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

**FORM 10-K**

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
**For the fiscal year ended December 31, 2012 or**

☐ **TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the transition period from __________to_________**

**Commission file number: 001-35330**

**Recovery Energy, Inc.**
(Name of registrant as specified in its charter)

| **NEVADA** | **74-3231613** |
|---|---|
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |

**1900 Grant Street, Suite #720, Denver, CO 80203**
(Address of principal executive offices, including zip code)

**Registrant's telephone number including area code: (303)-951-7920**

**Securities registered under Section 12(b) of the Act:**

None

**Securities registered under Section 12(g) of the Act:**

**Title of each class**
$0.0001 par value Common Stock

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Exchange Act. Yes ☐ No ☒

Indicate by check mark if 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 past 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company (as defined in Rule 12b-2 of the Act):

| | | | |
|---|---|---|---|
| Large accelerated filer | ☐ | Accelerated filer | ☐ |
| Non-accelerated filer | ☐ | Smaller reporting company | ☒ |

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

State the aggregate market value of 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 asked price of such common equity, as of the last business day of the fiscal quarter ending June 29, 2012: $21,411,978

As of April 9, 2013, 18,498,601 shares of the registrant's common stock were issued and outstanding.

**DOCUMENTS INCORPORATED BY REFERENCE**

Portions of the Registrant's definitive proxy statement for the 2013 Annual Meeting of Stockholders, scheduled to be held in June 2013, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2012, are incorporated by reference into Part III.

**FORM 10-K ANNUAL REPORT**
**FISCAL YEAR ENDED DECEMBER 31, 2012**
**RECOVERY ENERGY, INC.**

## FORWARD-LOOKING STATEMENTS

This annual report contains "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. All statements other than statements of historical fact are "forward-looking statements" for purposes of federal and state securities laws, including, but not limited to, any projections of earnings, revenue or other financial items; any statements of the plans, strategies and objectives of management for future operations; any statements concerning future production, reserves or other resource development opportunities; any projected well performance or economics, or potential joint ventures or strategic partnerships; any statements regarding future economic conditions or performance; any statements regarding future capital-raising activities; any statements of belief; and any statements of assumptions underlying any of the foregoing.

Forward-looking statements may include the words "may," "should," "could," "estimate," "intend," "plan," "project," "continue," "believe," "expect" or "anticipate" or other similar words. These forward-looking statements present our estimates and assumptions only as of the date of this presentation. Except as required by law, we do not intend, and undertake no obligation, to update any forward-looking statement.

Although we believe that the expectations reflected in any of our forward-looking statements are reasonable, actual results could differ materially from those projected or assumed in any of our forward-looking statements. Our future financial condition and results of operations, as well as any forward-looking statements, are subject to change and inherent risks and uncertainties. The factors impacting these risks and uncertainties include, but are not limited to:

- *availability of capital on an economic basis, or at all, to fund our capital needs;*
- *failure to meet requirements under our credit agreements or debentures, which could lead to foreclosure of significant assets;*
- *inability to address our negative working capital position;*
- *the inability of management to effectively implement our strategies and business plans;*
- *potential default under our secured obligations or material debt agreements;*
- *estimated quantities and quality of oil and natural gas reserves;*
- *exploration, exploitation and development results;*
- *fluctuations in the price of oil and natural gas, including reductions in prices that would adversely affect our revenue, cash flow, liquidity and access to capital;*
- *availability of, or delays related to, drilling, completion and production, personnel, supplies and equipment;*
- *the timing and amount of future production of oil and gas;*
- *the completion, timing and success of our drilling activity;*
- *lower oil and natural gas prices negatively affecting our ability to borrow or raise capital, or enter into joint venture arrangements;*
- *declines in the values of our natural gas and oil properties resulting in write-downs;*
- *inability to hire or retain sufficient qualified operating field personnel;*
- *increases in interest rates or our cost of borrowing;*
- *deterioration in general or regional (especially Rocky Mountain) economic conditions;*
- *the strength and financial resources of our competitors;*
- *the occurrence of natural disasters, unforeseen weather conditions, or other events or circumstances that could impact our operations or could impact the operations of companies or contractors we depend upon in our operations;*
- *inability to acquire or maintain mineral leases at a favorable economic value that will allow us to expand our development efforts;*
- *inability to successfully develop the acreage we currently hold;*
- *transportation capacity constraints or interruptions, curtailment of production, natural disasters, adverse weather conditions, or other issues affecting the DJ Basin;*
- *technique risks inherent in drilling in existing or emerging unconventional shale plays using horizontal drilling and completion techniques;*
- *delays, denials or other problems relating to our receipt of operational consents and approvals from governmental entities and other parties;*
- *unanticipated recovery or production problems, including cratering, explosions, fires and uncontrollable flows of oil, gas or well fluids;*

- *environmental liabilities;*
- *operating hazards and uninsured risks;*
- *loss of senior management or technical personnel;*
- *adverse state or federal legislation or regulation that increases the costs of compliance, or adverse findings by a regulator with respect to existing operations, including those related to climate change and hydraulic fracturing;*
- *changes in U.S. GAAP or in the legal, regulatory and legislative environments in the markets in which we operate; and*
- *other factors, many of which are beyond our control.*

Many of these factors are beyond our ability to control or predict. These factors are not intended to represent a complete list of the general or specific factors that may affect us.

For a detailed description of these and other factors that could cause actual results to differ materially from those expressed in any forward-looking statement, we urge you to carefully review and consider the disclosures made in the "Risk Factors" sections of our SEC filings, available free of charge at the SEC's website (www.sec.gov).

## GLOSSARY

In this report, the following abbreviation and terms are used:

*Bbl*. Stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to crude, condensate or natural gas liquids.

*Bcf*. Billion cubic feet of natural gas.

*BOE.* Barrels of crude oil equivalent, determined using the ratio of six mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

*BOE/d*. boe per day.

*Completion*. Installation of permanent equipment for production of natural gas or oil, or in the case of a dry hole, the reporting to the appropriate authority that the well has been abandoned.

*Condensate*. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure but that, when produced, is in the liquid phase at surface pressure and temperature.

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

*Drilling locations*. Total gross locations specifically quantified by management to be included in our multi-year drilling activities on existing acreage. Our actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, drilling results and other factors.

*Dry well. dry hole*. A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

*Exploratory well*. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir.

*Field*. An area consisting of either a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

*Formation*. An identifiable layer of rocks named after its geographical location and dominant rock type.

*Gross acres, gross wells, or gross reserves.* A well, acre or reserve in which the Company owns a working interest. The number of gross wells is the total number of wells in which the Company owns a working interest.

*Lease*. A legal contract that specifies the terms of the business relationship between an energy company and a landowner or mineral rights holder on a particular tract of land.

*Leasehold*. Mineral rights leased in a certain area to form a project area.

*Mbbls*. Thousand barrels of crude oil or other liquid hydrocarbons.

*Mboe.* Thousand barrels of crude oil equivalent, determined using the ratio of six mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

*Mcf.* Thousand cubic feet of natural gas.

*Mcfe*. Thousand cubic feet equivalent, determined using the ratio of six mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

*MMbtu*. Million British Thermal Units.

*MMcf*. Million cubic feet of natural gas.

*Net acres, net wells, or net reserves*. The sum of the fractional working interest own in gross acres, gross wells, or gross reserves, as the case may be.

*Net barrel of production.* The sum of the fractional revenue interest in gross production owned by the Company.

*Ngl.* Natural gas liquids, or liquid hydrocarbons found in association with natural gas.

*Overriding royalty interest*. Is similar to a basic royalty interest except that it is created out of the working interest. For example, an operator possesses a standard lease providing for a basic royalty to the lesser or mineral rights owner of 1/8 of 8/8. This then entitles the operator to retain 7/8 of the total oil and natural gas produced. The 7/8 in this case is the 100% working interest the operator owns. This operator may assign his working interest to another operator subject to a retained 1/8 overriding royalty. This would then result in a basic royalty of 1/8, an overriding royalty of 1/8 and a working interest of 3/4. Overriding royalty interest owners have no obligation or responsibility for developing and operating the property. The only expenses borne by the overriding royalty owner are a share of the production or severance taxes and sometimes costs incurred to make the oil or gas salable.

*Plugging and abandonment*. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.

*Present value of future net revenues (PV-10*). The present value of estimated future revenues to be generated from the production of estimated proved reserves, net of estimated production, future development costs and future plugging and abandonment costs, using the simple 12 month arithmetic of first of month prices and current costs (unless such prices or costs are subject to change pursuant to contractual provisions), without giving effect to non-property related expenses such as general and administrative expenses, debt service, future income tax expenses, depreciation, depletion and amortization or impairment, discounted using an annual discount rate of 10%. While this non-GAAP measure does not include the effect of income taxes as it would in the use of the standardized measure calculation, it does provide an indicative representation of the relative value of Recovery Energy on a comparative basis to other companies and from period to period.

*Production*. Natural resources, such as oil or gas, taken out of the ground.

*Proved reserves.* Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, under existing economic conditions , operating methods, and governance regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

*Proved developed oil and gas reserves.* Proved developed oil and gas reserves are proved reserves that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

*Proved undeveloped reserves*. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

*Probable Reserves.* Those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

*Possible Reserves.* Those additional reserves that are less certain to be recoverable than probable reserves.

*Productive well*. A well that is found to be capable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

*Project.* A targeted development area where it is probable that commercial gas can be produced from new wells.

*Prospect*. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

*Recompletion*. The process of re-entering an existing well bore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

*Reserves*. Estimated remaining quantities of oil, natural gas and gas liquids anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.

*Reservoir*. A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

*Secondary Recovery*. A recovery process that uses mechanisms other than the natural pressure of the reservoir, such as gas injection or water flooding, to produce residual oil and natural gas remaining after the primary recovery phase.

*Shut-in*. A well that has been capped (having the valves locked shut) for an undetermined amount of time. This could be for additional testing, could be to wait for pipeline or processing facility, or a number of other reasons.

*Standardized measure*. The present value of estimated future cash inflows from proved oil and natural gas reserves, less future development, abandonment, production and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized measure differs from PV-10 because standardized measure includes the effect of future income taxes.

*Successful*. A well is determined to be successful if it is producing oil or natural gas, or awaiting hookup, but not abandoned or plugged.

*Undeveloped acreage*. Leased acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or natural gas regardless of whether such acreage contains proved reserves.

*Water flood.* A method of secondary recovery in which water is injected into the reservoir formation to displace residual oil and enhance hydrocarbon recovery.

*Working interest.* The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

## PART I
## Items 1 and 2. BUSINESS AND PROPERTIES

Recovery Energy, Inc. (NASDAQ: RECV), ("we," "us," "our," "Recovery Energy," "Recovery," or the "Company") is a Denver based independent oil and gas company engaged in the acquisition, drilling and production of oil and natural gas properties and prospects. We were incorporated in August of 2007 in the State of Nevada as Universal Holdings, Inc. In October 2009, we changed our name to Recovery Energy, Inc.

Our executive offices are located at 1900 Grant Street, Suite #720, Denver, Colorado 80203, and our telephone number is (303) 951-7920. Our web site is www.recoveryenergyco.com. Additional information which may be obtained through our web site does not constitute part of this annual report on Form 10-K. Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports are accessible free of charge at our website. The SEC also maintains an internet site that contains reports, proxy and information statements and other information regarding our filings at www.sec.gov.

Our current operating activities are focused on the Denver-Julesburg Basin ("DJ Basin") in Colorado, Wyoming and Nebraska. Our business strategy is designed to maximize shareholder value by leveraging the knowledge, expertise and experience of our management team and via the future exploration and development of the approximate 129,000 net acres of developed and undeveloped acreage that are currently held by the Company, primarily in the northern DJ Basin.

The majority of our leases on which we have identified reserves and production are subject to security interests held by the lenders under our secured term loans or our 8% Senior Secured Convertible Debentures. As discussed below, we have recently amended the terms of both the secured term loans and the 8% Senior Convertible Debentures to among other things, extend the maturity dates under both the term loans and the debentures, and reduce the interest rate and the level of minimum monthly payments under the term loans. We currently have $19.34 million outstanding under our term loans and $13.40 million outstanding under our debentures. In addition, we currently have a working capital deficit of approximately $1.04 million, and approximately $3.63 million in current liabilities. We believe that the amendments referenced above provide us with significantly more flexibility in meeting our obligations. In addition, as discussed below, we have entered into an agreement with one of our existing debenture holders to invest at least $1.5 million in additional debentures on substantially the same terms as our existing senior secured debentures, with the possibility of an additional investment by our existing debenture holders of up to $3.5 million. We are aggressively exploring a number of other capital raising transactions aimed at improving our liquidity position in the long and short term, including asset sales, joint ventures and similar industry partnerships, asset monetization transactions, possible equity transactions, and other potential refinancing transactions with terms more favorable to us than those under the term loans and debentures. Our ability to fund some of our ongoing overhead, to meet our minimum principal and interest obligations and to fund our 2013 capital program is contingent on successfully raising additional capital via one or more of the above referenced transactions.

### Recent Developments

In April 2013, we amended both our secured term loans and our 8% Senior Secured Convertible Debentures to extend their maturity dates to May 16, 2014. In consideration for the extended maturity date of both loans and the reduced interest rate and minimum loan payment under the secured term loans, the Company will be required to provide both Hexagon and the holders of our debentures an additional security interest in 15,000 acres (or 30,000 acres in aggregate) of our undeveloped acreage. Additionally, pursuant to the amendment to our secured term loan, Hexagon has agreed to (i) reduce our interest rate from 15% to 10% beginning retroactively with March 2013, (ii) permit us to make interest-only payments for March, April, May, and June, after which time the minimum secured term loan payment will be $0.23 million or $0.19 million, depending on our ability to consummate the sale of certain of our assets by July 1, 2013, and (iii) forbear from exercising its rights under the term loan credit agreements for any breach that may have occurred prior to the amendment. In addition, we are required under the amendment to use our reasonable best efforts to pursue certain transactions to improve our financial condition, including the aforementioned sale of certain of our assets, an equity offering or similar capital-raising transaction, one or more joint venture development agreements, and an engineering study of certain of our producing properties to ascertain possible operations to enhance production from those properties. Pursuant to the debenture amendment, the Company and the debenture holders have agreed to waive any breach under the debentures that may have occurred prior to the date of the amendment.

On April 16, 2013, the Company entered into an agreement with one of its existing Debenture holders to issue up to an additional $5.0 million in additional debentures with substantially the same terms to the existing 8% Secured Convertible Debentures. Under the terms of this agreement, $1.5 million of additional debentures will be issued on or before July 16, 2013. The funds associated with the initial issuance of debentures will be used by the Company for the drilling and development of certain properties, and for general corporate purposes (see Note 14) .

Copies of the amendments are filed as Exhibits 10.56 through 10.59 to this annual report on Form 10-K.

### Overview of Our Business and Strategy

We have developed and acquired an oil and natural gas base of proved reserves, as well as a portfolio of exploration and development prospects with conventional and non-conventional reservoir opportunities, with an emphasis on multiple producing horizons, in particular the Niobrara shale and Codell resource plays. We believe these prospects offer the possibility of repeatable success allowing for meaningful production and reserve growth. Our acquisition, development and exploration pursuits are principally directed at oil and natural gas properties in the DJ Basin in Colorado, Nebraska, and Wyoming. Since early 2010, we have acquired and/or developed 29 producing wells. As of December 31, 2012 we owned interests in approximately 145,000 gross (129,000 net) leasehold acres, of which 122,000 gross (107,000 net) acres are classified as undeveloped acreage and all of which are located in Colorado, Wyoming and Nebraska within the DJ Basin. We intend to continue to evaluate and invest in internally generated prospects. It is our long-term goal to maximize our DJ Basin acreage position through development drilling of our conventional horizons as well as development of our Niobrara shale and Codell resource potential.

It is our belief that the exploration and production industry's most significant value creation occurs through the drilling of successful development wells and the enhancement of oil recovery in mature fields given appropriate economic conditions. Our goal is to create significant value while maintaining a low cost structure. To achieve this, our business strategy includes the following elements:

*Participation in development prospects in a known producing basin.* We pursue prospects in the DJ Basin, where we can capitalize on our development and production expertise. We intend to operate the majority of our properties and evaluate each prospect based on its geological and geophysical merits.

*Negotiated acquisitions of properties.* We acquire producing properties based on our knowledge of pricing cycles of oil and natural gas and available exploration and development opportunities of proved, probable and possible reserves.

*Retain Operational Control and Significant Working Interest.* In our principal development targets, we typically seek to maintain operational control of our development and drilling activities. As operator, we retain more control over the timing, selection and process of drilling prospects and completion design, which enhances our ability to maximize our return on invested capital and gives us greater control over the timing, allocation and amounts of capital expenditures. We have continued to generally maintain high working interests in our DJ Basin undeveloped acreage, which maximizes our exposure to generated cash flows and increases in value as the properties are developed. With operational control, we can also schedule our drilling program to satisfy most of our lease stipulations and continue to put our acreage into "held by production" status, thus eliminating leasehold expirations. The majority of our acreage is contiguous which will permit efficiencies in drilling and production operations.

*Leasing of Prospective Acreage.* In the course of our business, we identify drilling opportunities on properties that have not yet been leased. At times, we take the initiative to lease prospective acreage and we may sell all or any portion of the leased acreage to other companies that want to participate in the drilling and development of the prospect acreage.

*Controlling Costs.* We seek to maximize our returns on capital by minimizing our expenditures on general and administrative expenses. We also minimize initial capital expenditures on geological and geophysical overhead, seismic data, hardware and software by partnering with cost efficient operators that have already invested capital in such. We also outsource some of our technical functions in order to help reduce general and administrative and capital requirements.

From time to time, we use commodity price hedging instruments to reduce our exposure to oil and natural gas price fluctuations and to help ensure that we have adequate cash flow to fund our debt service costs and capital programs. From time to time, we will enter into futures contracts, collars and basis swap agreements, as well as fixed price physical delivery contracts. We intend to use hedging primarily to manage price risks and returns on certain acquisitions and drilling programs. Our policy is to consider hedging an appropriate portion of our production at commodity prices we deem attractive. In the future we may also be required by our lenders to hedge a portion of production as part of any financing. We do not currently have any commodity price hedging in place.

**Principal Oil and Gas Interests**

All references to production, sales volumes and reserves quantities are net to our interest unless otherwise indicated.

As of December 31, 2012 we owned interests in approximately 145,000 gross (129,000 net) leasehold acres, of which 122,000 gross (107,000 net) acres are classified as undeveloped acreage and all of which are located in Colorado, Wyoming and Nebraska within the DJ Basin. Our primary targets within the DJ Basin are the conventional Dakota and Muddy 'J' formations, and the developing unconventional Niobrara shale play. Additional horizons include the Codell, Greenhorn and other potential resource formations.

During 2012, we made capital expenditures of approximately $5.07 million, which included $0.54 million related to undeveloped acreage and $4.53 million related to drilling and completion operations where we drilled and completed 6 gross (4 net) wells. We sold undeveloped acreage for $1.4 million and leased other undeveloped acreage to a third party for $1.5 million. We paid our lender, Hexagon, LLC ("Hexagon"), $0.75 million of these proceeds as a prepayment of principal under our term loans.

During 2011, we made capital expenditures of approximately $16.4 million, including $9.4 million for the purchase of undeveloped acreage and $7.4 million related to drilling and completion operations where we drilled 4 gross (3.25 net) wells and completed 3 gross (2.25 net) wells; also, as of December 31, 2011 we had 2 gross (1.75 net) wells in progress.

## Reserves

The table below presents summary information with respect to the estimates of our proved oil and gas reserves for the year ended December 31, 2012. Prior to January 2010, we did not own any reserves nor did we have any production. We engaged Ralph E. Davis Associates, Inc. ("RE Davis") to audit internal engineering estimates for 100 percent of the PV-10 value of our proved reserves in 2012. The prices used in the calculation of proved reserve estimates as of December 31, 2012 were $87.37 per Bbl. and $2.75 per MCF; as of December 31, 2011 were $88.16 per Bbl. and $3.96 per MCF; and as of December 31, 2010, were $78.93 per Bbl. and $4.39 per MCF for oil and natural gas, respectively. The prices were adjusted for basis differentials, pipeline adjustments, and BTU content.

We emphasize that reserve estimates are inherently imprecise and that estimates of all new discoveries and undeveloped locations are more imprecise than estimates of established producing oil and gas properties. Accordingly, these estimates are expected to change as new information becomes available. The PV-10 values shown in the following table are not intended to represent the current market value of the estimated proved oil and gas reserves owned by us. Neither prices nor costs have been escalated. The following table should be read along with the section entitled "Risk Factors — Risks Related to Our Company". The actual quantities and present values of our proved oil and natural gas reserves may be less than we have estimated . No estimates of our proved reserves have been filed with or included in reports to any federal authority or agency, other than the Securities and Exchange Commission ("SEC"), since the beginning of the last fiscal year. We did not have third party engineers review probable and possible reserves or resources as of December 31, 2012.

| | As of December 31, | | |
|---|---|---|---|
| | **2012** | **2011** | **2010** |
| **Reserve data:** | | | |
| **Proved developed** | | | |
| Oil (MBbl) | 213 | 216 | 278 |
| Gas (MMcf) | 186 | 148 | 308 |
| MBOE(1) | 244 | 241 | 329 |
| **Proved undeveloped (2)** | | | |
| Oil (MBbl) | 138 | 392 | 415 |
| Gas (MMcf) | 221 | - | - |
| MBOE (2) | 175 | 392 | 415 |
| **Total Proved** | | | |
| Oil (MBbl) | 351 | 608 | 693 |
| Gas (MMcf) | 407 | 148 | 308 |
| MBOE | 419 | 633 | 744 |
| Proved developed reserves % | 58% | 38% | 44% |
| Proved undeveloped reserves % | 42% | 62% | 56% |
| | | | |
| **Reserve value data :** | | | |
| Proved developed PV-10 | $ 9,743,158 | $ 10,204,160 | $ 11,377,009 |
| Proved undeveloped PV-10 (2) | 5,678,972 | 9,809,885 | 12,217,798 |
| Total proved PV-10 | $ 15,422,130 | $ 20,014,045 | $ 23,594,807 |
| **Standardized measure of discounted future cash flows** | **$ 15,422,130** | **$ 20,014,045** | **$ 23,594,807** |
| **Reserve life (years)** | **42.42** | **22.58** | **21.92** |

(1) Increase in MBOE of proved developed to 244 MBOE from 241 MBOE, an increase of 3 MBOE or 1.2% during the year ended December 31, 2012 and 2011, respectively, was due to the Company purchasing reserves within the DJ Basin.

(2) Decrease in 2012 MBOE of proved undeveloped reserves to 175 MBOE from 392 MBOE in 2011, a decrease of 217 MBOE or 55% reflects the current uncertainty regarding whether the Company will have sufficient capital to support its current development plan. Proved undeveloped reserves therefore reflect the assumption that such reserves will be developed on a promoted basis of 25%, thereby reducing net PUD volumes that would otherwise by recoverable by 75% and also effecting a corresponding decrease in the PV10 value. The Company is working on alternative capital infusion plans that could allow it to maintain a higher working interest position in the undeveloped acreage locations. With the exception of a single well location, the Company currently holds a one hundred percent leasehold position in all the undrilled locations classified as proved undeveloped. A successful capital campaign could result in the Company increasing its proved undeveloped reserve position.

On April 16, 2013, the Company entered into an agreement with one of its existing Debenture holders to issue up to an additional $5.0 million in additional debentures with substantially the same terms to the existing 8% Secured Convertible Debentures. Under the terms of this agreement, $1.5 million of additional debentures will be issued on or before July 16, 2013. The funds associated with the initial issuance of debentures will be used by the Company for the drilling and development of certain properties, and for general corporate purposes.

As we currently do not expect to pay income taxes in the future, there is no difference between the PV-10 value and the standard measure of future net cash flows. Please see the definitions of standardized measure of discounted future net cash flows and PV-10 value in the "Glossary **.**"

*Internal Controls Over Reserves Estimate*

Our policy regarding internal controls over the recording of reserves is structured to objectively and accurately estimate our oil and gas reserve quantities and values in compliance with the regulations of the SEC. Responsibility for compliance in reserve bookings is delegated to our president with assistance from our senior geologist, principal accounting officer, and a senior reserve engineering consultant.

Technical reviews are performed throughout the year by our senior reserve engineering consultants and our senior geologist who evaluate all available geological and engineering data. This data, in conjunction with economic data and ownership information, is used in making a determination of estimated proved reserve quantities. The 2012 reserve process was overseen by Kent Lina, our senior reserve engineer consultant. Mr. Lina joined the Company in October 2010, and prior to that was employed by Delta Petroleum Company from March 2002 to September 2010 in various operations and reservoir engineering capacities culminating as the Senior V.P. of Corporate Engineering. Mr. Lina received a Bachelor of Science degree in Civil Engineering from University of Missouri at Rolla in 1981. Mr. Lina left the Company in December 2012, and continues to serve the Company in a consulting capacity.

*Third-party Reserves Study*

An independent third party reserve study as of December 31, 2012 was performed by RE Davis using their engineering assumptions and other economic data provided by us. One-hundred percent of our total calculated proved reserve PV-10 value was audited by RE Davis. RE Davis is an independent petroleum engineering consulting firm that has been providing petroleum engineering consulting services for over 20 years. The technical person at RE Davis primarily responsible for overseeing our reserve audit is Allen C. Barron, the President and CEO, who received a Bachelor of Science degree in Chemical and Petroleum Engineering from the University of Houston and is a registered Professional Engineer in the States of Texas. He is also a member of the Society of Petroleum Engineers. The RE Davis report dated February 15, 2013 is filed as Exhibit 99.1 to this Annual Report.

Oil and gas reserves and the estimates of the present value of future net revenues therefrom were determined based on prices and costs as prescribed by SEC and FASB guidelines. Reserve calculations involve the estimate of future net recoverable reserves of oil and gas and the timing and amount of future net revenues to be received therefrom. Such estimates are not precise and are based on assumptions regarding a variety of factors, many of which are variable and uncertain. Proved reserves were estimated in accordance with guidelines established by the SEC and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations except by contractual arrangements. For the year ended December 31, 2012, commodity prices over the prior 12-month period and year end costs were used in estimating net cash flows in accordance with SEC guidelines.

In addition to a third party reserve study, our reserves and the corresponding report are reviewed by our president, chief executive officer, senior geologist and principal accounting officer and the audit committee of our board of directors. Our president is responsible for reviewing and verifying that the estimate of proved reserves is reasonable, complete, and accurate. The audit committee reviews the final reserves estimate in conjunction with RE Davis's audit letter.

**Production**

The following table summarizes the average volumes and realized prices, excluding the effects of our economic hedges, of oil and gas produced from properties in which we held an interest during the periods indicated.  Also presented is a production cost per BOE summary:

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2012 | 2011 | 2010 |
| **Product** | | | |
| Oil (Bbl.) | 68,207 | 81,433 | 133,709 |
| Oil (Bbls)-average price (1) | $ 86.48 | $ 87.78 | $ 71.09 |
| | | | |
| Natural Gas (MCF)-volume | 80,438 | 88,999 | 14,911 |
| Natural Gas Liquids (NGL) - BOE | 16,953 | 26,584 | 3 |
| Natural Gas (MCF)-average price (2) | $ 5.05 | $ 6.15 | $ 4.56 |
| | | | |
| Barrels of oil equivalent (BOE) | 98,567 | 122,850 | 136,198 |
| Average daily net production (BOE) | 270 | 337 | 373 |
| Average Price per BOE (1) | 63.96 | $ 62.64 | $ 70.29 |

(1) Does not include the realized price effects of hedges
(2) Includes proceeds from the sale of NGL's

*Oil and gas production costs, production taxes, depreciation, depletion, and amortization*

| | 2012 | 2011 | 2010 |
|---|---|---|---|
| Average Price per BOE(1) | $ 63.96 | $ 62.64 | $ 70.29 |
| | | | |
| Production costs per BOE | 14.42 | 12.33 | 6.31 |
| Production taxes per BOE | 2.31 | 6.83 | 7.76 |
| Depreciation, depletion, and amortization per BOE | 46.15 | 35.39 | 36.98 |
| Total operating costs per BOE | $ 62.88 | $ 54.55 | $ 51.05 |
| | | | |
| Gross margin per BOE | $ 1.08 | $ 8.09 | $ 19.24 |
| | | | |
| Gross margin percentage | 2% | 13% | 27% |

(1) Does not include the realized price effects of hedges

### Productive Wells

As of December 31, 2012, we had working interests in 31 gross (29 net) productive oil wells, and 1 gross (1 net) productive gas well. Productive wells are either wells producing in commercial quantities or wells capable of commercial production although currently shut-in. Multiple completions in the same wellbore are counted as one well. A well is categorized under state reporting regulations as an oil well or a gas well based on the ratio of gas to oil produced when it first commenced production, and such designation may not be indicative of current production.

### Acreage

As of December 31, 2012 we owned 29 producing wells in the Wyoming, Nebraska and Colorado portion within the DJ Basin, as well as approximately 145,000 gross (129,000 net) acres, of which 123,000 gross (107,000 net) acres were classified as undeveloped acreage.

As of December 31, 2012 our primary assets included acreage located in Laramie and Goshen Counties in Wyoming; Banner, Kimball, and Scotts Bluff Counties in Nebraska; and Weld, Arapahoe and Elbert Counties in Colorado.

The following table sets forth certain information with respect to our developed and undeveloped acreage as of December 31, 2012.

| | Undeveloped | | Developed | |
|---|---|---|---|---|
| | Gross | Net | Gross | Net |
| DJ Basin | 122,200 | 107,200 | 21,800 | 21,800 |
| Total | 122,200 | 107,200 | 21,800 | 21,800 |

### Drilling Activity

The following table describes the development and exploratory wells we drilled during the years ended December 31, 2012, 2011, and 2010.

| | For the Year Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2012 | | 2011 | | 2010 | |
| | Gross | Net | Gross | Net | Gross | Net |
| Development: | | | - | - | | |
| Productive wells | 5 | 3 | 3 | 2.25 | 2 | 1.4 |
| Dry wells | 1 | 1 | 1 | 1 | 1 | 0.7 |
| | 6 | 4 | 4 | 3.25 | 3 | 2.1 |
| Exploratory: | | | | | | |
| Productive wells | - | - | - | - | - | - |
| Dry wells | - | - | - | - | - | - |
| Total | 6 | 4 | 4 | 3.25 | 3 | 2.1 |

The number of wells drilled refers to the number of wells completed at any time during the respective year, regardless of when drilling was initiated. As of December 31, 2012 we had no wells in progress.

**Title to Properties**

Substantially all of our interests are held pursuant to leases from third parties. The majorities of our producing properties are subject to mortgages securing indebtedness under our credit facility that we believe do not materially interfere with the use of or affects the value of such properties. We typically perform only minimal title due diligence before acquiring undeveloped acreage.

**2013 Capital Budget**

Our entire 2013 capital budget is subject to the securing of adequate financing. Our 2013 capital budget is currently projected to be approximately $15 million, but is subject to securing sufficient capital to support planned drilling and development expenses. We anticipate that approximately 50% of this budget will be allocated toward the development of two of our unconventional prospects located in the Wattenberg field within the DJ Basin that will target horizontal drilling and development of the Niobrara shale and Codell formations. The remainder of our 2013 budget is anticipated to be directed principally toward the conventional development of certain lower risk offset wells to existing production. We also anticipate the allocation of approximately 10% of our 2013 capital budget toward higher risk exploration activities, including the procurement of seismic data and the drilling of one conventional exploratory well.

Our 2013 capital program is subject to securing sufficient capital, principally via the issuance of additional equity and debt We may also secure additional capital by pursuing sales of certain assets and seek to finance certain projects via joint venture agreements or other arrangements with strategic or industry partners.

Our 2013 capital budget is subject to various factors, including availability of capital, market conditions, oilfield services and equipment availability, commodity prices and drilling results. Results from the wells identified in the capital budget may lead to additional adjustments to the capital budget as the cash flow from the wells could provide additional capital which we may use to increase our capital budget. We do not anticipate any significant expansion of our current DJ Basin acreage position.

Other factors that could cause us to further increase our level of activity and adjust our capital expenditure budget include a reduction in service and material costs, the formation of joint ventures with other exploration and production companies, the divestiture of non-strategic assets, a further improvement in commodity prices or well performance that exceeds our forecasts, any of which could positively impact our operating cash flow. Factors that could cause us to reduce our level of activity and adjust our capital budget include, but are not limited to, increases in service and materials costs, reductions in commodity prices or under-performance of wells relative to our forecasts, any of which could negatively impact our operating cash flow.

**Marketing and Pricing**

We derive revenue and cash flow principally from the sale of oil and natural gas.  As a result, our revenues are determined, to a large degree, by prevailing prices for crude oil and natural gas.  We sell our oil and natural gas on the open market at prevailing market prices or through forward delivery contracts.  The market price for oil and natural gas is dictated by supply and demand, and we cannot accurately predict or control the price we may receive for our oil and natural gas.

Our revenues, cash flows, profitability and future rate of growth will depend substantially upon prevailing prices for oil and natural gas.  Prices may also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital.  Lower prices may also adversely affect the value of our reserves and make it uneconomical for us to commence or continue production levels of natural gas and crude oil.  Historically, the prices received for oil and natural gas have fluctuated widely.  Among the factors that can cause these fluctuations are:

- changes in global supply and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- the price and quantity of imports of foreign oil and natural gas;
- acts of war or terrorism;
- political conditions and events, including embargoes, affecting oil-producing activity;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories;
- weather conditions;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Furthermore, regional natural gas, condensate, oil and NGLs prices may move independently of broad industry price trends. Because some of our operations are located outside major markets, we are directly impacted by regional prices regardless of Henry Hub, WTI or other major market pricing

From time to time, we enter into derivative contracts. These contracts economically hedge our exposure to decreases in the prices of oil and natural gas. Hedging arrangements may expose us to risk of significant financial loss in some circumstances including circumstances where:

- our production and/or sales of natural gas are less than expected;
- payments owed under derivative hedging contracts come due prior to receipt of the hedged month's production revenue; or
- the counterparty to the hedging contract defaults on its contract obligations.

In addition, hedging arrangements may limit the benefit we would receive from increases in the prices for oil and natural gas. We cannot assure you that any hedging transactions we may enter into will adequately protect us from declines in the prices of oil and natural gas.

As of December 31, 2012, we did not have any hedging arrangements in place, and therefore may be more adversely affected by changes in oil and natural gas prices than our competitors who engage in hedging transactions.

**Major Customers**

During the year ended December 31, 2012 and 2011, the Company had one customer, Shell Trading (US), which accounted for approximately 67 percent and 76 percent, respectively, of our revenues.

## Seasonality

Generally, but not always, the demand and price levels for natural gas increase during colder winter months and decrease during warmer summer months. To lessen seasonal demand fluctuations, pipelines, utilities, local distribution companies, and industrial users utilize natural gas storage facilities and forward purchase some of their anticipated winter requirements during the summer. However, increased summertime demand for electricity has placed increased demand on storage volumes. Demand for crude oil and heating oil is also generally higher in the winter and the summer driving season — although oil prices are much more driven by global supply and demand. Seasonal anomalies, such as mild winters, sometimes lessen these fluctuations. The impact of seasonality on crude oil has been somewhat magnified by overall supply and demand economics attributable to the narrow margin of production capacity in excess of existing worldwide demand for crude oil.

## Competition

The oil and gas industry is intensely competitive, particularly with respect to acquiring prospective oil and natural gas properties. We believe our leasehold position provides a sound foundation for a solid drilling program and our future growth. Our competitive position also depends on our geological, geophysical, and engineering expertise, and our financial resources. We believe the location of our acreage; our exploration, drilling, operational, and production expertise; available technologies; our financial resources and expertise; and the experience and knowledge of our management and technical teams enable us to compete effectively in our core operating areas. However, we face intense competition from a substantial number of major and independent oil and gas companies, which have larger technical staffs and greater financial and operational resources than we do. Many of these companies not only engage in the acquisition, exploration, development, and production of oil and natural gas reserves, but also have refining operations, market refined products, own drilling rigs, and generate electricity.

We also compete with other oil and gas companies in attempting to secure drilling rigs and other equipment and services necessary for the drilling, completion, and maintenance of wells. Consequently, we may face shortages or delays in securing these services from time to time. The oil and gas industry also faces competition from alternative fuel sources, including other fossil fuels such as coal and imported liquefied natural gas. Competitive conditions may also be affected by future new energy, climate-related, financial, and other policies, legislation, and regulations.

In addition, we compete for people, including experienced geologists, geophysicists, engineers, and other professionals and consultants. Throughout the oil and gas industry, the need to attract and retain talented people has grown at a time when the number of talented people available is constrained. We are not insulated from this resource constraint, and we must compete effectively in this market in order to be successful.

## Employees

As of December 31, 2012 we had 7 full-time employees and no part-time employees. For the foreseeable future, we intend to only add additional personnel as our operational requirements grow. In the interim, we plan to continue to use the services of independent consultants and contractors to perform various professional services, including land, legal, environmental and tax services. We believe that by limiting our management and employee costs, we are able to better control total costs and retain flexibility in terms of project management.

## Government Regulations

*General.* Our operations covering the exploration, production and sale of oil and natural gas are subject to various types of federal, state and local laws and regulations. The failure to comply with these laws and regulations can result in substantial penalties. These laws and regulations materially impact our operations and can affect our profitability. However, we do not believe that these laws and regulations affect us in a manner significantly different than our competitors. Matters regulated include permits for drilling operations, drilling and abandonment bonds, reports concerning operations, the spacing of wells and unitization and pooling of properties, restoration of surface areas, plugging and abandonment of wells, requirements for the operation of wells, and taxation of production. At various times, regulatory agencies have imposed price controls and limitations on production. In order to conserve supplies of oil and natural gas, these agencies have restricted the rates of flow of oil and natural gas wells below actual production capacity, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. Federal, state and local laws regulate production, handling, storage, transportation and disposal of oil and natural gas, by-products from oil and natural gas and other substances and materials produced or used in connection with oil and natural gas operations. While we believe we will be able to substantially comply with all applicable laws and regulations, the requirements of such laws and regulations are frequently changed. We cannot predict the ultimate cost of compliance with these requirements or their effect on our actual operations.

*Federal Income Tax*. Federal income tax laws significantly affect our operations. The principal provisions that affect us are those that permit us, subject to certain limitations, to deduct as incurred, rather than to capitalize and amortize, our domestic "intangible drilling and development costs" and to claim depletion on a portion of our domestic oil and natural gas properties based on 15% of our oil and natural gas gross income from such properties (up to an aggregate of 1,000 barrels per day of domestic crude oil and/or equivalent units of domestic natural gas).

