with Brigham Exploration Company in the Bakken/Three Forks formations; actual decline rates for producing wells in the Bakken/Three Forks formations; submission of a Plan of Operations to the U.S. Forest Service and approval of such Plan in connection with Mount Emmons and the expected length of time to permit and develop the Mount Emmons project; expected time to receive a return on investment from the geothermal prospects; continuing investment through capital calls and potential dilution of current ownership interest with Standard Steam Trust LLC; future cash flows and borrowings; pursuit of potential acquisition opportunities; anticipated business activities in the Gillette, Wyoming area and their impact on occupancy rates for the Gillette, Wyoming multi-family housing complex; our expected financial position; and 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," and si phrases. Though we believe that the expectations reflected in these statements are reasonable, they do involve certain assumptions, risks and uncertainties. Results could differ materially from those anticipated in these statements as a result of certain factors, including, among others:

For oil and gas:

- having sufficient cash flow from operations or other sources to fully develop our undeveloped acreage positions;

- volatility in oil and natural gas prices, including potential 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;

    - 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 prior 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; and
- competition, including competition in lease acquisitions, and for participation in drilling programs with operating companies, resulting in less favorable terms for participation.

For the molybdenum property:

- the ability to obtain permits required to initiate mining and processing operations, and Thompson Creek Metals' continued participation as operator of the property; and
- 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.

For real estate:

- failure of energy-related business activities in the Gillette, Wyoming area to support sufficient demand for apartments for us to realize a return on the investment.

For geothermal activities:

- the ability to acquire additional BLM and other acreage positions in targeted prospect areas, obtain required permits to explore the acreage, drill development wells to establish commercial geothermal resources, and the ability of Standard Steam Trust LLC to access third-party capital to reduce reliance on capital calls to its members (including U.S. Energy Corp.) for continued operations; and
- the ability to access sufficient capital to develop geothermal properties.

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., a Wyoming corporation organized in 1966, acquires and develops oil and gas and other mineral properties. Our corporate objective is to diversify capital investments in oil and gas, while proceeding with long-term development of our molybdenum property in Colorado and our geothermal properties. Historically, we have undertaken early stage development of various natural resource projects, and after advancing the projects, we have entered into partnership arrangements or have sold all or portions of those projects which have typically allowed us to realize value for shareholders. This strategy has resulted in several years of relatively low operating revenues, but in certain years we have realized substantial gains from disposition of these projects.

For 2010 and subsequent years, we are seeking to increase recurring revenues from oil and gas production. Simultaneously, we intend to advance our geothermal properties through exploration and development, and eventual third party funding, sale or joint venture, and advance our molybdenum property by working with our partner, Thompson Creek Metals Company (USA) to develop the Mount Emmons molybdenum project into a major operating mine. We completed a multifamily apartment project serving the residential market in Gillette, Wyoming in 2008, and it is generating positive cash flow. We do not intend to make more investments in the real estate housing sector.

Industry Segments/Principal Products

At December 31, 2009, we have three operating segments: Oil and gas, real estate, and minerals (including geothermal).

Office Location and Website

Principal executive offices are 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 for stock ownership by 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 is not incorporated by reference herein and our web address is included only for textual reference to the SEC filings.

Business Strategy and Activities

From 2005 through 2008, we generated substantial cash proceeds from selling our interests in our coalbed methane and uranium businesses, and most of our stock in a gold company. Utilizing a portion of these proceeds, we:

- initiated investment activities with three separate oil and gas industry partners in 2008 and with two others in 2009, including entering into a Drilling Participation Agreement with a subsidiary of Brigham Exploration Company (NASDAQ Global Select Market: BEXP);

-7-

- Negotiated an agreement with a subsidiary of Thompson Creek Metals Company Inc. (NYSE:TC), a major molybdenum mining and refining company, which provides for Thompson Creek Metals Company (USA) (“TCM”) investing substantial sums to earn up to a 75% interest in our Mount Emmons molybdenum property in Colorado;
- invested in the geothermal sector by acquiring a minority interest in Standard Steam Trust, LLC; and
- constructed an apartment complex in Gillette, Wyoming.

Oil and Gas

At December 31, 2009, our estimated proved reserves (approximately 75% oil and 25% natural gas) were 1,086,203 BOE, with a standardized measure of $19,984,000 and a present value before taxes (discounted at ten percent, (“PV10”)) of $25,760,000. Reflecting our commencement of drilling in the Williston Basin with Brigham Exploration Company in August 2009, this represents a 602% increase over the $3,318,000 standardized measure of proved reserves, and a 485% increase over PV10 at December 31, 2008.

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 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,		
	2009	2008	2007
Standardized measure of discounted net cash flows	$ 19,984	$ 3,318	$ --
Future income tax expense (discounted)	5,776	1,993	--
PV10	$ 25,760	$ 5,311	$ --

Average production in 2009 was 443 BOE/D (220 barrels of oil and 1,337 Mcf/D), an increase of 1,107% over the average 40 BOE/D in 2008. Substantially all of the increased production in 2009 is attributable to the six wells drilled and completed in the Williston Basin with Brigham in the fourth quarter.

As of February 22, 2010, daily production from all of our wells was approximately 700 barrels of oil and 1,780 Mcf (995 BOE/D). Initial production (on a BOE/D basis) from the 6 Williston Basin wells was in the range of 85% oil and 15% natural gas. The percentage of oil is expected to increase in the initial six-month production period for each of these wells, as gas production declines.

Activities with Operating Partners in Oil and Gas

We currently have active oil and gas investment activities structured with four third-party operating partners. These investments relate primarily to the drilling and completion of oil and gas wells, and to a limited extent, in seismic and other early stage activities leading to the identification of further drilling prospects. Thus far, we have entered into these drilling ventures with oil and gas operating companies that have records of successfully acquiring prospects and drilling and completing oil and gas wells utilizing their technical staff to identify prospects. We have chosen to allow these third parties to operate all of our current oil and gas properties, believing that these arrangements allow us to deliver value to our shareholders without our having to invest the time and capital to build our own team of geophysical, engineering and other technical personnel, and acquiring our own large acreage positions. We believe our finding costs per unit of oil and gas discovered will benefit from these cost savings. In the future, we may enter into other arrangements, or even acquire operating companies, which may involve hiring our own technical staff and possibly becoming operator on certain projects.

Existing oil and gas projects with our operating partners are as follows:

Williston Basin

With Brigham Exploration Company. On August 24, 2009, we entered into a Drilling Participation Agreement (the "DPA") with a wholly-owned subsidiary of Brigham Exploration Company. The DPA provides for U.S. Energy and 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 our agreement with Brigham, we can earn working interests, out of Brigham's interests, in up to fifteen 1,280-acre spacing units in Brigham's Rough Rider project area, which is located in Williams and McKenzie Counties, North Dakota. As of December 31, 2009, six of the initial wells have been completed and are producing. At March 1, 2010, three wells were in the drilling and/or completion stages. By electing to participate in all of the initial wells available to us, we have earned the rights to drill up to 30 total wells in the Bakken formation and an additional 30 wells in the Three Forks formation, for a total of 60 wells, based on current spacing rules in North Dakota. If the spacing is ultimately increased to three wells per 1,280 acre spacing unit, the potential number of drilling locations could increase to 90. Working interests earned will vary according to Brigham's initial working interest, after-payout provisions and the provisions governing each stage of the program. At our current projected drilling rate, we expect that it will take four to six years to drill all of the wells on these units.

We will earn working interests in up to 15 spacing units (approximately 1,280 acres each – two sections of 640 acres each) by participating in drilling up to 15 initial wells (one per unit). All the wells are expected to be horizontal wells, of moderate vertical depth (in the range of 10,000 feet) with long laterals (up to approximately 10,000 feet), each with approximately 28 to 32 fracture stimulation stages. The DPA expires on December 31, 2010; however, we will continue to hold the working interests we earn prior to expiration. 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, due to leases obtained by Brigham from third parties, while other leases may have rights to all depths.

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

-9-

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: In the fourth quarter of 2009, we drilled the six initial wells in the First Group to earn 65% of Brigham's initial working interest in six 1,280 acre units. As of the date this Annual Report was filed, all six wells have been completed and are producing oil and gas; oil is being sold, and gas is being sold or flared pending installation of gathering lines to hook up the wells to transmission lines.

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.

When each initial well was completed, U.S. Energy earned 36% of Brigham's initial working interest to all the acreage in the applicable unit. Brigham will have no back in rights on any subsequent drilling locations in the units. All working interest ownership in each initial well, and all the subsequent wells, will be subject to proportionate reduction for third party lease hold rights.

Second Group: In accordance with the DPA, following receipt from Brigham of initial 24-hour production reports (the "IP Reports") from the first four of the six initial wells in the First Group, we elected to participate in the drilling of the four wells in the Second Group. Brigham gave 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.

When each initial well in the Second Group is completed (or plugged and abandoned, if applicable), U.S. Energy will have earned working interests to all the acreage in the applicable unit. 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 lease hold 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. As of March 1, 2010, we have drilled 3 of the initial wells in the Second Group with Brigham, and earned working interests in 3 of the four units.

Third Group: The DPA provides us the right to participate in the Third Group's five initial wells, on an all-or-none basis, if we have participated in the Second Group, and we provide Brigham a participation notice for the Third Group within ten days of receiving an IP Report for the sixth initial well in the First Group. On January 11, 2010, Brigham gave 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.

When each initial well in the Third Group is completed (or plugged and abandoned, if applicable), we will have earned 36% of Brigham's initial working interest in all the acreage in the applicable unit (which will not be subject to back in rights), proportionately reduced for third party lease hold 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. As of the date this Annual Report was filed, we have not drilled any initial wells in the Third Group with Brigham.

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, we will have the right to elect not to participate in the drilling or completion in subsequent wells proposed to be drilled in a unit. If U.S. Energy 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. Pursuant to the DPA, neither we nor Brigham may propose the drilling of a subsequent well (unless necessary for lease maintenance purposes) before January 1, 2011 unless the parties mutually agree to do so.

Texas and Louisiana

With PetroQuest Energy, Inc. Two wells have been drilled in coastal Louisiana with PetroQuest (NYSE: PQ); one is producing natural gas and oil (we have a 14% working interest and a 9.76% net revenue interest), and the other well drilled with PetroQuest was a dry hole. We expect to drill up to five more wells with PetroQuest in 2010, and expect our working interest participation to be in the range of 4.2% to 20%. At payout (plus 6% annual interest) from each of our producing wells with PetroQuest, we will assign 15% of our working interest to a third-party consultant, and an additional 5% at 200% of payout.

With Yuma Exploration and Production Company, Inc. We have a working interest in a seismic, lease acquisition and drilling program with Yuma (a private company) that covers approximately 88,320 acres in South Louisiana. Seismic data collection has been completed and is being evaluated. This lease/option program continues through April 27, 2012, and we expect that Yuma will recommend drilling at least six prospects in 2010. Participants will have the opportunity to opt in or out of any prospect leasing program, and the initial well in each prospect. Each prospect will have a separate operating agreement designating Yuma as operator. It is expected that the program will yield multiple oil and natural gas prospects, with exploration activities continuing for a number of years. We anticipate participating in at least 6 wells with Yuma in 2010.

U.S. Energy holds a 4.79% working interest, Yuma owns an approximate 48% working interest, and the balance (approximately 47.21%) is held by third parties program. At payout we will assign to a third party consultant 12.5% of our working interest in each producing well. For their working interests, the participants (other than Yuma) have paid 80% of the initial seismic, overhead and some land costs (total $1,390,000), and Yuma is paying 20%. All land and exploration costs going forward are to be paid according to the working interest percentages.

With Houston Energy L.P. We have participated with Houston Energy in drilling three wells in Southeast Texas and Louisiana; two are producing (we have 8.5% and 25% working interests (6.23% and 17.625% net revenue interests)) and one well was a dry hole. At payout we will assign to a third party consultant 12.5% of our working interest in each producing well. We expect to participate in 3 additional wells with Houston Energy in 2010.

Going Forward

In 2010 and beyond, U.S. Energy intends to seek additional opportunities in the oil and natural gas sector, including further acquisition of assets, participation with current and new industry partners in their exploration and development projects, acquisition of operating companies, and purchase and exploration of new acreage positions.

Activities other than Oil and Gas

Molybdenum

On August 19, 2008, U.S. Energy and Thompson Creek Metals Company USA ("TCM"), a Colorado corporation headquartered in Englewood, Colorado, entered into an Exploration, Development and Mine Operating Agreement for our Mount Emmons molybdenum property. TCM assigned the agreement to Mt. Emmons Moly Company, a Colorado corporation and wholly owned subsidiary of TCM effective September 11, 2008. Under the terms of the agreement TCM may acquire up to a 75% interest for $400 million (option payments of $6.5 million and project expenditures of $393.5 million).

The Agreement covers two distinct periods of time: The Option Period, during which TCM may exercise an option to acquire up to a 50% interest in Mount Emmons; and the Joint Venture Period, during which TCM will form a joint venture with us, and also have an option to acquire up to an additional 25% interest in Mount Emmons.

The Option Period:

TCM paid us $500,000 at closing (not refundable), and paid the first two $1.0 million option payments on January 2, 2009 and December 30, 2009. TCM has the option to pay us an additional four annual payments of $1.0 million each beginning on January 1, 2011 for the option.

The option is exercisable in two stages:

First Stage - For 15%. At TCM's election within 36 months of incurring a minimum of $15,000,000 in expenditures on or related to Mount Emmons, TCM may acquire an undivided working interest of 15% in Mount Emmons. TCM also must make the option payments, but each such payment will be credited against the required annual expenditure amount. Following is a table of the options and expenditures due from TCM through 2011:

Option Payments and Expenditure Amounts, and Deadlines

$	500,000	Option Payment	At Closing*
$	2,000,000	Expenditures	December 31, 2008*
$	1,000,000	Option Payment	January 1, 2009**
$	4,000,000	Expenditures	December 31, 2009**
$	1,000,000	Option Payment	January 1, 2010**
$	4,000,000	Expenditures	December 31, 2010
$	1,000,000	Option Payment	January 1, 2011
$	1,500,000	Expenditures	June 30, 2011
$	15,000,000		

* Paid in 2008
** Paid in 2009

Costs to operate the water treatment plant at the property will be paid solely by us until TCM elects to exercise its option to own an interest in the property.