*Environmental, Health, and Safety Regulations.* Our operations are subject to stringent federal, state, and local laws and regulations relating to the protection of the environment and human health and safety. Environmental laws and regulations may require that permits be obtained before drilling commences, restrict the types, quantities, and concentration of various substances that can be released into the environment in connection with drilling and production activities, govern the handling and disposal of waste material, and limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, and other protected areas, including areas containing endangered animal species. As a result, these laws and regulations may substantially increase the costs of exploring for, developing, or producing oil and gas and may prevent or delay the commencement or continuation of certain projects. In addition, these laws and regulations may impose substantial clean-up, remediation, and other obligations in the event of any discharges or emissions in violation of these laws and regulations. Further, legislative and regulatory initiatives related to global warming or climate change could have an adverse effect on our operations and the demand for oil and natural gas. See "Risk Factors — Risks Related to the Oil and Gas Industry — Legislative and regulatory initiatives related to global warming and climate change could have an adverse effect on our operations and the demand for oil and natural gas."

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. For additional information about hydraulic fracturing and related regulatory matters, see *"*Risk Factors— Risks Relating to the Oil and Gas Industry.*"* Federal and state legislation and regulatory initiatives related to hydraulic fracturing could result in increased costs and additional operating restrictions or delays in the completion of oil and gas wells.

Federal and state occupational safety and health laws require us to organize and maintain information about hazardous materials used, released, or produced in our operations. Some of this information must be provided to our employees, state and local governmental authorities, and local citizens. We are also subject to the requirements and reporting framework set forth in the federal workplace standards.

The discharge of oil, gas or other pollutants into the air, soil or water may give rise to liabilities to the government and third parties and may require us to incur costs to remedy discharges. Natural gas, oil or other pollutants, including salt water brine, may be discharged in many ways, including from a well or drilling equipment at a drill site, leakage from pipelines or other gathering and transportation facilities, leakage from storage tanks and sudden discharges from damage or explosion at natural gas facilities of oil and gas wells. Discharged hydrocarbons may migrate through soil to water supplies or adjoining property, giving rise to additional liabilities.

A variety of federal and state laws and regulations govern the environmental aspects of natural gas and oil production, transportation and processing and may, in addition to other laws, impose liability in the event of discharges, whether or not accidental, failure to notify the proper authorities of a discharge, and other noncompliance with those laws. Compliance with such laws and regulations may increase the cost of oil and gas exploration, development and production; although we do not anticipate that compliance will have a material adverse effect on our capital expenditures or earnings. Failure to comply with the requirements of the applicable laws and regulations could subject us to substantial civil and/or criminal penalties and to the temporary or permanent curtailment or cessation of all or a portion of our operations.

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "superfund law," imposes liability, regardless of fault or the legality of the original conduct, on some classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of a disposal site or sites where the release occurred and companies that dispose or arrange for disposal of the hazardous substances found at the time.  Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and severable liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.  We could be subject to liability under CERCLA because our jointly owned drilling and production activities generate relatively small amounts of liquid and solid waste that may be subject to classification as hazardous substances under CERCLA.

The Resource Conservation and Recovery Act of 1976, as amended ("RCRA") is the principal federal statute governing the treatment, storage and disposal of hazardous wastes.  RCRA imposes stringent operating requirements, and liability for failure to meet such requirements, on a person who is either a "generator" or "transporter" of hazardous waste or an "owner" or "operator" of a hazardous waste treatment, storage or disposal facility.  At present, RCRA includes a statutory exemption that allows most oil and natural gas exploration and production waste to be classified as nonhazardous waste.  A similar exemption is contained in many of the state counterparts to RCRA. As a result, we are not required to comply with a substantial portion of RCRA's requirements because our operations generate minimal quantities of hazardous wastes.  At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes oil and natural gas exploration and production wastes from regulation as hazardous waste. Repeal or modification of the exemption by administrative, legislative or judicial process, or modification of similar exemptions in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us to incur increased operating expenses.

The Oil Pollution Act of 1990 ("OPA"), and regulations thereunder impose a variety of regulations on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in United States waters.  The OPA assigns liability to each responsible party for oil removal costs and a variety of public and private damages.  While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of federal safety, construction or operating regulations.  Few defenses exist to the liability imposed by OPA. In addition, to the extent we acquire offshore leases and those operations affect state waters, we may be subject to additional state and local clean-up requirements or incur liability under state and local laws.  OPA also imposes ongoing requirements on responsible parties, including proof of financial responsibility to cover at least some costs in a potential spill.  We cannot predict whether the financial responsibility requirements under the OPA amendments will adversely restrict our proposed operations or impose substantial additional annual costs to us or otherwise materially adversely affect us.  The impact, however, should not be any more adverse to us than it will be to other similarly situated owners or operators.

The Federal Water Pollution Control Act Amendments of 1972 and 1977 (the "Clean Water Act"), imposes restrictions and controls on the discharge of produced waters and other wastes into navigable waters.  Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the crude oil and natural gas industry into certain coastal and offshore waters.  Further, the Environmental Protection Agency ("EPA"), has adopted regulations requiring certain crude oil and natural gas exploration and production facilities to obtain permits for storm water discharges.  Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans.  The Clean Water Act and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges of crude oil and other pollutants and impose liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release.  We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from crude oil and natural gas production. The Safe Drinking Water Act of 1974, as amended, establishes a regulatory framework for underground injection, with the main goal being the protection of usable aquifers. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. Hazardous-waste injection well operations are strictly controlled, and certain wastes, absent an exemption, cannot be injected into underground injection control wells. Failure to abide by our permits could subject us to civil or criminal enforcement. We believe that we are in compliance in all material respects with the requirements of applicable state underground injection control programs and our permits.

The Clean Air Act of 1963 and subsequent extensions and amendments (collectively, the "Clean Air Act") and state air pollution laws adopted to fulfill its mandate provide a framework for national, state and local efforts to protect air quality. Our operations utilize equipment that emits air pollutants which may be subject to federal and state air pollution control laws. These laws require utilization of air emissions abatement equipment to achieve prescribed emissions limitations and ambient air quality standards, as well as operating permits for existing equipment and construction permits for new and modified equipment. We believe that we are in compliance in all material respects with the requirements of applicable federal and state air pollution control laws. Over the next several years, we may be required to incur capital expenditures for air pollution control equipment or other air emissions-related issues. These New Source Performance Standards ("NSPS 0000") became effective in 2012, adding administrative and operational costs. Colorado partially adopted the requirements of NSPS 0000 in 2012 and will consider full adoption in 2013.

There are numerous state laws and regulations in the states in which we operate which relate to the environmental aspects of our business. These state laws and regulations generally relate to requirements to remediate spills of deleterious substances associated with oil and gas activities, the conduct of salt water disposal operations, and the methods of plugging and abandonment of oil and gas wells which have been unproductive. Numerous state laws and regulations also relate to air and water quality.

We do not believe that our environmental risks will be materially different from those of comparable companies in the oil and gas industry. We believe our present activities substantially comply, in all material respects, with existing environmental laws and regulations. Nevertheless, we cannot assure you that environmental laws will not result in a curtailment of production or material increase in the cost of production, development or exploration or otherwise adversely affect our financial condition and results of operations. Although we maintain liability insurance coverage for liabilities from pollution, environmental risks generally are not fully insurable.

In addition, because we have acquired and may acquire interests in properties that have been operated in the past by others, we may be liable for environmental damage, including historical contamination, caused by such former operators. Additional liabilities could also arise from continuing violations or contamination not discovered during our assessment of the acquired properties.

*Federal Leases.* For those operations on federal oil and gas leases, such operations must comply with numerous regulatory restrictions, including various non-discrimination statutes, and certain of such operations must be conducted pursuant to certain on-site security regulations and other permits issued by various federal agencies. In addition, on federal lands in the United States, the Minerals Management Service, or MMS, prescribes or severely limits the types of costs that are deductible transportation costs for purposes of royalty valuation of production sold off the lease. In particular, MMS prohibits deduction of costs associated with marketer fees, cash out and other pipeline imbalance penalties, or long-term storage fees. Further, the MMS has been engaged in a process of promulgating new rules and procedures for determining the value of crude oil produced from federal lands for purposes of calculating royalties owed to the government. The natural gas and crude oil industry as a whole has resisted the proposed rules under an assumption that royalty burdens will substantially increase. We cannot predict what, if any, effect any new rule will have on our operations.

Some of our operations are conducted on federal lands pursuant to oil and gas leases administered by the Bureau of Land Management ("BLM"). These leases contain relatively standardized terms and require compliance with detailed regulations and orders, which are subject to change. In addition to permits required from other regulatory agencies, lessees must obtain a permit from the BLM before drilling and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, the valuation of production and payment of royalties, the removal of facilities, and the posting of bonds to ensure that lessee obligations are met. Under certain circumstances, the BLM may require our operations on federal leases to be suspended or terminated.

May 2010, the BLM adopted changes to its oil and gas leasing program that require, among other things, a more detailed environmental review prior to leasing oil and natural gas resources, increased public engagement in the development of master leasing and development plans prior to leasing areas where intensive new oil and gas development is anticipated, and a comprehensive parcel review process. These changes have increased the amount of time and regulatory costs necessary to obtain oil and gas leases administered by the BLM.

*Other Laws and Regulations*. Various laws and regulations require permits for drilling wells and also cover spacing of wells, the prevention of waste of natural gas and oil including maintenance of certain gas/oil ratios, rates of production and other matters. The effect of these laws and regulations, as well as other regulations that could be promulgated by the jurisdictions, in which we have production, could be to limit the number of wells that could be drilled on our properties and to limit the allowable production from the successful wells completed on our properties, thereby limiting our revenues.

To date we have not experienced any material adverse effect on our operations from obligations under environmental, health, and safety laws and regulations. We believe that we are in substantial compliance with currently applicable environmental, health, and safety laws and regulations, and that continued compliance with existing requirements will not have a materially adverse impact on us.

## Item 1A. RISK FACTORS

*Investing in our shares involves significant risks, including the potential loss of all or part of your investment. These risks could materially affect our business, financial condition and results of operations and cause a decline in the market price of our shares. You should carefully consider all of the risks described in this annual report, in addition to the other information contained in this annual report, before you make an investment in our shares. In addition to other matters identified or described by us from time to time in filings with the SEC, there are several important factors that could cause our future results to differ materially from historical results or trends, results anticipated or planned by us, or results that are reflected from time to time in any forward-looking statement. Some of these important factors, but not necessarily all important factors, include the following:*

### Risks Related to Our Company

***Our current liquidity position presents a substantial risk that we will be unable to satisfy our current debt obligations.*** We currently have $19.34 million outstanding under our term loans and $13.40 million outstanding under our 8% Senior Secured Convertible Debentures due May 16, 2014. Under the terms of the recent amendments to our secured term loans, beginning in July 2013 we will be required to make monthly payments of up to $0.23 million to our lender, Hexagon, and failure to make such payments could result in immediate acceleration of both the term loans and the debentures. The majority of our leases on which we have identified reserves are subject to security interests held by the lenders under our secured term loans or our debentures. As discussed below and in “Management’s Discussion & Analysis of Financial Position and Results of Operations,” we currently have a working capital deficit of approximately $1.04 million, and approximately $3.63 in current liabilities, and therefore we will need to access additional capital in order to fund our operating costs for the year ending December 31, 2013. On April 16, 2013, the Company entered into an agreement with one of its existing Debenture holders to issue up to an additional $5.0 million in additional debentures with substantially the same terms to the existing 8% Secured Convertible Debentures. Under the terms of this agreement, $1.5 million of additional debentures will be issued on or before July 16, 2013. The funds associated with the initial issuance of debentures will be used by the Company for the drilling and development of certain properties, and for general corporate purposes. We are pursuing a number of other capital raising transactions aimed at improving our liquidity position in the long and short term.

***Our credit agreements mature on May 16, 2014, and our lender can foreclose on several of our properties if we do not pay off or refinance our $19.34 million of loans.*** Our credit agreements, which mature on May 16, 2014, require us to make a minimum monthly payment of up to $0.23 million to Hexagon, our lender. Several of our oil and gas properties, including many of our producing properties, are pledged as collateral for our credit agreements. Failure to make a monthly payment, or to repay these loans at maturity, could cause a default under all three of the credit agreements, allowing Hexagon to foreclose on these properties.

***Our 8% Senior Secured Debentures mature on May 16, 2014 and require monthly interest payments, and the debenture holders can foreclose on several of our properties if we default.*** Some of our oil and gas properties, including producing properties, are pledged as collateral for our 8% Senior Secured Debentures. An event of default under the debentures or under our term loan agreements with Hexagon would allow the lenders to foreclose on these properties.

***Our level of indebtedness could adversely affect our ability to raise additional capital to fund our operations, limit our ability to react to changes in the economy or our industry and prevent us from meeting our obligations under our indebtedness.*** As of December 31, 2012, our total outstanding debt under our credit agreements and convertible debentures equaled $32.7 million, including $19.34 million outstanding under our credit agreements with Hexagon. Our degree of leverage could have important consequences, including the following :

- it may limit our ability to obtain additional debt or equity financing for working capital, capital expenditures, further exploration, debt service requirements, acquisitions and general corporate or other purposes;
- a substantial portion of our cash flows from operations will be dedicated to the payment of principal and interest on our indebtedness and will not be available for other purposes, including our operations, capital expenditures and future business opportunities;
- the debt service requirements of other indebtedness in the future could make it more difficult for us to satisfy our financial obligations;
- certain of our borrowings, including borrowings under our credit facility, are at variable rates of interest, exposing us to the risk of increased interest rates;
- as we have pledged most of our oil and natural gas properties and the related equipment, inventory, accounts and proceeds as collateral for the borrowings under our credit facility, they may not be pledged as collateral for other borrowings and would be at risk in the event of a default thereunder;
- it may limit our ability to adjust to changing market conditions and place us at a competitive disadvantage compared to our competitors that have less debt;
- we are vulnerable in the present downturn in general economic conditions and in our business, and we will likely be unable to carry out capital spending and exploration activities in excess of those that are currently planned; and
- we may from time to time be out of compliance with covenants under our term loan agreements, which will require us to seek waivers from our lenders, which may be difficult to obtain.

We may incur additional debt, including secured indebtedness, or issue preferred stock in order to maintain adequate liquidity and develop our properties to the extent desired. A higher level of indebtedness and/or preferred stock increases the risk that we may default on our obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, natural gas and oil prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, the value of our assets, the number of shares of capital stock we have authorized, unissued and unreserved and our performance at the time we need capital.

***Currently, a significant portion of our revenue after field level operating expenses is required to be paid to Hexagon as debt service.*** The terms of our term loan agreements with Hexagon require us to pay a significant portion of our operating cash flow as debt service, and also include a minimum monthly debt service payment of up to $0.23 million. The existence of the minimum debt service requirement results in consistent negative cash flow, and threatens the Company's ability to remain in business. If we fail to make any such minimum payments, Hexagon may declare a default and accelerate the amounts due. In that event, all of our debt, including the convertible debentures, would be in default. In addition, failure to make the required monthly payment could result in the acceleration of all amounts under the credit agreements, and foreclosure on a significant number of our properties. During the years ended December 31, 2012 and 2011, we paid $1.63 million and $0.84 million in principal and $3.21 million and $3.20 million in interest representing approximately 171% and 700% of our free cash flow from operations, respectively. In 2011, Hexagon deferred the payment of approximately $2 million of revenue toward debt service. In February 2012, we completed the sale of certain rights in our Grover Field property for $4.5 million, and in December 2012 we granted a four-year lease for the deep rights on approximately 6,300 net acres of our undeveloped acreage in the DJ Basin for approximately $1.5 million, of which $0.75 million was paid to Hexagon for an additional debt principal payment. As of December 31, 2012, we had working capital of negative $1.04 million. In April 2013, we amended our term loan agreements with Hexagon, reducing the interest rate from 15% to 10%, reducing the minimum monthly payments from $0.33 million to either $0.23 million or $0.19 million, depending on our ability to complete the sale of certain of our assets by July 1, 2013, and providing for interest-only payments for March through June 2013. Additionally, we will seek to obtain additional capital through the sale of our equity or debt securities, the successful deployment of our cash on hand, bank lines of credit, joint ventures, and project financing. Consequently, there can be no assurance we will be able to obtain continued access to capital as and when needed or, if so, that the terms of any available financing will be subject to commercially reasonable terms. If we are unable to access additional capital in significant amounts as needed, we may not be able to develop our current prospects and properties, may have to forfeit our interest in certain prospects and may not otherwise be able to develop our business. In such an event, our stock price could be materially adversely affected.

***Our largest stockholder and primary lender has the power to significantly influence the future of our Company.*** Our largest stockholder, Hexagon, is also our primary lender. As of December 31, 2012, Hexagon beneficially owned approximately 2,675,000 shares of our common stock, or approximately 13.82% of our outstanding shares. Pursuant to our credit agreements with Hexagon and certain amendments thereto, Hexagon has certain rights, including the right to designate a member of our Board of Directors and consent rights over certain types of actions. Consequently, Hexagon has the power to influence matters requiring approval by our stockholders, including the election of directors, and the approval of mergers and other significant corporate transactions. This concentration of ownership, along with the restrictive covenants contained in our credit agreements with Hexagon, may make it more difficult for other stockholders to effect substantial changes in our Company, may have the effect of delaying, preventing or expediting, as the case may be, a change in control of our Company, and may make it difficult for other significant investors to make the capital contributions we require in order to resolve our current liquidity issues. Hexagon also has the right to sell its Company stock if it chooses to do so and, as required by the terms of certain amendments to the credit agreements, all of its shares are currently registered for resale. In the event that Hexagon sells all or a substantial portion of its shares, it is possible that the market price of our stock could be adversely affected.

***We have historically incurred losses and cannot assure investors as to future profitability.*** We have historically incurred losses from operations during our history in the oil and natural gas business. We had a cumulative deficit of approximately $106.22 million and $68.48 million as of December 31, 2012 and 2011, respectively. Many of our properties are in the exploration stage, and to date we have established a limited volume of proved reserves on our properties. Our ability to be profitable in the future will depend on successfully addressing our near-term capital need to refinance our term loan indebtedness and fund our 2013 capital budget, and implementing our acquisition, exploration, development and production activities, all of which are subject to many risks beyond our control. Even if we become profitable on an annual basis, we cannot assure you that our profitability will be sustainable or increase on a periodic basis.

***We will require additional capital in order to achieve commercial success and, if necessary, to finance future losses from operations as we endeavor to build revenue, but we do not have any commitments to obtain such capital and we cannot assure you that we will be able to obtain adequate capital as and when required.*** The business of oil and gas acquisition, drilling and development is capital intensive and the level of operations attainable by an oil and gas company is directly linked to and limited by the amount of available capital. We believe that our ability to achieve commercial success and our continued growth will be dependent on our continued access to capital either through the additional sale of our equity or debt securities, bank lines of credit, project financing, joint ventures, sale or lease of undeveloped acreage, or cash generated from oil and gas operations.

***We do not have a significant operating history and, as a result, there is a limited amount of information about us on which to make an investment decision***. In January 2010, we acquired our first oil and gas prospects and received our first revenues from oil and gas production in February 2010. In November 2012, our chairman and chief executive officer retired, and we appointed W. Phillip Marcum to the position of chairman and chief executive officer, and appointed A. Bradley Gabbard to the position of president (in addition to his existing position as chief financial officer). Accordingly, there is little operating history upon which to judge our business strategy, our management team or our current operations.

***We have limited management and staff and will be dependent upon partnering arrangements.*** We had seven employees at the end of December 31, 2012. We use the services of independent consultants and contractors to perform various professional services, including reservoir engineering, oil and gas well supervision, land, legal, environmental and tax services. We also pursue alliances with partners in the areas of geological and geophysical services and prospect generation, evaluation and prospect leasing. Our dependence on third party consultants and service providers creates a number of risks, including but not limited to:

- the possibility that such third parties may not be available to us as and when needed; and
- the risk that we may not be able to properly control the timing and quality of work conducted with respect to our projects.

If we experience significant delays in obtaining the services of such third parties or poor performance by such parties, our results of operations and stock price could be materially adversely affected.

***The loss of our chief executive officer or our president and chief financial officer could adversely affect us.*** We are dependent on the experience of our executive officers to implement our operational objectives and growth strategy. The loss of the services of either of these individuals could have a negative impact on our operations and our ability to implement our strategy.

***In addition to acquiring producing properties, we may also grow our business through the acquisition and development of exploratory oil and gas prospects, which is the riskiest method of establishing oil and gas reserves***. In addition to acquiring producing properties, we may acquire, drill and develop exploratory oil and gas prospects that are profitable to produce. Developing exploratory oil and gas properties requires significant capital expenditures and involves a high degree of financial risk. The budgeted costs of drilling, completing, and operating exploratory wells are often exceeded and can increase significantly when drilling costs rise. Drilling may be unsuccessful for many reasons, including title problems, weather, cost overruns, equipment shortages, and mechanical difficulties. Moreover, the successful drilling or completion of an exploratory oil or gas well does not ensure a profit on investment. Exploratory wells bear a much greater risk of loss than development wells. We cannot assure you that our exploration, exploitation and development activities will result in profitable operations. If we are unable to successfully acquire and develop exploratory oil and gas prospects, our results of operations, financial condition and stock price may be materially adversely affected.

***If oil or natural gas prices decrease or exploration and development efforts are unsuccessful, wells in progress are deemed unsuccessful, or major tracts of undeveloped acreage expire, or other similar adverse events occur, we may be required to write-down the carrying value of our developed properties.*** We use the full cost method of accounting whereby all costs related to the acquisition and development of oil and natural gas properties are capitalized into a single cost center referred to as a full cost pool. These costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling wells, completing productive wells, or plugging and abandoning non-productive wells, costs related to expired leases, or leases underlying producing and non-producing wells, and overhead charges directly related to acquisition and exploration activities. Under the full cost method of accounting, capitalized oil and natural gas property that comprise the full cost pool, less accumulated depletion and net of deferred income taxes, may not exceed an amount equal to the present value, discounted at 10%, of estimated future net revenues from proved oil and natural gas reserves. This ceiling test is performed at least quarterly. Should the capitalized costs of the full cost pool exceed this ceiling, we would recognize impairment expense. During the year ended December 31, 2012, we recognized impairment expenses in the amount of approximately $26.66 million related to impairment of the carrying value of the developed properties that comprised the full cost pool. Future write-downs could occur for numerous reasons, including, but not limited to reductions in oil and gas prices that lower the estimate of future net revenues from proved oil and natural gas reserves, revisions to reserve estimates, or from the addition of non-productive capitalized costs to the full cost pool that do not result in corresponding increase in oil and gas reserves. Impairments of undeveloped acreage and plugging and abandonment of wells in progress are other areas where costs may be capitalized into the full cost pool, without any corresponding increase in reserve values; as such, these situations could result in future additional impairment expenses.

***Hedging transactions may limit our potential gains or result in losses*** . In order to manage our exposure to price risks in the marketing of our oil and natural gas, from time to time, we may enter into derivative contracts that economically hedge our oil and gas price on a portion of our production. These contracts may limit our potential gains if oil and natural gas prices were to rise substantially over the price established by the contract. In addition, such transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received;
- our production and/or sales of oil or natural gas are less than expected;
- payments owed under derivative hedging contracts come due prior to receipt of the hedged month’s production revenue; or
- the other party to the hedging contract defaults on its contract obligations.

Hedging transactions we may enter into may not adequately protect us from declines in the prices of oil and natural gas. In addition, the counterparties under our derivatives contracts may fail to fulfill their contractual obligations to us.

As of December 31, 2012, we did not have any hedging arrangements in place, and therefore may be more adversely affected by changes in oil and natural gas prices than our competitors who engage in hedging transactions.

***Our large inventory of undeveloped acreage and large percentage of undeveloped proved reserves may create additional economic risk.*** Our success is largely dependent upon our ability to develop our large inventory of future drilling locations, undeveloped acreage and undeveloped reserves. As of December 31, 2012, approximately 42% of our total proved reserves and 83% of our total acreage were undeveloped. To the extent our drilling results are not as successful as we anticipate, natural gas and oil prices decline, or sufficient funds are not available to drill these locations and reserves, we may not capture the expected or projected value of these properties. In addition, delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic.

***We may have difficulty managing growth in our business, which could adversely affect our financial condition and results of operations.*** Significant growth in the size and scope of our operations would place a strain on our financial, technical, operational and management resources. The failure to continue to upgrade our technical, administrative, operating and financial control systems or the occurrences of unexpected expansion difficulties, including the failure to recruit and retain experienced managers, geologists, engineers and other professionals in the oil and gas industry could have a material adverse effect on our business, financial condition and results of operations and our ability to timely execute our business plan.

***The actual quantities and present value of our proved reserves may be lower than we have estimated. In addition, the present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves.*** This annual report contains estimates of our proved oil and natural gas reserves and the estimated future net revenues from these reserves contained in our filings with the SEC. This December 31, 2012 annual report, reserve estimate was prepared by our current reserve engineer consultant reviewed by our president, senior geologist, and principal accounting officer, and audited by RE Davis. The process of estimating oil and natural gas reserves is complex and requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Accordingly, these estimates are inherently imprecise. Actual future production, oil and natural gas prices, revenues, taxes, development and operating expenses, and quantities of recoverable oil and natural gas reserves most likely will vary from these estimates and vary over time. Such variations may be significant and could materially affect the estimated quantities and present value of our proved reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development drilling, results of secondary and tertiary recovery applications, prevailing oil and natural gas prices and other factors, many of which are beyond our control. You should also not assume that our initial rates of production of our wells will lead to greater overall production over the life of the wells, or that early results suggesting lack of reservoir continuity will prove to be accurate.

You should not assume that the present value of future net revenues referred to in this prospectus is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are generally based on the un-weighted average of the closing prices during the first day of each of the year preceding the end of the fiscal year. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Any change in consumption by oil or natural gas purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of our oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor nor does it reflect discount factors used in the market place for the purchase and sale of oil and natural gas.

***Properties that we acquire may not produce oil or natural gas as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them, which could cause us to incur losses.*** One of our growth strategies is to pursue selective acquisitions of undeveloped acreage oil and natural gas reserves. If we choose to pursue an acquisition, we will perform a review of the target properties; however, these reviews are inherently incomplete. Generally, it is not feasible to review in depth every individual property involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. We may not perform an inspection on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, we may not be able to obtain effective contractual protection against all or part of those problems, and we may assume environmental and other risks and liabilities in connection with the acquired properties.

***All of our producing properties and operations are located in the DJ Basin region, making us vulnerable to risks associated with operating in one major geographic area.*** All of our estimated proved reserves at December 31, 2012, and all of our 2012, 2011 and 2010 sales were generated in the DJ Basin in southeastern Wyoming, northeastern Colorado and southwestern Nebraska. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production from these wells caused by transportation capacity constraints, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions, plant closures for scheduled maintenance or interruption of transportation of oil or natural gas produced from the wells in this area. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and gas producing areas such as the DJ Basin, which may cause these conditions to occur with greater frequency or magnify the effect of these conditions. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

***The marketability of our production is dependent upon transportation and processing facilities over which we may have no control.*** The marketability of our production depends in part upon the availability, proximity and capacity of pipelines, natural gas gathering systems, rail service, and processing facilities. We deliver crude oil and natural gas produced from these areas through gathering systems and pipelines, some of which we do not own. The lack of availability of capacity on third-party systems and facilities could reduce the price offered for our production or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Although we have some contractual control over the transportation of our production through firm transportation arrangements, third-party systems and facilities may be temporarily unavailable due to market conditions or mechanical reliability or other reasons, including adverse weather conditions. Activist or other efforts may delay or halt the construction of additional pipelines or facilities. Third-party systems and facilities may not be available to us in the future at a price that is acceptable to us. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities, could delay production, thereby harming our business and, in turn, our results of operations, cash flows, and financial condition.

***Our ability to produce crude oil and natural gas economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations.*** Drilling activities require the use of water. For example, the hydraulic fracturing process require the use and disposal of significant quantities of water. In certain areas, there may be insufficient local aquifer capacity to provide a source of water for drilling activities. Water must be obtained from other sources and transported to the drilling site. Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, could adversely impact our operations in certain areas.

***Our success is influenced by oil, natural gas, and NGL prices in the specific areas where we operate, and these prices may be lower than prices at major markets.*** Regional natural gas, condensate, oil and NGLs prices may move independently of broad industry price trends. Because some of our operations are located outside major markets, we are directly impacted by regional prices regardless of Henry Hub, WTI or other major market pricing.

***Unless we find new oil and gas reserves, our reserves and production will decline, which would materially and adversely affect our business, financial condition and results of operations.*** Producing oil and gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Thus, our future oil and gas reserves and production and, therefore, our cash flow and revenue are highly dependent on our success in efficiently obtaining reserves and acquiring additional recoverable reserves. We may not be able to develop, find or acquire reserves to replace our current and future production at costs or other terms acceptable to us, or at all, in which case our business, financial condition and results of operations would be materially and adversely affected.

***Part of our strategy involves drilling in existing or emerging unconventional shale plays using available horizontal drilling and completion techniques. The results of our planned exploratory and development drilling in these plays are subject to drilling and completion technique risks and drilling results may not meet our expectations for reserves or production. As a result, we may incur material write-downs and the value of our undeveloped acreage could decline if drilling results are unsuccessful.*** Unconventional operations involve utilizing drilling and completion techniques as developed by ourselves and our service providers. Risks that we face while drilling include, but are not limited to, landing our wellbore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the wellbore and being able to run tools and other equipment consistently through the horizontal wellbore. Risks that we face while completing our wells 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 wellbore during completion operations and successfully cleaning out the wellbore after completion of the final fracture stimulation stage.

Our experience with horizontal drilling utilizing the latest drilling and completion techniques specifically in the Niobrara is limited. Ultimately, the success of these drilling and completion techniques can only be developed over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems and limited takeaway capacity or otherwise, and/or natural gas and oil prices decline, the return on our investment in these areas may not be as attractive as we anticipate and we could incur material write-downs of undeveloped properties and the value of our undeveloped acreage could decline in the future.

***The unavailability or high cost of drilling rigs, equipment supplies or personnel could adversely affect our ability to execute our exploration and development plans.*** The oil and gas industry is cyclical and, from time to time, there are shortages of drilling rigs, equipment, supplies or qualified personnel. During these periods, the costs of rigs, equipment and supplies may increase substantially and their availability may be limited. In addition, the demand for, and wage rates of, qualified personnel, including drilling rig crews, may rise as the number of rigs in service increases. The higher prices of oil and gas during the last several years have resulted in shortages of drilling rigs, equipment and personnel, which have resulted in increased costs and shortages of equipment in the areas where we operate. If drilling rigs, equipment, supplies or qualified personnel are unavailable to us due to excessive costs or demand or otherwise, our ability to execute our exploration and development plans could be materially and adversely affected and, as a result, our financial condition and results of operations could be materially and adversely affected.

***Covenants in our credit agreements impose significant restrictions and requirements on us.*** Our three credit agreements contain a number of covenants imposing significant restrictions on us, including the maximum monthly payment requirement restrictions on our repurchase of, and payment of dividends on, our capital stock and limitations on our ability to incur additional indebtedness, make investments, engage in transactions with affiliates, sell assets and create liens on our assets. These restrictions may affect our ability to operate our business, to take advantage of potential business opportunities as they arise and, in turn, may materially and adversely affect our business, financial conditions and results of operations.

***We could be required to pay liquidated damages to some of our investors if we fail to maintain the effectiveness of a prior registration statement.*** We could default and accrue liquidated damages under registration rights agreements covering approximately 3.2 million shares of our common stock if we fail to maintain the effectiveness of a prior registration statement as required in the agreements. In such case, we would be required to pay monthly liquidated damages of up to $0.23 million. The maximum aggregate liquidated damages are capped at $1.37 million. If we do not make a monthly payment within seven days after the date payable, we are required to pay interest at an annual rate of 18% on the unpaid amount. If we default under the registration rights agreement and accrue liquidated damages, we could be required to either raise additional outside funds through financing or curtail or cease operations.

***We are exposed to operating hazards and uninsured risks.*** Our operations are subject to the risks inherent in the oil and natural gas industry, including the risks of:

- fire, explosions and blowouts;
- pipe failure;
- abnormally pressured formations; and
- environmental accidents such as oil spills, natural gas leaks, ruptures or discharges of toxic gases, brine or well fluids into the environment (including groundwater contamination).

These events may result in substantial losses to us from:

- injury or loss of life;
- severe damage to or destruction of property, natural resources and equipment;
- pollution or other environmental damage;
- clean-up responsibilities;
- regulatory investigation;
- penalties and suspension of operations; or
- attorney's fees and other expenses incurred in the prosecution or defense of litigation.

We maintain insurance against some, but not all, of these risks. We cannot assure you that our insurance will be adequate to cover these losses or liabilities. We do not carry business interruption insurance. Losses and liabilities arising from uninsured or underinsured events may have a material adverse effect on our financial condition and operations.

The producing wells in which we have an interest occasionally experience reduced or terminated production. These curtailments can result from mechanical failures, contract terms, pipeline and processing plant interruptions, market conditions and weather conditions. These curtailments can last from a few days to many months.

***We may be subject to risks in connection with acquisitions, and the integration of significant acquisitions may be difficult.*** We periodically evaluate acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions that appear to fit within our overall business strategy. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their appropriate differentials;
- development and operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an "as is" basis.

Significant acquisitions and other strategic transactions may involve other risks, including:

- diversion of our management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of ours while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate organizations;
- challenge of attracting and retaining personnel associated with acquired operations; and
- failure to realize the full benefit that we expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition, or to realize these benefits within the expected time frame.

The process of integrating operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer.

***Prospects that we decide in which to participate may not yield oil or natural gas in commercially viable quantities or quantities sufficient to meet our targeted rate of return***. A prospect is a property in which we own an interest and have what we believe, based on available seismic and geological information, to be indications of oil or natural gas. Our prospects are in various stages of evaluation, ranging from a prospect that is ready to be drilled to a prospect that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion cost or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analysis we perform using data from other wells, more fully explored prospects or producing fields will be useful in predicting the characteristics and potential reserves associated with our drilling prospects.

***Our reserve estimates will depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves*** . The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and the calculation of the present value of reserves shown in these reports.

In order to prepare reserve estimates in its reports, our independent petroleum consultant projected production rates and timing of development expenditures. Our independent petroleum consultant also analyzed available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary and may not be in our control. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and natural gas reserves are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will most likely vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, our independent petroleum consultant may adjust estimates of proved reserves to reflect production history, drilling results, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

**Risks Relating to the Oil and Gas Industry**

***Oil and natural gas prices are highly volatile, and our revenue, profitability, cash flow, future growth and ability to borrow funds or obtain additional capital, as well as the carrying value of our properties, are substantially dependent on prevailing prices of oil and natural gas.*** Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production and the levels of our production depend on numerous factors beyond our control. These factors include the following:

- changes in global supply and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries (“OPEC”);
- the price and quantity of imports of foreign oil and natural gas;
- acts of war or terrorism;
- political conditions and events, including embargoes, affecting oil-producing activity;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories;
- weather conditions;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- market concerns about global warming or changes in governmental policies and regulations due to climate change initiatives.

Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

Our revenues, operating results, profitability and future rate of growth depend primarily upon the prices we receive for oil and, to a lesser extent, natural gas that we sell. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. In addition, we may need to record asset carrying value write-downs if prices fall. A significant decline in the prices of natural gas or oil could adversely affect our financial position, financial results, cash flows, access to capital and ability to grow.

***Our industry is highly competitive, which may adversely affect our performance, including our ability to participate in ready to drill prospects in our core areas***. We operate in a highly competitive environment. In addition to capital, the principle resources necessary for the exploration and production of oil and natural gas are:

- leasehold prospects under which oil and natural gas reserves may be discovered;
- drilling rigs and related equipment to explore for such reserves; and
- knowledgeable personnel to conduct all phases of oil and natural gas operations.

We must compete for such resources with both major oil and natural gas companies and independent operators. Virtually all of these competitors have financial and other resources substantially greater than ours. We cannot assure you that such materials and resources will be available when needed. If we are unable to access material and resources when needed, we risk suffering a number of adverse consequences, including:

- the breach of our obligations under the oil and gas leases by which we hold our prospects and the potential loss of those leasehold interests;
- loss of reputation in the oil and gas community;
- a general slowdown in our operations and decline in revenue; and
- decline in market price of our common shares.

***Legislative and regulatory initiatives related to global warming and climate change could have an adverse effect on our operations and the demand for oil and natural gas.*** In December 2009, the EPA determined that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. The EPA recently adopted two sets of rules regulating greenhouse gas emissions under the CAA, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States on an annual basis, including petroleum refineries, as well as certain onshore oil and natural gas production facilities.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil, NGLs, and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

***Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells.***

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs. The process is typically regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuel under the federal Safe Drinking Water Act. In addition, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act and to require disclosure of the chemicals used in the hydraulic fracturing process. Under the proposed legislation, this information would be available to the public via the internet, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. At the state level, some states have adopted, and other states are considering adopting legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices and a committee of the U.S. House of Representatives has conducted an investigation of hydraulic fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with final results expected by 2014. In addition, the U.S. Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. The U.S. Department of the Interior is conducting a rule making, likely to result in new disclosure requirements and other mandates for hydraulic fracturing on federal lands. These ongoing studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory mechanisms.

***We are subject to numerous laws and regulations that can adversely affect the cost, manner or feasibility of doing business*** . Our operations are subject to extensive federal, state and local laws and regulations relating to the exploration, production and sale of oil and natural gas, and operating safety. Future laws or regulations, any adverse change in the interpretation of existing laws and regulations or our failure to comply with existing legal requirements may result in substantial penalties and harm to our business, results of operations and financial condition. We may be required to make large and unanticipated capital expenditures to comply with governmental regulations, such as:

- land use restrictions;
- lease permit restrictions;
- drilling bonds and other financial responsibility requirements, such as plugging and abandonment bonds;
- spacing of wells;
- unitization and pooling of properties;
- safety precautions;
- operational reporting; and
- taxation.

Under these laws and regulations, we could be liable for:

- personal injuries;
- property and natural resource damages;
- well reclamation cost; and
- governmental sanctions, such as fines and penalties.

Our operations could be significantly delayed or curtailed and our cost of operations could significantly increase as a result of regulatory requirements or restrictions. We are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. It is also possible that a portion of our oil and gas properties could be subject to eminent domain proceedings or other government takings for which we may not be adequately compensated. See “Business and Properties—Government Regulations” for a more detailed description of our regulatory risks.