Second Stage - For an Additional 35%. If by July 31, 2018, TCM has incurred a total of at least $43,500,000 of expenditures (including amounts during the first stage) and paid us the total $6,500,000 of option payments (for a total of $50,000,000) TCM may elect to acquire an additional 35% (for a total of 50% after it exercised the first stage option for 15%). None of the interests acquired by TCM will be subject to any overriding royalties to us.

Upon failure by TCM to incur the required amount of expenditures by a deadline, or make an Option Payment to U.S. Energy, subject to the terms of the Agreement, the Agreement may be terminated without further obligation to us from TCM. TCM may terminate the Agreement at any time, but if earned and elected to accept, TCM will retain the interest earned and be responsible for that share of all costs and expenses related to Mount Emmons.

The Joint Venture Period; Joint Venture Terms:

Within six months of TCM's election to acquire the 50% interest, TCM, in its sole discretion, shall elect to form a Joint Venture and either: (i) participate on a 50%-50% basis with us, with each party to bear their own share of expenditures from formation date; or (ii) acquire up to an additional 25% interest in the project by paying 100% of all expenditures equal to $350 million (for a total of $400 million, including the $50 million to earn the 50% interest in the Second Stage of the Option Period), at which point the participation would be 75% TCM and 25% U.S. Energy. Provided however, if TCM makes expenditures of at least $70 million of the $350 million in expenditures and TCM decides not to fund the additional $280 million in expenditures, TCM will have earned an additional 2.5% (for a total of 52.5%). Thereafter, TCM will earn an incremental added percentage interest for each dollar it spends toward the total $350 million amount.

At any time before incurring the entire $350 million, TCM in its sole discretion, may determine to cease funding 100% of expenditures, in which event U.S. Energy and TCM then would share expenditures in accordance with their participation interests at that date. With certain exceptions, either party's interest is subject to dilution in the event of non-participation in funding the Joint Venture's budgets.

Management of the Property

TCM is Project Manager of the Mount Emmons Project. A four person Management Committee governs the projects' operations, with two representatives each from U.S. Energy and TCM. TCM will have the deciding vote in the event of a committee deadlock.

If and when Mount Emmons goes into production, TCM will purchase our share of the molybdic oxide produced at an average price as published in Platt's Metals Weekly price less a discount with a cap and a floor. The discount band will be adjusted every five years based upon the United States' gross domestic product.

Renewable Energy — Geothermal

On December 17, 2008, we bought a 25% minority interest for $3.5 million in Standard Steam Trust, LLC ("SST"), a Denver, Colorado-based private geothermal resource acquisition and development company. At December 31, 2009, our investment was $3.0 million after recognizing an equity loss of $1.4 million at December 31, 2009. As a result of our election to not participate in a December, 2009 capital call our percentage ownership has been reduced to 23.8%. SST's capitalization as of December 31, 2009 was $18.2 million. Its assets now include four advanced stage and four early stage geothermal projects in the western United States, located on over 102,000 acres of BLM, state and fee land in eight prospect areas in three states. SST is managed by Terra Caliente, LLC ("Terra"), also a private Denver-based company, with oversight by an advisory board (U.S. Energy is one of three members) as to budgets, major expenditures, sale or other disposition of prospects and similar matters. Terra will receive a back-in interest of 25%, along with other members (but not U.S. Energy), at such time as all other investors (including Terra) receive cash distributions or securities equal to their investment.

SST intends to advance each individual prospect through the exploration and feasibility stages before determining whether to: (i) sell a prospect to a utility, (ii) bring an industry partner on a joint venture basis, or (iii) pursue further financing with institutional capital to further advance revenue generating capabilities, which may include the operation of power plants. The first phase of the project is assembling a portfolio of industrial scale prospects with an initial targeted power resource of approximately 1,000 MW; individual prospects are targeted at 100 to 500 MW. The second phase, consisting of early science of geology, geophysics and temperature gradient drilling, has commenced and is expected to continue in 2010 and thereafter, followed by production well drilling on at least one of the prospects during 2010 –2011 to quantify the geothermal resource.

Real Estate

At year end 2008, we completed construction of a nine building, 216-unit multifamily apartment complex in Gillette, Wyoming at a total all-in cost of $24.5 million. The occupancy rate was 80% at December 31, 2009.

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 Credit Crisis

The continued credit crisis and related turmoil in the global financial system may have a material impact on our ability to finance the purchase of producing or exploratory oil and gas properties. The availability of credit to our industry partners may also affect their ability to generate new exploration and development prospects. The current economic situation could also cause our partners to fail 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, the current economic situation could lead to reduced demand for natural gas and oil, or further reductions in the prices of natural gas and oil, or both, which could have a negative impact on our financial position, results of operations, and cash flows.

-14-

Risks Related to Climate Change

While the scope and timing of climate change is not determinate, the adoption of laws and regulations, and international accords to which the United States is a party, 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 perceived negative impacts on the climate from "greenhouse emissions," could result in lower world-wide consumption of, and prices for, crude oil. Additionally, 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.

With the stated aims (among others) of fostering a clean energy economy and reducing reliance on fossil fuels that contribute to climate change, the Federal budget for fiscal 2011 published by President Obama's administration includes proposals to terminate oil and gas company tax preferences, including repeals of expensing intangible drilling costs, passive loss limitations for working interests in oil and natural gas properties, percentage depletion for oil and natural gas wells, and increasing the amortization period for geological and geophysical expenses to seven years. If such proposals were enacted substantially as proposed, our income from oil and natural gas investments would be decreased and additional capital likely would become more expensive and more difficult to obtain. Additional adverse impacts could flow from enactment of Federal legislation aimed directly at controlling and reducing emissions of greenhouse emissions. See also the next risk factor.

The adoption of climate change legislation could result in increased operating costs and reduced demand for oil and natural gas.

On June 26, 2009, the U.S. House of Representatives approved adoption of the "American Clean Energy and Security Act of 2009," also known as the "Waxman-Markey cap-and-trade legislation" or ACESA. The purpose of ACESA is to control and reduce emissions of "greenhouse gases," or "GHGs," in the United States. GHGs are certain gases, including carbon dioxide and methane that may be contributing to warming of the Earth's atmosphere and other climatic changes. ACESA would establish an economy-wide cap on emissions of GHGs in the United States and would require an overall reduction in GHG emissions of 17% (from 2005 levels) by 2020, and by over 80% by 2050. Under ACESA, most sources of GHG emissions would be required to obtain GHG emission "allowances" corresponding to their annual emissions of GHGs. The number of emission allowances issued each year would decline as necessary to meet ACESA's overall emission reduction goals. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The net effect of ACESA will be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas.

The U.S. Senate has begun work on its own legislation for controlling and reducing emissions of GHGs in the United States. If the Senate adopts GHG legislation that is different from ACESA, the Senate legislation would need to be reconciled with ACESA and both chambers would be required to approve identical legislation before it could become law. The U.S. Environmental Protection Agency, or EPA, is also separately undertaking a rulemaking process to determine whether GHGs will be designated as “pollutants” under the existing Federal Clean Air Act. President Obama has indicated that he is in support of the adoption of legislation to control and reduce emissions of GHGs through an emission allowance permitting system that results in fewer allowances being issued each year but that allows parties to buy, sell and trade allowances as needed to fulfill their GHG emission obligations. Although it is not possible at this time to predict whether or when the Senate may act on climate change legislation or the EPA or analogous state agencies may adopt climate change regulations, or how any bill approved by the Senate or any regulation approved by the EPA would be reconciled with ACESA, 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 the oil and natural gas we produce.

Limited recurring business revenues may constrain future investments, and earnings will continue to be influenced by transaction events.

At December 31, 2009, USE had $9.5 million in retained earnings, and a loss from operations (before investment and property transactions) of $9.3 million. At December 31, 2008, we had $17.7 million in retained earnings, a loss from operations (before investment and property transactions) of $9.5 million. During 2008 and 2009 we began modifying our business to build an asset base that generates recurring revenues and cash flows. We have initiated this goal by entering into the oil and gas business. We expect our other businesses to continue to experience fluctuations in revenues and cash flows as projects like our Mount Emmons molybdenum and geothermal investment are mid to long-term projects which are capital intensive and take years to develop.

Working capital constraints may limit our ability to develop, or to fund our current share in the development of, our mineral, oil and gas and geothermal properties.

Working capital at December 31, 2009 and December 31, 2008 was $53.4 million and $52.8 million, respectively. We were able to maintain our working capital level primarily as a result of selling 5 million shares of our common stock in a public offering during December 2009 for net proceeds (after expenses) of $24.3 million. While this represents a strong position of liquidity, we do not have sufficient capital to fully develop our oil and gas, mineral and oil and gas properties. 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 drilling programs could be marginal but warrant investing in more wells. Dry holes, over budget exploration costs, low commodity prices, or any combination of these 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 for investment in other programs.

- Further investments of cash into the geothermal program may be required to maintain our interest and bring the properties to a stage of development where they can be sold or joint ventured with an industry partner. Any return on the investment may not be realized for three to five years or longer. To the extent additional capital is not obtained from third parties, cash to sustain operations will have to be raised from the sale of properties or from current members in Standard Steam Trust LLC (including U.S. Energy Corp.) through capital calls, in which event the cash required to maintain our percentage interest could be substantial. Failure to fund cash calls will dilute our position.

- We are paying the annual costs (approximately $1.6 million) to operate and maintain the water treatment plant at the Mount Emmons Project until such time as Thompson Creek Metals elects to acquire an interest. Thereafter, we would be responsible for paying our proportionate share of plant costs. If Thompson Creek Metals elects to participate in the Mount Emmons Project up to the 75% level and expends $400 million on the property, thereafter we would be responsible for our 25% share of the development and operating costs.

We believe that we have sufficient cash reserves to execute our business plan in 2010 and subsequent years, assuming our various projects generate revenues as projected. However, adverse developments in one or more programs would require a reassessment of priorities and therefore potential re-allocations of capital. If internal cash from current reserves and projected revenues are insufficient, we may have to obtain investment capital to maintain the full range of activities. Additional capital also could be required to expand activities in oil and gas beyond the programs now in place.

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 opportunities to partner with (or acquire) established oil and gas operations. 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 is subject to risks related to horizontal drilling and completion techniques.

Operations in the Williston Basin 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 results of our drilling program in the Williston Basin are subject to more uncertainties than drilling in more established formations in other areas.

Brigham has only recently begun drilling wells 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. Brigham's experience as well as the industry's drilling and production history in the formation generally are limited. The ultimate success of these drilling and completion strategies and techniques in these formations will be better evaluated over time as more wells are drilled and longer term production profiles are established.

In addition, based on reported decline rates in these formations, estimated average monthly rates of production may decline by approximately 70% during the first twelve months of production. However, actual decline rates may be significantly different than expected. Due to the limited horizontal production data for the Bakken and Three Forks formations, drilling and production results are more uncertain than encountered in other formations and areas with histories. Good results from wells we drill with Brigham may not be replicated in additional wells, even in the same drilling unit.

Through the date this Annual Report was filed, all the wells we have drilled with Brigham have been drilled into the Bakken formation. Brigham (and other operators) have reported successful completion of Three Forks wells in other parts of the Williston Basin, but Brigham has not drilled any Three Forks wells in the Rough Rider Prospect area. 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 with Brigham, compared with drilling Bakken wells. See "Business - Oil and Gas – Williston Basin."

Operating in less developed regions of the Williston Basin has risks that include, but are not limited to, securing access to takeaway capacity and securing access to equipment and service providers on a timely and cost effective basis, and some of the initial gas production is lost to flaring.

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 in other areas. Additionally, access to equipment and service providers may not be available on a timely or cost effective basis, which could delay a drilling program.

As of the date this Annual Report was filed, 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 into the atmosphere) 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 this Annual Report was filed, three of the wells we have drilled with Brigham have been hooked up to gas transmission lines.

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

We may not be able to participate in all or even a substantial portion of the many locations we earn through the Drilling Participation Agreement with Brigham. 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, and other factors.

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

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

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

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

Effective for years ending on and after December 31, 2009, the SEC amended the disclosure rules to require such revenue estimates to be based on the average price received during the 12-month period before the ending date of the period covered by the report, determined as an unweighted average of the first-day-of-the-month price for each month within such period. Accordingly, our estimated future net revenues as of December 31, 2009 are based on the monthly average price received during the full year period. For the year ended December 31, 2008, in accordance with SEC disclosure requirements previously in effect, estimated future net revenues (discounted at 10% per annum) from proved reserves were calculated based upon prices for oil and natural gas at December 31, 2008.

Full cost pool capitalized costs are amortized over the life of production of proven properties. Capitalized costs at December 31, 2009 and 2008, which were not included in the amortized cost pool, were $5.4 million and $3.0 million, respectively. These costs consist of wells in progress, costs for seismic analysis of potential drilling locations, as well as 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, 2009 and 2008, 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, 2009, we used $61.18 per barrel for oil and $3.866 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 in the fourth quarter of 2009 did not exceed the ceiling test limit. Non-cash write downs of $1.5 million for oil and gas properties were recorded during the first three quarters of 2009. As a result of the increased price for oil and gas at December 31, 2009 and additional reserves being developed during the fourth quarter of 2009, no further impairment was taken at December 31, 2009. 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.

The Williston Basin oil price differential could have adverse impacts.

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 than prices for other areas in the United States.

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, a significant prolonged downturn in oil prices on a national basis could result in a ceiling limitation write-down of the oil and gas properties we hold. Such a price downturn also could reduce cash flow from the Williston Basin properties, and adversely impact our ability to participate fully in the future drilling of the acreage in all 15 units under the Drilling Participation Agreement.

Our business may be impacted by adverse commodity prices.

In June of 2008, oil prices spiked to a ten year high with a spot price of $133.88 per barrel. At December 31, 2008, the spot price for oil had declined to $41.12 per barrel. At December 31, 2009, the price had recovered somewhat to $74.47 per barrel. Global markets have caused these large fluctuations in the price of oil. Natural gas prices are historically volatile, and reached a ten year high during July 2008 on the City Gate at $12.48 per thousand cubic feet of natural gas. As with oil, the City Gate price for natural gas declined through the balance of 2008 and was $8.16 per Mcf as of December 31, 2008, and $6.24 per Mcf at December 31, 2009. 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, 2009 was $11.50 per pound. The global economic recession may continue to suppress prices and prices could drop further. Significant price declines from December 31, 2009 levels would decrease anticipated revenues and could impair the carrying value of our producing properties.

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

We have not yet completed a feasibility study on the Mount 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).