***Our operations may incur substantial expenses and resulting liabilities from compliance with environmental laws and regulations*** . Our oil and natural gas operations are subject to stringent federal, state and local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations:

- require the acquisition of a permit before drilling commences;
- restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities, including new environmental regulations governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- impose substantial liabilities for pollution resulting from our operations.

Failure to comply with these laws and regulations may result in:

- the assessment of administrative, civil and criminal penalties;
- incurrence of investigatory or remedial obligations; and
- the imposition of injunctive relief.

Changes in environmental laws and regulations occur frequently and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to reach and maintain compliance and may otherwise have a material adverse effect on our industry in general and on our own results of operations, competitive position or financial condition. Under these environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or contamination or if our operations met previous standards in the industry at the time they were performed. Our permits require that we report any incidents that cause or could cause environmental damages. See "Business and Properties—Government Regulations" for a more detailed description of our environmental risks.

**Risks Relating to Our Common Stock**

***There is a limited public market for our shares and we cannot assure you that an active trading market or a specific share price will be established or maintained.*** Our common stock trades on the Nasdaq Global Market, generally in small volumes each day. The value of our common stock could be affected by:

- actual or anticipated variations in our operating results;
- changes in the market valuations of other oil and gas companies;
- announcements by us or our competitors of significant acquisitions, strategic partnerships, joint ventures or capital commitments;
- adoption of new accounting standards affecting our industry;
- additions or departures of key personnel;
- sales of our common stock or other securities in the open market;
- actions taken by our lenders or the holders of our convertible debentures;
- changes in financial estimates by securities analysts;
- conditions or trends in the market in which we operate;
- changes in earnings estimates and recommendations by financial analysts;
- our failure to meet financial analysts' performance expectations; and
- other events or factors, many of which are beyond our control.

In a volatile market, you may experience wide fluctuations in the market price of our securities. These fluctuations may have an extremely negative effect on the market price of our common stock and may prevent you from obtaining a market price equal to your purchase price when you attempt to sell our common stock in the open market. In these situations, you may be required either to sell at a market price which is lower than your purchase price, or to hold our common stock for a longer period of time than you planned. An inactive market may also impair our ability to raise capital by selling shares of capital stock and may impair our ability to acquire other companies or oil and gas properties by using common stock as consideration.

***Our common stock is subject to penny stock rules which limit the market for our common stock*** . The SEC has adopted Rule 15g-9 which establishes the definition of a "penny stock," for the purposes relevant to us, as any equity security that has a market price of less than $5.00 per share or with an exercise price of less than $5.00 per share, subject to certain exceptions. For any transaction involving a penny stock, unless exempt, the rules require:

- that a broker or dealer approve a person's account for transactions in penny stocks; and
- that broker or dealer receives from the investor a written agreement to the transaction, setting forth the identity and quantity of the penny stock to be purchased.

In order to approve a person's account for transactions in penny stocks, the broker or dealer must:

- obtain financial information and investment experience objectives of the person; and
- make a reasonable determination that the transactions in penny stocks are suitable for that person and the person has sufficient knowledge and experience in financial matters to be capable of evaluating the risks of transactions in penny stocks.

The broker or dealer must also deliver, prior to any transaction in a penny stock, a disclosure schedule prescribed by the SEC relating to the penny stock market, which, in highlight form:

- sets forth the basis on which the broker or dealer made the suitability determination; and
- that the broker or dealer received a signed, written agreement from the investor prior to the transaction.

Disclosure also has to be made about the risks of investing in penny stocks in both public offerings and in secondary trading and about the commissions payable to both the broker-dealer and the registered representative, current quotations for the securities and the rights and remedies available to an investor in cases of fraud in penny stock transactions. Finally, monthly statements have to be sent disclosing recent price information for the penny stock held in the account and information on the limited market in penny stocks.

Generally, brokers may be less willing to execute transactions in securities subject to the "penny stock" rules. This may make it more difficult for investors to dispose of our common stock and cause a decline in the market value of our stock.

***Sales of a substantial number of shares of our common stock, or the perception that such sales might occur, could have an adverse effect on the price of our common stock.*** As of December 31, 2012, approximately 13.82% of our common stock was held by Hexagon, and two other investors hold more than 5%. Sales by Hexagon or our other large investors of a substantial number of shares of our common stock into the public market, or the perception that such sales might occur, could have an adverse effect on the price of our common stock.

***We may issue shares of preferred stock with greater rights than our common stock.*** Our articles of incorporation authorize our board of directors to issue one or more series of preferred stock and set the terms of the preferred stock without seeking any further approval from our stockholders. Any preferred stock that is issued may rank ahead of our common stock, in terms of dividends, liquidation rights and voting rights.

***There may be future dilution of our common stock.*** To the extent options to purchase common stock under our employee and director stock option plans, outstanding warrants to purchase common stock are exercised or the price vesting triggers under the performance shares granted to our executive officers are satisfied, or additional shares of restricted stock are issued to our employees, holders of our common stock will experience dilution. As of December 31, 2012, we had outstanding options and warrants to purchase 5,638,900 shares of common stock at a weighted average exercise price of $7.00. If we sell additional equity or convertible debt securities, such sales could result in increased dilution to our existing stockholders and cause the price of our outstanding securities to decline. Further, our convertible debentures, currently convertible into 3,152,941 shares of our common stock, include a full-ratchet anti-dilution provision that provides for the adjustment of the conversion price in the event we sell additional equity or convertible securities at a price that is below the $4.25 conversion price of the debentures.

***We do not expect to pay dividends on our common stock.*** We have never paid dividends with respect to our common stock, and we do not expect to pay any dividends, in cash or otherwise, in the foreseeable future. We intend to retain any earnings for use in our business. In addition, the credit agreement relating to our credit facility prohibits us from paying any dividends and the indenture governing our senior notes restricts our ability to pay dividends. In the future, we may agree to further restrictions.

***Our common stock is an unsecured equity interest in our Company.*** As an equity interest, our common stock is not secured by any of our assets. Therefore, in the event we are liquidated, the holders of the common stock will receive a distribution only after all of our secured and unsecured creditors have been paid in full. There can be no assurance that we will have sufficient assets after paying our secured and unsecured creditors to make any distribution to the holders of the common stock.

***Securities analysts may not initiate coverage of our shares or may issue negative reports, which may adversely affect the trading price of the shares.*** We cannot assure you that securities analysts will cover our company. If securities analysts do not cover our company, this lack of coverage may adversely affect the trading price of our shares. The trading market for our shares will rely in part on the research and reports that securities analysts publish about us and our business. If one or more of the analysts who cover our company downgrades our shares, the trading price of our shares may decline. If one or more of these analysts ceases to cover our company, we could lose visibility in the market, which, in turn, could also cause the trading price of our shares to decline. Further, because of our small market capitalization, it may be difficult for us to attract securities analysts to cover our company, which could significantly and adversely affect the trading price of our shares.

***Failure to maintain an effective system of internal control over financial reporting may have an adverse effect on our stock price.*** Pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, and the rules and regulations promulgated by the Securities and Exchange Commission, or the SEC, to implement Section 404, we are required to furnish a report by our management to include in our annual report on Form 10-K regarding the effectiveness of our internal control over financial reporting. The report includes, among other things, an assessment of the effectiveness of our internal control over financial reporting as of the end of our fiscal year, including a statement as to whether or not our internal control over financial reporting is effective. This assessment must include disclosure of any material weaknesses in our internal control over financial reporting identified by management.

We may discover areas of our internal control over financial reporting which may require improvement. If we are unable to assert that our internal control over financial reporting is effective now or in any future period, or if our auditors are unable to express an opinion on the effectiveness of our internal controls, we could lose investor confidence in the accuracy and completeness of our financial reports, which could have an adverse effect on our stock price.

## Item 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

## Item 3. LEGAL PROCEEDINGS

*Parker v. Tracinda Corporation*, Denver District Court, Case No. 2011CV561. In November 2012, the Company filed a motion to intervene in garnishment proceedings involving Roger Parker, the Company's former Chief Executive Officer and Chairman. The Defendant has served various writs of garnishment on the Company to enforce a judgment against Mr. Parker seeking, among other things, shares of unvested, restricted stock. The Company has asserted rights to lawful set-offs and deductions in connection with certain tax consequences, which may be material to the Company. As a result of bankruptcy proceedings filed by Mr. Parker, the garnishment proceedings have been stayed. At this stage, we cannot express an opinion as to the probable outcome of this matter.

There are no other material pending legal proceedings to which we or our properties are subject.

## Item 4. MINE SAFETY DISCLOSURES

Not applicable.

# PART II

## Item 5. MARKET FOR COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

**Recent Market Prices**

On November 2, 2011 our common stock began trading on the Nasdaq Global Market under the symbol "RECV." Between September 25, 2009 and November 1, 2011 our stock traded on the OTC Bulletin Board under the symbol "RECV.OB."

The following table shows the high and low reported sales prices of our common stock for the periods indicated. Effective October 19, 2011 we completed a 1:4 reverse stock split, and stock prices prior to such date have been adjusted to reflect the effect of the stock split.

| | High | Low |
|---|---|---|
| **2012** | | |
| Fourth Quarter | $ 4.95 | $ 1.40 |
| Third Quarter | $ 4.75 | $ 1.64 |
| Second Quarter | $ 3.99 | $ 2.25 |
| First Quarter | $ 4.90 | $ 2.31 |
| **2011** | | |
| Fourth Quarter | $ 7.00 | $ 2.99 |
| Third Quarter | $ 11.00 | $ 4.88 |
| Second Quarter | $ 13.00 | $ 8.80 |
| First Quarter | $ 15.56 | $ 7.80 |

On March 29, 2013, there were approximately 30 owners of record of our common stock.

**Dividend Policy**

We have never paid any cash dividends on our common stock and do not anticipate paying any dividends in the foreseeable future. Our current business plan is to retain any future earnings to finance the expansion and development of our business. Any future determination to pay cash dividends will be at the discretion of our board of directors, and will be dependent upon our financial condition, results of operations, capital requirements and other factors as our board may deem relevant at that time.

**Recent Sales of Unregistered Securities**

We have previously disclosed by way of quarterly reports on Form 10-Q and current reports on Form 8-K filed with the SEC all sales by us of our unregistered securities during 2012.

## Item 6. SELECTED FINANCIAL DATA

Not applicable.

## Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

*The following discussion should be read in conjunction with our financial statements included in Part IV in this annual report. This discussion contains forward-looking statements that involve risks and uncertainties. Our actual results could differ materially from those anticipated in these forward-looking statements as a result of various factors including those set forth under Item "1A. Risk Factors ".*

### General

We are an independent oil and gas company engaged in the acquisition, drilling and production of oil and natural gas properties and prospects within the DJ Basin. Our business strategy is designed to create shareholder value by developing our undeveloped acreage and leveraging the knowledge, expertise and experience of our management team.

We principally target low to medium risk projects that have the potential for multiple producing horizons, and offer repeatable success allowing for meaningful production and reserve growth. Our acquisition and exploration pursuits of oil and natural gas properties are principally located in Colorado, Nebraska, and Wyoming within the DJ Basin.

The majority of our leases on which we have identified reserves and production are subject to security interests held by the lenders under our secured term loans or our 8% Senior Secured Convertible Debentures. As discussed below, we have recently amended the terms of both the secured term loans and the 8% Senior Convertible Debentures to among other things, extend the maturity dates under both the term loans and the debentures, and reduce the interest rate and the level of minimum monthly payments under the term loans. We currently have $19.34 million outstanding under our term loans and $13.40 million outstanding under our debentures. In addition, we currently have a working capital deficit of approximately $1.04 million, and approximately $3.63 million in current liabilities. We believe that the amendments referenced above provide us with significantly more flexibility in meeting our obligations. In the immediate term, the Company expects that additional capital will be required to fund its capital budget for 2013, partially to fund some of its ongoing overhead, provide for payment of minimum interest and principal payments required by term notes, and to provide additional capital to generally improve its working capital position. In addition, as discussed below, we have entered into an agreement with one of our existing debenture holders to invest at least $1.5 million in additional debentures on substantially the same terms as our existing senior secured debentures, with the possibility of an additional investment by our existing debenture holders of up to $3.5 million. We are aggressively exploring a number of other capital raising transactions aimed at improving our liquidity position in the long and short term, including asset sales, joint ventures and similar industry partnerships, asset monetization transactions, possible equity transactions, and other potential refinancing transactions with terms more favorable to us than those under the term loans and debentures. Our ability to fund some of our ongoing overhead, to meet our minimum principal and interest obligations and to fund our 2013 capital program is contingent on successfully raising additional capital via one or more of the above described transactions.

On a longer term basis, the Company will require capital to retire our term notes and our 8% Senior Secured Convertible Debentures when such debts mature in May 2014.

Pursuant to our credit agreements with Hexagon, a substantial portion of our monthly net revenues derived from our producing properties is required to be used for debt and interest payments. In addition, our debt instruments contain provisions that, absent consent of Hexagon, may restrict our ability to raise additional capital.

### Financial Condition and Liquidity

We have incurred a cumulative net loss of approximately $106.22 million, negative working capital of $1.04 million and current liabilities of $3.63 million for the year ended December 31, 2012.

Information about our financial position is presented in the following table :

| | Year ended December 31, | |
|---|---|---|
| | 2012 | 2011 |
| **Financial Position Summary** | | |
| Cash and cash equivalents | $ 970,035 | $ 2,707,722 |
| Working capital | $ (1,041,491) | $ 1,294,706 |
| Balance outstanding on term loans and convertible debentures payable | $ 32,736,341 | $ 29,680,636 |
| Shareholders' equity | $ 12,082,212 | $ 49,668,225 |

During the year ended December 31, 2012, our working capital decreased to negative $1.04 million compared to positive working capital of $1.29 million at December 31, 2011. This lower level of working capital is primarily the result of cash used in operations and cash investing activities that exceeded cash provided by financing activities. In view of the maturity of our secured indebtedness in 2014, we will be required to complete a capital-raising transaction, such as a sale of assets, an offering of our securities, or a refinancing transaction with terms more favorable to us, before our secured debt matures. If we default under our secured debt, our lenders will be entitled to exercise their rights to foreclose on the properties held as security for the term loans and the debentures, and may be entitled to collect any amounts remaining under the loans and debentures that is not satisfied through sale of such properties.

Pursuant to our credit agreements with Hexagon, a substantial portion of our monthly net revenues derived from our producing properties is required to be used for debt and interest payments. In addition, our debt instruments contain provisions that, absent consent of the lenders, may restrict our ability to raise additional capital.

*Cash Flows*

Cash used in operating activities during the year ended December 31, 2012 was $3.39 million. This use of cash, coupled with the cash used in investing activities, exceeded cash provided by financing activities by $1.74 million, and resulted in a corresponding decrease in cash. This net use of cash contributed to a $2.34 million decrease in working capital as of December 31, 2012, compared to working capital as of December 31, 2011.

The following table compares cash flow items during the year ended December 31, 2012 to December 31, 2011:

| | Year ended December 31, | |
|---|---|---|
| | **2012** | **2011** |
| Cash provided by (used in): | | |
| Operating activities | $ (3,389,403) | $ (570,247) |
| Investing activities | (1,403,961) | (13,308,468) |
| Financing activities | 3,055,677 | 11,057,693 |
| Net change in cash | $ (1,737,687) | $ (2,821,022) |

During the year ended December 31, 2012, net cash used in operating activities was $3.39 million, compared to a net cash used in operating activities of $0.57 million during the year ended December 31, 2011, an increase of $2.82 million or 494%. The primary changes in operating cash during the year ended December 31 2012 was $37.74 million of net loss, adjusted for non-cash charges of $6.87 million of depreciation, depletion, amortization and accretion expenses, $26.66 million of impairment of developed acreage, $1.60 million of amortization of deferred financing costs and issuance of stock for convertible debentures interest, and offset by a non-cash change in fair value of convertible debentures conversion option of $0.32 million, $0.97 million of an increase in stock-based compensation expense, and offset by a non-cash charge for the change in commodity price derivatives of $0.86 million.

During the year ended December 31, 2012, net cash used in investing activities was $1.40 million, compared to net cash used in investing activity of $13.31 million during the year ended December 31, 2011, an increase of $11.91 million or 89%. The primary changes in investing cash during the year ended December 31, 2012 were $0.54 million related to our acquisitions of undeveloped acreage and drilling capital expenditures of $4.53 million offset by the proceeds from the sale of undeveloped acreage of $2.92 million and proceeds from hedge settlements of $0.78 million.

During the year ended December 31, 2012, net cash provided by financing activities was $3.06 million, compared to net cash provided by financing activities of $11.06 million during the year ended December 31, 2011, a decrease of $8 million, or 72%. The changes in financing cash during the year ended December 31, 2012 were due to net proceeds from the issuance of new convertible debentures of $5.00 million, offset by the net repayments of debt of $1.94 million.

As of December 31, 2012 our balances outstanding on term loans and convertible debentures was $32.74 million, compared to $29.68 million as of December 31, 2011. The primary changes in the balances outstanding relate to an increase of $5.0 million in 2012 in our convertible debentures, offset by principal payments on our secured debts of $1.94 million.

In April 2013, we amended both our secured term loans and our 8% Senior Secured Convertible Debentures to extend their maturity dates to May 16, 2014. In consideration for the extended maturity date of both loans and the reduced interest rate and minimum loan payment under the secured term loans, the Company will be required to provide both Hexagon and the holders of our debentures an additional security interest in 15,000 acres (or 30,000 acres in aggregate) of our undeveloped acreage. Additionally, pursuant to the amendment to our secured term loan, Hexagon has agreed to (i) reduce our interest rate from 15% to 10% beginning retroactively with March 2013, (ii) permit us to make interest-only payments for March, April, May, and June, after which time the minimum secured term loan payment will be $0.23 million or $0.19 million, depending on our ability to consummate the sale of certain of our assets by July 1, 2013, and (iii) forbear from exercising its rights under the term loan credit agreements for any breach that may have occurred prior to the amendment. In addition, we are required under the amendment to use our reasonable best efforts to pursue certain transactions to improve our financial condition, including the aforementioned sale of certain of our assets, an equity offering or similar capital-raising transaction, one or more joint venture development agreements, and an engineering study of certain of our producing properties to ascertain possible operations to enhance production from those properties. Pursuant to the debenture amendment, the Company and the debenture holders have agreed to waive any breach under the debentures that may have occurred prior to the date of the amendment.

On April 16, 2013, the Company entered into an agreement with one of its existing Debenture holders to issue up to an additional $5.0 million in additional debentures with substantially the same terms to the existing 8% Secured Convertible Debentures. Under the terms of this agreement, $1.5 million of additional debentures will be issued on or before July 16, 2013. The funds associated with the initial issuance of debentures will be used by the Company for the drilling and development of certain properties, and for general corporate purposes.

We currently have $19.34 million outstanding under our secured term loans and $13.40 million outstanding under our 8% Senior Convertible Debentures. In addition, we currently have a working capital deficit of approximately $1.04 million, and approximately $3.63 million in current liabilities. We believe that the amendments discussed above provide us with significantly more flexibility in meeting our obligations. We are aggressively seeking to obtain this additional capital through a combination of the issuance of additional equity or debt securities, use of existing working capital and operating cash flows, and from cash provided by potential joint venture participants. We may also choose to sell certain assets in order to partially repay our secured debt and supplement the funding of our 2013 capital budget.

Currently, we have no agreements or understandings with any third parties for additional capital. Further, under the terms of our term loan agreements, we are prohibited from incurring any additional debt from third parties without prior consent from Hexagon. Our ability to obtain additional working capital through bank lines of credit and project financing would likely be subject to the repayment of the approximately $19.34 million debt related to our primary credit facility. Consequently, there can be no assurance we will be able to obtain continued access to capital as and when needed or, if so, that the terms of any available financing will be subject to commercially reasonable terms. If we are unable to access additional capital in significant amounts as needed, we may not be able to develop our current prospects and properties, may have to forfeit our interest in certain prospects and may not otherwise be able to develop our business. In such an event, our stock price will be materially adversely affected.

*Notable Financing Transactions*

In December 2011, we sold certain undeveloped acreage for total proceeds of $4.5 million.

In February 2012, we completed the sale of our Grover Prospect acreage, under which we agreed to sell all of our oil and gas leases in the Grover Field in Weld County, Colorado to Bill Barrett Corporation for approximately $4.54 million.

On March 19, 2012, we entered into agreements with our existing convertible debenture holders to issue up to an additional $5.0 million in convertible debentures (the “Supplemental Debentures”). All terms of the new convertible debentures are substantively identical to the existing convertible debentures. This financing was completed in August 2012.

In August 2012, the Company restructured the terms of the Supplemental Debenture offering and concluded the offering by issuing an additional $1.96 million of convertible debentures. On September 8, 2012, the Company issued 50,000 shares, valued at $0.23 million, to T.R. Winston & Company LLC for acting as a placement agent of the Supplemental Debentures.

On November 5, 2012, the Company liquidated all of its price derivatives (commodity hedges) for proceeds of $0.61 million. As of December 31, 2012, the Company did not have any derivative instruments.

In December 2012, the Company leased certain deep rights to 6,300 undeveloped acres to a private company for proceeds of approximately $1.50 million, of which $0.75 million was paid toward principal on our long-term debt.

As discussed above, in April 2013 we amended both our senior secured debentures, including the Supplemental Debentures, and our secured term loans. See “Cash Flows” above.

*Term Loans*

The Company entered into three separate loan agreements with Hexagon in January, March and April 2010, each with an original maturity date of December 1, 2010. All three loans originally bore annual interest of 15% (which has been reduced, as discussed below), currently mature on May 16, 2014, have similar terms, including customary representations and warranties and indemnification, and require the Company to repay the loans with the proceeds of the monthly net revenues from the production of the acquired properties. The loans contain cross collateralization and cross default provisions and are collateralized by mortgages against a portion of the Company's developed and undeveloped leasehold acreage.

We entered into a loan modification agreement on May 28, 2010, which extended the maturity date of the loans to December 1, 2011. In consideration for extending the maturity of the loans, Hexagon received 250,000 warrants with an exercise price of $6.00 per share. The loan modification agreement also required the Company to issue 250,000 five year warrants to purchase common stock at $6.00 per share to Hexagon if the Company did not repay the loans in full by January 1, 2011. Since the loans were not paid in full by January 1, 2011, the Company issued 250,000 additional warrants with an exercise price of $6.00 per share to Hexagon which was valued at approximately $1.60 million. This amount was recorded as a deferred financing cost and is being amortized over the remaining term of the loan.

In December 2010, Hexagon extended the maturity date of the loans to September 1, 2012. During the last six months of 2011, Hexagon agreed to temporarily suspend for five months the requirement to remit monthly net revenues in the total amount of approximately $2.00 million as payment on the loans. In November 2011, Hexagon extended the maturity to January 1, 2013. In November 2011, Hexagon also temporarily advanced the Company an additional amount of $0.31 million, which was repaid in full in February 2012. In March 2012, Hexagon extended the maturity of the loans to June 30, 2013, and in connection there with, the Company agreed to make minimum monthly note payments of $0.33 million, effective immediately. In July 2012, Hexagon extended the maturity date to September 30, 2013. In November 2012, Hexagon extended the maturity date of the loans to December 31, 2013.

On December 27, 2012, in connection with the Company's lease of deep rights on approximately 6,300 net acres to a third party for total consideration of $1.5 million, the Company paid Hexagon $0.75 million, which reduced the long-term debt principal amount.

As discussed above, we reached agreement in April 2013 with Hexagon to amend all three loan agreements . See "Cash Flows" above .

The Company is subject to certain non-financial covenants with respect to the Hexagon loan agreements. As of December 31, 2012, the Company was in compliance with all covenants under the facilities. However, we do not currently have sufficient liquidity available to continue to make the monthly payments as they come due. Unless we complete a capital-raising transaction, such as a sale of assets (either to our lenders in exchange for loan forgiveness or to a third party, enabling us to pay down our outstanding debt), an offering of our securities, or a refinancing transaction with terms more favorable to us, our lenders will be entitled to exercise their rights to foreclose on the properties held as security for the term loans and the debentures (as discussed below), and may be entitled to collect any amounts remaining under the loans and debentures that is not satisfied through sale of such properties.

*Convertible Debentures Payable*

In February 2011, the Company completed a private placement of $8.40 million aggregate principal amount of 8% Senior Secured Debentures (the "Debentures"), secured by mortgages on several of our properties. Initially, the Debentures were convertible at any time at the holders' option into shares of our common stock at $9.40 per share, subject to certain adjustments, including the requirement to reset the conversion price based upon any subsequent equity offering at a lower price per share amount. Interest at an annualized rate of 8% is payable quarterly on each May 15, August 15, November 15 and February 15 in cash or, at the Company's option, in shares of common stock, valued at 95% of the volume weighted average price of the common stock for the 10 trading days prior to an interest payment date. The Company can redeem some or all of the Debentures at any time. The redemption price is 115% of principal plus accrued interest. If the holders of the Debentures elect to convert the Debentures, following notice of redemption, the conversion price will include a make-whole premium equal to the remaining interest through the 18 month anniversary of the original issue date of the Debentures, payable in common stock. T.R. Winston & Company LLC acted as placement agent for the private placement and received $0.40 million of Debentures equal to 5% of the gross proceeds from the sale. The Company is amortizing the $0.40 million over the life of the loan as deferred financing costs. The Company amortized $0.16 million of deferred financing costs into interest expense during the year ended December 31, 2012, and has $0.14 million of deferred financing costs to be amortized through maturity.

In December 2011, the Company agreed to amend the Debentures to lower the conversion price to $4.25 from $9.40 per share. This amendment was an inducement consideration to the Debenture holders for their agreement to release a mortgage on certain properties so the properties could be sold. The sale of these properties was effective December 31, 2011, and a final closing occurred during the three months ended March 31, 2012.

On March 19, 2012, the Company entered into agreements with some of its existing Debenture holders to issue up to an additional $5.0 million in additional debentures (the "Supplemental Debentures"). Under the terms of the Supplemental Debenture agreements, proceeds derived from the issuance of Supplemental Debentures were used principally for the development of certain of the Company's proved undeveloped properties and other undeveloped acreage currently targeted by the Company for exploration, as well as for other general corporate purposes. Any new producing properties developed from the proceeds of Supplemental Debentures are to be pledged as collateral under a mortgage to secure future payment of the Debentures and Supplemental Debentures. All terms of the Supplemental Debentures are substantively identical to the Debentures. The Agreements also provided for the payment of additional consideration to the purchasers of Supplemental Debentures in the form of a proportionately reduced 5% carried working interest in any properties developed with the proceeds of the Supplemental Debenture offering.

Through July 2012, we received $3.04 million of proceeds from the issuance of Supplemental Debentures, which were used for the drilling and development of six new wells, resulting in a total investment of $3.69 million. Five of these wells resulted in commercial production, and one well was plugged and abandoned.

In August 2012, the Company and holders of the Supplemental Debentures agreed to renegotiate the terms of the Supplemental Debenture offering. These negotiations concluded with the issuance of an additional $1.96 million of Supplemental Debentures. The August 2012 modifications to the Supplemental Debenture agreements increased the carried working interest from 5% to 10% and also provided for a one-year, proportionately reduced net profits interest of 15% in the properties developed with the proceeds of the Supplemental Debenture offering, as well as the next four properties to be drilled and developed by the Company.

As described above, in April 2013 the holders of our 8% Senior Secured Convertible Debentures agreed to extend their maturity date to May 16, 2014. On April 16, 2013, the Company entered into an agreement with one of its existing Debenture holders to issue up to an additional $5.0 million in additional debentures with substantially the same terms to the existing 8% Secured Convertible Debentures. Under the terms of this agreement, $1.5 million of additional debentures will be issued on or before July 16, 2013. The funds associated with the initial issuance of debentures will be used by the Company for the drilling and development of certain properties, and for general corporate purposes .

The Company has estimated the total value of consideration paid to Supplemental Debenture holders in the form of the modified net profits interest and carried working interest to be approximately $1.16 million, and recorded this amount as a debt discount to be amortized over the remaining life of the Supplemental Debentures.

We periodically engage a third party valuation firm to complete a valuation of the conversion feature associated with the Debentures, and with respect to December 31, 2012, the Supplemental Debentures. This valuation resulted in an estimated derivative liability as of December 31, 2012 and December 31, 2011 of $1.68 million and $1.30 million, respectively. The portion of the derivative liability that is associated with the Supplemental Debentures, in the approximate amount of $0.70 million, has been recorded as a debt discount, and is being amortized over the remaining life of the Supplemental Debentures.

During the year ended December 31, 2012 and 2011, the Company amortized $2.36 million and $1.52 million, respectively, of debt discounts.

On September 8, 2012, the Company issued 50,000 shares, valued at $0.23 million, to T.R. Winston & Company LLC for acting as a placement agent of the Supplemental Debentures. The Company is amortizing the $0.23 million over the life of the loan as deferred financing costs. The Company amortized $0.05 million of deferred financing costs into interest expense during the year ended December 31, 2012, and has $0.18 million of deferred financing costs to be amortized through May 2014.

As of December 31, 2012 and December 31, 2011, the convertible debt is recorded as follows:

| | As of December 31, 2012 | As of December 31, 2011 |
|---|---|---|
| Convertible debentures | $ 13,400,000 | $ 8,400,000 |
| Debt discount | (3,099,639) | (3,470,932) |
| Total convertible debentures, net | $ 10,300,361 | $ 4,929,068 |

Annual debt maturities as of December 31, 2012 are as follows:

| | |
|---|---|
| Year 1 | $ 388,351 |
| Year 2 | 32,347,963 |
| Thereafter | - |
| Total | $ 32,736,314 |

Failure to make periodic interest payments due under the Debentures (including the Supplemental Debentures) may result in acceleration of all principal and interest then outstanding under the Debentures, and may entitle the holders of the Debentures to exercise their rights to foreclose under the mortgages securing the Debentures. In addition, failure to make the required monthly payments under our term loans could result in immediate acceleration of both the term loans and the Debentures.

*Interest Expense*

For the year ended December 31, 2012 and 2011, the Company incurred interest expense of approximately $8.06 million and $8.22 million, respectively, of which approximately $4.85 million and $5.02 million, respectively, were non-cash interest expense and amortization of the deferred financing costs, accretion of the convertible debentures payable discount, and convertible debentures interest paid in common stock.

**Capital Resources**

Our 2013 capital program is subject to securing sufficient capital, principally via the issuance of additional equity and debt both to fund our capital program and to refinance the Hexagon loans which are due on May 16, 2014. We are aggressively exploring a number of capital raising transactions aimed at improving our liquidity position in the long and short term, including asset sales, joint ventures and similar industry partnerships, asset monetization transactions, possible equity transactions, and other potential refinancing transactions with terms more favorable to us than those under the term loans and debentures.

Currently, the majority of our cash flows from operations are applied to the payment of principal and interest of our loans. Due to the Company's continuing operating losses and the large amounts of capital expenditures, during 2011 and 2012, our liquidity and working capital have deteriorated. We will seek additional capital to refinance our debts, partially fund our operations, and fund our 2013 Capital Budget. We will also require substantial additional capital in order to fully test, develop and evaluate our 129,000 net undeveloped acres. We expect to obtain this capital through a variety of sources, including, but not limited to, future debt and equity financings and potentially from future joint venture partners. Unless we are successful in competing a substantial debt and/or equity financing or other similar transaction in the near term, we may be required to sell certain assets in order to meet obligations as they arise. We cannot provide assurance that we will secure a major financing, nor can we predict the terms of any future potential financing transactions.

We cannot give assurances that our working capital on hand, our cash flow from operations or any available borrowings, equity offerings or other financings, or asset sales will be sufficient to fund our operations or our anticipated 2013 capital expenditures.

**Results of Operations**

*Year ended December 31, 2012 compared to the year ended December 31, 2011*

The following table compares operating data for the fiscal year ended December 31, 2012 to December 31, 2011:

| | 2012 | 2011 |
|---|---|---|
| Revenue | | |
| Oil sales | $ 5,898,459 | $ 7,148,110 |
| Gas sales | 406,216 | 547,190 |
| Operating fees | 174,779 | 117,360 |
| Realized gain on commodity price derivatives | 780,135 | 625,043 |
| Unrealized loss on commodity price derivatives | - | (75,609) |
| Total revenues | 7,259,589 | 8,362,094 |
| | | |
| Costs and expenses | | |
| Production costs | 1,421,177 | 1,514,784 |
| Production taxes | 227,455 | 838,714 |
| General and administrative | 4,331,328 | 10,544,347 |
| Depreciation, depletion and amortization | 4,549,303 | 4,347,117 |
| Bad debt expense | 77,957 | - |
| Impairment of developed properties | 26,658,707 | 2,821,176 |
| Total costs and expenses | 37,265,927 | 20,066,138 |
| | | |
| Loss from operations | (30,006,338) | (11,704,044) |
| | | |
| Other income | 5,896 | 71,253 |
| Convertible notes conversion derivative gain | 320,000 | 3,821,792 |
| Debt inducement expense | - | (2,800,000) |
| Interest expense | (8,056,232) | (8,218,225) |
| | | |
| Net Loss | $ (37,736,674) | $ (18,829,224) |

*Total revenues*

Total revenues were $7.26 million for the year ended December 31, 2012, compared to $8.36 million for the year ended December 31, 2011, a decrease of $1.10 million, or 13%. The decrease in revenues was due primarily to a decrease in production volumes. During December 2012 and 2011, production amounts were 98,567 and 112, 850 BOE, respectively, a decrease of 14,283, or 13%. The decrease was partially offset by an increase in overall average price per BOE to $63.96 in 2012 from $62.64 in 2011, an increase of $1.32 or 2%. Additionally, in 2012 the Company had increases in realized gains from commodity price hedges and operating fees.

The following table shows a comparison of production volumes and average prices:

| | For the Year Ended December 31, 2012 | For the Year Ended December 31, 2011 |
|---|---|---|
| **Product** | | |
| Oil (Bbl.) | 68,207 | 81,433 |
| Oil (Bbls)-average price (1) | $ 86.48 | $ 87.78 |
| | | |
| Natural Gas (MCF)-volume | 80,438 | 88,999 |
| Natural Gas Liquids (NGL) - BOE | 16,953 | 26,584 |
| Natural Gas (MCF)-average price (2) | $ 5.05 | $ 6.15 |
| | | |
| Barrels of oil equivalent (BOE) | 98,567 | 122,850 |
| Average daily net production (BOE) | 270 | 337 |
| Average Price per BOE (1) | 63.96 | $ 62.64 |

(1) Does not include the realized price effects of hedges
(2) Includes proceeds from the sale of NGL's

*Oil and gas production costs, production taxes, depreciation, depletion, and amortization*

| | 2012 | 2011 |
|---|---|---|
| Average Price per BOE(1) | $ 63.96 | $ 62.64 |
| | | |
| Production costs per BOE | 14.42 | 12.33 |

| | | | | |
|---|---|---|---|---|
| Production taxes per BOE | | 2.31 | | 6.83 |
| Depreciation, depletion, and amortization per BOE | | 46.15 | | 35.39 |
| Total operating costs per BOE | $ | 62.88 | $ | 54.55 |
| | | | | |
| Gross margin per BOE | $ | 1.08 | $ | 8.09 |
| | | | | |
| Gross margin percentage | | 2% | | 13% |

(1) Does not include the realized price effects of hedges

*Commodity Price Derivative Activities*

Changes in the market price of oil can significantly affect our profitability and cash flow. In the past we have entered into various commodity derivative instruments to mitigate the risk associated with downward fluctuations in oil prices. These derivative instruments consisted exclusively of swaps. The duration and size of our various derivative instruments varies, and depends on our view of market conditions, available contract prices and our operating strategy.

Commodity price derivative net realized gain was $0.78 million during the year ended December 31, 2012, as compared to a realized gain of $0.63 million for the year ended December 31, 2011, for a decrease in realized gain of $0.15 million, or 24%. We also recorded no unrealized gain on commodity price derivatives for the year ended December 31, 2012 compared to a loss of $0.08 million during the year ended December 31, 2011, for an increase of $0.8 million, or 100%. The Company had no commodity price derivatives at December 31, 2012.

*Production costs*

Production costs were $1.42 million during the year ended December 31, 2012, compared to $1.51 million for the year ended December 31, 2011, a decrease of $0.09 million, or 6%. Decrease in production costs in 2012 was from a decrease on the number of work overs, property improvements, and onsite work on productive wells. Production costs per BOE increased to $14.42 in 2012 from $12.33 in 2011, an increase of $2.09 per BOE, or 17%. The increase per BOE increased was from a decrease in BOE to 98,567 from 122,850, a decrease of 24,283 or 20% compared to a decrease of production costs of 6%, for the years ended December 31, 2012 and 2011, respectively.

*Production taxes*

Production taxes was $0.23 million for the year ended December 31, 2012, compared to $0.84 million for the year ended December 31, 2011, a decrease of $0.61 million , or 73%. Decrease in production taxes was from a decrease in production and product mix per state. Currently, ad valorem, severance and conservation taxes range from 1% to 10% based on the state and county which production is derived. Production taxes per BOE decreased to $2.31 in 2012 from $6.83 in 2011, a decrease of $4.52 or 66%.

*General and administrative*

General and administrative expenses were $4.33 million during the year ended December 31, 2012, compared to $10.54 million during the year ended December 31, 2011, a decrease of $6.21 million, or 59%. In 2012, general and administrative includes an adjustment to non-cash consulting fee and other non-cash compensation expenses that resulted in income of $0.40 million compared to an expense of $6.70 million during the year ended December 31, 2011.

The year ended December 31, 2012, also includes a non-cash income item related to the separation agreement of our former CEO. On November 15, 2012, Roger Parker retired from the Company as its chief executive officer. At the time of his retirement, Mr. Parker had 1,350,000 shares of unvested common stock outstanding. As a result of his separation from the Company, it was deemed improbable that these shares would vest to Mr. Parker in his capacity as an employee of the Company due to the termination of employment; however, it was deemed probable that these shares will vest under his separation agreement. As a result, the Company reversed all of the compensation expense, in the amount of $6.75 million, associated with stock grants to Mr. Parker during his tenure as an employee. In conjunction with Mr. Parker's retirement, the Company and Mr. Parker entered into a separation agreement that provided, in part, for the payment of severance equal to one year of Mr. Parker's salary. Pursuant to the termination agreement, the 1,350,000 shares of unvested restricted stock that would otherwise have been forfeited upon his termination will vest in two tranches, 675,000 on May 15, 2013, and the remaining 675,000 on November 15, 2013, subject to Mr. Parker's execution of a mutual release, and Mr. Parker's availability to the Company for a minimum of 10 hours per week during the severance period on a consulting basis. Thus, the Company recorded a consulting expense (in the amount of $3.59 million) related to the shares of stock that are expected to vest during the severance period of the separation agreement. The net difference of these two amounts resulted in a reduction in 2012 general and administrative expenses (non-cash compensation expense) of $3.16 million.

Excluding the above referenced non-cash items, cash general and administrative for the year ended December 31, 2012 was $4.47 million compared to $3.9 million during the year ending December 31, 2011, an increase of $0.57 million, or 12.8%. The increase in cash general and administrative expenses was due to increases in professional and consulting fees, cash salary expense, and insurance expense.

The separation agreement with Mr. Parker provided that Mr. Parker receive severance payments consisting of one year's salary and health benefits for the year. In return, the Company received a general release and certain non-compete terms from Mr. Parker, and also is entitled to receive no less than 10 hours per week of Mr. Parker's time as a consultant to the Company. As of December 31, 2012, the Company owes Mr. Parker $0.26 million in severance salary and health insurance, all of which was accrued as an expense during the year ended December 31, 2012.

*Depreciation, depletion, and amortization*

Depreciation, depletion, and amortization were $4.55 million during the year ended December 31, 2012, compared to $4.35 million during the year ended December 31, 2011, an increase of $0.20 million, or 5%. Increase in depreciation, depletion, and amortization was from production amounts decreasing to 98,567 from 122,850 for the years ended December 31, 2012 and 2011, respectively, a decrease of 24,283, or 19% and a decrease in reserves to $15.42 million from $20.01 million of $4.59 million or 23%, respectively. Depreciation, depletion, and amortization per BOE increased to $46.15 from $35.59, respectively, for the years ended December 31, 2011 and 2012, an increase of $10.56, or 30%, from a decrease of reserves of 23%.

*Impairment of developed properties*

Impairment of developed properties was $26.66 million during the year ended December 31, 2012, compared to $2.82 million during the year ended December 31, 2011, an increase of $23.84 million or 845%.  The increase was a result of capitalized costs exceeding the standardized measure of reserve values, and in particular was related to the impairment of undeveloped acreage and wells in progress related to the Company's Chugwater prospect, in the total amount of $17.09 million, which were transferred to the full cost pool.  As a result of the Company's review for impairment in its undeveloped acreage, the Company also transferred $5.94 million of undeveloped acreage costs relating principally to leases that have lease terms that expire throughout 2015 which the Company is not intending to extend.  Furthermore, the Company reduced the PV-10 of the proved undeveloped reserve acreage by utilizing a promoted basis which reduced the reserve production amounts to 25% of the Company's 100% ownership. As a result, the ceiling test performed by the Company yielded an increased impairment. The combination of these impairments and the respective transfers to the full cost pool resulted in total 2012 impairment expense of $26.66 million.

*Interest Expense*

Interest expense was $8.06 million during the year ended December 31, 2012, compared to $8.22 million during the year ended December 31, 2011, a decrease of $0.16 million, or 2%.  Interest expense, during December 31, 2012, includes non-cash loan costs amortization and debt discount of $4.85 million, and cash interest expense of $3.2 million, compared to cash interest expense of $3.2 million, during the year ended December 31, 2011.  Cash interest remained consistent due to the level of debt.

**Off-Balance Sheet Arrangements**

We do not have any off-balance sheet arrangements.

**2013 Capital Budget**

Our 2013 Capital Budget is currently projected to be approximately $15 million, but is subject to securing sufficient capital to support planned drilling and development expenses.  We anticipate that approximately 50% of this budget will be allocated toward the development of two of our unconventional prospects located in the Wattenberg field within the DJ Basin that will target horizontal drilling and development of the Niobrara shale and Codell formations.  The remainder of our 2013 budget is anticipated to be directed principally toward the conventional development of certain lower risk offset wells to existing production.  We also anticipate the allocation of approximately 10% of our 2013 capital budget toward higher risk exploration activities, including the procurement of seismic data and the drilling of one conventional exploratory well.

Our 2013 capital expenditure budget was subject to various factors, including market conditions, availability of capital, oilfield services and equipment availability, commodity prices and drilling results.  Results from the wells identified in the capital budget may lead to additional adjustments to the capital budget as the cash flow from the wells could provide additional capital which we may use to increase our capital budget. We do not anticipate any significant expansion of our current acreage position.

Other factors that could cause us to increase our level of activity and adjust our capital expenditure budget include a reduction in service and material costs, the formation of joint ventures with other exploration and production companies, the divestiture of non-strategic assets, a further improvement in commodity prices or well performance that exceeds our forecasts, any of which could positively impact our operating cash flow. Factors that could cause us to reduce level of activity and adjust our capital budget include, but are not limited to, increases in service and materials costs, reductions in commodity prices or under-performance of wells relative to our forecasts, any of which could negatively impact our operating cash flow.

**Plan of Operations**

Our plan of operations is to identify and develop oil and natural gas prospects from our existing inventory of undeveloped acreage. We anticipate the investment of substantial capital during the next few years to evaluate, assess and develop this inventory. Currently, our inventory of developed and undeveloped acreage includes approximately 21,800 net acres that are held by production, approximately 12,900 net acres that expire in 2013, and approximately 25,000 net acres, 59,000 net acres and 10,300 net acres that expire in the years 2014, 2015 and thereafter, respectively. Approximately 64% of our inventory of undeveloped acreage provide for extension of lease terms from two to five years, at the option of the Company, via payment of varying, but typically nominal, extension amounts. However, due to our current liquidity issues, we may enter into one or more transactions to sell a significant number of leases, both developed and undeveloped  to enable us to pay down our outstanding debt .

The business of oil and natural gas acquisition, exploration and development is capital intensive and the level of operations attainable by an oil and gas company is directly linked to and limited by the amount of available capital. Therefore, a principal part of our plan of operations is to raise the additional capital required to finance the exploration and development of our current oil and natural gas prospects and the acquisition of additional properties. As explained under "Financial Condition and Liquidity", based on our present working capital and current rate of cash flow from operations, we will need to raise additional capital to partially fund our overhead, and fund our exploration and development budget through, at least, December 31, 2013. We will seek additional capital through the sale of our securities, through debt and project financing, and through sale of assets. However, under the terms of our term loan agreements and debentures, we are prohibited from incurring any additional debt from third parties or selling any properties held as collateral under the term loans or debentures without prior consent from the lenders. Thus our ability to obtain additional capital through new debt instruments, project financing and sale of assets may be subject to the repayment of our term loans and/or our debentures.

We intend to use the services of independent consultants and contractors to perform various professional services, including land, legal, environmental, investor relations and tax services. We believe that by limiting our management and employee costs, we may be able to better control total costs and retain flexibility in terms of project management.

**Marketing and Pricing**

We derive revenue principally from the sale of oil and natural gas. As a result, our revenues are determined, to a large degree, by prevailing prices for crude oil and natural gas. We sell our oil and natural gas on the open market at prevailing market prices or through forward delivery contracts. The market price for oil and natural gas is dictated by supply and demand, and we cannot accurately predict or control the price we may receive for our oil and natural gas.

Our revenues, cash flows, profitability and future rate of growth will depend substantially upon prevailing prices for oil and natural gas. Prices may also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. Lower prices may also adversely affect the value of our reserves and make it uneconomical for us to commence or continue production levels of oil and natural gas. Historically, the prices received for oil and natural gas have fluctuated widely. Among the factors that can cause these fluctuations are:

- changes in global supply and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- the price and quantity of imports of foreign oil and natural gas;
- acts of war or terrorism;
- political conditions and events, including embargoes, affecting oil-producing activity;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories;
- weather conditions;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

From time to time, we will enter into hedging arrangements to reduce our exposure to decreases in the prices of oil and natural gas. Hedging arrangements may expose us to risk of significant financial loss in some circumstances including circumstances where:

- our production and/or sales of natural gas are less than expected;
- payments owed under derivative hedging contracts come due prior to receipt of the hedged month's production revenue; or
- the counter party to the hedging contract defaults on its contract obligations.

In addition, hedging arrangements may limit the benefit we would receive from increases in the prices for oil and natural gas. We cannot assure you that any hedging transactions we may enter into will adequately protect us from declines in the prices of oil and natural gas. On the other hand, where we choose not to engage in hedging transactions in the future, we may be more adversely affected by changes in oil and natural gas prices than our competitors who engage in hedging transactions.

**Obligations and Commitments**

We have the following contractual obligations and commitments as of December 31, 2012 (in thousands):

| | Payments due by period | | | | |
|---|---|---|---|---|---|
| Contractual obligations | **Total** | **Within 1 year** | **1-3 years** | **4-5 years** | **More than 5 years** |
| Secured debt | $ 19,336,314 | $ 388,351 | $ 18,947,963 | $ - | $ - |
| Interest on secured debt | 2,309,767 | 1,603,761 | 706,006 | - | - |
| Convertible debentures | 13,400,000 | - | 13,400,000 | - | - |
| Separation agreement with Roger Parker (2) | 256,569 | 256,569 | - | - | - |
| Interest on convertible debentures | 1,476,978 | 1,072,000 | 404,978 | - | - |
| Operating leases | 89,520 | 89,520 | - | - | - |
| Total contractual cash obligations (1) | $ 36,869,148 | $ 3,410,201 | $ 33,458,947 | $ - | $ - |

(1) We could be liable for liquidated damages under registration rights agreements covering approximately 3.2 million shares of our common stock if we fail to maintain the effectiveness of a prior registration statement as required in the agreements. In such case, we would be required to pay monthly liquidated damages of up to $228,050. The maximum aggregate liquidated damages are capped at $1,368,300.

(2) Includes $224,700 salary, $17,942 employer taxes, $13,927 health, dental, and vision insurance, in accordance with Mr. Parker's separation agreement dated November 15, 2012.

**Critical Accounting Policies and Estimates**

The preparation of our consolidated financial statements in conformity with generally accepted accounting principles in the United States, or GAAP, requires our management to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities at the date of our financial statements and the reported amounts of revenues and expenses during the reporting period. The following is a summary of the significant accounting policies and related estimates that affect our financial disclosures.

Critical accounting policies are defined as those significant accounting policies that are most critical to an understanding of a company's financial condition and results of operation. We consider an accounting estimate or judgment to be critical if (i) it requires assumptions to be made that were uncertain at the time the estimate was made, and (ii) changes in the estimate or different estimates that could have been selected could have a material impact on our results of operations or financial condition.

*Use of Estimates*

The financial statements included herein were prepared from the records of Recovery in accordance with GAAP, and reflect all normal recurring adjustments which are, in the opinion of management, necessary to provide a fair statement of the results of operations and financial position for the interim periods. The preparation of the financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. We evaluate our estimates on an on-going basis and base our estimates on historical experience and on various other assumptions we believe to be reasonable under the circumstances. Although actual results may differ from these estimates under different assumptions or conditions, we believe that our estimates are reasonable. Our most significant financial estimates are associated with our estimated proved oil and gas reserves as well as valuation of common stock used in various issuances of common stock, options and warrants and estimated fair value of the asset held for sale.

*Oil and Natural Gas Reserves*

We follow the full cost method of accounting. All of our oil and gas properties are located within the United States, and therefore all costs related to the acquisition and development of oil and gas properties are capitalized into a single cost center referred to as a full cost pool. Depletion of exploration and development costs and depreciation of production equipment is computed using the units-of-production method based upon estimated proved oil and gas reserves. Under the full cost method of accounting, capitalized oil and gas property costs less accumulated depletion and net of deferred income taxes may not exceed an amount equal to the present value, discounted at 10%, of estimated future net revenues from proved oil and gas reserves less the future cash outflows associated with the asset retirement obligations that have been accrued on the balance sheet plus the cost, or estimated fair value if lower, of unproved properties. Should capitalized costs exceed this ceiling, impairment would be recognized. Under the SEC rules, we prepared our oil and gas reserve estimates as of December 31, 2012, using the average, first-day-of-the-month price during the 12-month period ending December 31, 2012.

Estimating accumulations of gas and oil is complex and is not exact because of the numerous uncertainties inherent in the process. The process relies on interpretations of available geological, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserve estimate is a function of the quality and quantity of available data; the interpretation of that data; the accuracy of various mandated economic assumptions; and the judgment of the persons preparing the estimate.

We believe estimated reserve quantities and the related estimates of future net cash flows are the most important estimates made by an exploration and production company such as ours because they affect the perceived value of our company, are used in comparative financial analysis ratios, and are used as the basis for the most significant accounting estimates in our financial statements, including the quarterly calculation of depletion, depreciation and impairment of our proved oil and natural gas properties. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. We determine anticipated future cash inflows and future production and development costs by applying benchmark prices and costs, including transportation, quality and basis differentials, in effect at the end of each quarter to the estimated quantities of oil and natural gas remaining to be produced as of the end of that quarter. We reduce expected cash flows to present value using a discount rate that depends upon the purpose for which the reserve estimates will be used. For example, the standardized measure calculation requires us to apply a 10% discount rate. Although reserve estimates are inherently imprecise, and estimates of new discoveries and undeveloped locations are more imprecise than those of established proved producing oil and natural gas properties, we make considerable effort to estimate our reserves, including through the use of independent reserves engineering consultants. We expect that quarterly reserve estimates will change in the future as additional information becomes available or as oil and natural gas prices and operating and capital costs change. We evaluate and estimate our oil and natural gas reserves as of December 31 of each year and quarterly throughout the year. For purposes of depletion, depreciation, and impairment, we adjust reserve quantities at all quarterly periods for the estimated impact of acquisitions and dispositions. Changes in depletion, depreciation or impairment calculations caused by changes in reserve quantities or net cash flows are recorded in the period in which the reserves or net cash flow estimate changes.

*Oil and Natural Gas Properties—Full Cost Method of Accounting*

We use the full cost method of accounting whereby all costs related to the acquisition and development of oil and natural gas properties are capitalized into a single cost center referred to as a full cost pool. These costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling and overhead charges directly related to acquisition and exploration activities.

Capitalized costs, together with the costs of production equipment, are depleted and amortized on the unit-of-production method based on the estimated gross proved reserves as determined by independent petroleum engineers. For this purpose, we convert our petroleum products and reserves to a common unit of measure.

Costs of acquiring and evaluating unproved properties are initially excluded from depletion calculations. This undeveloped acreage is assessed quarterly to ascertain whether impairment has occurred. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to the full cost pool and becomes subject to depletion calculations.

Proceeds from the sale of oil and natural gas properties are applied against capitalized costs, with no gain or loss recognized, unless the sale would alter the rate of depletion by more than 25%. Royalties paid, net of any tax credits received, are netted against oil and natural gas sales.

In applying the full cost method, we perform a ceiling test on properties that restricts the capitalized costs, less accumulated depletion, from exceeding an amount equal to the estimated undiscounted value of future net revenues from proved oil and natural gas reserves, as determined by independent petroleum engineers. The estimated future revenues are based on sales prices achievable under existing contracts and posted average reference prices in effect at the end of the applicable period, and current costs, and after deducting estimated future general and administrative expenses, production related expenses, financing costs, future site restoration costs and income taxes. Under the full cost method of accounting, capitalized oil and natural gas property costs, less accumulated depletion and net of deferred income taxes, may not exceed an amount equal to the present value, discounted at 10%, of estimated future net revenues from proved oil and natural gas reserves, plus the cost, or estimated fair value if lower, of unproved properties. Should capitalized costs exceed this ceiling, we would recognize impairment.

Impairment of developed properties was $26.66 million during the year ended December 31, 2012, compared to $2.82 million during the year ended December 31, 2011, an increase of $23.84 million or 845%. The increase was a result of capitalized costs exceeding the standardized measure of reserve values, and in particular was related to the impairment of undeveloped acreage and wells in progress related to the Company's Chugwater prospect, in the total amount of $17.09 million, which were transferred to the full cost pool. As a result of the Company’s review for impairment in its undeveloped acreage, the Company also transferred $5.94 million of undeveloped acreage costs relating principally to leases that have lease terms that expire throughout 2015 which the Company is not intending to extend. Furthermore, the Company reduced the PV-10 of the proved undeveloped acreage by utilizing a promoted basis which reduced the production amounts to 25% of the Company’s 100% ownership. As a result, the ceiling test performed by the Company yielded an increased impairment. The combination of these impairments and the respective transfers to the full cost pool resulted in total 2012 impairment expense of $26.66 million.

*Revenue Recognition*

The Company derives revenue primarily from the sale of produced natural gas and crude oil. The Company reports revenue as the gross amount received before taking into account production taxes and transportation costs, which are reported as separate expenses and are included in oil and gas production expense in the accompanying consolidated statements of operations. Revenue is recorded in the month the Company’s production is delivered to the purchaser, but payment is generally received between 30 and 90 days after the date of production. No revenue is recognized unless it is determined that title to the product has transferred to the purchaser. At the end of each month, the Company estimates the amount of production delivered to the purchaser and the price the Company will receive. The Company uses its knowledge of its properties, their historical performance, NYMEX and local spot market prices, quality and transportation differentials, and other factors as the basis for these estimates.

*Share Based Compensation*

The Company accounts for share-based compensation by estimating the fair value of share-based payment awards made to employees and directors, including restricted stock grants, on the date of grant. The value of the portion of the award that is ultimately expected to vest is recognized as an expense ratably over the requisite service periods.

*Derivative Instruments*

Periodically, the Company entered into swaps to reduce the effect of price changes on a portion of our future oil production. We reflect the fair market value of our derivative instruments on our balance sheet. Our estimates of fair value are determined by obtaining independent market quotes as well as utilizing a valuation model that is based upon underlying forward curve data and risk free interest rates. Changes in commodity prices will result in substantially similar changes in the fair value of our commodity derivative agreements. We do not apply hedge accounting to any of our derivative contracts, therefore we recognize mark-to-market gains and losses in earnings currently.

## Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Not applicable.

## Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Our financial statements appear immediately after the signature page of this report. See "Index to Financial Statements" included in this report.

## Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

## Item 9A. CONTROLS AND PROCEDURES

**Evaluation of Disclosure Controls and Procedures**

As of the end of the year covered by this Annual Report, management performed, with the participation of our Chief Executive Officer, or CEO, and Chief Financial Officer, or CFO, an evaluation of the effectiveness of our disclosure controls and procedures as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act of 1934, as amended, or Exchange Act. Our disclosure controls and procedures are designed to ensure that information required to be disclosed in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our CEO and CFO, to allow timely decisions regarding required disclosures. Based on this evaluation, our CEO and CFO have concluded that the Company's disclosure controls and procedures were effective as of December 31, 2012.

**Management's Annual Report on Internal Control over Financial Reporting**

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with generally accepted accounting principles in the United States, or GAAP. A company's internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the consolidated financial statements.

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

Our management, with the participation of our CEO and CFO, assessed the effectiveness of our internal control over financial reporting as of December 31, 2012. Management's assessment of internal control over financial reporting was conducted using the criteria in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, or COSO. Management concluded that, as of December 31, 2012, the Company's internal control over financial reporting was effective.

**Changes in Internal Control over Financial Reporting**

There were no changes in our internal control over financial reporting during the quarter-ended December 31, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

### Item 9B. OTHER INFORMATION

None.

## PART III

### Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2013 annual shareholders meeting and is incorporated by reference in this report.

### Item 11. EXECUTIVE COMPENSATION

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2013 annual shareholders meeting and is incorporated by reference in this report.

### Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2013 annual shareholders meeting and is incorporated by reference in this report.

### Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2013 annual shareholders meeting and is incorporated by reference in this report.

### Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2013 annual shareholders meeting and is incorporated by reference in this report.

## PART IV

**Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES**

### INDEX TO FINANCIAL STATEMENTS

**a)**



**b)** Financial statement schedules

Not applicable.

**c) Exhibits**

The information required by this Item is set forth on the exhibit index that follows the signature page to this Annual Report on Form 10-K.

## SIGNATURES

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

**RECOVERY ENERGY INC.**

Date: April 17, 2013

By: /s/ W. Phillip Marcum
W. Phillip Marcum
*Chief Executive Officer and Chairman of the Board of Directors*
*(Authorized Signatory)*

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

| Signature | Title | Date |
|---|---|---|
| /s/ W. Phillip Marcum<br>W. Phillip Marcum | Chief Executive Officer and Chairman of the Board of Directors<br>(Principal Executive Officer) | April 17, 2013 |
| /s/ A. Bradley Gabbard<br>A. Bradley Gabbard | President, Chief Financial and Accounting Officer, Director<br>(Principal Financial Officer) | April 17, 2013 |
| /s/ Eric Ulwelling<br>Eric Ulwelling | Principal Accounting Officer | April 17, 2013 |
| /s/ Tim Poster<br>Tim Poster | Director | April 17, 2013 |
| /s/ Kirk Edwards<br>Kirk Edwards | Director | April 17, 2013 |
| /s/ Bruce White<br>Bruce White | Director | April 17, 2013 |

**Exhibit Index**

The following exhibits are either filed herewith or incorporated herein by reference:

| | |
|---|---|
| 2.1 | Membership Unit Purchase Agreement by and among Recovery Energy, Lanny M. Roof, Judith Lee and Michael Hlvasa dated as of September 21, 2009 (incorporated herein by reference to Exhibit 10.1 from our current report filed on Form 8-K filed on September 22, 2009). |
| 3.1 | Articles of Incorporation (incorporated herein by reference to Exhibit 3.1 to the Company's Form S-1 filed on July 28, 2008). |
| 3.2 | Amended and Restated Bylaws (incorporated herein by reference to Exhibit 3.2 to the Company's current report on Form 8-K filed on June 18, 2010). |
| 4.1 | Warrant to Purchase Common Stock dated December 11, 2009 (incorporated by reference to Exhibit 4.2 to the Company's current report filed on Form 8-K filed on December 17, 2009). |
| 4.2 | Recovery Energy, Inc. 2012 Equity Incentive Plan dated August 31, 2012 (incorporated by reference to Exhibit 4.1 to the Company's current report filed on Form 8-K on September 5, 2012). |
| 10.1 | Cancellation agreements, dated September 21, 2009 between Universal Holdings, Inc. and two former shareholders (incorporated herein by reference to Exhibit 10.1 to the Company's annual report on Form 10-K for the year ended December 31, 2010). |
| 10.2 | Credit Agreement with Hexagon Investments, LLC dated effective as of January 29, 2010 (incorporated herein by reference to Exhibit 10.12 to the Company's current report filed on Form 8-K filed on March 4, 2010). |
| 10.3 | Promissory Note for financing with Hexagon Investments, LLC dated as of January 29, 2010 (incorporated herein by reference to Exhibit 10.13 to the Company's current report filed on Form 8-K filed on March 4, 2010). |
| 10.4 | Nebraska Mortgage to Hexagon Investments, LLC dated as of January 29, 2010 (incorporated herein by reference to Exhibit 10.14 to the Company's current report filed on Form 8-K filed on March 4, 2010). |
| 10.5 | Colorado Mortgage to Hexagon Investments, LLC dated as of January 29, 2010 (incorporated herein by reference to Exhibit 10.15 to the Company's current report filed on Form 8-K filed on March 4, 2010). |
| 10.6 | Purchase and Sale Agreement with Edward Mike Davis, L.L.C. dated effective as of April 1, 2010 (incorporated herein by reference to Exhibit 10.16 to the Company's current report filed on Form 8-K filed on March 25, 2010). |
| 10.7 | Credit Agreement with Hexagon Investments, LLC dated effective as of March 25, 2010 (incorporated herein by reference to Exhibit 10.17 to the Company's current report filed on Form 8-K filed on March 25, 2010). |
| 10.8 | Promissory Note for financing with Hexagon Investments, LLC dated as of March 25, 2010 (incorporated herein by reference to Exhibit 10.18 to the Company's current report filed on Form 8-K filed on March 25, 2010). |
| 10.9 | Nebraska Mortgage to Hexagon Investments, LLC dated as of March 25, 2010 (incorporated herein by reference to Exhibit 10.19 to the Company's current report filed on Form 8-K filed on March 25, 2010). |
| 10.10 | Wyoming Mortgage to Hexagon Investments, LLC dated as of March 25, 2010 (incorporated herein by reference to Exhibit 10.20 to the Company's current report filed on Form 8-K filed on March 25, 2010). |
| 10.11 | Purchase and Sale Agreement with Edward Mike Davis, L.L.C. for purchase of oil and gas properties dated as of April 1, 2010 (incorporated herein by reference to Exhibit 10.1 to the Company's current report filed on Form 8-K filed on April 20, 2010). |
| 10.12 | Credit Agreement with Hexagon Investments, LLC dated as of April 14, 2010 (incorporated herein by reference to Exhibit 10.2 to the Company's current report filed on Form 8-K filed on April 20, 2010). |

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| 10.13 | Promissory Note with Hexagon Investments, LLC dated April 14, 2010 (incorporated herein by reference to Exhibit 10.3 to the Company's current report filed on Form 8-K filed on April 20, 2010). |
| 10.14 | Warrant to Purchase Common Stock by Hexagon Investments, LLC dated April 14, 2010 (incorporated herein by reference to Exhibit 10.4 to the Company's current report filed on Form 8-K filed on April 20, 2010). |
| 10.15 | Wyoming Mortgage to Hexagon Investments, LLC dated April 14, 2010 (incorporated herein by reference to Exhibit 10.5 to the Company's current report filed on Form 8-K filed on April 20, 2010). |
| 10.16 | Securities Purchase Agreement dated as of April 26, 2020 (incorporated herein by reference to Exhibit 10.1 to the Company's current report filed on Form 8-K filed on April 30, 2010). |
| 10.17 | Agreement with C.K. Cooper dated April 8, 2010 (incorporated herein by reference to Exhibit 10.1 to the Company's current report filed on Form 8-K filed on May 4, 2010). |
| 10.18 | Purchase Agreement dated May 6, 2010 (incorporated herein by reference to Exhibit 10.1 to the Company's current report filed on Form 8-K filed on May 12, 2010). |
| 10.19 | Promissory Note dated May 6, 2010 (incorporated herein by reference to Exhibit 10.2 to the Company's current report filed on Form 8-K filed on May 12, 2010). |
| 10.20 | Security Agreement dated May 6, 2010 (incorporated herein by reference to Exhibit 10.3 to the Company's current report filed on Form 8-K filed on May 12, 2010). |
| 10.21 | Purchase Agreement with Edward Mike Davis, L.L.C. and Spottie, Inc. dated May 15, 2010 (incorporated herein by reference to Exhibit 10.1 to the Company's current report filed on Form 8-K filed on May 20, 2010). |
| 10.22 | Employment Agreement with Jeffrey A. Beunier (incorporated herein by reference to Exhibit 10.2 to the Company's current report filed on Form 8-K filed on December 23, 2010). |
| 10.23 | Director Appointment Agreement with James Miller (incorporated herein by reference to Exhibit 10.3 to the Company's current report filed on Form 8-K filed on May 20, 2010). |
| 10.24 | Form of Warrant Issued in Private Placement (incorporated herein by reference to Exhibit 4.1 to the Company's current report filed on Form 8-K filed on June 4, 2010). |
| 10.25 | Warrant issued to Hexagon Investments, LLC (incorporated herein by reference to Exhibit 4.2 to the Company's current report filed on Form 8-K filed on June 4, 2010). |
| 10.26 | Form of Securities Purchase Agreement (incorporated herein by reference to Exhibit 10.1 to the Company's current report filed on Form 8-K filed on June 4, 2010). |
| 10.27 | Form of Registration Rights Agreement (incorporated herein by reference to Exhibit 10.2 to the Company's current report filed on Form 8-K. |
| 10.28 | Form of Lockup Agreement (incorporated herein by reference to Exhibit 10.3 to the Company's current report filed on Form 8-K filed on June 4, 2010). |
| 10.29 | Letter Agreement with Hexagon Investments, LLC (incorporated herein by reference to Exhibit 10.4 to the Company's current report filed on Form 8-K filed on June 4, 2010). |
| 10.30 | Independent Director Appointment Agreement with Conway J. Schatz (incorporated herein by reference to Exhibit 10.2 to the Company's current report filed on Form 8-K filed on June 7, 2010). |

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| 10.31 | Consulting Agreement with Market Development Consulting Group, Inc. (incorporated herein by reference to Exhibit 10.1 to the Company's current report filed on Form 8-K filed on June 18, 2010). |
| 10.32 | Five Year Warrant to Market Development Consulting Group, Inc. (incorporated herein by reference to Exhibit 10.2 to the Company's current report filed on Form 8-K filed on June 18, 2010). |
| 10.33 | Three Year Warrant to Market Development Consulting Group, Inc. (incorporated herein by reference to Exhibit 10.3 to the Company's current report filed on Form 8-K filed on June 18, 2010). |
| 10.34 | Warrant to Globe Media (incorporated herein by reference to Exhibit 10.4 to the Company's current report filed on Form 8-K filed on June 18, 2010). |
| 10.35 | Registration Rights Agreement with Hexagon Investments, Inc. (incorporated herein by reference to Exhibit 10.5 to the Company's current report filed on Form 8-K filed on June 18, 2010). |
| 10.36 | Stockholders Agreement with Hexagon Investments Incorporated (incorporated herein by reference to Exhibit 10.1 to the Company's current report filed on Form 8-K filed on June 29, 2010). |
| 10.37 | Form of $2.20 Warrant Issued to Persons Exercising $1.50 Warrants (incorporated herein by reference to Exhibit 10.1 to the Company's current report on Form 8-K filed on October 8, 2010). |
| 10.38 | Purchase Agreement with Edward Mike Davis, L.L.C. and Spottie, Inc. dated November 19, 2010 (incorporated herein by reference to Exhibit 10.1 to the Company's current report on Form 8-K filed on November 26, 2010). |
| 10.39 | Put Option Agreement with Grandhaven Energy, LLC dated November 19, 2010 (incorporated herein by reference to Exhibit 10.2 to the Company's current report on Form 8-K filed on November 26, 2010). |
| 10.40 | Warrant Issued to Hexagon Investments, LLC on January 1, 2011 (incorporated herein by reference to Exhibit 10.1 to the Company's current report on Form 8-K filed on January 4, 2011). |
| 10.41 | Amendments to Hexagon Investments, LLC Promissory Notes (incorporated herein by reference to Exhibit 10.2 to the Company's current report on Form 8-K filed on January 4, 2011). |
| 10.42 | Form of Convertible Debenture Securities Purchase Agreement dated February 2, 2011 (incorporated herein by reference to Exhibit 10.1 to the Company's current report on Form 8-K filed on February 3, 2011). |
| 10.43 | Form of Convertible Debenture (incorporated herein by reference to Exhibit 10.2 to the Company's current report on Form 8-K filed on February 3, 2011). |
| 10.44 | Purchase Agreement with Wapiti Oil & Gas, L.L.C. (incorporated herein by reference to Exhibit 10.1 to the Company's current report on Form 8-K filed on February 24, 2011). |
| 10.45 | Amendments to three Credit Agreements with Hexagon, LLC, dated March 15, 2012 (incorporated herein by reference to Exhibit 10.55 to the Company's annual report filed on Form 10-K on March 21, 2012). |
| 10.46 | Second Amendment to 8% Senior Secured Convertible Debentures dated March 19, 2012 (incorporated herein by reference to Exhibit 10.56 to the Company's annual report filed on Form 10-K on March 21, 2012). |
| 10.47 | Securities Purchase Agreement for additional 8% Senior Secured Convertible Debentures dated March 19, 2012 (incorporated herein by reference to Exhibit 10.57 to the Company's annual report filed on Form 10-K on March 21, 2012). |
| 10.48 | Form of 8% Senior Secured Convertible Debentures dated March 19, 2012 (incorporated herein by reference to Exhibit 10.58 to the Company's annual report filed on Form 10-K on March 21, 2012). |

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| 10.49 | Separation Agreement with Roger A. Parker dated as of November 15, 2012 (incorporated herein by reference to Exhibit 10.1 to the Company's current report on Form 8-K filed on December 4, 2012). |
| 10.50 | Amendment to Securities Purchase Agreement dated August 7, 2012 (incorporated herein by reference to Exhibit 10.1 to the Company's current report on Form 8-K filed on August 9, 2012). |
| 10.51 | Amendment to Securities Purchase Agreement dated August 7, 2012 (incorporated herein by reference to Exhibit 10.2 to the Company's current report on Form 8-K filed on August 9, 2012). |
| 10.52 | Second Amendments to three Credit Agreements with Hexagon, LLC, dated July 31, 2012 (incorporated herein by reference to Exhibit 10.1 to the Company's current report on Form 8-K filed on August 2, 2012). |
| 10.53 | Independent Director Appointment Agreement with W. Phillip Marcum dated April 27, 2012 (incorporated herein by reference to Exhibit 10.1 to the Company's current report on Form 8-K filed on May 2, 2012). |
| 10.54 | Independent Director Appointment Agreement with Bruce B. White dated April 27, 2012 (incorporated herein by reference to Exhibit 10.2 to the Company's current report on Form 8-K filed on May 2, 2012). |
| 10.55 | Amended and Restated Independent Director Appointment Agreement with Timothy N. Poster dated April 27, 2012 (incorporated herein by reference to Exhibit 10.32 to the Company's current report on Form 8-K filed on June 1, 2010). |
| 10.56 | Amendment to 8% Senior Secured Convertible Debentures due February 8, 2014, dated April 15, 2013. |
| 10.57 | Fourth Amendment to Credit Agreement (First Credit Agreement), dated April 15, 2013. |
| 10.58 | Fourth Amendment to Credit Agreement (Second Credit Agreement), dated April 15, 2013. |
| 10.59 | Fourth Amendment to Credit Agreement (Third Credit Agreement), dated April 15, 2013. |
| 14.1 | Code of Ethics (incorporated herein by reference to Exhibit 14.1 to the Company's annual report on Form 10-K for the year ended December 31, 2009). |
| 16.1 | Letter from Jewett, Schwartz, Wolfe & Associates to the U.S. Securities and Exchange Commission dated January 19, 2010 (incorporated herein by reference to Exhibit 16.1 to the Company's current report on Form 8-K dated January 21, 2010). |
| 21.1 | List of subsidiaries of the registrant (incorporated herein by reference to Exhibit 21.1 to the Company's registration statement on Form S-1 (333-164291). |
| 23.1 | Consent of Hein & Associates, LLP (included in their report on page F-1) |
| 23.2 | Consent of RE Davis. |
| 31.1 | Certifications Pursuant to Section 302 of Sarbanes Oxley Act of 2002. |
| 31.2 | Certifications Pursuant to Section 302 of Sarbanes Oxley Act of 2002. |
| 32.1 | Certifications Pursuant to Section 906 of Sarbanes Oxley Act of 2002. |
| 32.2 | Certifications Pursuant to Section 906 of Sarbanes Oxley Act of 2002. |
| 99.1 | Report of RE Davis. |

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
Recovery Energy, Inc.

We have audited the accompanying consolidated balance sheet of Recovery Energy, Inc. and subsidiaries (together, the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of operations, shareholders' equity, and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Recovery Energy, Inc. and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for the years then ended, in conformity with U.S. generally accepted accounting principles.

Hein & Associates LLP

Denver, Colorado
April 17, 2013

**RECOVERY ENERGY, INC.**
**CONSOLIDATED BALANCE SHEETS**

| | December 31 2012 | December 31, 2011 |
|---|---|---|
| **Assets** | | |
| Current assets | | |
| Cash | $ 970,035 | $ 2,707,722 |
| Restricted cash | 671,382 | 932,165 |
| Accounts receivable (net of allowance of $50,000 and $0, at December 31, 2012 and 2011, respectively) | 934,591 | 2,227,466 |
| Prepaid assets | 13,458 | 75,376 |
| Total current assets | 2,589,466 | 5,942,729 |
| | | |
| Oil and gas properties (full cost method), at cost: | | |
| Developed properties | 58,610,095 | 32,113,143 |
| Undeveloped acreage, excluded from amortization | 28,067,005 | 45,697,481 |
| Wells in progress, excluded from amortization | 193,515 | 6,425,509 |
| Total oil and gas properties, at cost | 86,870,615 | 84,236,133 |
| | | |
| Less accumulated depreciation, depletion , amortization, and impairment | (43,187,962) | (12,099,098) |
| Net oil and gas properties, at cost | 43,682,653 | 72,137,035 |
| | | |
| Other assets: | | |
| Office equipment, net | 90,630 | 106,286 |
| Prepaid advisory fees | - | 574,160 |
| Deferred financing costs, net | 974,856 | 2,341,595 |
| Restricted cash and deposits | 215,435 | 186,055 |
| Total other assets | 1,280,921 | 3,208,096 |
| | | |
| Total Assets | $ 47,553,040 | $ 81,287,860 |

The accompanying notes are an integral part of these financial statements.

**RECOVERY ENERGY, INC.**
**CONSOLIDATED BALANCE SHEETS**

| | December 31 2012 | December 31, 2011 |
|---|---|---|
| **Liabilities and Shareholders' Equity** | | |
| Current liabilities | | |
| Accounts payable | $ 1,831,590 | $ 2,050,768 |
| Commodity price derivative liability | - | 75,609 |
| Related party payable | - | 16,475 |
| Accrued expenses | 1,411,016 | 1,354,204 |
| Short term notes payable | 388,351 | 1,150,967 |
| Total current liabilities | 3,630,957 | 4,648,023 |
| | | |
| Long term liabilities | | |
| Asset retirement obligation | 911,546 | 612,874 |
| Term notes payable | 18,947,963 | 20,129,670 |
| Convertible notes payable, net of discount | 10,300,361 | 4,929,068 |
| Convertible notes conversion derivative liability | 1,680,000 | 1,300,000 |
| Total long-term liabilities | 31,839,870 | 26,971,612 |
| | | |
| Total liabilities | 35,470,827 | 31,619,635 |
| | | |
| Commitments and contingencies – Note 3,6,8, and 9 | | |
| | | |
| Shareholders’ equity | | |
| Preferred stock, 10,000,000 authorized, none issued and outstanding | - | - |
| Common stock, $0.0001 par value: 100,000,000 shares authorized; 18,394,401 and 17,436,825 shares issued and outstanding as of December 31, 2012 and December 31, 2011, respectively | 1,839 | 1,744 |
| Additional paid in capital | 118,296,679 | 118,146,119 |
| Accumulated deficit | (106,216,305) | (68,479,638) |
| Total shareholders' equity | 12,082,213 | 49,668,225 |
| | | |
| Total Liabilities and Shareholders’ Equity | $ 47,553,040 | $ 81,287,860 |

The accompanying notes are an integral part of these financial statements.