Geothermal renewable reserve reports estimate the energy potential of geothermal properties in terms of capacity to generate electricity with plants to be built on the properties in the future. Currently we have no reserve reports for our geothermal properties.

The timing and cost to obtain reports for the Mt. Emmons molybdenum property or the geothermal properties 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 maintain business relationships with current industry partners, or attract new partners or investment capital.

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 risks, 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;
- permitting with State and Federal agencies;
- easements from land owners;
- adverse weather conditions;
- pressure or irregularities in geologic formations;
- equipment failures;
- title problems;
- fires, explosions, blowouts, cratering, pollution and other environmental risks or accidents;
- changes in government regulations;
- reductions in commodity prices;
- pipeline ruptures; and
- unavailability or high cost of equipment and field services and labor.

A productive well may become uneconomic in the event that unusual quantities of water or other non-commercial substances are encountered in the well bore, which impair or prevent production. We may participate in wells that are unproductive or, though productive, won’t produce in economic quantities. In addition, initial 24-hour or other limited-duration production rates announced regarding our oil and gas properties are not indicative of future production rates. Such stated rates on our wells should not be used as an indication of future production rates.

We do not currently operate any 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 do not currently operate or expect to operate any of our currently identified drilling locations. As we carry out our exploration and development programs, we have entered into, and may enter into future arrangements, for our properties to be operated by others. Our objective in not being the operator is to keep overhead low and not have large engineering, geophysical and administrative staffs. By eliminating the overhead, we can react quicker to opportunities as well as conserve cash in budgetary restrictive times.

Allowing others to operate our properties limits our ability to exercise influence over the operations of the drilling programs. The success and timing of exploration and development activities operated by our partners will depend on a number of factors, including:

- the timing and amount of capital expenditures;
- the operator's expertise and financial resources;
- approval of other participants in drilling wells;
- selection of technology; and
- the rate of production, if any.

This limited ability to exercise control over the operations may cause a material adverse effect on our results of operations and financial condition.

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 producing and proved undeveloped properties, utilizing current commodity prices and taking into account 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, 2009, 97% of our estimated proved reserves were producing and 3% were proved developed non-producing. Estimation of proved undeveloped reserves and proved developed non-producing reserves is almost always based on analogy to existing wells, 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 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 average prices in 2009. 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 did not have any such instruments in place in 2009, but may adopt some in 2010 and/or future years. 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.

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

We may engage in hedging arrangements for a significant part of our production to reduce exposure to price fluctuations in oil and gas prices. These arrangements would expose us to risk of financial loss in some circumstances, including when production is less than expected, the counterparty to the hedging contract defaults on its contract obligations, or there is a change in the expected differential between the underlying price in the hedging agreement and the actual price received. In addition, these hedging arrangements may limit the benefits we would otherwise receive from increases in prices for oil and natural gas. Currently, we have no hedges in place for oil or gas production.

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

Typically, operators obtain a preliminary title opinion or at least a landman's evaluation of title, prior to drilling. To date, our operators have provided preliminary title opinions prior to drilling. In addition, we rely on the operators to warrant that title is in order and provide us with ownership of the interest we pay for. 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 even a productive well because the operator (and therefore USE) would not own the interest.

Oil and gas, mineral and geothermal operations are subject to environmental 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 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, restrictions on drilling activities in restricted areas, emissions into the environment, water discharges, and storage and disposition of hazardous wastes. In addition, state laws require wells and facility sites to be abandoned and reclaimed to the satisfaction of state authorities. Such laws and regulations have been frequently changed in the past, and we are unable to predict the ultimate cost of compliance as a result of future changes. The adoption or enforcement of stricter regulations, if enacted, could have a significant impact on our operating costs.

Our business activities in geothermal and mining are regulated by government agencies. 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.

We must comply with numerous environmental regulations on a continuous basis, to comply with United States environmental laws, including the National Environmental Policy Act (“NEPA”), Clean Air Act, the Clean Water Act, and the Resource Conservation and Recovery Act (“RCRA”). For example, water and dust discharged from mines and tailings from prior mining or milling operations must be monitored and contained and reports filed with federal, state and county regulatory authorities. Additional monitoring and reporting is required by state and local regulatory agencies. 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.

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 which could materially increase our operating and capital costs. Additionally, our Gulf Coast operations are subject to the risk of hurricanes.

Our geothermal assets may not be developed.

To complete our geothermal project business plan through acquisition of land positions in numerous prospects and establishing the power potential through drilling will require substantial capital. While we did not fund a cash call in December 2009, it may become necessary to continue investing through the partnership’s capital calls. In 2010 and beyond, we may decline any capital call without penalty, and such non-participation would dilute our ownership. At December 31, 2009 we had a 23.8% ownership in SST. Notwithstanding the current increase of interest in geothermal power generally, SST may be unable to raise sufficient capital from new investors due to the condition of the global financial markets. In that event, the project might have less than the optimum number of prospects and/or be unable to establish prospective value through drilling. This could substantially reduce the value of our investment.

All the prospects are undeveloped. Prospect value may only initially be determined by drilling at least three production wells, at substantial expense, on each prospect that demonstrate sufficient water temperature and flow to support a commercial power plant. Even if resources are drilling-validated as to power potential, realization of our investment will depend on the sale of our partnership equity, or the partnership's distribution of proceeds from sale of the properties to a utility, energy company, or other investor, or construction of a power plant (which will require institutional financing) and sale of electricity to utilities.

Risks associated with development of the Mount Emmons Project.

The Mount Emmons molybdenum property is located on fee property within the boundary of U.S. Forest Service ("USFS") land. Although mining of the mineral resource will occur on the fee property, associated ancillary activities will occur on USFS land. USE and Thompson Creek Metals expect to submit a Plan of Operations to the USFS in 2010 for USFS approval, which must be approved before initiating construction, and mining and processing can occur. 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 and/or an Environmental Impact Statement to evaluate the predicted environmental and socio-economic impacts of the proposed development and mining of the property. 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 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 and a water discharge permit under the National Pollution Discharge Elimination System ("NPDES") is required before the USFS can approve the Plan of Operations. We currently have a NPDES Permit from the State of Colorado for the operation of the water treatment plant, however this permit may need to be updated.

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, USE and Thompson Creek Metals 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, USE and Thompson Creek Metals 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 Mount Emmons Project will be complex, time-consuming, and expensive. Changes in a mine's design, production rates, quality of material mined, and many other matters, often require submission of the proposed changes for agency approval prior to implementation. In addition, changes in operating conditions beyond our and Thompson Creek Metals' control, or changes in agency policy and Federal and State laws, could further affect the successful permitting of the mine operations. The timing and cost, and ultimate success of the mining operation cannot be predicted.

Reliance on Thompson Creek Metals. Thompson Creek Metals is the operator of the Mount Emmons Project and has an option to acquire up to a 75% interest by performing and paying for the work to get the project permitted and operational, and making option payments. Thompson Creek could exit our agreement at any time without penalty. Should we be unable to find a replacement partner in due course, U.S. Energy Corp. would have to fund the considerable permitting and development costs thereafter to advance development of the project. We may be unable to obtain such funding on acceptable terms, or at all.

-25-

We depend on key personnel.

Our employees have experience in dealing with the exploration 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, and on Thompson Creek Metals for mining expertise. 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. We are searching for employees to replace some or all of our third party geophysical and geological consultants. As of the date of the filing of this Annual Report we have not engaged any such employees.