**RECOVERY ENERGY, INC.**
**CONSOLIDATED STATEMENTS OF OPERATIONS**
**Years Ended December 31, 2012 and 2011**

| | 2012 | 2011 |
|---|---|---|
| Revenue | | |
| Oil sales | $ 5,898,459 | $ 7,148,110 |
| Gas sales | 406,216 | 547,190 |
| Operating fees | 174,779 | 117,360 |
| Realized gains on commodity price derivatives | 780,135 | 625,043 |
| Unrealized loss on commodity price derivatives | - | (75,609) |
| Total revenue | 7,259,589 | 8,362,094 |
| | | |
| Costs and expenses | | |
| Production costs | 1,421,177 | 1,514,784 |
| Production taxes | 227,455 | 838,714 |
| General and administrative | 4,331,328 | 10,544,347 |
| Depreciation, depletion and amortization | 4,549,303 | 4,347,117 |
| Bad debt expense | 77,957 | - |
| Impairment of developed properties | 26,658,707 | 2,821,176 |
| Total costs and expenses | 37,265,927 | 20,066,138 |
| | | |
| Loss from operations | (30,006,338) | (11,704,044) |
| | | |
| Other income | 5,896 | 71,253 |
| Convertible notes conversion derivative gain | 320,000 | 3,821,792 |
| Debt inducement expense | - | (2,800,000) |
| Interest expense | (8,056,232) | (8,218,225) |
| | | |
| Net Loss | $ (37,736,674) | $ (18,829,224) |
| Net loss per common share | | |
| Basic and diluted | $ (2.11) | $ (1.21) |
| Weighted average shares outstanding: | | |
| Basic and diluted | 17,902,013 | 15,543,758 |

The accompanying notes are an integral part of these financial statements.

**RECOVERY ENERGY, INC.**
**CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY**
**Years Ended December 31, 2012 and 2011**

| | Common Stock Subject to Redemption | | Common Stock | | Additional Paid-In Capital | Accumulated Deficit | Total |
|---|---|---|---|---|---|---|---|
| | Shares | Amount | Shares | Amount | | | |
| Balance, December 31, 2010 | 10,625 | $ 86,258 | 14,453,593 | $ 1,444 | $ 93,819,314 | $ (49,650,407) | $ 44,170,352 |
| 1:4 Reverse stock split | - | - | - | - | 387 | - | 387 |
| Common stock issued for property acquisitions | - | - | 2,269,543 | 228 | 10,895,665 | - | 10,895,893 |
| Common stock no longer subject to redemption | (10,625) | (86,258) | 10,625 | 1 | 86,254 | - | 86,255 |
| Common stock issued in connection with interest payment on convertible debt | - | - | 78,982 | 8 | 559,863 | - | 559,871 |
| Common stock issued for services | - | - | 10,000 | 1 | 81,996 | - | 81,997 |
| Restricted stock issued to employees and directors | - | - | 238,750 | 24 | 6,161,041 | - | 6,161,065 |
| Warrants issued for cash | - | - | 375,333 | 38 | 2,129,801 | - | 2,129,839 |
| Warrants issued for debt extension | - | - | - | - | 1,611,797 | | 1,611,797 |
| Debt conversion expense | - | - | - | - | 2,800,000 | - | 2,800,000 |
| Net loss | - | - | - | - | - | (18,829,224) | (18,829,224) |
| Balance, December 31, 2011 | - | $ - | 17,436,825 | $ 1,744 | $ 118,146,119 | $ (68,479,631) | $ 49,668,232 |
| Common stock issued in connection with interest payment on convertible debt | - | - | 278,225 | 28 | 894,063 | - | 894,091 |
| Common stock issued for deferred financing costs | - | - | 50,000 | 5 | 229,995 | | 230,000 |
| Common stock issued for services | - | - | 100,000 | 10 | 348,990 | | 349,000 |
| Common stock issued for compensation (board and employees) | - | - | 529,351 | 52 | 1,836,512 | | 1,836,564 |
| Modification for common stock issued for compensation | | | | | (3,159,000) | | (3,159,000) |
| Net Loss | - | - | - | - | - | (37,736,674) | (37,736,674) |
| Balance, December 31, 2012 | - | $ - | 18,394,401 | $ 1,839 | $118,296,678 | $(106,216,305) | $ 12,082,212 |

The accompanying notes are an integral part of these financial statements.

**RECOVERY ENERGY, INC.**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**Years Ended December 31, 2012 and 2011**

| | Year ended December 31, 2012 | Year ended December 31, 2011 |
|---|---|---|
| **Cash flows from operating activities:** | | |
| Net loss | $ (37,736,674) | $ (18,829,224) |
| Adjustments to reconcile net loss to net cash used in operating activities: | | |
| Impairment provision, proved leases | 26,658,707 | 2,821,176 |
| Debt inducement and warrant modification expense | - | 2,800,000 |
| Common stock issued for convertible note interest | 894,092 | 559,873 |
| Bad debt | 77,957 | - |
| Common stock for services and compensation | (973,432) | 6,566,152 |
| Changes in the fair value of commodity price derivatives | (855,744) | (549,434) |
| Amortization of deferred financing costs | 1,596,739 | 4,446,911 |
| Change in fair value of convertible notes conversion derivative | (320,000) | (3,821,792) |
| Depreciation, depletion, amortization and accretion of asset retirement obligation | 6,865,733 | 4,347,117 |
| Changes in operating assets and liabilities: | | |
| Accounts receivable | (228,934) | 73,940 |
| Restricted cash | 260,783 | 218,376 |
| Other assets | 636,078 | 39,451 |
| Accounts payable and other accrued expenses | (264,708) | 757,207 |
| **Net cash used in operating activities** | (3,389,403) | (570,247) |
| | | |
| **Cash flows from investing activities:** | | |
| Acquisition of undeveloped acreage | (536,249) | (9,433,073) |
| Drilling capital expenditures | (4,533,954) | (7,017,523) |
| Sale of undeveloped acreage interests | 2,918,414 | 3,000,000 |
| Additions of office equipment | (2,928) | (83,727) |
| Proceeds from hedge settlements | 780,135 | 226,203 |
| Investment in operating bonds | (29,379) | (348) |
| **Net cash used in investing activities** | (1,403,961) | (13,308,468) |
| | | |
| **Cash flows from financing activities:** | | |
| Proceeds from sale of common stock, units and excise of warrants | - | 2,129,870 |
| Proceeds from debt | 5,000,000 | 9,411,597 |
| Repayment of debt | (1,944,323) | (483,774) |
| **Net cash provided by financing activities** | 3,055,677 | 11,057,693 |
| | | |
| Change in cash and cash equivalents | (1,737,687) | (2,821,022) |
| **Cash and cash equivalents at beginning of period** | 2,707,722 | 5,528,744 |
| | | |
| **CASH AND CASH EQUIVALENTS AT END OF PERIOD** | $ 970,035 | $ 2,707,722 |
| | | |
| **Supplemental disclosure:** | | |
| Cash paid for interest | $ 3,206,804 | $ 3,201,312 |
| Cash paid for income taxes | $ - | $ - |
| | | |
| **Non-cash transactions:** | | |
| Sale of property for receivable | $ - | $ 1,443,852 |
| Debt issuance cost | $ - | $ 400,000 |
| Purchase of properties for common stock | $ - | $ 10,895,893 |
| Stock and warrants issued for deferred financing costs | $ 230,000 | $ 1,611,832 |
| Stock and warrants issued for prepaid financial advisory fees | $ 349,000 | $ - |
| Stock and warrants issued for prepaid financial office rent | $ - | $ 81,997 |
| Property additions for asset retirement obligation | $ 198,110 | $ 61,469 |
| Stock issued for payment on long-term debt | $ 894,091 | $ 559,872 |

The accompanying notes are an integral part of these financial statements.

## NOTE 1 – ORGANIZATION

On September 21, 2009, Universal Holdings, Inc. ("Universal"), a Nevada corporation, completed the acquisition of Coronado Acquisitions, LLC ("Coronado"). Under the terms of the acquisition, Coronado was merged into Universal. On October 12, 2009, Universal changed its name to Recovery Energy, Inc. ("Recovery", "Recovery Energy", "we", "our", and the "Company"). The Agreement was accounted for as a reverse acquisition with Coronado being treated as the acquirer for accounting purposes. Accordingly, the financial statements of Coronado have been adopted as the historical financial statements of Recovery.

The Company is an independent oil and gas exploration and production company focused on the Denver-Julesburg Basin ("DJ Basin") where it holds 129,000 net acres. Recovery drills for, operates and produces oil and natural gas wells through the Company's land holdings located in Wyoming, Colorado, and Nebraska.

All references to production, sales volumes and reserves quantities are net to our interest unless otherwise indicated.

## NOTE 2 – LIQUIDITY

As discussed in "Note 14—Subsequent Events" the Company entered into amendments to both our term loans and our 8% Senior Secured Convertible Debentures agreements to extend the maturity dates of these debts to May 16, 2014. In addition, the amendments to our term loans also provided for the reduction of interest rate from 15% to 10% effective March 1, 2013; the payment of interest only for the months of March through June, 2013; a reduction in the minimum monthly payments of principal and interest thereafter from \$0.33 million per month to either \$0.23 million or \$0.19 million, depending on our ability to consummate the sale of certain of our assets by July 1, 2013; and forbearance by the secured lender from exercising its rights under the term loan credit agreements for any breach that may have occurred prior to the amendment.

In consideration for the extended maturity date of both loans and the reduced interest rate and minimum loan payment under the secured term loans, the Company will be required to provide both the secured lender and the holders of our debentures an additional security interest in 15,000 acres (or 30,000 acres in aggregate) of our undeveloped acreage. In addition, we are required under the amendment to use our reasonable best efforts to pursue certain transactions to improve our financial condition, including the aforementioned sale of certain of our assets, an equity offering or similar capital-raising transaction, one or more joint venture development agreements, and an engineering study of certain of our producing properties to ascertain possible operations to enhance production from those properties. Pursuant to the debenture amendment, the Company and the debenture holders have agreed to waive any breach under the debentures that may have occurred prior to the date of the amendment.

We currently have \$19.34 million outstanding under our term loans and \$13.40 million outstanding under our debentures.

We have a history of sustained losses and cash used by operating activities, including a loss in 2012 of \$37.7 million and cash used by operating activities in 2012 of \$3.4 million. In addition, as of December 31, 2012, we had a net working capital deficit of \$1.2 million. Commencing in late 2012, we implemented a number of cost reduction measures, including a substantial reduction in our staff. On April 16, 2013, we entered into an agreement with one of our existing Debenture holders to issue up to an additional \$5.0 million in additional debentures with substantially the same terms to the existing 8% Secured Convertible Debentures. Under the terms of this agreement, \$1.5 million of additional debentures will be issued on or before July 16, 2013. The funds associated with the initial issuance of debentures will be used by the Company for the drilling and development of certain properties, and for general corporate purposes (see Note 14). The combination of these measures coupled with the aforementioned debt modifications will provide substantial near term relief to our cash flow and liquidity.

In the immediate term, the Company expects that additional capital will be required to fund its capital budget for 2013, partially to fund some of its ongoing overhead, provide for payment of minimum interest and principal payments required by term notes, and to provide additional capital to generally improve its working capital position. A portion of this additional capital will be provided by the new convertible debentures as described above. We anticipate that additional funding will be provided by a combination of capital raising activities, including the selling of additional debt and/or equity securities, the selling of certain assets and by the development of certain of our undeveloped properties via arrangements with joint venture partners. If we are not successful in obtaining sufficient cash sources to fund the aforementioned capital requirements, we may be required to curtail our expenditures, restructure our operations, sell assets on terms which may not be deemed favorable and/or curtail other aspects of our operations, including deferring portions of our 2013 capital budget.

On a longer term basis, the Company will require capital to retire our term notes and our 8% Senior Secured Convertible Debentures when such debts mature in May 2014.

Pursuant to our credit agreements with Hexagon, a substantial portion of our monthly net revenues derived from our producing properties is required to be used for debt and interest payments. In addition, our debt instruments contain provisions that, absent consent of Hexagon, may restrict our ability to raise additional capital.

## NOTE 3 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES

*Basis of Presentation*

The accompanying financial statements were prepared by Recovery in accordance with generally accepted accounting principles ("GAAP") in the United States. The financial statements reflect all normal recurring adjustments which are, in the opinion of management, necessary to provide a fair statement of the results of operations and financial position.

All common stock share information is retroactively adjusted for the effect of a 4:1 reverse stock split that was effective October 19, 2011.

*Reclassification*

Certain amounts in the December 31, 2011 consolidated financial statements have been reclassified to conform to the December 31, 2012 consolidated financial statement presentation. Such reclassifications had no effect on net income.

*Principles of Consolidation*

The accompanying consolidated financial statements include Recovery Energy, Inc. and its wholly−owned subsidiaries Recovery Oil and Gas, LLC, and Recovery Energy Services, LLC. All intercompany accounts and transactions have been eliminated in consolidation. Both subsidiaries were inactive and were dissolved in the fourth quarter of the year ended December 31, 2011.

*Use of Estimates*

The preparation of the financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. We evaluate our estimates on an ongoing basis and base our estimates on historical experience and on various other assumptions we believe to be reasonable under the circumstances. Although actual results may differ from these estimates under different assumptions or conditions, we believe that our estimates are reasonable. Our most significant financial estimates are associated with our estimated proved oil and gas reserves, and the assessment of impairment related to our unproven properties, as well as valuation of common stock used in issuances of common stock, warrants and the valuation of the conversion rights related to the convertible debentures payable.

*Liquidity*

Cash used in operating activities during the year ended December 31, 2012 was $3.39 million and cash used in investing activities exceeded cash provided by financing activities by approximately $1.74 million. This net cash use contributed to a substantial decrease in our net working capital as of December 31, 2012. Expenditures subsequent to December 31, 2012 have continued to exceed cash receipts, causing a further reduction of the Company's working capital position.

In the immediate term, the Company expects that additional capital will be required to fund its capital budget for 2013, partially to fund some of its ongoing overhead, and to provide additional capital to generally improve its working capital position. We anticipate that these capital requirements will be funded by a combination of capital raising activities, including the selling of additional debt and/or equity securities and the selling of certain assets. If we are not successful in obtaining sufficient cash sources to fund the aforementioned capital requirements, we may be required to curtail our expenditures, restructure our operations, sell assets on terms which may not be deemed favorable and/or curtail other aspects of our operations, including deferring portions of our 2013 capital budget.

Pursuant to our credit agreements with Hexagon, a substantial portion of our monthly net revenues derived from our producing properties is required to be used for debt and interest payments. In addition, our debt instruments contain provisions that, absent consent of Hexagon, may restrict our ability to raise additional capital.

In December 2011, the Company sold certain undeveloped acreage for total proceeds of $4.5 million. During 2011, Hexagon agreed to temporarily suspend for five months the requirement to remit monthly net revenues of approximately $2.00 million in the aggregate as payment on the Hexagon debt. In November 2011, Hexagon extended the maturity date of their notes to January 1, 2013, and also advanced an additional $0.31 million to the Company. The Company repaid the $0.31 million advance in February 2012. In March 2012, Hexagon extended the maturity date of their notes to June 30, 2013, and in connection therewith, the Company agreed to make minimum note payments of $0.33 million, effective immediately. The Company will continue to pursue alternatives to shore up its working capital position and to provide funding for its planned 2013 expenditures.

In February 2012, we completed the sale of certain undeveloped acreage, under which we agreed to sell all of our oil and gas leases in the Grover Field in Weld County, Colorado for approximately $4.54 million.

In August 2012, the Company restructured the terms of the Supplemental Debenture offering and concluded the offering by issuing an additional $1.96 million of convertible debentures. On September 8, 2012, the Company issued 50,000 shares, valued at $0.23 million, to T.R. Winston & Company LLC for acting as a placement agent of the Supplemental Debentures.

On November 5, 2012, the Company liquidated all of its price derivatives (commodity hedges) for proceeds of $0.61 million. As of December 31, 2012, the Company did not have any derivative instruments.

In December 2012, the Company leased certain deep rights to 6,300 undeveloped acres to a private company for proceeds of approximately $1.50 million which $0.75 million was paid toward principal on our long-term debt.

In April 2013, the Company amended its secured term loans and 8% Senior Secured Convertible Debentures to extend their maturity dates to May 16, 2014. In addition, pursuant to the amendment of its secured term loans, the Company's interest rate has been reduced to 10% from 15% beginning retroactively with March 2013, and the Company is required to make only interest payments for March, April, May, and June, after which time the minimum secured term loan payment will be $0.23 million or $0.19 million, depending on the Company's ability to consummate the sale of certain of its assets by that time. In consideration for the extended maturity date of both loans and the reduced interest rate and minimum loan payment under the secured term loans, the Company will be required to provide both Hexagon and the holders of its debentures an additional security interest in 15,000 acres (or 30,000 acres in aggregate) of its undeveloped acreage (see Note 14).

On April 16, 2013, the Company entered into an agreement with one of its existing Debenture holders to issue up to an additional $5.0 million in additional debentures with substantially the same terms to the existing 8% Secured Convertible Debentures. Under the terms of this agreement, $1.5 million of additional debentures will be issued on or before July 16, 2013. The funds associated with the initial issuance of debentures will be used by the Company for the drilling and development of certain properties, and for general corporate purposes (see Note 14).

*Cash and Cash Equivalents*

Cash and cash equivalents include cash in banks and highly liquid debt securities which have original maturities of 90 days or less at the purchase date.

*Restricted Cash*

Restricted cash consists of severance and ad valorem tax proceeds which are payable to various tax authorities. As of December 31, 2012 and 2011, the restricted cash balance was $0.67 million and $0.93 million, respectively.

*Accounts Receivable*

The Company records actual and estimated oil and gas revenue receivable from third parties at its net revenue interest. The Company also reflects costs incurred on behalf of joint interest partners in accounts receivable. Management periodically reviews accounts receivable amounts for collectability and records its allowance for uncollectible receivables under the specific identification method. The Company recorded allowance for uncollectible receivables of $50,000 during the year ended December 31, 2012. No allowance was recorded for December 31, 2011. Allowance for doubtful accounts are based primarily on joint interest billings for expenses related to oil and natural gas wells. Receivables which derive from sales of certain oil and gas production are collateral for our Loan Agreements (see Note 8).

During the year ended December 31, 2012, the Company wrote off accounts receivable for $0.03 million as bad debt expense. During the year ended December 31, 2011 no receivable amounts were written off to bad debt expense.

*Assets Held For Sale*

Assets held for sale are recorded at the lower of cost or estimated net realizable value. As of December 31, 2012 and 2011, the Company did not have any assets held for sale.

*Concentration of Credit Risk*

The Company's cash, cash equivalents and short-term investments are invested at major financial institutions primarily within the United States. At December 31, 2012 and December 2011, the Company's cash and cash equivalents were maintained in accounts that are insured up to the limit determined by the federal governmental agency. The Company may at times have balances in excess of the federally insured limits.

The Company's receivables are comprised of oil and gas revenue receivables and joint interest billings receivable. The amounts are due from a limited number of entities. Therefore, the collectability is dependent upon the general economic conditions and financial health of a small number purchasers and joint interest owners. The receivables are not collateralized. However, to date the Company has had minimal bad debts. As of December 31, 2012, the Company recorded an allowance for doubtful accounts of $50,000.

*Significant Customers*

During the year ended December 31, 2012 and December 31, 2011, approximately 67% and 76%, respectively, of the Company's revenue was derived from sales to one customer, Shell Trading (US). However, the Company does not believe that the loss of a single purchaser, including Shell Trading (US), would materially affect the Company's business because there are numerous other purchasers in the area in which the Company sells its production.

*Reserves*

All of the reserves data included herein are estimates. Estimates of our crude oil and natural gas reserves are prepared in accordance with guidelines established by the SEC, including rule revisions designed to modernize the oil and gas company reserves reporting requirements, which we implemented effective December 31, 2010. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. Uncertainties include the projection of future production rates and the expected timing of development expenditures. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserves estimates may be different from the quantities of crude oil and natural gas that are ultimately recovered. In addition, economic producibility of reserves is dependent on the oil and gas prices used in the reserves estimate. Our reserves estimates are based on 12-month average commodity prices, unless contractual arrangements otherwise designate the price to be used, in accordance with SEC rules. However, oil and gas prices are volatile and, as a result, our reserves estimates will change in the future.

Estimates of proved crude oil and natural gas reserves significantly affect our depreciation, depletion, and amortization "DD&A" expense. For example, if estimates of proved reserves decline, the DD&A rate will increase, resulting in a decrease in net income. A decline in estimates of proved reserves could also result in an impairment charge, which would reduce earnings.

*Oil and Gas Producing Activities*

The Company follows the full cost method of accounting for oil and gas operations whereby all costs related to the exploration, development and acquisition of oil and natural gas reserves are capitalized. Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling, developing and completing productive wells and/or plugging and abandoning non-productive wells, and any other costs directly related to acquisition and exploration activities. Proceeds from property sales are generally applied as a credit against capitalized exploration and development costs, with no gain or loss recognized, unless such a sale would significantly alter the relationship between capitalized costs and the proved reserves attributable to these costs. A significant alteration would typically involve a sale of 25% or more of proved reserves.

Depletion of exploration and development costs and depreciation of production equipment is computed using the units-of-production method based upon estimated proved oil and gas reserves. Costs included in the depletion base to be amortized include (a) all proved capitalized costs including capitalized asset retirement costs net of estimated salvage values, less accumulated depletion, (b) estimated future development cost to be incurred in developing proved reserves; and (c) estimated dismantlement and abandonment costs, net of estimated salvage values, that are not otherwise included in capitalized costs.

The costs of undeveloped acreage are withheld from the depletion base until it is determined whether or not proved reserves can be assigned to the properties. The properties are reviewed quarterly for impairment. When proved reserves are assigned to such properties or one or more specific properties are deemed to be impaired, the cost of such properties or the amount of the impairment is added to full cost pool which is subject to depletion calculations.

Under the full cost method of accounting, capitalized oil and gas property costs less accumulated depletion and net of deferred income taxes may not exceed an amount equal to sum of i.) the present value, discounted at 10%, of estimated future net revenues from proved oil and gas reserves, plus ii.) the cost of unproved properties not subject to amortization (without regard to estimates of fair value), or estimated fair value, if lower, of unproved properties that are not subject to amortization. Should capitalized costs exceed this ceiling, an impairment expense is recognized.

The present value of estimated future net revenues was computed by applying a twelve month average of the first day of the month price of oil and gas to estimated future production of proved oil and gas reserves as of period-end, less estimated future expenditures to be incurred in developing and producing the proved reserves (assuming the continuation of existing economic conditions), less any applicable future taxes.

The Company recognized impairment charges of $26.66 million and $2.80 million, respectively, during the years ended December 31, 2012 and 2011 (see Note 4).

*Wells in Progress*

Wells in progress represent wells that are currently in the process of being drilled or completed or otherwise under evaluation as to their potential to produce oil and gas reserves in commercial quantities. Such wells continue to be classified as wells in progress and withheld from the depletion calculation and the ceiling test until such time as either proved reserves can be assigned, or the wells are otherwise abandoned. Upon either the assignment of proved reserves or abandonment, the costs for these wells are then transferred to the full cost pool and become subject to both depletion and the ceiling test calculations. During the year ended December 31, 2012, the Company transferred $17.09 million of costs from wells in progress and their respected undeveloped acreage into the full cost pool (see Note 4).

*Deferred Financing Costs*

As of December 31, 2012 and December 31, 2011, the Company recorded unamortized deferred financing costs of approximately $0.97 million and $2.3 million, respectively, related to the closing of its loans and credit agreements (see Note 8). Deferred financing costs include origination (warrants issued and overriding royalty interests assigned to Hexagon), legal and engineering fees incurred in connection with the Company's credit facility, which are being amortized over the term of the credit facility. The Company recorded amortization expense of approximately $1.60 million and $5.0 million, respectively, in the years ended December 31, 2012 and December 31, 2011.

*Prepaid Advisory Fees*

The Company accounts for prepaid advisory services with the total consideration amortized over the underlying service agreement period. As of December 31, 2012 and 2011 prepaid financial and marketing advisory fees were approximately $0 and $0.57 million, respectively. The prepaid fees were paid with non-cash consideration (shares of our common stock and warrants exercisable for shares of our common stock issued to our financial advisors).

*Property and Equipment*

Property and equipment are stated at cost. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets. The estimated useful lives of property and equipment range from one to seven years. The Company recorded $0.02 million and $0.03 million of depreciation for the years ended December 31, 2012 and December 31, 2011, respectively.

*Impairment of Long-lived Assets*

The Company accounts for long-lived assets (other than oil and gas properties) at cost. Other long-lived assets include property and equipment, prepaid advisory fees, and identifiable intangible assets with finite useful lives (subject to amortization, depletion, and depreciation). The Company may impair these assets whenever events or changes in circumstances indicate that the carrying amount such assets may not be fully recoverable. Recoverability is measured by comparing the carrying amount of an asset to the expected undiscounted future net cash flows generated by the asset. If it is determined that the asset may not be recoverable, and if the carrying amount of an asset exceeds its estimated fair value, an impairment charge is recognized to the extent of the difference.

As of December 31, 2012 and 2011, no impairment has been recorded for long lived assets other than the impairment of capitalized oil and gas property costs during December 31, 2012 and 2011 as discussed in undeveloped acreage and wells in progress (see Note 4).

*Fair Value of Financial Instruments*

As of December 31, 2012 and 2011, the carrying value of cash and cash equivalents, short-term investments, accounts receivable, accounts payable, accrued expenses, interest payable and customer deposits approximates fair value due to the short-term nature of such items. The carrying value of the Company’s secured debt is carried at cost as the related interest rate, approximates rates currently available to the Company. Certain other assets and liabilities are measured at fair value (see Note 7).

*Commodity Derivative Instrument*

The Company utilizes swaps to reduce the effect of price changes on a portion of our future oil production. On a monthly basis, a swap requires us to pay the counterparty if the settlement price exceeds the strike price and the same counterparty is required to pay us if the settlement price is less than the strike price. The objective of the Company's use of derivative financial instruments is to achieve more predictable cash flows in an environment of volatile oil and gas prices and to manage its exposure to commodity price risk. While the use of these derivative instruments limits the downside risk of adverse price movements, such use may also limit the Company's ability to benefit from favorable price movements. The Company may, from time to time, add incremental derivative contracts to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of the Company's existing positions (see Note 6).

The use of derivatives involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. The Company's derivative contracts have typically been arranged with one counterparty. The Company has netting arrangements with this counterparty that provide for the offset of payables against receivables from separate derivative arrangements with the counterparty in the event of contract termination. The derivative contracts may be terminated by a non-defaulting party in the event of default by one of the parties to the agreement (see Note 6). On November 5, 2012, the Company liquidated all of its price derivatives (commodity hedges) for proceeds of $0.61 million. As of December 31, 2012, the Company did not have any derivative instruments.

*Revenue Recognition*

We record revenues from the sales of crude oil, natural gas and natural gas liquids when the product is delivered at a fixed or determinable price, title has transferred and collectability is reasonably assured.

*Asset Retirement Obligation*

The Company incurs retirement obligations for certain assets at the time they are placed in service. The fair values of these obligations are recorded as liabilities on a discounted basis. The costs associated with these liabilities are capitalized as part of the related assets and depreciated. Over time, the liabilities are accreted for the change in their present value.

For purposes of depletion calculations, the Company also includes estimated dismantlement and abandonment costs, net of salvage values, associated with future development activities that have not yet been capitalized as asset retirement obligations.

Asset retirement obligations incurred are classified as Level 3 (unobservable inputs) fair value measurements. The asset retirement liability is allocated to operating expense using a systematic and rational method. As of December 31, 2012 and 2011, the Company recorded a related liability of $911,546 and $612,874, respectively (see Note 6).

The information below reconciles the value of the asset retirement obligation for the periods presented:

| | For the years ended December 31, | |
|---|---|---|
| | 2012 | 2011 |
| Balance, beginning of period | $ 612,874 | 507,280 |
| Liabilities incurred | 198,111 | 61,469 |
| Accretion expense | 100,561 | 44,125 |
| Change in estimate | - | - |
| Balance, end of period | $ 911,546 | $ 612,874 |

*Share Based Compensation*

The Company measures the fair value of share-based compensation expense awards made to employees and directors, including stock options, restricted stock and employee stock purchases related to employee stock purchase plans, on the date of grant using an option-pricing model. The value of the portion of the award that is ultimately expected to vest is recognized as an expense ratably over the requisite service periods. The measurement of share-based compensation expense is based on several criteria, including but not limited to the valuation model used and associated input factors, such as expected term of the award, stock price volatility, risk free interest rate, dividend rate and award cancellation rate. These inputs are subjective and are determined using management's judgment. If differences arise between the assumptions used in determining share-based compensation expense and the actual factors, which become known over time, Recovery may change the input factors used in determining future share-based compensation expense.

Recovery accounts for warrant grants to non-employees whereby the fair values of such warrants are determined using the Black-Scholes option pricing model at the earlier of the date at which the non-employee's performance is complete or a performance commitment is reached (Note 12).

*Warrant Modification Expense*

The Company accounts for the modification of warrants as an exchange of the old award for a new award. The incremental value is measured as the excess, if any, of the fair value of the modified award over the fair value of the original award immediately before modification, and is either expensed as a period expense or amortized over the performance or vesting date. We estimate the incremental value of each warrant using the Black-Scholes option pricing model. The Black-Scholes model is highly complex and dependent on key estimates by management. The estimate with the greatest degree of subjective judgment is the estimated volatility of our stock price (Note 11).

*Loss per Common Share*

Earnings (losses) per share are computed based on the weighted average number of common shares outstanding during the period presented. Diluted earnings (losses) per share are computed using the weighted-average number of common shares outstanding plus the number of common shares that would be issued assuming exercise or conversion of all potentially dilutive common shares. Potentially dilutive securities, such as conversion derivatives and stock purchase warrants, are excluded from the calculation when their effect would be anti-dilutive. As of December 31, 2012, a total of 5,638,900 and 3,152,941, respectively of outstanding warrants and derivative shares related to convertible debentures payable have been excluded from the diluted share calculations as they were anti-dilutive as a result of net losses incurred. Accordingly, basic shares equal diluted shares for all periods presented.

*Income Taxes*

Prior to December 31, 2011, the Company filed its tax returns on an April 30 fiscal year end. During the year ended December 31, 2012, the Company received approval by the Internal Revenue Service ("IRS") to move the Company's tax year end to December 31 from April.

The Company uses the asset liability method in accounting for income taxes. Deferred tax assets and liabilities are recognized for temporary differences between financial statement carrying amounts and the tax bases of assets and liabilities, and are measured using the tax rates expected to be in effect when the differences reverse. Deferred tax assets are also recognized for operating loss and tax credit carry forwards. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the results of operations in the period that includes the enactment date. A valuation allowance is used to reduce deferred tax assets when uncertainty exists regarding their realization.

We recognize tax benefits only for tax positions that are more likely than not to be sustained upon examination by tax authorities. The amount recognized is measured as the largest amount of benefit that is greater than 50 percent likely to be realized upon settlement. A liability for "unrecognized tax benefits" is recorded for any tax benefits claimed in our tax returns that do not meet these recognition and measurement standards. As of December 31, 2012 and 2011, the Company has determined that no liability is required to be recognized.

Our policy is to recognize any interest and penalties related to unrecognized tax benefits in income tax expense. However, we did not accrue interest or penalties at December 31, 2012 and December 31, 2011, because the jurisdiction in which we have unrecognized tax benefits does not currently impose interest on underpayments of tax and we believe that we are below the minimum statutory threshold for imposition of penalties. We do not expect that the total amount of unrecognized tax benefits will significantly increase or decrease during the next 12 months. The earliest years remaining subject to examination are December 31, 2011, April 30, 2011 and April 30, 2010.

*Recently Issued Accounting Pronouncements*

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2011-04: Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in US GAAP and IFRSs (ASU 2011-04). ASU 2011-04 clarifies application of fair value measurement and disclosure requirements and is effective for annual and interim periods beginning after December 15, 2011.

In December 2011, the FASB issued Accounting Standards Update No. 2011-11 Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities (ASU 2011-11). ASU 2011-11 requires that an entity disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. ASU 2011-11 is effective for annual periods beginning on January 1, 2013.

**NOTE 4 – OIL AND GAS PROPERTIES & OIL AND GAS PROPERTIES ACQUISITIONS AND DIVESTITURES**

*DJ Basin Properties Acquisitions*

In December 2010, the Company entered into an acquisition and development agreement with TRW Exploration, LLC (a related party, see Note 9) whereby TRW paid $2,000,000 for the purchases of an interest in approximately 2,000 net undeveloped acres and also agreed to carry the Company’s 40% interest in two horizontal wells to be drilled on lands defined by the agreement. TRW subsequently funded the drilling and completion costs of two horizontal wells on the lands covered by the leases, at a total cost of approximately $7 million. This agreement was terminated in December, 2011 and TRW sold back its interest in the wells along with all of its rights to the undeveloped acreage, in consideration for the issuance by the Company of 1,500,000 shares of unregistered common stock valued at $4.88 million. Additional amounts were incurred in drilling the wells and were paid by the Company. The Company allocated $2 million of this purchase price to the undeveloped acreage, and the remainder to the purchase of the two wells.

In February 2011, the Company purchased undeveloped oil and gas acreage from various private individuals for $1.25 million in cash and $0.65 million in stock in the Grover Field and surrounding area in Weld County, Colorado, and Goshen County, Wyoming.

In March 2011, the Company purchased undeveloped oil and gas acreage interests located in Laramie County, Wyoming. The purchase price was $6.47 million cash and shares of common stock valued at $5.80 million in stock. The Company also closed on two acquisitions of undeveloped oil and gas acreage from various private individuals for a combined $0.55 million in cash in Goshen County, Wyoming.

In February 2012, we completed the sale of our Grover Prospect acreage, under which we agreed to sell all of our oil and gas leases in the Grover Field in Weld County, Colorado to Bill Barrett Corporation for approximately $4.54 million.

In April, 2012, we made the decision to abandon one of our unconventional Niobrara wells that was categorized as a well in progress as of December 31, 2011. In conjunction with that decision, all capitalized drilling, completion and allocable lease costs related to this well in the amount of $4.8 million were transferred to developed properties. This transfer of costs contributed to a $3.27 impairment charge of developed properties derived from the ceiling test completed as of March 31, 2012. In December 2012, the Company made a decision to abandon the one remaining unconventional Niobrara well. In conjunction with the decision, all capitalized drilling, completion and allocable lease costs related to both wells-in-progress in the amount of $10.06 million were transferred to developed properties. Furthermore, the company analyzed all of their undeveloped acreage with expiration dates during the year ended December 31, 2015 and transferred $5.94 million to developed properties. Also, the Company reduced the PV-10 of the proved undeveloped reserve acreage by utilizing the assumption that its proven undeveloped reserves would be developed on a promoted basis, which reduced the production amounts to 25% of the Company’s 100% ownership. As a result, the ceiling test performed by the Company yielded an increased impairment. The transfer of both of the costs to the developed properties and a reduction of proved undeveloped reserve acreage resulted in an impairment of $23.39 million during December 2012, for a total impairment of $26.66 million for the year ended December 31, 2012.

During 2012, the Company purchased $0.20 million of undeveloped oil and gas acreage interest located in the DJ Basin.

*DJ Basin Properties Divestitures*

Effective December 31, 2011 the Company sold 2,838 net acres of undeveloped acreage for consideration of approximately $4.5 million. A gain of $1.8 million related to the sale of this acreage was applied as a credit to the carrying costs of developed oil and gas properties.

On December 27, 2012, the Company leased undeveloped acreage for total proceeds of $1.5 million in the DJ Basin to a private company granting a four-year lease for the deep rights on approximately 6,300 net acres. The Company paid Hexagon $0.75 million of the proceeds which reduced the long-term debt principal amount.

Depreciation, depletion and amortization ("DD&A") expenses related to the proved properties were approximately $4.55 million and $4.34 million for the years ended December 31, 2012 and December 31, 2011, respectively. During the year ended December 31, 2012 and 2011, the company impaired the carrying costs of its developed oil and gas properties by $26.66 million and $2.8 million, respectively, as a result of an excess of carrying costs above the applicable ceiling threshold based on the fair market value of the proved developed and proved undeveloped acreage.

The following table sets forth a summary of oil and gas property costs (net of divestitures) not being amortized as of December 31, 2012 and 2011:

| | As of December 31, 2012 | As of December 31, 2011 |
|---|---|---|
| **Undeveloped acreage** | | |
| Beginning Balance | $ 45,697,481 | $ 33,605,594 |
| Acquisitions | 203,596 | 14,981,153 |
| Leased deep rights of undeveloped acreage | (1,443,852) | - |
| Impairment and other reclassification to developed properties | (16,390,220) | (2,889,266) |
| Total undeveloped acreage | $ 28,067,005 | $ 45,697,481 |
| **Wells in progress:** | | |
| Beginning Balance | $ 6,425,509 | $ 1,219,254 |
| Acquisitions | 3,824,172 | 8,904,818 |
| Reclassification to developed properties | (10,056,166) | (3,698,563) |
| Total wells in progress | $ 193,515 | $ 6,425,509 |
| Total property not subject to DD&A | $ 28,260,520 | $ 52,122,990 |

As of December 31, 2012, the company analyzed all of its undeveloped acreage for impairment, and transferred $16.39 million to developed properties which were subject to DD&A and the ceiling test (see Note 4).

**NOTE 5 – WELLS IN PROGRESS**

The following table reflects the net changes in capitalized additions to wells in progress during 2012 and 2011:

| | As of December 31, | |
|---|---|---|
| | 2012 | 2011 |
| **Wells in progress:** | | |
| Beginning Balance | $ 6,425,509 | $ 1,219,254 |
| Acquisitions | 3,824,172 | 8,904,818 |
| Reclassification to developed properties | (10,056,166) | (3,698,563) |
| Total wells in progress | $ 193,515 | $ 6,425,509 |

In April, 2012, we made the decision to abandon one of our unconventional Niobrara wells that was categorized as a well in progress as of December 31, 2011. In conjunction with that decision, all capitalized drilling, completion and allocable lease costs related to this well in the amount of $4.8 million were transferred to developed properties. This transfer of costs contributed to a $3.27 impairment charge of developed properties derived from the ceiling test completed as of March 31, 2012. In December 2012, the Company made a decision to abandon the one remaining unconventional Niobrara well. In conjunction with the decision, all capitalized drilling, completion and allocable lease costs related to both wells-in-progress in the amount of $10.06 million were transferred to developed properties. Furthermore, the company analyzed all of their undeveloped acreage with expiration dates during the year ended December 31, 2013 and transferred $1.31 million to developed properties. The transfer of both of the costs to the developed properties resulted in an impairment of $23.39 million during December 2012, for a total impairment of $26.66 million for the year ended December 31, 2012.

**NOTE 6 - FINANCIAL INSTRUMENTS AND DERIVATIVES**

Periodically, the Company enters into various commodity derivative financial instruments intended to hedge against exposure to market fluctuations of oil prices. During the year ended December 31, 2012 and 2011, the Company terminated and settled certain future commodity swaps resulting in a realized gain of approximately $0.61 million and $0.63 million, respectively.

The Company had no active commodity swaps as of December 31, 2012. As of December 31, 2011, the Company maintained an active commodity swap for 100 barrels per day through December 31, 2011, at a price of $96.25 per barrel.

The amount of gain (loss) recognized in income related to our derivative financial instruments was as follows:

| | For the Year Ended December 31, | |
|---|---|---|
| | 2012 | 2011 |
| Realized gain on oil price hedges | $ 780,135 | $ 570,233 |
| Unrealized gain (loss) oil price hedges | $ - | $ (75,609) |

Unrealized gains and losses resulting from derivatives are recorded at fair value on the consolidated balance sheet and changes in fair value are recognized in the unrealized gain (loss) on hedge contracts line on the consolidated statement of operations. Realized gains and losses resulting from the contract settlement of derivatives are recorded in the realized gain (loss) line on the consolidated statement of income.

**NOTE 7 - FAIR VALUE OF FINANCIAL INSTRUMENTS**

The Company measures fair value of its financial assets on a three-tier value hierarchy, which prioritizes the inputs, used in the valuation methodologies in measuring fair value:

- Level 1 – Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 – Other inputs that are directly or indirectly observable in the marketplace.
- Level 3 – Unobservable inputs which are supported by little or no market activity.

The fair value hierarchy also requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

The Company's cash equivalents, short-term investments, accounts receivable, accounts payable, accrued expenses, interest payable and customer deposits approximate fair value due to the short-term nature or maturity of the instruments. The Company's fixed rate 10% and 8% term loans and convertible debentures are measured using Level 1 inputs.

*Derivative Instruments*

The Company determines its estimate of the fair value of derivative instruments using a market approach based on several factors, including quoted market prices in active markets, quotes from third parties, and the credit rating of its counterparty. The Company also performs an internal valuation to ensure the reasonableness of third-party quotes.

The types of derivative instruments utilized by the Company included commodity swaps. The oil derivative markets are highly active. Although the Company's economic hedges are valued using public indices, the instruments themselves are traded with third-party counterparties and are not openly traded on an exchange. As such, the Company has classified these instruments as Level 2.

In evaluating counterparty credit risk, the Company assessed the possibility of whether the counterparty to the derivative would default by failing to make any contractually required payments. The Company considered that the counterparty is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions.

*Asset Retirement Obligation*

The income valuation technique is utilized to determine the fair value of its asset retirement obligation liability at the point of inception by taking into account: 1) the cost of abandoning oil and gas wells, which is based on the Company's historical experience for similar work, or estimates from independent third-parties; 2) the economic lives of its properties, which are based on estimates from reserve engineers; 3) the inflation rate; and 4) the credit adjusted risk-free rate, which takes into account the Company's credit risk and the time value of money. Given the unobservable nature of the inputs, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs.

*Convertible Debentures Payable Conversion Feature*

In February 2011, the Company issued in a private placement $8.40 million aggregate principal amount of three year 8% Senior Secured Convertible Debentures ("Debentures") with a group of accredited investors. During the year ended December 31, 2012, the Company issued an additional $5.00 million of Debentures, resulting in a total of $13.40 million of Debentures outstanding as of December 31, 2012. As of December 31, 2012, the Debentures are convertible at any time at the holders' option into shares of our common stock at $4.25 per share, subject to certain adjustments, including the requirement to reset the conversion price based upon any subsequent equity offering at a lower price per share amount. The Company engaged a third party to complete a valuation of this conversion.

The following table provides a summary of the fair values of assets and liabilities measured at fair value:

December 31, 2012

| | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| **Assets** | | | | |
| Commodity derivative instruments | $ - | $ - | $ - | $ - |
| Total assets, at fair value | $ - | $ - | $ - | $ - |
| | | | | |
| **Liability** | | | | |
| Convertible debentures conversion derivative liability | $ - | $ - | $ (1,680,000) | $ (1,680,000) |
| Total liability, at fair value | $ - | $ - | $ (1,680,000) | $ (1,680,000) |

December 31, 2011

| | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| **Liability** | | | | |
| Commodity derivative instruments | $ - | $ (75,609) | $ - | $ (75,609) |
| Convertible debentures conversion derivative liability | - | - | (1,300,000) | (1,300,000) |
| Total liability at fair value | $ - | $ (75,609) | $ (1,300,000) | $ (1,375,609) |

The following table provides a summary of changes in fair value of the Company's Level 3 financial assets and liabilities as of December 31, 2012:

| | |
|---|---|
| Beginning balance, December 31, 2011 | $ (1,300,000) |
| Convertible debentures conversion derivative gain | 320,000 |
| Additions to derivative liability from Supplemental Debenture | (700,000) |
| Ending balance, December 31, 2012 | $ (1,680,000) |

The Company did not have any transfers of assets or liabilities between Level 1, Level 2 or Level 3 of the fair value measurement hierarchy during the year ending December 31, 2012 and 2011.

**NOTE 8 - LOAN AGREEMENTS**

*Term Loans*

The Company entered into three separate loan agreements with Hexagon in January, March and April 2010, each with an original maturity date of December 1, 2010. All three loans originally bore annual interest of 15% (which has been reduced, as discussed below), currently mature on May 16, 2014, and have similar terms, including customary representations and warranties and indemnification, and require the Company to repay the loans with the proceeds of the monthly net revenues from the production of the acquired properties. The loans contain cross collateralization and cross default provisions and are collateralized by mortgages against a portion of the Company's developed and undeveloped leasehold acreage.

We entered into a loan modification agreement on May 28, 2010, which extended the maturity date of the loans to December 1, 2011. In consideration for extending the maturity of the loans, Hexagon received 250,000 warrants with an exercise price of $6.00 per share. The loan modification agreement also required the Company to issue 250,000 five year warrants to purchase common stock at $6.00 per share to Hexagon if the Company did not repay the loans in full by January 1, 2011. Since the loans were not paid in full by January 1, 2011, the Company issued 250,000 additional warrants with an exercise price of $6.00 per share to Hexagon which was valued at approximately $1.60 million. This amount was recorded as a deferred financing cost and is being amortized over the remaining term of the loan.

In December 2010, Hexagon extended the maturity date of the loans to September 1, 2012. During the last six months of 2011, Hexagon agreed to temporarily suspend for five months the requirement to remit monthly net revenues in the total amount of approximately $2.00 million as payment on the loans. In November 2011, Hexagon extended the maturity to January 1, 2013. In November 2011, Hexagon also temporarily advanced the Company an additional amount of $0.31 million, which was repaid in full in February 2012. In March 2012, Hexagon extended the maturity of the loans to June 30, 2013, and in connection there with, the Company agreed to make minimum monthly note payments of $0.33 million, effective immediately. In July 2012, Hexagon extended the maturity date to September 30, 2013. In November 2012, Hexagon extended the maturity date of the loans to December 31, 2013.

On December 27, 2012, in connection with the Company's lease of deep rights on approximately 6,300 net acres to a third party for total consideration of $1.5 million, the Company paid Hexagon $0.75 million, which reduced the long-term debt principal amount.

In April 2013, Hexagon agreed to amend all three loan agreements to extended the maturity date to May 16, 2014, reduce the interest rate to 10% from 15% beginning retroactively with March 2013, decrease our minimum payment under the term loans to $0.23 or $0.19, depending on our ability to complete the sale of certain of our assets by July 1, 2013, and require us to pay interest only for March, April, May, and June. In consideration for the extended maturity date, reduced interest rate, and reduced minimum loan payment, we are required to provide them an additional security interest in 15,000 acres of our undeveloped acreage (see Note 14).

The Company is subject to certain non-financial covenants with respect to the Hexagon loan agreements. As of December 31, 2012, the Company was in compliance with all covenants under the facilities.

*Convertible Debentures Payable*

In February 2011, the Company completed a private placement of $8.40 million aggregate principal amount of 8% Senior Secured Debentures (the "Debentures"), secured by mortgages on several of our properties. Initially, the Debentures were convertible at any time at the holders' option into shares of our common stock at $9.40 per share, subject to certain adjustments, including the requirement to reset the conversion price based upon any subsequent equity offering at a lower price per share amount. Interest at an annualized rate of 8% is payable quarterly on each May 15, August 15, November 15 and February 15 in cash or, at the Company's option, in shares of common stock, valued at 95% of the volume weighted average price of the common stock for the 10 trading days prior to an interest payment date. The Company can redeem some or all of the Debentures at any time. The redemption price is 115% of principal plus accrued interest. If the holders of the Debentures elect to convert the Debentures, following notice of redemption, the conversion price will include a make-whole premium equal to the remaining interest through the 18 month anniversary of the original issue date of the Debentures, payable in common stock. T.R. Winston & Company LLC acted as placement agent for the private placement and received $0.40 million of Debentures equal to 5% of the gross proceeds from the sale. The Company is amortizing the $0.40 million over the life of the loan as deferred financing costs. The Company amortized $0.16 million of deferred financing costs into interest expense during the year ended December 31, 2012, and has $0.14 million of deferred financing costs to be amortized through May 2014.

In December 2011, the Company agreed to amend the Debentures to lower the conversion price to $4.25 from $9.40 per share. This amendment was an inducement consideration to the Debenture holders for their agreement to release a mortgage on certain properties so the properties could be sold. The sale of these properties was effective December 31, 2011, and a final closing occurred during the three months ended March 31, 2012.

On March 19, 2012, the Company entered into agreements with some of its existing Debenture holders to issue up to an additional $5.0 million in additional debentures (the "Supplemental Debentures"). Under the terms of the Supplemental Debenture agreements, proceeds derived from the issuance of Supplemental Debentures were used principally for the development of certain of the Company's proved undeveloped properties and other undeveloped acreage currently targeted by the Company for exploration, as well as for other general corporate purposes. Any new producing properties developed from the proceeds of Supplemental Debentures are to be pledged as collateral under a mortgage to secure future payment of the Debentures and Supplemental Debentures. All terms of the Supplemental Debentures are substantively identical to the Debentures. The Agreements also provided for the payment of additional consideration to the purchasers of Supplemental Debentures in the form of a proportionately reduced 5% carried working interest in any properties developed with the proceeds of the Supplemental Debenture offering.

Through July 2012, we received $3.04 million of proceeds from the issuance of Supplemental Debentures, which were used for the drilling and development of six new wells, resulting in a total investment of $3.69 million. Five of these wells resulted in commercial production, and one well was plugged and abandoned.

In August 2012, the Company and holders of the Supplemental Debentures agreed to renegotiate the terms of the Supplemental Debenture offering. These negotiations concluded with the issuance of an additional $1.96 million of Supplemental Debentures. The August 2012 modifications to the Supplemental Debenture agreements increased the carried working interest from 5% to 10% and also provided for a one-year, proportionately reduced net profits interest of 15% in the properties developed with the proceeds of the Supplemental Debenture offering, as well as the next four properties to be drilled and developed by the Company.

The Company has estimated the total value of consideration paid to Supplemental Debenture holders in the form of the modified net profits interest and carried working interest to be approximately $1.16 million, and recorded this amount as a debt discount to be amortized over the remaining life of the Supplemental Debentures.

We periodically engage a third party valuation firm to complete a valuation of the conversion feature associated with the Debentures, and with respect to December 31, 2012, the Supplemental Debentures. This valuation resulted in an estimated derivative liability as of December 31, 2012 and December 31, 2011 of $1.68 million and $1.30 million, respectively. The portion of the derivative liability that is associated with the Supplemental Debentures, in the approximate amount of $0.70 million, has been recorded as a debt discount, and is being amortized over the remaining life of the Supplemental Debentures.

During the year ended December 31, 2012 and 2011, the Company amortized $2.36 million and $1.52 million, respectively, of debt discounts.

On September 8, 2012, the Company issued 50,000 shares, valued at $0.23 million, to T.R. Winston & Company LLC for acting as a placement agent of the Supplemental Debentures. The Company is amortizing the $0.23 million over the life of the loan as deferred financing costs. The Company amortized $0.05 million of deferred financing costs into interest expense during the year ended December 31, 2012, and has $0.18 million of deferred financing costs to be amortized through May 2014.

In April 2013, the holders of our 8% Senior Secured Convertible Debentures agreed to extend their maturity date to May 16, 2014. In consideration for the extended maturity date the Company is required to provide them an additional security interest in 15,000 acres of our undeveloped acreage (see Note 14).

On April 16, 2013, the Company entered into an agreement with one of its existing Debenture holders to issue up to an additional $5.0 million in additional debentures with substantially the same terms to the existing 8% Secured Convertible Debentures. Under the terms of this agreement, $1.5 million of additional debentures will be issued on or before July 16, 2013. The funds associated with the initial issuance of debentures will be used by the Company for the drilling and development of certain properties, and for general corporate purposes (see Note 14).

As of December 31, 2012 and December 31, 2011, the convertible debt is recorded as follows:

| | As of December 31, 2012 | As of December 31, 2011 |
|---|---|---|
| Convertible debentures | $ 13,400,000 | $ 8,400,000 |
| Debt discount | (3,099,639) | (3,470,932) |
| Total convertible debentures, net | $ 10,300,361 | $ 4,929,068 |

Annual debt maturities as of December 31, 2012 are as follows:

| | |
|---|---|
| Year 1 | $ 388,351 |
| Year 2 | 32,347,963 |
| Thereafter | - |
| Total | $ 32,736,314 |

Failure to make periodic interest payments due under the Debentures (including the Supplemental Debentures) may result in acceleration of all principal and interest then outstanding under the Debentures, and may entitle the holders of the Debentures to exercise their rights to foreclose under the mortgages securing the Debentures. In addition, failure to make the required monthly payments under our term loans could result in immediate acceleration of both the term loans and the Debentures.

*Interest Expense*

For the year ended December 31, 2012 and 2011, the Company incurred interest expense of approximately $8.06 million and $8.22 million, respectively, of which approximately $4.85 million and $5.02 million, respectively, were non-cash interest expense and amortization of the deferred financing costs, accretion of the convertible debentures payable discount, and convertible debentures interest paid in common stock.

**NOTE 9 - COMMITMENTS and CONTINGENCIES**

*Environmental and Governmental Regulation*

At December 31, 2012, there were no known environmental or regulatory matters which are reasonably expected to result in a material liability to the Company. Many aspects of the oil and gas industry are extensively regulated by federal, state, and local governments in all areas in which the Company has operations. Regulations govern such things as drilling permits, environmental protection and pollution control, spacing of wells, the unitization and pooling of properties, reports concerning operations, royalty rates, and various other matters including taxation. Oil and gas industry legislation and administrative regulations are periodically changed for a variety of political, economic, and other reasons. As of December 31, 2012, the Company had not been fined or cited for any violations of governmental regulations that would have a material adverse effect upon the financial condition of the Company.

*Legal Proceedings*

The Company may from time to time be involved in various legal actions arising in the normal course of business. In the opinion of management, the Company's liability, if any, in these pending actions would not have a material adverse effect on the financial positions of the Company. The Company's general and administrative expenses would include amounts incurred to resolve claims made against the Company.

*Parker v. Tracinda Corporation*, Denver District Court, Case No. 2011CV561. In November 2012, the Company filed a motion to intervene in garnishment proceedings involving Roger Parker, the Company's former Chief Executive Officer and Chairman. The Defendant has served various writs of garnishment on the Company to enforce a judgment against Mr. Parker seeking, among other things, shares of unvested, restricted stock. The Company has asserted rights to lawful set-offs and deductions in connection with certain tax consequences, which may be material to the Company. As a result of bankruptcy proceedings filed by Mr. Parker, the garnishment proceedings have been stayed. At this stage, we cannot express an opinion as to the probable outcome of this matter.

*Other Contingencies*

We could be liable for liquidated damages under registration rights agreements covering approximately 3.2 million shares of our common stock if we fail to maintain the effectiveness of a prior registration statement as required in the agreements. In such case, we would be required to pay monthly liquidated damages of up to $0.23 million. The maximum aggregate liquidated damages are capped at $1.37 million.

*Operating Leases*

The Company leases an office space under a one year operating lease in Denver, Colorado. Rent expense for the years ended December 31, 2012 and December 31, 2011, was $0.09 million and $0.08 million, respectively. The Company will have minimum lease payments of $0.09 million for the year ending December 31, 2013.

## NOTE 10 - RELATED PARTY TRANSACTIONS

During fiscal years 2011 and 2012, we have engaged in the following transactions with related parties:

***Roger Parker.*** Roger Parker, our chief executive officer until November 15, 2012, has interest in certain of our wells for which he is receiving revenue and join-interest billings. As of December 31, 2012, Mr. Parker had $0.01 million in receivables outstanding and continued to have additional receivables based on monthly production and well maintenance. Furthermore, upon his resignation on November 15, 2012, the Company entered into a separation agreement which provided that Mr. Parker receive a one-year salary severance and health benefits for the year, and also provide for the deferral of vesting of 1,350,000 shares into 2013. In return, the Company received a general release and certain non-compete terms from Mr. Parker, and are also to receive no less than 10 hours per week of Mr. Parker's time as a consultant to the Company. As of December 31, 2012, the Company owes Mr. Parker $0.26 million in severance salary and health insurance, all of which was accrued as an expense in 2012.

At the time of his retirement, Mr. Parker had been granted 1,350,000 shares of unvested common stock. As a result of his separation from the Company, it was deemed improbable that these shares would vest to Mr. Parker in his capacity as an employee of the Company due to the termination of employment; however, it was deemed probable that these shares will vest under his separation agreement. As a result, the Company reversed all of the compensation expense, in the amount of $6.75 million, associated with stock grants to Mr. Parker during his tenure as an employee, and recorded a consulting expense (in the amount of $3.59 million) related to the shares of stock that are expected to vest during the severance period of the separation agreement. The net difference of these two amounts resulted in a reduction in 2012 general and administrative expenses of $3.16 million.

***Edward Mike Davis***. Prior to 2011, we acquired a significant portion of our oil and gas properties from Edward Mike Davis, L.L.C. and Spottie, Inc., both owned by Edward Mike Davis. We paid for these acquisitions in a combination of cash and stock. As a result of these transactions, the Davis entities received an aggregate of 3,291,667 shares of our common stock. As of December 31, 2012, Davis had sold substantially all of his Recovery stock.

During 2011 and 2012, the Company entered into minor leasing activities with Mr. Davis and his affiliates, which included swapping certain tracts of undeveloped acreage, the purchase of certain seismic data, and the farm out and farming of certain tracts of acreage. All of these transactions were competed on terms that were consistent with those that could be achieved with other third parties.

### *T.R. Winston*

On September 8, 2012, the Company issued 50,000 shares, valued at $0.23 million, to T.R. Winston & Company LLC for acting as a placement agent of the Supplemental Debentures. The Company is amortizing the $0.23 million over the life of the loan as deferred financing costs. The Company amortized $0.01 million of deferred financing costs into interest expense during the nine months ended September 30, 2012, and has $0.22 million of deferred financing costs to be amortized through May 2014.

### *TRW Exploration*

Under the terms of a December 2010 joint venture agreement, TRW Exploration paid us $2 million for the purchase of an interest in the 2,400 net acres and also paid $7.1 million of the drilling and completion costs of two horizontal wells to earn a 60% working interest in each well. These two wells were drilled and completed in 2011. Both wells were carried as wells in progress as of December 31, 2011, but were transferred to developed properties in 2012, and the Company currently attributes no commercial reserves to either property Upon termination of the joint venture in December 2011, TRW sold the Company its interest in the wells along with all of its rights to the undeveloped acreage in consideration for the issuance by the Company of 1,500,000 shares of unregistered common stock that we valued at $4,875,000, and certain mutual releases. TRW Exploration was majority owned by several of our shareholders, at least one of whom owned more than 5% of our outstanding common stock at the time the shares were issued.

### Conflict of Interest Policy

We have a corporate conflict of interest policy that prohibits conflicts of interests unless approved by the board of directors. Our board of directors has established a course of conduct whereby it considers in each case whether the proposed transaction is on terms as favorable or more to the Company than would be available from a non-related party. Our board also looks at whether the transaction is fair and reasonable to us, taking into account the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us. Each of the related party transactions was presented to our board of directors for consideration and each of these transactions was unanimously approved by our board of directors after reviewing the criteria set forth in the preceding two sentences. Each of our purchases from Davis was individually negotiated, and none of the transactions was contingent upon or otherwise related to any other transaction.

**NOTE 11 - INCOME TAXES**

The tax effects of temporary differences that gave rise to the deferred tax liabilities and deferred tax assets as of December 31, 2012 and 2011 were:

| | 2012 | 2011 |
|---|---|---|
| Deferred tax assets: | | |
| Oil and gas properties and equipment | $ 8,496,988 | $ (515,123) |
| Net operating loss carry-forward | 14,910,936 | 11,291,513 |
| Share based compensation | 3,885,974 | 4,675,241 |
| Abandonment obligation | 238,864 | 205,145 |
| Derivative instruments | 173,826 | 176,514 |
| Other | (48,909) | (91,304) |
| Total deferred tax asset | 27,657,679 | 15,741,986 |
| Valuation allowance | (27,657,679) | (15,741,986) |
| Net deferred tax asset | $ - | $ - |

Reconciliation of the Company's effective tax rate to the expected federal tax rate is:

| | For the Year Ended December 31, | |
|---|---|---|
| | 2012 | 2011 |
| Effective federal tax rate | 35.00% | 35.00% |
| Effect of permanent differences | -4.43% | -7.35% |
| State tax rate | 1.64% | 1.22% |
| Change in rate | -% | -% |
| Other | -% | -% |
| Valuation allowance | -32.21% | -28.87% |
| Net | -% | -% |

At December 31, 2012 and 2011, the Company had net operating loss carry-forwards for federal income tax purposes of approximately $40,699,000 and $30,350,000, respectively that may be offset against future taxable income. The Company has established a valuation allowance for the full amount of the deferred tax assets as management does not currently believe that it is more likely than not that these assets will be recovered in the foreseeable future. To the extent not utilized, the net operating loss carry-forwards as of December 31, 2012 will expire in 2032. Net operating loss carryovers may be subject to reduction or limitation by application of Internal Revenue Code Section 382 from the result of ownership changes .

**NOTE 12 - SHAREHOLDERS' EQUITY**

*Common Stock*

Effective October 19, 2011, the Company completed a four-for-one reverse stock split of its common shares. All references to common stock and common stock prices have been adjusted to reflect the effects of the reverse stock split.

As of December 31, 2012, the Company had 100,000,000 shares of common stock and 10,000,000 shares of preferred stock authorized, of which 18,394,401 shares of common stock were issued and outstanding. No preferred shares were issued or outstanding.

During the year ended December 31, 2012, the Company granted 777,699 shares of common stock as restricted stock grants to employees, board members, and consultants valued at $2.08 million. The Company also issued 278,225 shares for payment of quarterly interest expense on the convertible debentures valued at $0.89 million, and 50,000 shares, valued at $0.23 million, to T.R. Winston & Company LLC for acting as placement agent of the Supplemental Debentures. During 2012, the Company cancelled 123,184 shares of unvested common stock as a result of employee terminations.

*Warrants*

A summary of warrant activity for the nine months ended December 31, 2012 is presented below:

| | **Warrants** | **Weighted-Average Exercise Price** |
|---|---|---|
| Outstanding at December 31, 2011 | 5,638,900 | $ 7.04 |
| Granted | 600,000 | 5.00 |
| Exercised, forfeited, or expired | (600,000) | (5.00) |
| Outstanding at December 31, 2012 | 5,638,900 | $ 7.04 |

During 2012, the Company entered into a financial advisory agreement with a consulting firm that provided for the issuance of 600,000 warrants. However, this agreement was cancelled by mutual agreement during 2012 and no warrants were actually earned by the consulting firm. The Company recorded no compensation expense related to these warrants.

The aggregate intrinsic value of the warrants was approximately $0 as of both December 31, 2012 and December 31, 2011, based on the Company's closing common stock price of $1.99 and $3.01, respectively; and the weighted average remaining contract life was 2.56 years and 2.93 years, respectively.

**NOTE 13 - SHARE BASED AND OTHER COMPENSATION**

*Share-Based Compensation*

In September 2012, the Company adopted the 2012 Equity Incentive Plan (the "Plan"). Each member of the board of directors and the management team has been periodically awarded restricted stock grants, and in the future will be awarded such grants under the terms of the Plan.

The costs of employee services received in exchange for an award of equity instruments are based on the grant-date fair value of the award, recognized over the period during which an employee is required to provide services in exchange for such award.

During the year ended December 31, 2012, the Company granted 693,289 shares of restricted common stock to employees and directors of which 335,996, 132,287, 132,294, and 92,712 shares vest during the years ended December 31, 2012, 2013, 2014, and 2015, respectively. The fair value of these share grants was calculated to be approximately $1.28 million. As of December 31, 2012, 1,485,378 shares expired due to termination of management personal. The Company also granted 100,000 shares to a consultant and 50,000 shares to T.R. Winston & Company LLC for acting as a placement agent of the Supplemental Debentures, valued at $0.58 million

The Company recognized a credit to stock compensation expense of approximately $1.75 million and an expense of $6.16 million, respectively, for the year ended December 31, 2012 and 2011.

A summary of restricted stock grant activity for the year ended December 31, 2012 is presented below:

| | Shares |
|---|---|
| Balance outstanding at December 31, 2011 | 2,340,235 |
| Granted | 2,984,181 |
| Vested | (986,769) |
| Expired/ cancelled | (2,606,937) |
| Balance outstanding at December 31, 2012 | 1,730,710 |

Total unrecognized compensation cost related to unvested stock grants was approximately $0.92 million as of December 31, 2012. The cost at December 31, 2012 is expected to be recognized over a weighted-average remaining service period of 3 years.

On November 15, Roger Parker retired from the Company as its chief executive officer. At the time of his retirement, Mr. Parker had been granted 1,350,000 shares of unvested common stock. As a result of his separation from the Company, it was deemed improbable that these shares would vest to Mr. Parker in his capacity as an employee of the Company due to the termination of employment; however, it was deemed probable that these shares will vest under his separation agreement. As a result, the Company reversed all of the compensation expense, in the amount of $6.75 million, associated with stock grants to Mr. Parker during his tenure as an employee, and recorded a consulting expense (in the amount of $3.59 million) related to the shares of stock that are expected to vest during the severance period of the separation agreement. The net difference of these two amounts resulted in a reduction in 2012 general and administrative expenses of $3.16 million.

*Other Compensation*

We sponsor a 401(k) savings plan. All regular full-time employees are eligible to participate. We make contributions to match employee contributions up to 5% of compensation deferred into the plan. The Company made cash contributions of $0.04 million in 2012.

**NOTE 14- SUBSEQUENT EVENTS**

In April 2013, we amended both our secured term loans and our 8% Senior Secured Convertible Debentures to extend their maturity dates to May 16, 2014. In consideration for the extended maturity date of both loans and the reduced interest rate and minimum loan payment under the secured term loans, the Company will be required to provide both Hexagon and the holders of our debentures an additional security interest in 15,000 acres (or 30,000 acres in aggregate) of our undeveloped acreage. Additionally, pursuant to the amendment to our secured term loan, Hexagon has agreed to (i) reduce our interest rate from 15% to 10% beginning retroactively with March 2013, (ii) permit us to make interest-only payments for March, April, May, and June, after which time the minimum secured term loan payment will be $0.23 million or $0.19 million, depending on our ability to consummate the sale of certain of our assets by July 1, 2013, and (iii) forbear from exercising its rights under the term loan credit agreements for any breach that may have occurred prior to the amendment. In addition, we are required under the amendment to use our reasonable best efforts to pursue certain transactions to improve our financial condition, including the aforementioned sale of certain of our assets, an equity offering or similar capital-raising transaction, one or more joint venture development agreements, and an engineering study of certain of our producing properties to ascertain possible operations to enhance production from those properties. Pursuant to the debenture amendment, the Company and the debenture holders have agreed to waive any breach under the debentures that may have occurred prior to the date of the amendment.

On April 16, 2013, the Company entered into an agreement with one of its existing Debenture holders to issue up to an additional $5.0 million in additional debentures with substantially the same terms to the existing 8% Secured Convertible Debentures. Under the terms of this agreement, $1.5 million of additional debentures will be issued on or before July 16, 2013. The funds associated with the initial issuance of debentures will be used by the Company for the drilling and development of certain properties, and for general corporate purposes.

We currently have $19.34 million outstanding under our term loans and $13.40 million outstanding under our debentures .

**NOTE 15- SUPPLEMENTAL OIL AND GAS RESERVE INFORMATION (UNAUDITED)**

The following table sets forth information for the years ended December 31, 2012 and 2011 with respect to changes in the Company's proved (i.e. proved developed and undeveloped) reserves:

| | Crude Oil (Bbls) | Natural Gas (Mcf) |
|---|---|---|
| December 31, 2010 | 692,388 | 308,579 |
| Purchase of reserves | - | - |
| Revisions of previous estimates | (268,718) | (44,919) |
| Extensions, discoveries | 266,000 | - |
| Sale of reserves | | |
| Production | (81,433) | (115,583) |
| December 31, 2011 | 608,237 | 148,077 |
| Purchase of reserves | 39,327 | - |
| Revisions of previous estimates (2) | (310,919) | 25,813 |
| Extensions, discoveries | 99,615 | 313,958 |
| Sale of reserves | - | - |

| | | |
|---|---|---|
| Production | (85,160) | (80,438) |
| December 31, 2012 | 351,100 | 407,410 |
| Proved Developed Reserves, included above: | | |
| Balance, December 31, 2010 | 277,669 | 308,579 |
| Balance, December 31, 2011 | 215,693 | 148,077 |
| Balance, December 31, 2012 | 213,306 | 186,017 |
| Proved Undeveloped Reserves, included above: | | |
| Balance, December 31, 2010 | 414,719 | - |
| Balance, December 31, 2011 | 392,545 | - |
| Balance, December 31, 2012 (2) | 137,555 | 221,314 |

As of December 31, 2012 and December 31, 2011, we had estimated proved reserves of 350,861 and 608,237 barrels of oil, respectively and 67,889 and 24,680 thousand cubic feet ("MCF") of natural gas, respectively. Our reserves are comprised of 84% and 93% crude oil and 16% and 7% natural gas on an energy equivalent basis, as of December 31, 2012 and December 31, 2011, respectively.

The following values for the December 31, 2012 and December 31, 2011 oil and gas reserves are based on the 12 month arithmetic average first of month price January through December 31; resulting in a natural gas price of $2.75 and $3.96 per MMBtu (NYMEX price), respectively, and crude oil price of $87.37 and $88.16 per barrel (West Texas Intermediate price), respectively. All prices are then further adjusted for transportation, quality and basis differentials.

The following summary sets forth the Company's future net cash flows relating to proved oil and gas:

| | For the Year Ended December 31, (in thousands) | |
|---|---|---|
| | **2012** | **2011** |
| Future oil and gas sales | $ 32,612 | $ 55,295 |
| Future production costs | (9,718) | (16,579) |
| Future development costs | (546) | (8,481) |
| Future income tax expense (1) | - | - |
| Future net cash flows | 22,348 | 30,235 |
| 10% annual discount | (6,926) | (10,221) |
| Standardized measure of discounted future net cash flows (2) | $ 15,422 | $ 20,014 |

(1) Our calculations of the standardized measure of discounted future net cash flows include the effect of estimated future income tax expenses for all years reported. We expect that all of our Net Operating Loss' ("NOL") will be realized within future carry forward periods. All of the Company's operations, and resulting NOLs, are attributable to our oil and gas assets. There were no taxes in any year as the tax basis and NOLs exceeded the future net revenue.

(2) The decrease in oil barrels of proved undeveloped reserves to 138 MBO as of the end of 2012 from 392 MBO as of the end of 2011, a decrease of 254 MBO or 65%, reflects the current uncertainty regarding whether the Company will have sufficient capital to support its current development plan. As of December 31, 2012, proved undeveloped reserves reflect the assumption that such reserves will be developed on a promoted basis of 25%, thereby reducing net PUD volumes that would otherwise by recoverable by 75%, and also effecting a corresponding decrease in the PV10 value. This change in assumptions is reflected in "Revisions of Previous Estimates in the above table, and also reflected in "Revisions of previous quantity estimates" in the table below. The elimination of the capital costs associated with the promoted interest assumption is reflected in the table below in the caption "Net changes in future development costs". The Company is working on alternative capital infusion plans that could allow it to maintain a higher working interest position in the undeveloped acreage locations. With the exception of a single well location, the Company currently holds a one hundred percent leasehold position in all the undrilled locations classified as proved undeveloped. A successful capital campaign could result in the Company materially increasing its proved undeveloped reserve position. .

The principle sources of change in the standardized measure of discounted future net cash flows are:

| | 2012 | 2011 |
|---|---|---|
| **Balance at beginning of period** | $ 20,014 | $ 23,595 |
| Sales of oil and gas, net | (4,656) | (5,342) |
| Net change in prices and production costs | (1,724) | 8,006 |
| Net change in future development costs (2) | 7,766 | - |
| Extensions and discoveries | 3,916 | 5,883 |
| Acquisition of reserves | 1,677 | - |
| Sale of reserves | - | - |
| Revisions of previous quantity estimates (2) | (15,031) | (14,804) |
| Previously estimated development costs incurred | 638 | - |
| Net change in income taxes | - | - |
| Accretion of discount | 2,001 | 2,360 |
| Other | 821 | 316 |
| **Balance at end of period** | **$ 15,422** | **$ 20,014** |

Revisions in 2012 of previous quantity estimates, reflect both the application of the assumption that PUD's will be developed in the future on a promoted bases, as well as other revisions of certain proven undeveloped well locations that were included in the reserve estimates dated December 31, 2011 .

A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are reservoir simulation, decline curve analysis, volumetric, material balance, advance production type curve matching, petro-physics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields.

**Exhibit 10.56**

**AMENDMENT TO**
**8% SENIOR SECURED CONVERTIBLE DEBENTURES DUE FEBRUARY 8, 2014**

This Amendment ("**Amendment**"), made as of April 15, 2013, by and between Recovery Energy, Inc., a Nevada corporation (the " **Company**"), and each holder identified on the signature page hereto (the " **Holders**"), amends that certain Securities Purchase Agreement, dated as of February 2, 2011, as amended on July 23, 2012 and August 7, 2012, between the Company and the Holders identified as original holders on the signature page hereto (the "**Original Purchase Agreement**"); that certain Securities Purchase Agreement, dated as of March 19, 2012, as amended on July 23, 2012 and August 7, 2012, between the Company and certain of the Original Holders as well as the Holders identified as supplemental holders on the signature page hereto (the "**Supplemental Purchase Agreement**" and together with the Original Purchase Agreement, the " **Purchase Agreements**"); those certain 8% Senior Secured Convertible Debentures due February 8, 2014, as amended on December 16, 2011, March 23, 2012 and July 23, 2012, issued pursuant to the Original Purchase Agreement (the "**Original Debentures**"); and those certain 8% Senior Secured Convertible Debentures due February 8, 2014, as amended on July 23, 2012, issued pursuant to the Supplemental Purchase Agreement (the " **Supplemental Debentures**" and together with the Original Debentures, the "**Debentures**").

**Recitals**

WHEREAS, the Company issued the Original Debentures pursuant to the Original Purchase Agreement and the Supplemental Debentures pursuant to the Supplemental Purchase Agreement;

WHEREAS, the Company and the Holders wish to amend the Debentures to (i) extend the maturity date from February 8, 2014 to May 16, 2014, and (ii) grant to the Holders an additional security interest in fifteen thousand (15,000) net acres of property not currently pledged as collateral under the Debentures, which shall include the Company's interest in the Sawyer property and the Lang Prospect, each being ¼ section tracts in the Weld County, Colorado (the "**Additional Collateral**"); and

WHEREAS, the Company and the Holders wish to waive certain provisions contained in the Debentures, and to clarify others.

NOW THEREFORE, in consideration of the promises and mutual covenants and obligations herein set forth and for other good and valuable consideration, the receipt, sufficiency and adequacy of which is hereby acknowledged, accepted and agreed to, the parties hereto, intending to be legally bound, hereby agree as follows:

**Agreement**

1. Maturity Date. The Company and the Holders hereby agree to extend the Maturity Date (as defined in the Debentures) from February 14, 2014 to May 16, 2014.

2. Grant of Lien on Additional Collateral. The Company hereby grants Holders a first priority lien in the Additional Collateral as security for the obligations of the Company under the Debentures, to be reflected in appropriate Security Documents (as defined in the Purchase Agreements). The Company agrees to use its reasonable best efforts to execute and record such Security Documents with respect to the lien by May 15, 2013.

3. Waiver. Each of the Company and each Holder hereby waives any actual or alleged breach of the terms of the Debentures or the Purchase Agreements that may have occurred prior to the date of this Amendment.

4. Clarification. Each of the Company and the Holder hereby agrees that pursuant to the original intent of the parties to the Debentures, no past or future payment by the Company of interest on the Debentures in shares of the Company's common stock shall constitute a Dilutive Issuance pursuant to Section 5(b) of the Debentures or a Preemptive Issuance pursuant to Section 9(j) of the Debentures.

5. Authority. Each Holder hereby represents and warrants that it is a party to one or both of the Purchase Agreements and has full power and authority to enter into this Amendment on the terms set forth herein.

6. Further Assurances. Holders shall from time to time execute such additional instruments and documents, take such additional actions, and give such further assurances as are or may be reasonable or necessary to implement this Amendment.

7. Binding Effect. The terms of this Amendment shall be binding upon and inure to the benefit of the parties hereto and their respective heirs, personal representatives, successors and assigns.

8. Reaffirmation of Debenture Terms. All terms of the Purchase Agreements, as previously amended, shall, except as amended hereby, remain in full force and effect, and are hereby ratified and confirmed.

9. Governing Law. This Amendment shall be governed by and construed and enforced in accordance with the internal laws of the State of New York, without regard for principles of conflict of laws thereof.

10. Counterparts. This Amendment may be executed in two or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

[*Signature page follows*]

**IN WITNESS WHEREOF**, the parties hereto have duly executed this Amendment effective as of the date first set forth above.

**COMPANY**

Recovery Energy, Inc.