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 as restricted, the stock was sold at a discount to market prices, and/or the debt-to-stock conversion price was at or lower than market. 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 could result in dilution to existing shareholders.

Although we do not presently intend to do so, we may seek to raise capital from the equity markets using private placements at discounted prices, which could result in dilution to existing shareholders.

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.

We have in place take-over defense mechanisms that could discourage some advantageous transactions.

We have adopted a shareholder rights plan, also known as a poison pill. The plan is designed to discourage a takeover of the Company at an unfair price. However, it is possible that the board of directors and a potential takeover acquirer would not agree on a higher price, in which case the takeover might be abandoned, even though the takeover price might be at a significant premium to market prices. Therefore, as a result of the mere existence of the plan, shareholders may not receive the premium price.

Our stock price likely will continue to be volatile due to several factors.

Our stock is traded on the Nasdaq Capital Market. In the two years ended December 31, 2009, the stock has traded as high as $6.79 per share and as low as $1.52 per share. The principal factors which have contributed, 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 USE stock trading on any given day;
- fluctuations in USE's financial operating results;
- industry trends; and
- legislative and regulatory changes

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 are based on reserve reports prepared by Ryder Scott Company, L.P. ("Ryder Scott"), and Cawley, Gillespie & Associates, Inc. ("CGA"). Our reserve estimates as of December 31, 2008 are based on a reserve report prepared by Ryder Scott Company, L.P. Ryder Scott and CGA are nationally recognized independent petroleum engineering firms. Ryder Scott is a Texas Registered Engineering Firm (F-1580) and CGA is a Texas Registered Engineering Firm (F-693). Ryder Scott prepared the estimates related to our Gulf Coast Basin, including Louisiana and Texas properties and CGA prepared the estimates or our North Dakota properties. The reserve estimates were based upon the review by the relevant engineering firm(s) of production histories and other geological, economic, ownership and engineering data, as provided by us and by the operators. Copies of these reports are filed as exhibits to this Annual Report.

We do not have in-house geological, geophysical and reserve engineering expertise. We therefore primarily rely on the operators of our producing wells who provide production data to our contract reserve engineers. Once the reserve engineers have reviewed all data and established preliminary reserves for the operators of the wells for which we rely on the operator, they also prepare a standalone report for us.

Summary of Oil and Gas Reserves as of Fiscal Year End Based on Average Fiscal-Year Prices (1)

	December 31, 2009	2008	2007
Net proved reserves			
Oil (Bbls)			
Developed	811,789	29,798	--
Undeveloped	--	--	--
Total	811,789	29,798	--
Natural gas (Mcf)			
Developed	1,502,296	1,000,000	--
Undeveloped	--	--	--
Total	1,502,296	1,000,000	--
Natural gas liquids (Bbls)			
Developed	24,031	--	--
Undeveloped	--	--	--
Total	24,031	--	--
Total proved reserves (BOE)	1,086,203	196,465	--

(1) Reserves for 2009 are based on 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.

U.S. Energy has no reserves of synthetic oil or synthetic gas, and does not produce or have reserves of any petroleum products.

As of December 31, 2009, our proved reserves totaled 1,086,203 BOE (100% proved developed), comprised of 811,789 Bbls of oil (75% of the total), 1,502,296 Mcf of natural gas and 24,031 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”.

Proved Undeveloped Reserves

We had no proved undeveloped reserves at December 31, 2009.

Oil and Gas Production, Production Prices, and Production Costs

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

	December 31, 2009	2008	2007
Production Volume			
Oil (Bbls)	80,461	2,330	--
Natural gas (Mcf)	487,978	73,635	--
BOE	161,791	14,603	--
Daily Average Production Volume			
Oil (Bbls/d)	220	6	--
Natural gas (Mcf/d)	1,337	202	--
BOE/d	443	40	--
Oil Price per Bbl Produced			
Realized Price	$ 60.01	$ 36.78	--
Natural Gas Price per Mcf Produced			
Realized Price	$ 4.13	$ 6.59	--
Average Sale Price per BOE (1)	$ 42.30	$ 39.10	
Expense per BOE			
Production costs (2)	$ 2.15	$ 4.26	--
Depletion, depreciation and amortization	$ 22.07	$ 26.16	--

(1) Amounts shown are based on oil and natural gas sales, divided by sales volumes. Natural gas produced but flared is not included.
(2) Production costs are comprised of oil and natural gas production expenses (excluding ad valorem and severance taxes), and are computed using production costs as determined under ASC 932-235-55.

Drilling and Other Exploratory and Development Activities

The following table sets forth information with respect to development and exploration wells we completed from January 1, 2007 through December 31, 2009. The number of gross wells is the total number of wells we participated in, regardless of our ownership interest in the wells.

	Development Wells Drilled 2009	2008	2007
Producing			

Gross	--	--	--
Net	--	--	--
Dry			
Gross	--	--	--
Net	--	--	--

	Exploration Wells Drilled		
	2009	2008	2007
Producing			
Gross	8.0000	1.0000	--
Net	3.3286	0.1500	--
Dry			
Gross	2.0000	1.0000	--
Net	0.5833	0.2000	--

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, 2009. 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	7.00	3.24	46.33714%
Natural Gas	2.00	0.23	11.25000%
Total (1)	9.00	3.47	38.54000%

(1) The average working interest for the five Williston Basin wells producing at December 31, 2009 is 49.89%; the remaining three wells (Southeast Texas and Louisiana), have 8.5%, 14%, and 25% working interests, respectively.

The following map reflects where our oil and gas wells are generally located in the Williston Basin of North Dakota:

Acreage

The following table summarizes our estimated developed and undeveloped leasehold acreage as of December 31, 2009.

	Developed		Undeveloped		Total	
Area	Gross	Net	Gross	Net	Gross	Net
Williston Basin Wells with Brigham Exploration	7,680	3,832	2,560	749	10,240	4,581
So. East Texas and Louisiana	1,251	154	89,334	4,408	90,585	4,562
Total	8,931	3,986	91,894	5,157	100,825	9,143

Present Activities

As of March 1, 2010, we were drilling 1 gross (0.2 net) wells in Louisiana (offshore), and in the process of completing 3 gross (0.92 net) wells in the Williston Basin.

Molybdenum – Mount Emmons Project

We re-acquired the Mount Emmons (formerly known as the Lucky Jack molybdenum property) located near Crested Butte, Colorado on February 28, 2006. The property was returned to us by Phelps Dodge Corporation (“PD”) in accordance with a 1987 Amended Royalty Deed and Agreement between us and Amax Inc. (“Amax”). The Mount Emmons Project includes a total of 25 patented and approximately 1,219 unpatented mining and mill site claims, which together approximate 9,311 acres, or over 13 square miles of claims.

We own both surface and mineral rights at the Mount Emmons Project in fee pursuant to mineral patents issued by the United States of America. 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 $125 per claim to the Bureau of Land Management; the total amount paid for claim maintenance fees in 2009 was $126,500, which was paid by TCM.

The breakdown of the property is as follows:

	Acres	Number of Claims
Patented / Fee	365	25
Unpatented Claims	6,171	664
Mill Site Claims	2,775	555
Fee Property (1)	160	n/a
Total	9,471	1,244

(1) This property (fee ownership) is in the vicinity of the mining claims but presently is not considered by TCM and U.S. Energy to be part of the Mount Emmons Project.