By: /s/ A. Bradley Gabbard
Name: A. Bradley Gabbard
Title: President and Chief Financial Officer

**HOLDERS**

**Original Holders**

EZ Colony Partners, LLC, a Delaware limited liability company

/s/ Bryan Ezralow
Name: Bryan Ezralow as Trustee of the Bryan Ezralow 1994 Trust
Title: Managing General Partner

Jonathan & Nancy Glaser Family Trust DTD 12/16/1998 Jonathan M. Glaser and Nancy E. Glaser TTEES

/s/ Jonathan Glaser
Name: Jonathan Glaser
Title: Trustee

T.R. Winston & Company, LLC

/s/ John W. Galuchie, Jr.
Name: John W. Galuchie, Jr.
Title: President

Wallington Investment Holdings, Ltd.

/s/ Michael Khoury
Name: Michael Khoury
Title: Director

Steven B. Dunn and Laura Dunn Revocable Trust DTD 10/28/10, Steven B. Dunn & Laura Dunn TTEES

/s/ Steven B. Dunn
Name: Steven B. Dunn
Title: Trustee

**Supplemental Holders**

G. Tyler Runnels and Jasmine N. Runnels TTEES The Runnels Family Trust DTD 1-11-2000

/s/ G. Tyler Runnels
Name: G. Tyler Runnels
Title: Trustee

Ezralow Marital Trust u/t/d 01/12/2002

/s/ Marc Ezralow
Name: Marc Ezralow
Title: Trustee

Ezralow Family Trust u/t/d 12/09/1980

/s/ Marc Ezralow
Name: Marc Ezralow
Title: Trustee

EMSE, LLC,
a Delaware limited liability company

/s/ Marc Ezralow
Name: Marc Ezralow
Title: Manager

Elevado Investment Company, LLC,
a Delaware limited liability company

/s/ Marc Ezralow
Name: Marc Ezralow
Title: Trustee of the Ezralow Family Trust

**FOURTH AMENDMENT TO CREDIT AGREEMENT**
**(First Credit Agreement)**

This FOURTH AMENDMENT TO CREDIT AGREEMENT (this "Amendment"), dated effective as of March 1, 2013 (the "Effective Date"), is between Recovery Energy, Inc., a Nevada corporation ("Borrower"), and Hexagon, LLC, a Colorado limited liability company, formerly known as Hexagon Investments, LLC ("Lender").

RECITALS

A. Borrower and Lender have entered into a Credit Agreement, dated as of January 29, 2010 (as modified by (i) that certain Amendment to Promissory Note, dated December 29, 2010, (ii) that certain Second Amendment to Promissory Note, dated November 14, 2011, (iii) that certain Amendment to Credit Agreement dated March 15, 2012, (iv) that certain Second Amendment to Credit Agreement dated July 31, 2012, (v) that certain Third Amendment to Credit Agreement dated November 8, 2012, and as further amended, modified, supplemented, substituted or replaced, the " Credit Agreement"), providing for a term loan in the original principal amount of $4,500,000. Defined terms used herein and not defined herein shall have the meanings set forth in the Credit Agreement.

B. Borrower has asked Lender, and Lender has agreed to amend the terms and conditions of the Credit Agreement to extend the Maturity Date until May 16, 2014, subject to and as more fully set forth in this Amendment.

AGREEMENT

In consideration of the foregoing and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Borrower and Lender agree as follows:

1. Amendment to Credit Agreement. Effective as of the Effective Date and upon the terms and subject to the conditions set forth in this Amendment:

(a) Section 1.1 of the Credit Agreement is hereby amended by deleting "December 31, 2013" in the definition of "Maturity Date" and replacing it with "May 16, 2014".

(b) Section 2.1(d) of the Credit Agreement is hereby deleted in its entirety and replaced with the following:

> "(d) The Loan shall bear interest at a rate of 15.00% per annum for all periods prior to March 1, 2013. For all periods commencing March 1, 2013 and thereafter, the Loan shall bear interest at a rate of 10.00% per annum."

(c) Section 2.2 of the Credit Agreement is hereby deleted in its entirety and replaced with the following:

"**Section 2.2 Mandatory Prepayments**. Commencing with March, 2013, Borrower shall be required only to make payments of interest accruing under the Loan for the months of March, April, May and June 2013, each such interest payment to be due for a particular month on or before the last day of that month. Commencing with July, 2013, Borrower shall repay the Loan and any amounts due under the Other Credit Agreements (as defined below) with the greater of: (a) the sum of 100% of the Net Proceeds from the Oil and Gas Properties as defined in the Credit Agreement plus 100% of the Net Proceeds from the Oil and Gas Properties as defined in the Credit Agreement dated March 25, 2010 and the Credit Agreement dated April 14, 2010, each between Borrower and Lender (the "Other Credit Agreements"), and (b) either (i) $190,000 if a sale of the Palm Field (as described in Section 2.6(a) below) has closed on or before July 1, 2013 for a sale price of $4,500,000 or such other price as is mutually agreed by Borrower and Lender, or (ii) $225,000 if the condition in clause (i) is not satisfied. Such amounts paid under this Section 2.2 shall be applied to amounts due under the Loan and the amounts due under the Other Credit Agreements in a manner as determined by Lender in its sole discretion."

(d) Section 2.4 of the Credit Agreement is hereby amended by deleting "December 31, 2013" in the second line and replacing it with "May 16, 2014".

(e) Section 2.5 of the Credit Agreement is hereby amended by deleting Sections 2.5(b) and 2.5(c) in their entirety.

(f) A new Section 2.6 of the Credit Agreement is hereby added as follows:

"**Section 2.6 Additional Equity and Development Covenants**. Borrower agrees to use its reasonable best efforts to pursue the following transactions and other actions to improve the financial condition of Borrower:

(a) A sale for cash on or before July 1, 2013 of all of Borrower's oil and gas interests and wells in the Palm Field located in T. 17 N., R. 58 W., Banner County, Nebraska, for a price that is mutually agreed by Borrower and Lender. All of the proceeds of any such sale shall be paid to Lender and shall reduce the amount outstanding under the Credit Agreement dated March 25, 2010 and, to the extent the proceeds exceed the amount outstanding under such Credit Agreement, the amounts due under this Credit Agreement or the Credit Agreement dated April 14, 2010, the allocation of which Lender shall determine in its sole discretion.

(b) An equity offering or other transaction to provide additional equity for the Borrower, through an investment banking firm deemed by Borrower in its reasonable discretion to have suitable qualifications for such transaction.

(c) One or more joint venture development agreements to develop the Borrower's oil and gas assets with a financial or oil and gas industry entity with suitable financial strength and technical expertise for the successful implementation of such development agreements.

(d) Engineering study of Borrower's producing oil and gas properties in the Wilke and State Line Fields (in Banner and Kimball Counties, Nebraska and Laramie County, Wyoming) to ascertain possible operations to enhance production from such properties.

(g) A new Section 2.7 of the Credit Agreement is hereby added as follows:

"**Section 2.7 Additional Collateral**. Promptly, and in no event more than 10 business days following the execution of this Amendment, Borrower shall execute and deliver an Amendment to the Mortgages, in form provided by Lender's counsel, adding to the collateral covered by the Mortgages 15,171 net acres of undeveloped leases owned by Borrower in the Pine Bluffs Prospect, Banner and Kimball Counties, Nebraska and Laramie County, Wyoming."

2. Other Agreements. (a) Borrower and Lender agree that all of the Loan Documents are hereby amended to reflect the amendments set forth herein and that no further amendments to any Loan Documents are required to reflect the foregoing; and (b) all references in any document to "Credit Agreement" or any "Loan Document" shall refer to the Credit Agreement or any such Loan Document, as amended pursuant to this Amendment.

3. Representations and Warranties. Borrower hereby certifies to Lender that as of the date of this Amendment and as of the Effective Date (taking into consideration the transactions contemplated by this Amendment) all of Borrower's representations and warranties contained in the Credit Agreement and each of the Loan Documents are true, accurate and complete in all material respects. Without limiting the generality of the foregoing, Borrower represents and warrants that (i) the execution and delivery of this Amendment has been authorized by all necessary action on the part of Borrower, (ii) the person executing this Amendment on behalf of Borrower is duly authorized to do so, and (iii) this Amendment constitutes the legal, valid, binding and enforceable obligation of Borrower.

4. Additional Documents. Borrower shall execute and deliver, and shall cause to be executed and delivered, to Lender at any time and from time to time such documents and instruments, including without limitation additional amendments to the Credit Agreement and the Loan Documents, as Lender may reasonably request to confirm and carry out the transactions contemplated hereby or by any other Loan Documents executed in connection herewith.

5. Continuation of the Credit Agreement and Loan Documents. Except as specified in this Amendment, the provisions of the Credit Agreement and the Loan Documents shall remain in full force and effect, and if there is a conflict between the terms of this Amendment and those of the Credit Agreement or the Loan Documents, the terms of this Amendment shall control. This Amendment is a Loan Document.

6. Ratification and Reaffirmation of Obligations by Borrower. Borrower hereby (a) ratifies and confirms all of its Obligations under the Credit Agreement and each of the other Loan Documents, and acknowledges and agrees that such Obligations remain in full force and effect, and (b) ratifies, reaffirms and reapproves in favor of Lender the terms and provisions of the Credit Agreement and each of the other Loan Documents, including (without limitation), its pledges and other grants of Liens and security interests pursuant to the Loan Documents.

7. Release and Indemnification.

(a) Borrower hereby fully, finally, and forever releases and discharges Lender, and its successors, assigns, directors, officers, employees, agents and representatives, from any and all causes of action, claims, debts, demands and liabilities, of whatever kind or nature, in law or equity, of Borrower, whether now known or unknown to Borrower in respect of (i) the Obligations under the Credit Agreement and each of the other Loan Documents or (ii) the actions or omissions of Lender in any manner related to the Obligations under the Credit Agreement and each of the other Loan Documents; *provided* that this Section shall only apply to and be effective with respect to events or circumstances existing or occurring prior to and including the date of this Amendment.

(b) Without limiting Section 7.3 of the Credit Agreement, Borrower hereby agrees to indemnify, defend, and hold harmless Lender and its successors, assigns, directors, officers, employees, agents and representatives (each an " Indemnified Party" and collectively the "Indemnified Parties") from and against any and all accounts, covenants, agreements, obligations, claims, debts, liabilities, offsets, demands, costs, expenses, actions or causes of action of every nature, character and description, whether arising at law or equity or under statute, regulation or otherwise, and whether liquidated or unliquidated, contingent or noncontingent, known or unknown, suspected or unsuspected (" Claims"), arising from or made under any legal theory, which any of Indemnified Parties may incur as a direct or indirect consequence of or in relation to any acts or omissions of Borrower arising from or relating to any of: (i) the Credit Agreement; (ii) the Loan Documents; (iii) this Amendment; or (iv) any documents executed by Borrower in connection with this Amendment. Should any Indemnified Party incur any such Claims, or defense of or response to any Claims or demand related thereto, the amount thereof, including costs, expenses and attorneys' fees, shall be added to the amounts due under the Loan Documents, and shall be secured by any and all liens created under and pursuant to the Loan Documents. This indemnity shall survive until the Obligations have been indefeasibly paid in full and the termination, release or discharge of Borrower. To the extent permissible under applicable law, this indemnity shall not limit any other rights of indemnification, subrogation or assignment, whether explicit, implied, legal or equitable, that any Indemnified Party may have.

8. Forbearance. Lender hereby agrees to forbear from exercising its rights and remedies under the Credit Agreement and the other Loan Documents arising as a result of any actual or alleged breach of the terms of the Credit Agreement or other Loan Documents that may have occurred prior to the date of this Amendment (a "Forbearance Default"); provided, however, that upon the occurrence of any Event of Default other than a Forbearance Default, Lender shall be entitled to exercise any and all of their rights and remedies under the Credit Agreement, the other Loan Documents and applicable law, without further notice other than as required therein.

9. No Waiver. This Amendment does not constitute a waiver by Lender of Borrower's compliance with any covenants, or a waiver of any Defaults or Events of Default, under the Credit Agreement or any of the Loan Documents, and shall not entitle the Borrower to any amendments or waivers in the future.

10. Miscellaneous. Article VIII of the Credit Agreement is hereby incorporated by reference into this Amendment.

11. Condition to Effectiveness. The effectiveness of this Amendment is conditioned upon Borrower obtaining from all of the holders of its 8% Senior Secured Debentures due February 14, 2014 extensions of the due date of such debentures until a date not earlier than May 16, 2014. Borrower has provided Lender with evidence of its satisfaction of this condition, and Lender's execution of this Amendment shall evidence Lender's agreement that such condition has been satisfied and that such evidence provided by Borrower is satisfactory to Lender.

[Signature Pages Follow]

Borrower and Lender have executed this Fourth Amendment to Credit Agreement on April 15, 2013, effective as of the Effective Date first above written.

| | |
|---|---|
| HEXAGON, LLC<br>By: Hexagon, Inc., its Manager | RECOVERY ENERGY, INC. |
| By: /s/ Brian Fleishmann<br>Brian Fleischmann<br>Executive Vice President | By: /s/ A. Bradley Gabbard<br>A. Bradley Gabbard<br>Chief Financial Officer |

**FOURTH AMENDMENT TO CREDIT AGREEMENT**
**(Second Credit Agreement)**

This FOURTH AMENDMENT TO CREDIT AGREEMENT (this "Amendment"), dated effective as of March 1, 2013 (the "Effective Date"), is between Recovery Energy, Inc., a Nevada corporation ("Borrower"), and Hexagon, LLC, a Colorado limited liability company, formerly known as Hexagon Investments, LLC ("Lender").

RECITALS

A. Borrower and Lender have entered into a Credit Agreement, dated as of March 25, 2010 (as modified by (i) that certain Amendment to Promissory Note, dated December 29, 2010, (ii) that certain Second Amendment to Promissory Note, dated November 14, 2011, (iii) that certain Amendment to Credit Agreement dated March 15, 2012, (iv) that certain Second Amendment to Credit Agreement dated July 31, 2012, (v) that certain Third Amendment to Credit Agreement dated November 8, 2012, and as further amended, modified, supplemented, substituted or replaced, the " Credit Agreement"), providing for a term loan in the original principal amount of $6,000,000. Defined terms used herein and not defined herein shall have the meanings set forth in the Credit Agreement.

B. Borrower has asked Lender, and Lender has agreed to amend the terms and conditions of the Credit Agreement to extend the Maturity Date until May 16, 2014, subject to and as more fully set forth in this Amendment.

AGREEMENT

In consideration of the foregoing and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Borrower and Lender agree as follows:

1. Amendment to Credit Agreement. Effective as of the Effective Date and upon the terms and subject to the conditions set forth in this Amendment:

(a) Section 1.1 of the Credit Agreement is hereby amended by deleting "December 31, 2013" in the definition of "Maturity Date" and replacing it with "May 16, 2014".

(b) Section 2.1(c) of the Credit Agreement is hereby deleted in its entirety and replaced with the following:

"(c) The Loan shall bear interest at a rate of 15.00% per annum for all periods prior to March 1, 2013. For all periods commencing March 1, 2013 and thereafter, the Loan shall bear interest at a rate of 10.00% per annum."

(c) Section 2.2 of the Credit Agreement is hereby deleted in its entirety and replaced with the following:

> "**Section 2.2 Mandatory Prepayments**. Commencing with March, 2013, Borrower shall be required only to make payments of interest accruing under the Loan for the months of March, April, May and June 2013, each such interest payment to be due for a particular month on or before the last day of that month. Commencing with July, 2013, Borrower shall repay the Loan and any amounts due under the Other Credit Agreements (as defined below) with the greater of: (a) the sum of 100% of the Net Proceeds from the Oil and Gas Properties as defined in the Credit Agreement plus 100% of the Net Proceeds from the Oil and Gas Properties as defined in the Credit Agreement dated January 29, 2010 and the Credit Agreement dated April 14, 2010, each between Borrower and Lender (the " Other Credit Agreements"), and (b) either (i) $190,000 if a sale of the Palm Field (as described in Section 2.6(a) below) has closed on or before July 1, 2013 for a sale price of $4,500,000 or such other price as is mutually agreed by Borrower and Lender, or (ii) $225,000 if the condition in clause (i) is not satisfied. Such amounts paid under this Section 2.2 shall be applied to amounts due under the Loan and the amounts due under the Other Credit Agreements in a manner as determined by Lender in its sole discretion."

(d) Section 2.4 of the Credit Agreement is hereby amended by deleting "December 31, 2013" in the second line and replacing it with "May 16, 2014".

(e) Section 2.5 of the Credit Agreement is hereby amended by deleting Sections 2.5(b) and 2.5(c) in their entirety.

(f) A new Section 2.6 of the Credit Agreement is hereby added as follows:

"**Section 2.6 Additional Equity and Development Covenants**. Borrower agrees to use its reasonable best efforts to pursue the following transactions and other actions to improve the financial condition of Borrower:

(a) A sale for cash on or before July 1, 2013 of all of Borrower's oil and gas interests and wells in the Palm Field located in T. 17 N., R. 58 W., Banner County, Nebraska, for a price that is mutually agreed by Borrower and Lender. All of the proceeds of any such sale shall be paid to Lender and shall reduce the amount outstanding under the Loan and, to the extent the proceeds exceed the amount outstanding under the Loan, the amounts due under the Other Credit Agreements, the allocation of which Lender shall determine in its sole discretion.

(b) An equity offering or other transaction to provide additional equity for the Borrower, through an investment banking firm deemed by Borrower in its reasonable discretion to have suitable qualifications for such transaction.

(c) One or more joint venture development agreements to develop the Borrower's oil and gas assets with a financial or oil and gas industry entity with suitable financial strength and technical expertise for the successful implementation of such development agreements.

(d) Engineering study of Borrower's producing oil and gas properties in the Wilke and State Line Fields (in Banner and Kimball Counties, Nebraska and Laramie County, Wyoming) to ascertain possible operations to enhance production from such properties.

2. Other Agreements. (a) Borrower and Lender agree that all of the Loan Documents are hereby amended to reflect the amendments set forth herein and that no further amendments to any Loan Documents are required to reflect the foregoing; and (b) all references in any document to "Credit Agreement" or any "Loan Document" shall refer to the Credit Agreement or any such Loan Document, as amended pursuant to this Amendment.

3. Representations and Warranties. Borrower hereby certifies to Lender that as of the date of this Amendment and as of the Effective Date (taking into consideration the transactions contemplated by this Amendment) all of Borrower's representations and warranties contained in the Credit Agreement and each of the Loan Documents are true, accurate and complete in all material respects. Without limiting the generality of the foregoing, Borrower represents and warrants that (i) the execution and delivery of this Amendment has been authorized by all necessary action on the part of Borrower, (ii) the person executing this Amendment on behalf of Borrower is duly authorized to do so, and (iii) this Amendment constitutes the legal, valid, binding and enforceable obligation of Borrower.

4. Additional Documents. Borrower shall execute and deliver, and shall cause to be executed and delivered, to Lender at any time and from time to time such documents and instruments, including without limitation additional amendments to the Credit Agreement and the Loan Documents, as Lender may reasonably request to confirm and carry out the transactions contemplated hereby or by any other Loan Documents executed in connection herewith.

5. Continuation of the Credit Agreement and Loan Documents. Except as specified in this Amendment, the provisions of the Credit Agreement and the Loan Documents shall remain in full force and effect, and if there is a conflict between the terms of this Amendment and those of the Credit Agreement or the Loan Documents, the terms of this Amendment shall control. This Amendment is a Loan Document.

6. Ratification and Reaffirmation of Obligations by Borrower. Borrower hereby (a) ratifies and confirms all of its Obligations under the Credit Agreement and each of the other Loan Documents, and acknowledges and agrees that such Obligations remain in full force and effect, and (b) ratifies, reaffirms and reapproves in favor of Lender the terms and provisions of the Credit Agreement and each of the other Loan Documents, including (without limitation), its pledges and other grants of Liens and security interests pursuant to the Loan Documents.

7. Release and Indemnification.

(a) Borrower hereby fully, finally, and forever releases and discharges Lender, and its successors, assigns, directors, officers, employees, agents and representatives, from any and all causes of action, claims, debts, demands and liabilities, of whatever kind or nature, in law or equity, of Borrower, whether now known or unknown to Borrower in respect of (i) the Obligations under the Credit Agreement and each of the other Loan Documents or (ii) the actions or omissions of Lender in any manner related to the Obligations under the Credit Agreement and each of the other Loan Documents; *provided* that this Section shall only apply to and be effective with respect to events or circumstances existing or occurring prior to and including the date of this Amendment.

(b) Without limiting Section 7.3 of the Credit Agreement, Borrower hereby agrees to indemnify, defend, and hold harmless Lender and its successors, assigns, directors, officers, employees, agents and representatives (each an "Indemnified Party" and collectively the "Indemnified Parties") from and against any and all accounts, covenants, agreements, obligations, claims, debts, liabilities, offsets, demands, costs, expenses, actions or causes of action of every nature, character and description, whether arising at law or equity or under statute, regulation or otherwise, and whether liquidated or unliquidated, contingent or noncontingent, known or unknown, suspected or unsuspected ("Claims"), arising from or made under any legal theory, which any of Indemnified Parties may incur as a direct or indirect consequence of or in relation to any acts or omissions of Borrower arising from or relating to any of: (i) the Credit Agreement; (ii) the Loan Documents; (iii) this Amendment; or (iv) any documents executed by Borrower in connection with this Amendment. Should any Indemnified Party incur any such Claims, or defense of or response to any Claims or demand related thereto, the amount thereof, including costs, expenses and attorneys' fees, shall be added to the amounts due under the Loan Documents, and shall be secured by any and all liens created under and pursuant to the Loan Documents. This indemnity shall survive until the Obligations have been indefeasibly paid in full and the termination, release or discharge of Borrower. To the extent permissible under applicable law, this indemnity shall not limit any other rights of indemnification, subrogation or assignment, whether explicit, implied, legal or equitable, that any Indemnified Party may have.

8. Forbearance. Lender hereby agrees to forbear from exercising its rights and remedies under the Credit Agreement and the other Loan Documents arising as a result of any actual or alleged breach of the terms of the Credit Agreement or other Loan Documents that may have occurred prior to the date of this Amendment (a "Forbearance Default"); provided, however, that upon the occurrence of any Event of Default other than a Forbearance Default, Lender shall be entitled to exercise any and all of their rights and remedies under the Credit Agreement, the other Loan Documents and applicable law, without further notice other than as required therein.

9. No Waiver. This Amendment does not constitute a waiver by Lender of Borrower's compliance with any covenants, or a waiver of any Defaults or Events of Default, under the Credit Agreement or any of the Loan Documents, and shall not entitle the Borrower to any amendments or waivers in the future.

10. Miscellaneous. Article VIII of the Credit Agreement is hereby incorporated by reference into this Amendment.

11. Condition to Effectiveness. The effectiveness of this Amendment is conditioned upon Borrower obtaining from all of the holders of its 8% Senior Secured Debentures due February 14, 2014 extensions of the due date of such debentures until a date not earlier than May 16, 2014. Borrower has provided Lender with evidence of its satisfaction of this condition, and Lender's execution of this Amendment shall evidence Lender's agreement that such condition has been satisfied and that such evidence provided by Borrower is satisfactory to Lender.

[Signature Pages Follow]

Borrower and Lender have executed this Fourth Amendment to Credit Agreement on April 15, 2013, effective as of the Effective Date first above written.

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|---|---|
| HEXAGON, LLC<br>By: Hexagon, Inc., its Manager | RECOVERY ENERGY, INC. |
| By:/s/ Brian Fleishmann<br>Brian Fleischmann<br>Executive Vice President | By:/s/ A. Bradley Gabbard<br>A. Bradley Gabbard<br>Chief Financial Officer |

**Exhibit 10.59**

**FOURTH AMENDMENT TO CREDIT AGREEMENT**
**(Third Credit Agreement)**

This FOURTH AMENDMENT TO CREDIT AGREEMENT (this "Amendment"), dated effective as of March 1, 2013 (the "Effective Date"), is between Recovery Energy, Inc., a Nevada corporation ("Borrower"), and Hexagon, LLC, a Colorado limited liability company, formerly known as Hexagon Investments, LLC ("Lender").

RECITALS

A. Borrower and Lender have entered into a Credit Agreement, dated as of April 14, 2010 (as modified by (i) that certain Amendment to Promissory Note, dated December 29, 2010, (ii) that certain Second Amendment to Promissory Note, dated November 14, 2011, (iii) that certain Amendment to Credit Agreement dated March 15, 2012, (iv) that certain Second Amendment to Credit Agreement dated July 31, 2012, (v) that certain Third Amendment to Credit Agreement dated November 8, 2012, and as further amended, modified, supplemented, substituted or replaced, the " Credit Agreement"), providing for a term loan in the original principal amount of $15,000,000. Defined terms used herein and not defined herein shall have the meanings set forth in the Credit Agreement.

B. Borrower has asked Lender, and Lender has agreed to amend the terms and conditions of the Credit Agreement to extend the Maturity Date until May 16, 2014, subject to and as more fully set forth in this Amendment.

AGREEMENT

In consideration of the foregoing and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, Borrower and Lender agree as follows:

1. Amendment to Credit Agreement. Effective as of the Effective Date and upon the terms and subject to the conditions set forth in this Amendment:

(a) Section 1.1 of the Credit Agreement is hereby amended by deleting "December 31, 2013" in the definition of "Maturity Date" and replacing it with "May 16, 2014".

(b) Section 2.1(c) of the Credit Agreement is hereby deleted in its entirety and replaced with the following:

"(c) The Loan shall bear interest at a rate of 15.00% per annum for all periods prior to March 1, 2013. For all periods commencing March 1, 2013 and thereafter, the Loan shall bear interest at a rate of 10.00% per annum."

(c) Section 2.2 of the Credit Agreement is hereby deleted in its entirety and replaced with the following:

"**Section 2.2 Mandatory Prepayments**. Commencing with March, 2013, Borrower shall be required only to make payments of interest accruing under the Loan for the months of March, April, May and June 2013, each such interest payment to be due for a particular month on or before the last day of that month. Commencing with July, 2013, Borrower shall repay the Loan and any amounts due under the Other Credit Agreements (as defined below) with the greater of: (a) the sum of 100% of the Net Proceeds from the Oil and Gas Properties as defined in the Credit Agreement plus 100% of the Net Proceeds from the Oil and Gas Properties as defined in the Credit Agreement dated January 29, 2010 and the Credit Agreement dated March 25, 2010, each between Borrower and Lender (the " Other Credit Agreements"), and (b) either (i) $190,000 if a sale of the Palm Field (as described in Section 2.6(a) below) has closed on or before July 1, 2013 for a sale price of $4,500,000 or such other price as is mutually agreed by Borrower and Lender, or (ii) $225,000 if the condition in clause (i) is not satisfied. Such amounts paid under this Section 2.2 shall be applied to amounts due under the Loan and the amounts due under the Other Credit Agreements in a manner as determined by Lender in its sole discretion."

(d) Section 2.4 of the Credit Agreement is hereby amended by deleting "December 31, 2013" in the second line and replacing it with "May 16, 2014".

(e) Section 2.5 of the Credit Agreement is hereby amended by deleting Sections 2.5(b) and 2.5(c) in their entirety.

(f) A new Section 2.6 of the Credit Agreement is hereby added as follows:

"**Section 2.6 Additional Equity and Development Covenants** . Borrower agrees to use its reasonable best efforts to pursue the following transactions and other actions to improve the financial condition of Borrower:

(a) A sale for cash on or before July 1, 2013 of all of Borrower's oil and gas interests and wells in the Palm Field located in T. 17 N., R. 58 W., Banner County, Nebraska, for a price that is mutually agreed by Borrower and Lender. All of the proceeds of any such sale shall be paid to Lender and shall reduce the amount outstanding under the Credit Agreement dated March 25, 2010 and, to the extent the proceeds exceed the amount outstanding under such Credit Agreement, the amounts due under this Credit Agreement or the Credit Agreement dated January 29, 2010, the allocation of which Lender shall determine in its sole discretion.

(b) An equity offering or other transaction to provide additional equity for the Borrower, through an investment banking firm deemed by Borrower in its reasonable discretion to have suitable qualifications for such transaction.

(c) One or more joint venture development agreements to develop the Borrower's oil and gas assets with a financial or oil and gas industry entity with suitable financial strength and technical expertise for the successful implementation of such development agreements.

(d) Engineering study of Borrower's producing oil and gas properties in the Wilke and State Line Fields (in Banner and Kimball Counties, Nebraska and Laramie County, Wyoming) to ascertain possible operations to enhance production from such properties.

2. Other Agreements. (a) Borrower and Lender agree that all of the Loan Documents are hereby amended to reflect the amendments set forth herein and that no further amendments to any Loan Documents are required to reflect the foregoing; and (b) all references in any document to "Credit Agreement" or any "Loan Document" shall refer to the Credit Agreement or any such Loan Document, as amended pursuant to this Amendment.

3. Representations and Warranties. Borrower hereby certifies to Lender that as of the date of this Amendment and as of the Effective Date (taking into consideration the transactions contemplated by this Amendment) all of Borrower's representations and warranties contained in the Credit Agreement and each of the Loan Documents are true, accurate and complete in all material respects. Without limiting the generality of the foregoing, Borrower represents and warrants that (i) the execution and delivery of this Amendment has been authorized by all necessary action on the part of Borrower, (ii) the person executing this Amendment on behalf of Borrower is duly authorized to do so, and (iii) this Amendment constitutes the legal, valid, binding and enforceable obligation of Borrower.

4. Additional Documents. Borrower shall execute and deliver, and shall cause to be executed and delivered, to Lender at any time and from time to time such documents and instruments, including without limitation additional amendments to the Credit Agreement and the Loan Documents, as Lender may reasonably request to confirm and carry out the transactions contemplated hereby or by any other Loan Documents executed in connection herewith.

5. Continuation of the Credit Agreement and Loan Documents. Except as specified in this Amendment, the provisions of the Credit Agreement and the Loan Documents shall remain in full force and effect, and if there is a conflict between the terms of this Amendment and those of the Credit Agreement or the Loan Documents, the terms of this Amendment shall control. This Amendment is a Loan Document.

6. Ratification and Reaffirmation of Obligations by Borrower. Borrower hereby (a) ratifies and confirms all of its Obligations under the Credit Agreement and each of the other Loan Documents, and acknowledges and agrees that such Obligations remain in full force and effect, and (b) ratifies, reaffirms and reapproves in favor of Lender the terms and provisions of the Credit Agreement and each of the other Loan Documents, including (without limitation), its pledges and other grants of Liens and security interests pursuant to the Loan Documents.

7. Release and Indemnification.

(a) Borrower hereby fully, finally, and forever releases and discharges Lender, and its successors, assigns, directors, officers, employees, agents and representatives, from any and all causes of action, claims, debts, demands and liabilities, of whatever kind or nature, in law or equity, of Borrower, whether now known or unknown to Borrower in respect of (i) the Obligations under the Credit Agreement and each of the other Loan Documents or (ii) the actions or omissions of Lender in any manner related to the Obligations under the Credit Agreement and each of the other Loan Documents; *provided* that this Section shall only apply to and be effective with respect to events or circumstances existing or occurring prior to and including the date of this Amendment.

(b) Without limiting Section 7.3 of the Credit Agreement, Borrower hereby agrees to indemnify, defend, and hold harmless Lender and its successors, assigns, directors, officers, employees, agents and representatives (each an " Indemnified Party" and collectively the "Indemnified Parties") from and against any and all accounts, covenants, agreements, obligations, claims, debts, liabilities, offsets, demands, costs, expenses, actions or causes of action of every nature, character and description, whether arising at law or equity or under statute, regulation or otherwise, and whether liquidated or unliquidated, contingent or noncontingent, known or unknown, suspected or unsuspected (" Claims"), arising from or made under any legal theory, which any of Indemnified Parties may incur as a direct or indirect consequence of or in relation to any acts or omissions of Borrower arising from or relating to any of: (i) the Credit Agreement; (ii) the Loan Documents; (iii) this Amendment; or (iv) any documents executed by Borrower in connection with this Amendment. Should any Indemnified Party incur any such Claims, or defense of or response to any Claims or demand related thereto, the amount thereof, including costs, expenses and attorneys' fees, shall be added to the amounts due under the Loan Documents, and shall be secured by any and all liens created under and pursuant to the Loan Documents. This indemnity shall survive until the Obligations have been indefeasibly paid in full and the termination, release or discharge of Borrower. To the extent permissible under applicable law, this indemnity shall not limit any other rights of indemnification, subrogation or assignment, whether explicit, implied, legal or equitable, that any Indemnified Party may have.

8. Forbearance. Lender hereby agrees to forbear from exercising its rights and remedies under the Credit Agreement and the other Loan Documents arising as a result of any actual or alleged breach of the terms of the Credit Agreement or other Loan Documents that may have occurred prior to the date of this Amendment (a "Forbearance Default"); provided, however, that upon the occurrence of any Event of Default other than a Forbearance Default, Lender shall be entitled to exercise any and all of their rights and remedies under the Credit Agreement, the other Loan Documents and applicable law, without further notice other than as required therein.

9. No Waiver. This Amendment does not constitute a waiver by Lender of Borrower's compliance with any covenants, or a waiver of any Defaults or Events of Default, under the Credit Agreement or any of the Loan Documents, and shall not entitle the Borrower to any amendments or waivers in the future.

10. Miscellaneous. Article VIII of the Credit Agreement is hereby incorporated by reference into this Amendment.

11. Condition to Effectiveness. The effectiveness of this Amendment is conditioned upon Borrower obtaining from all of the holders of its 8% Senior Secured Debentures due February 14, 2014 extensions of the due date of such debentures until a date not earlier than May 16, 2014. Borrower has provided Lender with evidence of its satisfaction of this condition, and Lender's execution of this Amendment shall evidence Lender's agreement that such condition has been satisfied and that such evidence provided by Borrower is satisfactory to Lender.

[Signature Pages Follow]

Borrower and Lender have executed this Fourth Amendment to Credit Agreement on April __, 2013, effective as of the Effective Date first above written.

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|---|---|
| HEXAGON, LLC<br>By: Hexagon, Inc., its Manager | RECOVERY ENERGY, INC. |
| By: /s/ Brian Fleishmann<br>Brian Fleischmann<br>Executive Vice President | By: /s/ A. Bradley Gabbard<br>A. Bradley Gabbard<br>Chief Financial Officer |

**Exhibit 23.1**

**CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

We consent to the incorporation by reference in the Registration Statement on Form S-3 (333-169070) and the Registration Statement on Form S-8 (Registration No. 333-185122) of Recovery Energy, Inc. of our report dated April 17, 2013, relating to our audit of the consolidated financial statements included in the Annual Report on Form 10-K of Recovery Energy, Inc. for the year ended December 31, 2012.

***/s/ HEIN & ASSOCIATES LLP***

Denver, Colorado
April 17, 2013

**Exhibit 23.2**

RALPH E. DAVIS
ASSOCIATES, INC.

April 17, 2013

Recovery Energy, Inc.
1900 Grant Street, Suite 720
Denver, CO 80203
Attention: A. Bradley Gabbard

Dear Mr. Gabbard:

Ralph E. Davis Associates, Inc. here by consents to the reference to our firm in the form and context in which they appear in the Annual Report on Form 10-K of Recovery Energy, Inc. for the year ended December 31, 2012 (the "Annual Report"). We hereby further consent to the inclusion in the Annual Report of estimates of oil and gas reserves contained in our report dated April 3, 2013, and to the inclusion of our report as an exhibit to the Annual Report and in all current and future registration statements of the Company that incorporate by reference such Annual Report.

Sincerely,

**RALPH E. DAVIS ASSOCIATES, INC.**

/s/ Allen C. Barron
Allen C Barron, P.E.
President

1717 St. James Place, Suite 460 Houston, Texas 77056 Office 713-622-8955 Fax 713-626-3664 www.ralphedavis.com
*Worldwide Energy Consultants Since 1924*

**Exhibit 31.1**

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER**
**PURSUANT TO**
**18 U.S.C. SECTION 1350,**
**AS ADOPTED PURSUANT TO SECTION 302 OF**
**THE SARBANES-OXLEY ACT OF 2002**

I, W. Phillip Marcum, certify that:

1. I have reviewed this Form 10-K of Recovery Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involved management or other employees who have a significant role in the registrant's internal control over financial reporting.

By: */s/ W. Phillip Marcum*
W. Phillip Marcum
Chief Executive Officer

April 17, 2013

**Exhibit 31.2**

**CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 302 OF
THE SARBANES-OXLEY ACT OF 2002**

I, A. Bradley Gabbard, certify that:

1. I have reviewed this Form 10-K of Recovery Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involved management or other employees who have a significant role in the registrant's internal control over financial reporting.

By: */s/ A. Bradley Gabbard*
A. Bradley Gabbard
Chief Financial Officer

April 17, 2013

**Exhibit 32.1**

**OFFICER'S CERTIFICATION**
**PURSUANT TO**
**SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**
**(18 U.S.C 1350)**

The undersigned W. Phillip Marcum, the Chief Executive Officer of Recovery Energy, Inc., (the "Corporation"), in connection with the Corporation's Yearly Report on Form 10-K for the year ended December 31, 2012, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), does hereby represent, warrant and certify pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, as amended, that, to the best of his knowledge:

1. The Report is in full compliance with the reporting requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operation of the Corporation.

By: /s/ W. Phillip Marcum
W. Phillip Marcum
Chief Executive Officer

April 17, 2013

**Exhibit 32.2**

**OFFICER'S CERTIFICATION**
**PURSUANT TO**
**SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**
**(18 U.S.C 1350)**

The undersigned A. Bradley Gabbard, the Chief Financial Officer of Recovery Energy, Inc., (the "Corporation"), in connection with the Corporation's Yearly Report on Form 10-K for the year ended December 31, 2012, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), does hereby represent, warrant and certify pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, as amended, that, to the best of his knowledge:

1. The Report is in full compliance with the reporting requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operation of the Corporation.

By: /s/ A. Bradley Gabbard
A. Bradley Gabbard
Chief Financial Officer

April 17, 2013

Exhibit 99.1

**RECOVERY ENERGY COMPANY, INC.**

**ESTIMATED RESERVES**
**AND**
**FUTURE NET REVENUE**

**PROVED RESERVES**
**AS OF DECEMBER 31, 2012**

**RALPH E. DAVIS ASSOCIATES, INC.**
**HOUSTON, TEXAS**

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## RECOVERY ENERGY COMPANY, INC.

## Table of Contents

# Engineering Letter

RALPH E. DAVIS
ASSOCIATES, INC.