The Mount Emmons Project is located in Gunnison County, Colorado. The property is accessed by vehicle traffic on Gunnison County Road 12.

Thompson Creek Metals Company (USA) has an option to acquire up to a 75% interest in the Project. See Part I above.

We had leased various patented and unpatented mining claims on the Mount Emmons molybdenum property to Amax in 1974. In the late 1970s, Amax delineated a large deposit of molybdenum on the properties, reportedly containing approximately 155 million tons of mineralized material averaging 0.44% molybdenum disulfide (MoS2). In 1981, Amax constructed a water treatment plant at the Mount Emmons molybdenum property 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. PD then acquired Mount Emmons 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 1970's by Amax, Inc. 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 Mount 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 also are a number of existing mine adits located on the property. Historic work completed by Amax, Inc. 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. Amax, Inc. also facilitated the completion of an Environmental Impact Statement ("EIS") as required by NEPA for the Plan of Operations submitted to the United States Forest Service ("USFS"). The Amax, Inc. EIS is now outdated.

In its 1992 patent application, Cyprus Amax stated that the size and grade of the Mount 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 BLM relied on a mineral report prepared by Western Mine Engineering ("WME") for the U.S. Forest Service, which directed and administered the WME contract. WME's analysis 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. WME consulted a variety of sources in preparation of its report, including a study prepared in 1990 by American Mine Services, Inc. and a pre-feasibility report later prepared by Behre Dolbear & Company, Inc. in 1998.

Even with the historical data available, the size, configuration and operations of the mine plan that may be proposed by TCM have not been finalized. These factors, as well as the prevailing prices for molybdic oxide when the mine is active, will determine the economic viability of the project. We note that the statements made by the predecessor owners of the Mount Emmons Project regarding "recoverable" minerals and "mineable "reserves" were based on costs, permitting requirements, and commodity prices then prevailing. The $4.61 price used by WME should not be considered to be a current breakeven price for Mount Emmons. It is anticipated that a full feasibility study will be prepared in the future, 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 for $4 million ($2 million in January 2009, $400,000 annually for five years). We share with TCM the purchase cost of this land on a 50-50 basis.

Geology

The sedimentary sequence in the Mount Emmons area spans from late Cretaceous to early Tertiary time. 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 Mount 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 Mount 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 Mount 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 Mount Emmons. Capping Mount 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 Mount 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 Mount Emmons stock has intruded the Mancos and Mesaverde sediments, strongly metamorphosing both formations to hornfels up to 1500 feet outward from the igneous body.

Sedimentary rocks on Mount 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 Mount Emmons molybdenum mineralized zone and the associated alteration zones. Hydrothermal alteration associated with the Mount 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 Mount Emmons stock.

Water Treatment Plant; Site Facilities

PD's 2006 re-conveyance of the property to U.S. Energy 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 until such time as Thompson Creek Metals elects to acquire a 15% interest in the property. Thereafter, costs will be shared according to our and Thompson Creek's participation interests. We also are evaluating using the plant in milling operations.

The water treatment plant was constructed by Amax, Inc. in 1981 (at a cost of approximately $15 million) to treat mine discharge water from the historic lead and zinc Keystone Mine. A certified water treatment plant operations contractor with four licensed and/or trained employees operate the water treatment plant on a continuous basis, treating water discharged from the historic lead and zinc 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 compliance with the approved NPDES Permit for the plant, and solids are dewatered and mixed with cement for proper disposal in accordance with state and federal law.

Additional equipment used in the operation of the water treatment plant includes a large front-end loaders, forklifts, specialized snow removal equipment and pickup trucks. The Mount Emmons Project currently has a 24-hour, seven days a week security contract service to protect the property.

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, Inc. reportedly spent approximately $150 million in exploration and related activities on the Mount Emmons Project, which included construction of the water treatment plant. During 2007, Kobex Resources, the predecessor of TCM, spent approximately $10.5 million on the property. From August 2008 to December 31, 2009, TCM has spent approximately $7.6 million on the property. The 2010 TCM budget for the Project is projected to be $8.4 million. Our annual operating cost for the water treatment plant is approximately $1.6 million. The total costs associated with future drilling and the development of the Project has not yet been determined by TCM.

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. TCM 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 will 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 time table for completing drilling, and the permitting and construction of the mine and milling facilities, is dependent upon several factors, including State and Federal regulations and availability of capital, which is driven by the market price for molybdenum.

Activities in 2009 and Plans for 2010

TCM, the Project Manager, is currently preparing and evaluating engineering and environmental reports and studies to prepare a Plan of Operations, which we anticipate will be submitted to the USFS in 2010. We expect that the Initial Plan of Operations will facilitate the base line data collection needed for additional permitting efforts. The Initial Plan of Operations review will follow the NEPA process, requiring the collection of environmental baseline data and studies for the preparation of an environmental analysis.

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 $11.29 in 2009, compared to $29.71 in 2008 ($17.79 in the fourth quarter 2008 and $10.00 as of December 31, 2008). The decrease in the average annual price for molybdenum is a result of the global recession which has led to dramatic reductions in steel output and pricing, and correspondingly in market demand for molybdenum and its pricing.

Energy Housing

Remington Village - Gillette, Wyoming. We have built and own a nine building multifamily apartment complex, with 216 units on 10.15 acres (purchased in 2007) 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 88.6% in 2009. For that year, we realized average monthly revenues of approximately $219,000 (a 7 % return on investment (approximately 6.8% higher than the return realized on our Treasury Bills for the year)). The occupancy rate at December 31, 2008 was 88% and 80% at December 31, 2009. The decrease in occupancy rate from 2008 to 2009 is due to the national economic downturn and reduced activities in the oil and gas sector in Wyoming. Construction of a coal fired power plant 7 miles north of Gillette is expected to continue through 2011. A continued increase in oil and gas and coal mine activities in the area from the modest increases viewed in late 2009 and early 2010 may favorably impact our occupancy rate in 2010 and later years.

In January 2010 we pledged the apartment complex along with our corporate aircraft as collateral for a $10 million commercial line of credit with a financial institution.

In August 2007, Zions Bank provided secured construction financing, which also was guaranteed by U.S. Energy. The loan was $16.8 million at December 31, 2008. Total cost to buy the land, pay a developer's fee, obtain permits and entitlements, site work and construction, was approximately $24.5 million at December 31, 2008, of which $7.7 million cash was invested by us (including $1.2 million for land purchase). The interest rate on the loan balance at December 31, 2008 was 2.71% (payable monthly) based on LIBOR. Loan maturity was March 1, 2009. In January 2009, we paid off the construction financing ($16.8 million) with internal funds. The property currently has no debt, although we may seek further collateral financing for the project in 2010 to provide additional access to capital for our oil and gas activities as warranted.

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. 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; two vacant lots covering 13.2 acres in Fremont County, Wyoming, and two city lots and improvements including one small office building.

On December 28, 2007, we purchased 13.84 acres of undeveloped land across the street from USE's corporate office building for $500,400 cash, with the intention of developing the land for mixed commercial and multifamily residential purposes. Our basis in the property and improvements at December 31, 2009 is $656,300. When the real estate market recovers we intend to sell the property without development. The timing of sale is not known.

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 future receipt of funds from any of these contingencies is not predicted.

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.

Environmental

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 the National Environmental Policy Act (“NEPA”), Clean Air Act, the Clean Water Act, the Resource Conservation and Recovery Act ("RCRA"), and the Comprehensive Environmental Response Compensation Liability Act ("CERCLA"). With respect to proposed mining operations at the Mount Emmons property, 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. 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 Mount Emmons project, see the consolidated financial statements included in Part II of this Annual Report.

Gas and oil operations also are 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. 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 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, we don't expect to make any material capital expenditures for environmental control facilities.

Failure to comply with these 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.

Employees

As of March 11, 2010, we had 18 full-time employees.

Mining Claim Holdings

Title

Approximately 25 of the Mount Emmons 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 Mount Emmons 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, 2009, and developments in those proceedings from that date to the date this Annual Report was filed, are summarized below.

Water Rights Litigation –Mount Emmons Molybdenum Property

1. Concerning the Application of the United States of America in the Gunnison River, Gunnison County, Case No. 99CW267. This case involves an application filed by the United States of America to appropriate 0.033 cubic feet per second of water for wildlife use and for incidental irrigation of riparian vegetation at the Mount Emmons Iron Bog Spring, located in the vicinity of Mount Emmons. MEMCO filed a Statement of Opposition to protect proposed mining operations against any adverse impacts by the water requirements of the Iron Bog on such operations. This case is pending while the parties attempt to reach a settlement on the proposed decree terms and conditions.

2. Concerning the Application of U.S. Energy, Case No. 2008CW81. On July 25, 2008, the Company filed an Application for Finding of Reasonable Diligence with the Water Court concerning the conditional water rights associated with Mount Emmons. The conditional water decree ("Decree") requires the Company to file its proposed plan of operations and associated permits ("Plan") with the Forest Service and BLM within six years of entry of the 2002 Decree, or within six years of the final determination in the Applicant's pending patent application, whichever occurs later. Although the BLM issued the mineral patents on April 2, 2004, the patents remained subject to a challenge by High Country Citizens' Alliance, the Town of Crested Butte, and the Board of County Commissioners of Gunnison County (collectively "Protestors"). The Company vigorously defended this legal action through the Federal District Court for the District of Colorado and the Tenth Circuit Court of Appeals. On April 30, 2007, the United States Supreme Court made a final determination upholding BLM's issuance of the mineral patents. The Company believes that the deadline for filing the Plan specified by the Decree is April 30, 2013 (six years from the final determination of issuance of the mineral patents by the United States Supreme Court). The Forest Service has indicated that the deadline should be April 2, 2010 (six years from the issuance of the mineral patents by BLM). The United States, on behalf of the Forest Service and BLM, filed a Statement of Opposition on this specific issue only. Statements of Opposition were also filed by six other parties including the City of Gunnison, the State of Colorado, and High Country Citizens' Alliance in September for various reasons, including requesting the Company be put on strict proof as to demonstrating evidence of reasonable diligence in developing the conditional water rights. Although, the Company and TCM will be prepared to file a Plan by the April 2, 2010 proposed deadline, the Company and TCM will pursue a ruling from the Water Court that the deadline specified in the Decree requires the filing of the Plan by April 30, 2013.

Ordinance Related to the Crested Butte Watershed

On May 19, 2008, the Town Council adopted a revised Watershed Ordinance. The Company and TCM intend to work with the Town of Crested Butte concerning activities at Mount Emmons consistent with lawful and applicable rules, regulations, and statutes. It is possible that unexpected delays, and/or increased costs, may be encountered in developing a new mine plan for Mount Emmons as a result of the revised Watershed Ordinance.

Appeal of Approval of Notice of Intent to Conduct Prospecting for the Mount Emmons Molybdenum Property

On March 8, 2008, High Country Citizens' Alliance ('HCCA") filed a request for hearing before the Colorado Land Reclamation Board ("Board") of the approval of a Notice of Intent to Conduct Prospecting Notice for the Mount Emmons molybdenum property ("NOI"), which was approved by the Division of Reclamation, Mining and Safety of the Colorado Department of Natural Resources ("DRMS") on January 3, 2008. The NOI as approved provided for continued exploration of the molybdenum deposit to update, improve and verify, in accordance with current industry standards and legal requirements, mineralization data that was collected by Amax in the late 1970's.

On March 28, 2008, the Company and the Colorado Attorney General's Office filed independent Motions to Dismiss alleging among other matters that: (i) HCCA had no standing to appeal the NOI; (ii) the NOI is not an appealable decision under Colorado law; (iii) HCCA's appeal is not timely; and (iv) the appeal is based on information obtained in violation of Colorado law.

On May 14, 2008, the Board denied HCCA's Request for Hearing and also denied their Request for a Declaratory Order. Citing Colorado law, the Board determined that HCCA did not have standing or the right to appeal DRMS's approval of the NOI under Colorado law.

On August 28, 2008, HCCA appealed the Board's decision in Denver District Court. Plaintiff: High Country Citizen's Alliance v. Defendants: Colorado Mined Land Reclamation Board, Colorado Division of Reclamation Mining and Safety and U.S. Energy Corp., Case No.: 08CV6156 (District Court, 2d Jud. Dist., City and County of Denver). The Board has filed an answer with the Court. The DRMS and the Company (in conjunction with TCM) have both filed the responsive pleadings in addition to motions to dismiss the HCCA complaint. No hearing date has been scheduled in the District Court of Colorado concerning DRMS's issuance of the NOI to the Company for the Mount Emmons molybdenum property.

Water Treatment Facility – Permit Renewal Protest

The Company received a NPDES Permit renewal for Mount Emmons from the Colorado Department of Public Health and Environment – Water Quality Division ("Water Quality Division") effective September 1, 2008. The NPDES Permit is for a five (5) year period (2008 - 2013). On August 28, 2008, the Town of Crested Butte, Board of County Commissioners for the County of Gunnison and High Country Citizens' Alliance ("Petitioners") filed a Request for Adjudicatory Hearing before the Water Quality Division to challenge the NPDES Permit. The Petitioners seek revisions to the Permit that would require the Company to maintain a prepaid operating contract and provide additional financial security for long term operation of the plant.

A hearing before the Administrative Law Judge ("ALJ") in the Office of Administrative Courts was held on October 2, 2009 in Denver, Colorado. On October 30, 2009 the ALJ issued an order upholding the issuance of the NPDES Permit and rejecting the Petitioners request for financial assurances as a condition of the NPDES permit.

Item 4 – Submission of Matters to a Vote of Security Holders

On June 26, 2009, the annual meeting of shareholders was held for the election of two directors to serve until the terms stated in the Proxy Statement (until the 2012 Annual Meeting of Shareholders and until their successors are elected or appointed and qualified). With respect to the election of the directors, the votes cast were as follows:

Name of Director	Votes For	Withheld
Keith G. Larsen	16,525,397	322,997
Allen S. Winters	16,449,761	398,633

The directors now are Keith G. Larsen, Mark J. Larsen, Robert Scott Lorimer, H. Russell Fraser, Allen S. Winters, Michael T. Anderson and Michael Feinstein.

The shareholders also voted on the ratification of appointment of Hein & Associates LLP, the votes cast were as follows:

	Votes For	Votes Against	Abstain
Ratification of appointment of Hein & Associates LLP as independent auditors for the current fiscal year.	14,482,178	214,537	42,203

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, 2009		