April 3, 2013

Recovery Energy Company, Inc.
1900 Grant Street, Suite 720
Denver, Colorado 80203

Attn: Mr. A. Brad Gabbard
President & CFO

**Re: Estimated Reserves and Future Net Revenue,**
**Recovery Energy Company, Inc.**
**As of December 31, 2012**

Gentlemen:

At the request of Recovery Energy Company, Inc. ("Recovery"), the firm of Ralph E. Davis Associates, Inc. ("Davis") of Houston, Texas has prepared an estimate of the oil and natural gas reserves and future net revenue associated with specific leaseholds in which Recovery owns certain interests. The purpose of this report is to present a summary of the Proved Developed Producing and Undeveloped reserves, future production and income attributable to the subject interests as of the effective date of this report, December 31, 2012.

Davis has reviewed 100% of Recovery's proved developed and undeveloped properties located in the Denver Julesberg Basin of the United States. It is our opinion that these properties represent all of Recovery's assets that may be classified as proved as per the Securities and Exchange Commission directives as detailed later in this report.

The reserves associated with this review have been classified in accordance with the definitions of the Securities and Exchange Commission as found in Part 210—Form and Content of and Requirements for Financial Statements, Securities Act of 1933, Securities Exchange Act of 1934, Public Utility Holding Company Act of 1935, Investment Company Act of 1940, Investment Advisers Act of 1940, and Energy Policy and Conservation Act of 1975, under Rules of General Application
§ 210.4-10 Financial accounting and reporting for oil and gas producing activities pursuant to the Federal securities laws and the Energy Policy and Conservation Act of 1975. A summation of these definitions is included as a portion of this letter.

We have also estimated the future net revenue and discounted present value associated with these reserves as of December 31, 2012 utilizing a scenario of non-escalated product prices as well as non-escalated costs of operations, i.e., prices and costs were not escalated above current values as detailed later in this report. The present value is presented for your information and should not be construed as an estimate of the fair market value.

1717 St. James Place, Suite 460 Houston, Texas 77056 Office 713-622-8955 Fax 713-626-3664 www.ralphedavis.com
Worldwide Energy Consultants Since 1924

The results of our study related to our estimate of the Total Proved Reserves attributable to Recovery and remaining to be produced as of December 31, 2012 are as follows:

***Non Escalated Pricing Scenario*** **Estimated**
**Reserves and Future Net Income Net to**
**Recovery Energy Company, Inc.**
**As of December 31, 2012**

| | Estimated Net Reserves | | Estimated Future Net Cash Flow ($1000) | |
|---|---|---|---|---|
| Reserve Category | MBbls | MMC F | Undiscounted | Discounted@ 10% |
| **Proved Reserves** | | | | |
| Producing | 213.3 | 186.0 | 13,271.9 | 9,743.2 |
| Undeveloped | 137.6 | 221.3 | 9,076.9 | 5,679.0 |
| **Total Proved** | **350.9** | **407.3** | **22,348.9** | **15,422.1** |

Liquid volumes are expressed in thousands of barrels (MBbls) of stock tank oil. Gas volumes are expressed in millions of standard cubic feet (MMSCF) at the official temperature and pressure bases of the areas wherein the gas reserves are located.

The economic cash flow presentation of the above volumes and revenues are presented for the individual reserve classifications, as well as appropriate summaries, as Exhibit No. I.

**DISCUSSION:**

The scope of this study was to prepare an estimate of the proved reserves attributable to Recovery's ownership position in the subject properties. Reserve estimates were prepared by Davis using acceptable evaluation principles for each source and were based in large part on the basic information supplied by Recovery.

The quantities presented herein are estimated reserves of oil and natural gas volumes that geologic and engineering data demonstrate can be recovered from known reservoirs under current economic conditions with reasonable certainty. Proved undeveloped locations are scheduled to be drilled such that the investment cost will be fully recovered prior to recovery of the estimated reserve volume.

This evaluation has been prepared in accordance with the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" as proclaimed by the Society of Petroleum Engineers, the SPE Standards.

The estimated future net revenue and discounted present value associated with the reserves as of December 31, 2012 were prepared utilizing a pricing scenario that is detailed later in this report. Costs of operations were provided by Recovery or the operator of the properties on a well by well basis. These costs were reviewed by Davis and are considered to be reasonable. Capital costs were also provided by Recovery, including those future well stimulation costs anticipated as necessary to recover estimated reserve volumes from existing wells. These costs were compared to actual costs of recently drilled wells, taking into account depth of the wells to be drilled. The capital costs included in this report are also considered to be reasonable.

**DATA SOURCE**

Basic well and field data used in the preparation of this report were furnished by Recovery or were obtained from commercial sources or from Davis' own database of information. Records as they pertain to factual matters such as acreage controlled the number and depths of wells, reservoir pressure and production history, the existence of contractual obligations to others and similar matters were accepted as presented.

Additionally, the analyses of these properties utilized not only the basic data on the subject wells but also data on analogous properties as provided. Well logs, ownership interest, revenues received from the sale of products and operating costs were furnished by Recovery Energy. No physical inspection of the properties was made nor any well tests conducted at this time.

**OWNERSHIP**

Ownership interests in the subject properties have been furnished by Recovery Energy and accepted by Davis without independent verification.

**RESERVE ESTIMATES**

The estimate of reserves included in this report is based primarily upon production history or analogy with wells in the area producing from the same or similar formations. In addition to individual well production history, geological and well test information, when available, were utilized in the evaluation. Individual well production histories were evaluated utilizing decline curve analysis on the individual properties and forecast until a calculated economic limit.

Exhibit No. I is a summary presentation of the economic cash flow analyses for the various reserve categories. Exhibit's II through IV are various one-line summary presentations of the reserve categories and individual properties. Exhibit V is a presentation of the individual proved developed producing properties with production curves. Exhibit VI is a presentation by reserve category of the undrilled locations classified as proved undeveloped at this time.

Estimates of reserves to be recovered from undrilled locations are based upon not only the ultimate reserve of existing Recovery wells, but also completions by other operators in the area of interest. Studies of analogous completions have resulted in the development of an average completion that can be anticipated for a specific area, as well as a production profile that recovers the estimated ultimate reserve. This methodology has been utilized in this evaluation.

Additional development potential was based upon geological interpretations, seismic indications of individual structures and well log analysis of know indicators of production. Well spacing was based upon historical activity in the same reservoirs in nearby fields. In all cases, proved undeveloped locations were limited to a direct offset to a proved developed producing well or unit or successful well test in the same reservoir.

Net interest reserve estimates of undrilled locations are based upon Recovery's intention to secure industry financing to drill and complete each of the scheduled locations. Recovery anticipates a proposed trade in which it will be carried through the completion phase, and be able to maintain twenty–five percent (25.0%) of its current leasehold working interest position. The company would pay its proportional share of any future associated well expense. This interest model was applied to all the undrilled locations scheduled within the reserve evaluation.

Recovery has indicated that in addition to pursuing industry financing in order to drill locations as detailed above, the company is working on an alternative capital infusion that could allow it to maintain a higher working interest position in the undrilled locations. With the exception of a single well location, the company holds a one hundred percent (100.0%) leasehold position in all the undrilled locations classified as proved for this evaluation. Consequently, a successful capital campaign could result in the company increasing its proved undeveloped reserves position by a factor of four (4).

The accuracy of reserve estimates is dependent upon the quality of available data and upon the independent geological and engineering interpretation of that data. It should be noted that all reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made.

The uncertainty depends primarily on the amount of reliable geological and engineering data available at the time of the estimate and the interpretation of these data. These reserves have been determined using methods and procedures widely accepted within the industry and are believed to be appropriate for the purposes of this report. In our opinion, we used all methods and procedures necessary under the circumstances to prepare this report.

**PRODUCING RATES**

For the purpose of this report, estimated reserves are scheduled for recovery primarily on the basis of actual producing rates or appropriate well test information. They were prepared giving consideration to engineering and geological data such as reservoir pressure, anticipated producing mechanisms, the number and types of completions, as well as past performance of analogous reservoirs.

These and other future rates may be subject to regulation by various agencies, changes in market demand or other factors; consequently, reserves recovered and the actual rates of recovery may vary from the estimates included herein. Scheduled dates of future well completions may vary from that provided by Recovery Energy due to changes in market demand or the availability of materials and/or capital; however, the timing of the wells and their estimated rates of production are reasonable and consistent with established performance to date.

**PRICING PROVISIONS AND DIFFERENTIALS**

Prices utilized in the evaluation results presented in the letter portion of this report and summarized in the various tables included in this evaluation were furnished by Recovery. Prices received for products sold, adjustments due to the BTU content of the gas, shrinkage for transportation, measuring or the removal of liquids, the liquid yield from gas processed, etc., were accepted as presented.

The unit price used throughout this report for crude oil, condensate and natural gas is based upon the appropriate price in effect the first trading of each month during the previous twelve calendar months through December 2012, and averaged for the time period.

***Crude Oil and Condensate -*** The unit price used throughout this report for crude oil and condensate is based upon the average of prices for the previous twelve months as indicated above. An average crude oil price for West Texas Intermediate crude of $95.01 per barrel was held constant throughout the producing life of the properties. A pricing differential from this posted price of -
$7.64 was utilized to account for location and grade of crude based upon historical sales information for each producing property and was utilized in this evaluation. This pricing differential was similarly held constant. Prices for liquid reserves scheduled for initial production at some future date were estimated using current prices on the same properties.

Natural Gas Liquids were priced at forty-four percent (44.0%) of the existing oil and condensate price for the State-Bradbury 13-36 well, the only property with NGL's extracted from the production stream.

***Natural Gas*** - The unit price used throughout this report for natural gas is based upon the average of prices for previous twelve months as indicated above. An average gas price of $2.75 per MMBTU representing the Henry Hub natural gas price was held constant throughout the producing life of the properties. Prices for gas reserves scheduled for initial production at some future date were estimated using this same price differential.

**FUTURE NET INCOME**

Future net income is based upon gross income from future production, less direct operating expenses and taxes (production, severance, ad valorem or other). Estimated future capital for development and work-over costs was also deducted from gross income at the time it will be expended. No allowance was made for depletion, depreciation, income taxes or administrative expense.

Direct lease operating expense includes direct cost of operations of each lease or an estimated value for future operations based upon analogous properties. Lease operating expense and/or capital costs for drilling and/or major work over expense were not escalated throughout the remaining producing life of the properties. Neither the cost to abandon properties nor the salvage value of equipment was considered in this report.

Future net income has been discounted for present worth at values ranging from 0 to 100 percent using continuous discounting. In this report the future net income is discounted at a primary rate of ten (10.0) percent.

**GENERAL**

Recovery Energy Company, Inc. has provided access to all of its accounts, records, geological and engineering data, reports and other information as required for this evaluation. The ownership interests, product classifications relating to prices and other factual data were accepted as furnished without verification.

No consideration was given in this report to either gas contract disputes including take or pay demands or gas sales imbalances.

No consideration was given in this report to potential environmental liabilities which may exist, nor were any costs included for potential liability to restore and clean up damages, if any, caused by past operating practices.

Neither Ralph E. Davis Associates, Inc. nor any of its employees have any interest in Recovery Energy Company, Inc. or any other related company or the properties reported on herein. The employment and compensation to make this study are not contingent on our estimate of reserves. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the SPE standards.

This report has been prepared for public disclosure by Recovery Energy Company, Inc. in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please feel free to contact us if we can be of further service.

We appreciate the opportunity to be of service to you in the matter of this report and will be glad to address any questions or inquiries you may have.

Very truly yours,

**RALPH E. DAVIS ASSOCIATES, INC.**

Date

/s/ Allen C. Barron

Allen C. Barron, P. E.
President

Texas Registered Engineering Firm F-1529

# Reserves Definitions

## Securities and Exchange Commission
## Definitions of Reserves

The following information is taken from the United States Securities and Exchange Commission:

*PART 210—FORM AND CONTENT OF AND REQUIREMENTS FOR FINANCIAL STATEMENTS, SECURITIES ACT OF 1933, SECURITIES EXCHANGE ACT OF 1934, PUBLIC UTILITY HOLDING COMPANY ACT OF 1935, INVESTMENT COMPANY ACT OF 1940, INVESTMENT ADVISERS ACT OF 1940, AND ENERGY POLICY AND CONSERVATION ACT OF 1975*

***Rules of General Application***
***§ 210.4-10 Financial accounting and reporting for oil and gas producing activities pursuant to the Federal securities laws and the Energy Policy and Conservation Act of 1975.***

**Reserves**
Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir ( *i.e.*, absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources ( *i.e.*, potentially recoverable resources from undiscovered accumulations).

**Proved Oil and Gas Reserves**
Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:
(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

*Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

*Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

**Probable Reserves**
Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

**Possible Reserves**
Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

**Developed Oil and Gas Reserves**
Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

**Undeveloped Oil and Gas Reserves**
Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Additional Definitions:

**Deterministic Estimate**
The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

**Probabilistic Estimate**
The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

**Reasonable Certainty**
If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

# Exhibits

# Summary Economic Cash Flow Presentations

RECOVERY ENERGY
TOTAL PROVED
RESERVES AND REVENUES AS OF 12/31/2012
REVISED EVALUATION AT 04/01 2013

DATE : 04/01/2013
TIME : 13:51:46
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO : RED_JAN13

## R E S E R V E S   A N D   E C O N O M I C S

### AS OF DATE: 12/31/2012

| --END-- MO-YEAR | GROSS OIL PRODUCTION MBBLS | GROSS GAS PRODUCTION MMCF | NET OIL PRODUCTION MBBLS | NET GAS PRODUCTION MMCF | NET OIL PRICE $/BBL | NET GAS PRICE $/MCF | NET OIL SALES M$ | NET GAS SALES M$ | TOTAL NET SALES M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 231.626 | 666.916 | 58.638 | 56.730 | 87.370 | 2.663 | 5123.214 | 151.064 | 5499.152 |
| 12-2014 | 253.286 | 418.070 | 60.764 | 44.795 | 87.370 | 2.673 | 5308.948 | 119.726 | 5628.631 |
| 12-2015 | 195.699 | 300.953 | 45.295 | 34.857 | 87.370 | 2.670 | 3957.449 | 93.051 | 4194.470 |
| 12-2016 | 141.213 | 225.092 | 31.229 | 26.216 | 87.370 | 2.668 | 2728.477 | 69.945 | 2902.081 |
| 12-2017 | 110.845 | 179.162 | 23.255 | 20.772 | 87.370 | 2.664 | 2031.774 | 55.337 | 2161.745 |
| 12-2018 | 100.679 | 176.656 | 20.694 | 22.788 | 87.370 | 2.649 | 1808.033 | 60.368 | 1922.137 |
| 12-2019 | 86.478 | 156.697 | 17.386 | 20.493 | 87.370 | 2.643 | 1519.007 | 54.173 | 1611.870 |
| 12-2020 | 73.515 | 131.640 | 14.410 | 16.710 | 87.370 | 2.641 | 1258.981 | 44.126 | 1330.964 |
| 12-2021 | 64.875 | 112.794 | 12.381 | 13.725 | 87.370 | 2.632 | 1081.771 | 36.124 | 1130.386 |
| 12-2022 | 57.081 | 98.232 | 10.565 | 11.432 | 87.370 | 2.621 | 923.069 | 29.968 | 953.037 |
| 12-2023 | 48.328 | 89.601 | 8.507 | 10.462 | 87.370 | 2.621 | 743.278 | 27.420 | 770.697 |
| 12-2024 | 41.975 | 82.397 | 7.139 | 9.650 | 87.370 | 2.620 | 623.771 | 25.289 | 649.059 |
| 12-2025 | 37.436 | 76.255 | 6.184 | 8.954 | 87.370 | 2.620 | 540.275 | 23.461 | 563.736 |
| 12-2026 | 33.341 | 70.789 | 5.319 | 8.248 | 87.370 | 2.619 | 464.699 | 21.601 | 486.300 |
| 12-2027 | 30.068 | 65.948 | 4.622 | 7.627 | 87.370 | 2.618 | 403.849 | 19.968 | 423.818 |
| S TOT | 1506.444 | 2851.204 | 326.389 | 313.460 | 87.370 | 2.653 | 28516.588 | 831.620 | 30228.084 |
| AFTER | 239.286 | 758.872 | 24.473 | 93.872 | 87.370 | 2.618 | 2138.204 | 245.743 | 2383.947 |
| TOTAL | 1745.730 | 3610.076 | 350.862 | 407.331 | 87.370 | 2.645 | 30654.793 | 1077.363 | 32612.031 |

| --END-- MO-YEAR | AD VALOREM TAX M$ | PRODUCTION TAX M$ | DIRECT OPER EXPENSE M$ | INTEREST PAID M$ | CAPITAL REPAYMENT M$ | EQUITY INVESTMENT M$ | FUTURE NET CASHFLOW M$ | CUMULATIVE CASHFLOW M$ | CUM. DISC. CASHFLOW M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 309.640 | 212.932 | 833.119 | 0.000 | 0.000 | 76.875 | 4066.587 | 4066.587 | 3874.847 |
| 12-2014 | 276.401 | 204.064 | 885.503 | 0.000 | 0.000 | 250.000 | 4012.664 | 8079.251 | 7351.183 |
| 12-2015 | 205.810 | 150.373 | 694.740 | 0.000 | 0.000 | 0.000 | 3143.546 | 11222.798 | 9837.360 |
| 12-2016 | 144.167 | 100.344 | 483.240 | 0.000 | 0.000 | 0.000 | 2174.330 | 13397.128 | 11399.500 |
| 12-2017 | 109.907 | 73.183 | 355.071 | 0.000 | 0.000 | 0.000 | 1623.583 | 15020.712 | 12459.438 |
| 12-2018 | 102.703 | 58.795 | 351.494 | 0.000 | 0.000 | 218.750 | 1190.395 | 16211.106 | 13164.162 |
| 12-2019 | 86.620 | 48.037 | 344.519 | 0.000 | 0.000 | 0.000 | 1132.694 | 17343.801 | 13775.336 |
| 12-2020 | 70.835 | 39.685 | 333.864 | 0.000 | 0.000 | 0.000 | 886.579 | 18230.381 | 14210.047 |
| 12-2021 | 59.695 | 33.884 | 322.484 | 0.000 | 0.000 | 0.000 | 714.322 | 18944.701 | 14528.415 |
| 12-2022 | 50.382 | 28.777 | 301.996 | 0.000 | 0.000 | 0.000 | 571.881 | 19516.584 | 14760.247 |
| 12-2023 | 42.268 | 23.529 | 270.396 | 0.000 | 0.000 | 0.000 | 434.504 | 19951.088 | 14920.358 |
| 12-2024 | 37.233 | 19.525 | 246.196 | 0.000 | 0.000 | 0.000 | 346.105 | 20297.191 | 15036.246 |
| 12-2025 | 33.312 | 16.689 | 231.896 | 0.000 | 0.000 | 0.000 | 281.840 | 20579.031 | 15122.040 |
| 12-2026 | 29.566 | 14.277 | 210.327 | 0.000 | 0.000 | 0.000 | 232.129 | 20811.162 | 15186.274 |
| 12-2027 | 26.443 | 12.333 | 193.908 | 0.000 | 0.000 | 0.000 | 191.133 | 21002.297 | 15234.355 |
| S TOT | 1584.982 | 1036.429 | 6058.754 | 0.000 | 0.000 | 545.625 | 21002.297 | 21002.297 | 15234.355 |
| AFTER | 178.488 | 18.012 | 840.882 | 0.000 | 0.000 | 0.000 | 1346.564 | 22348.861 | 15422.130 |
| TOTAL | 1763.470 | 1054.441 | 6899.636 | 0.000 | 0.000 | 545.625 | 22348.859 | 22348.861 | 15422.130 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 38.0 | 1.0 | LIFE, YRS. | 42.42 | 5.00 | 18110.877 |
| GROSS ULT., MB & MMF | 2461.803 | 4816.261 | DISCOUNT % | 10.00 | 8.00 | 16374.374 |
| GROSS CUM., MB & MMF | 716.073 | 1206.183 | UNDISCOUNTED PAYOUT, YRS. | 0.02 | 10.00 | 15422.128 |
| GROSS RES., MB & MMF | 1745.730 | 3610.077 | DISCOUNTED PAYOUT, YRS. | 0.02 | 12.00 | 14593.596 |
| NET RES., MB & MMF | 350.862 | 407.331 | UNDISCOUNTED NET/INVEST. | 41.96 | 15.00 | 13531.830 |
| NET REVENUE, M$ | 30654.793 | 1077.363 | DISCOUNTED NET/INVEST. | 37.50 | 18.00 | 12638.278 |
| INITIAL PRICE, $ | 87.370 | 2.634 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 10119.967 |
| INITIAL N.I., PCT. | 40.176 | 5.931 | INITIAL W.I., PCT. | 26.632 | 60.00 | 7041.921 |
| | | | | | 80.00 | 5976.986 |
| | | | | | 260.00 | 3054.993 |

**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529

RECOVERY ENERGY
TOTAL PROVED
RESERVES AND REVENUES AS OF 12/31/2012
REVISED EVALUATION AT 04/01 2013

DATE : 04/01/2013
TIME : 13:51:46
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO : RED_JAN13

## R E S E R V E S   A N D   E C O N O M I C S

### AS OF DATE: 12/31/2012

| --END-- MO-YEAR | GROSS OIL PRODUCTION MBBLS | GROSS GAS PRODUCTION MMC | NET OIL PRODUCTION MBBL | NET GAS PRODUCTION MMCF | NET OIL PRICE $/BBL | NET GAS PRICE $/MCF | NET OIL SALES M$ | NET GAS SALES M$ | TOTAL NET SALES M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 197.939 | 638.405 | 51.927 | 50.921 | 87.370 | 2.668 | 4536.825 | 135.843 | 4897.542 |
| 12-2014 | 129.647 | 354.038 | 36.386 | 31.748 | 87.370 | 2.694 | 3179.041 | 85.544 | 3464.542 |
| 12-2015 | 95.000 | 239.715 | 25.459 | 22.380 | 87.370 | 2.697 | 2224.379 | 60.361 | 2428.709 |
| 12-2016 | 73.896 | 177.636 | 17.946 | 16.547 | 87.370 | 2.696 | 1567.923 | 44.612 | 1716.193 |
| 12-2017 | 60.615 | 138.560 | 13.331 | 12.499 | 87.370 | 2.693 | 1164.708 | 33.663 | 1273.004 |
| 12-2018 | 52.483 | 111.924 | 11.113 | 9.599 | 87.370 | 2.689 | 970.963 | 25.813 | 1050.512 |
| 12-2019 | 46.294 | 92.838 | 9.387 | 7.482 | 87.370 | 2.684 | 820.117 | 20.084 | 878.891 |
| 12-2020 | 41.396 | 78.672 | 8.015 | 5.917 | 87.370 | 2.679 | 700.229 | 15.850 | 743.937 |
| 12-2021 | 37.301 | 65.519 | 6.890 | 4.093 | 87.370 | 2.660 | 601.958 | 10.887 | 625.337 |
| 12-2022 | 33.758 | 54.960 | 5.917 | 2.615 | 87.370 | 2.626 | 516.941 | 6.868 | 523.809 |
| 12-2023 | 30.497 | 49.521 | 4.942 | 2.296 | 87.370 | 2.624 | 431.774 | 6.024 | 437.798 |
| 12-2024 | 27.904 | 45.014 | 4.338 | 2.033 | 87.370 | 2.622 | 379.027 | 5.332 | 384.359 |
| 12-2025 | 25.574 | 41.223 | 3.829 | 1.816 | 87.370 | 2.620 | 334.500 | 4.760 | 339.260 |
| 12-2026 | 23.412 | 37.871 | 3.351 | 1.541 | 87.370 | 2.614 | 292.789 | 4.028 | 296.817 |
| 12-2027 | 21.412 | 35.005 | 2.905 | 1.323 | 87.370 | 2.608 | 253.824 | 3.450 | 257.274 |
| S TOT | 897.129 | 2160.900 | 205.734 | 172.810 | 87.370 | 2.680 | 17974.994 | 463.119 | 19317.984 |
| AFTER | 155.559 | 362.971 | 7.572 | 13.207 | 87.370 | 2.605 | 661.588 | 34.401 | 695.989 |
| TOTAL | 1052.689 | 2523.871 | 213.306 | 186.017 | 87.370 | 2.675 | 18636.582 | 497.520 | 20013.975 |

| --END-- MO-YEAR | AD VALOREM TAX M$ | PRODUCTION TAX M$ | DIRECT OPER EXPENSE M$ | INTEREST PAID M$ | CAPITAL REPAYMENT M$ | EQUITY INVESTMENT M$ | FUTURE NET CASHFLOW M$ | CUMULATIVE CASHFLOW M$ | CUM. DISC. CASHFLOW M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 282.191 | 202.694 | 804.669 | 0.000 | 0.000 | 76.875 | 3531.113 | 3531.113 | 3375.591 |
| 12-2014 | 198.328 | 142.352 | 769.203 | 0.000 | 0.000 | 0.000 | 2354.660 | 5885.773 | 5423.761 |
| 12-2015 | 142.456 | 98.852 | 556.440 | 0.000 | 0.000 | 0.000 | 1630.962 | 7516.734 | 6712.760 |
| 12-2016 | 103.171 | 68.054 | 344.940 | 0.000 | 0.000 | 0.000 | 1200.027 | 8716.762 | 7574.643 |
| 12-2017 | 79.236 | 50.150 | 216.771 | 0.000 | 0.000 | 0.000 | 926.846 | 9643.608 | 8179.603 |
| 12-2018 | 64.990 | 41.107 | 213.194 | 0.000 | 0.000 | 0.000 | 731.221 | 10374.829 | 8613.465 |
| 12-2019 | 54.182 | 34.206 | 210.619 | 0.000 | 0.000 | 0.000 | 579.884 | 10954.713 | 8926.246 |
| 12-2020 | 45.813 | 28.824 | 208.764 | 0.000 | 0.000 | 0.000 | 460.536 | 11415.249 | 9152.071 |
| 12-2021 | 38.143 | 24.552 | 197.384 | 0.000 | 0.000 | 0.000 | 365.258 | 11780.507 | 9314.891 |
| 12-2022 | 31.533 | 21.109 | 179.096 | 0.000 | 0.000 | 0.000 | 292.071 | 12072.578 | 9433.246 |
| 12-2023 | 26.198 | 18.301 | 159.596 | 0.000 | 0.000 | 0.000 | 233.703 | 12306.281 | 9519.340 |
| 12-2024 | 23.214 | 15.982 | 159.596 | 0.000 | 0.000 | 0.000 | 185.567 | 12491.848 | 9581.493 |
| 12-2025 | 20.689 | 14.047 | 159.596 | 0.000 | 0.000 | 0.000 | 144.928 | 12636.776 | 9625.629 |
| 12-2026 | 18.163 | 12.418 | 155.627 | 0.000 | 0.000 | 0.000 | 110.609 | 12747.385 | 9656.256 |
| 12-2027 | 15.968 | 10.923 | 148.008 | 0.000 | 0.000 | 0.000 | 82.375 | 12829.760 | 9676.997 |
| S TOT | 1144.273 | 783.573 | 4483.504 | 0.000 | 0.000 | 76.875 | 12829.760 | 12829.760 | 9676.997 |
| AFTER | 53.133 | 13.219 | 187.457 | 0.000 | 0.000 | 0.000 | 442.180 | 13271.939 | 9743.167 |
| TOTAL | 1197.406 | 796.792 | 4670.961 | 0.000 | 0.000 | 76.875 | 13271.940 | 13271.939 | 9743.167 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 24.0 | 1.0 | LIFE, YRS. | 34.00 | 5.00 | 11160.462 |
| GROSS ULT., MB & MMF | 1768.762 | 3730.055 | DISCOUNT % | 10.00 | 8.00 | 10251.478 |
| GROSS CUM., MB & MMF | 716.073 | 1206.183 | UNDISCOUNTED PAYOUT, YRS. | 0.02 | 10.00 | 9743.169 |
| GROSS RES., MB & MMF | 1052.689 | 2523.872 | DISCOUNTED PAYOUT, YRS. | 0.02 | 12.00 | 9295.615 |
| NET RES., MB & MMF | 213.306 | 186.017 | UNDISCOUNTED NET/INVEST. | 173.64 | 15.00 | 8715.323 |
| NET REVENUE, M$ | 18636.578 | 497.520 | DISCOUNTED NET/INVEST. | 128.75 | 18.00 | 8221.428 |
| INITIAL PRICE, $ | 87.370 | 2.635 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 6803.890 |
| INITIAL N.I., PCT. | 40.176 | 5.931 | INITIAL W.I., PCT. | 27.804 | 60.00 | 5016.243 |
| | | | | | 80.00 | 4378.413 |
| | | | | | 260.00 | 2520.648 |

**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529

RECOVERY ENERGY
TOTAL PROVED
RESERVES AND REVENUES AS OF 12/31/2012
REVISED EVALUATION AT 04/01 2013

DATE : 04/01/2013
TIME : 13:51:46
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO : RED_JAN13

## R E S E R V E S A N D E C O N O M I C S

### AS OF DATE: 12/31/2012

| --END-- MO-YEAR | GROSS OIL PRODUCTION MBBLS | GROSS GAS PRODUCTION MMCF | NET OIL PRODUCTION MBBLS | NET GAS PRODUCTION MMCF | NET OIL PRICE $/BBL | NET GAS PRICE $/MCF | NET OIL SALES M$ | NET GAS SALES M$ | TOTAL NET SALES M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 33.687 | 28.512 | 6.712 | 5.809 | 87.370 | 2.620 | 586.390 | 15.220 | 601.610 |
| 12-2014 | 123.638 | 64.032 | 24.378 | 13.047 | 87.370 | 2.620 | 2129.907 | 34.182 | 2164.089 |
| 12-2015 | 100.698 | 61.238 | 19.836 | 12.477 | 87.370 | 2.620 | 1733.070 | 32.690 | 1765.760 |
| 12-2016 | 67.317 | 47.456 | 13.283 | 9.669 | 87.370 | 2.620 | 1160.554 | 25.333 | 1185.888 |
| 12-2017 | 50.230 | 40.602 | 9.924 | 8.273 | 87.370 | 2.620 | 867.067 | 21.674 | 888.741 |
| 12-2018 | 48.196 | 64.732 | 9.581 | 13.189 | 87.370 | 2.620 | 837.070 | 34.556 | 871.625 |
| 12-2019 | 40.184 | 63.859 | 7.999 | 13.011 | 87.370 | 2.620 | 698.889 | 34.090 | 732.979 |
| 12-2020 | 32.119 | 52.968 | 6.395 | 10.792 | 87.370 | 2.620 | 558.751 | 28.276 | 587.027 |
| 12-2021 | 27.573 | 47.275 | 5.492 | 9.632 | 87.370 | 2.620 | 479.812 | 25.237 | 505.049 |
| 12-2022 | 23.323 | 43.273 | 4.648 | 8.817 | 87.370 | 2.620 | 406.128 | 23.100 | 429.228 |
| 12-2023 | 17.831 | 40.080 | 3.565 | 8.166 | 87.370 | 2.620 | 311.504 | 21.395 | 332.900 |
| 12-2024 | 14.070 | 37.383 | 2.801 | 7.617 | 87.370 | 2.620 | 244.744 | 19.956 | 264.700 |
| 12-2025 | 11.862 | 35.032 | 2.355 | 7.138 | 87.370 | 2.620 | 205.774 | 18.701 | 224.475 |
| 12-2026 | 9.929 | 32.919 | 1.968 | 6.707 | 87.370 | 2.620 | 171.910 | 17.573 | 189.483 |
| 12-2027 | 8.656 | 30.943 | 1.717 | 6.305 | 87.370 | 2.620 | 150.025 | 16.518 | 166.543 |
| S TOT | 609.315 | 690.304 | 120.655 | 140.650 | 87.370 | 2.620 | 10541.596 | 368.502 | 10910.098 |
| AFTER | 83.726 | 395.901 | 16.901 | 80.665 | 87.370 | 2.620 | 1476.615 | 211.342 | 1687.958 |
| TOTAL | 693.041 | 1086.205 | 137.555 | 221.314 | 87.370 | 2.620 | 12018.211 | 579.844 | 12598.056 |

| --END-- MO-YEAR | AD VALOREM TAX M$ | PRODUCTION TAX M$ | DIRECT OPER EXPENSE M$ | INTEREST PAID M$ | CAPITAL REPAYMENT M$ | EQUITY INVESTMENT M$ | FUTURE NET CASHFLOW M$ | CUMULATIVE CASHFLOW M$ | CUM. DISC. CASHFLOW M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 27.449 | 10.238 | 28.450 | 0.000 | 0.000 | 0.000 | 535.474 | 535.474 | 499.256 |
| 12-2014 | 78.074 | 61.712 | 116.300 | 0.000 | 0.000 | 250.000 | 1658.004 | 2193.478 | 1927.422 |
| 12-2015 | 63.354 | 51.522 | 138.300 | 0.000 | 0.000 | 0.000 | 1512.585 | 3706.062 | 3124.600 |
| 12-2016 | 40.996 | 32.289 | 138.300 | 0.000 | 0.000 | 0.000 | 974.303 | 4680.365 | 3824.857 |
| 12-2017 | 30.671 | 23.032 | 138.300 | 0.000 | 0.000 | 0.000 | 696.737 | 5377.102 | 4279.834 |
| 12-2018 | 37.713 | 17.688 | 138.300 | 0.000 | 0.000 | 218.750 | 459.173 | 5836.275 | 4550.696 |
| 12-2019 | 32.438 | 13.831 | 133.900 | 0.000 | 0.000 | 0.000 | 552.810 | 6389.085 | 4849.090 |
| 12-2020 | 25.023 | 10.861 | 125.100 | 0.000 | 0.000 | 0.000 | 426.043 | 6815.129 | 5057.976 |
| 12-2021 | 21.552 | 9.333 | 125.100 | 0.000 | 0.000 | 0.000 | 349.064 | 7164.193 | 5213.524 |
| 12-2022 | 18.849 | 7.668 | 122.900 | 0.000 | 0.000 | 0.000 | 279.811 | 7444.003 | 5327.001 |
| 12-2023 | 16.070 | 5.229 | 110.800 | 0.000 | 0.000 | 0.000 | 200.801 | 7644.804 | 5401.018 |
| 12-2024 | 14.019 | 3.543 | 86.600 | 0.000 | 0.000 | 0.000 | 160.538 | 7805.342 | 5454.753 |
| 12-2025 | 12.623 | 2.641 | 72.300 | 0.000 | 0.000 | 0.000 | 136.911 | 7942.253 | 5496.412 |
| 12-2026 | 11.403 | 1.859 | 54.700 | 0.000 | 0.000 | 0.000 | 121.520 | 8063.773 | 5530.018 |
| 12-2027 | 10.474 | 1.410 | 45.900 | 0.000 | 0.000 | 0.000 | 108.758 | 8172.532 | 5557.357 |
| S TOT | 440.709 | 252.856 | 1575.250 | 0.000 | 0.000 | 468.750 | 8172.532 | 8172.532 | 5557.357 |
| AFTER | 125.355 | 4.793 | 653.425 | 0.000 | 0.000 | 0.000 | 904.385 | 9076.917 | 5678.957 |
| TOTAL | 566.064 | 257.649 | 2228.675 | 0.000 | 0.000 | 468.750 | 9076.917 | 9076.917 | 5678.957 |

| | OIL | GAS | | | P.W. % | P.W., MS |
|---|---|---|---|---|---|---|
| GROSS WELLS | 14.0 | 0.0 | LIFE, YRS. | 42.42 | 5.00 | 6950.415 |
| GROSS ULT., MB & MMF | 693.041 | 1086.205 | DISCOUNT % | 10.00 | 8.00 | 6122.896 |
| GROSS CUM., MB & MMF | 0.000 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 5678.958 |
| GROSS RES., MB & MMF | 693.041 | 1086.205 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 5297.981 |
| NET RES., MB & MMF | 137.555 | 221.314 | UNDISCOUNTED NET/INVEST. | 20.36 | 15.00 | 4816.507 |
| NET REVENUE, M$ | 12018.210 | 579.844 | DISCOUNTED NET/INVEST. | 17.40 | 18.00 | 4416.851 |
| INITIAL PRICE, $ | 87.370 | 2.620 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 3316.077 |
| INITIAL N.I., PCT. | 19.923 | 20.375 | INITIAL W.I., PCT. | 25.000 | 60.00 | 2025.678 |
| | | | | | 80.00 | 1598.573 |
| | | | | | 260.00 | 534.344 |

**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529

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# Oneline Summary
# Well Information

## RECOVERY ENERGY, INC. REVISED
## RESERVES AND REVENUES AS OF
## 12/31/2012
## SORTED BY CATEGORY, STATE, FIELD, AND LEASE

| API | RESERVE CAT | LEASE | FIELD | RESERVOIR | OPERATOR | COUNTY | STATE | MAJOR | START DATE | WI | NRI |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **PROVED DEVELOPED PRODUCING** | | | | | | | | | | |
| 05005071280000 | 1PDP | STATE-BRADBURY 13-36 | PEACE PIPE | J SAND | RECOVERY ENERGY, INC. | ARAPAHOE | CO | GAS | 3/1/2013 | 62.50000% | 48.12500% |
| 05121083670000 | 1PDP | LEO PEIPER #1&3 | RED CLOUD | J SAND | RECOVERY ENERGY, INC. | WASHINGTON | CO | OIL | 2/1/2013 | 100.00000% | 78.00000% |
| 05001088980000 | 1PDP | CIMYOTTE #6-21 | TRAPPER | D SAND | RECOVERY ENERGY, INC. | ADAMS | CO | OIL | 11/1/2012 | 94.50000% | 77.08002% |
| 05123142720001 | 1PDP | SAWYER 32-2 | WATTENBERG | J SAND | RECOVERY ENERGY, INC. | WELD | CO | OIL | 11/1/2012 | 57.22250% | 40.53555% |
| 05123346790000 | 1PDP | SLW STATE PC BB18-65HN | WATTENBERG | NIOBRARA | NOBLE ENERGY INC. | WELD | CO | GAS | 12/1/2012 | 7.90409% | 6.91608% |
| 05123346740000 | 1PDP | SLW STATE PC BB18-67HN | WATTENBERG | NIOBRARA | NOBLE ENERGY INC. | WELD | CO | GAS | 12/1/2012 | 6.75559% | 5.91114% |
| 05123352730000 | 1PDP | VINCE STATE B13-63HN | WATTENBERG | NIOBRARA | NOBLE ENERGY INC. | WELD | CO | GAS | 12/1/2012 | 2.20043% | 1.92538% |
| 26007218980000 | 1PDP | PALM 21A-20, 43-20, 23-21 | ALBIN WEST | J SAND | RECOVERY ENERGY, INC. | BANNER | NE | OIL | 1/1/2013 | 100.00000% | 82.50000% |
| 26007218870000 | 1PDP | PALM EGLE 34-17 | ALBIN WEST | J SAND | RECOVERY ENERGY, INC. | BANNER | NE | OIL | 1/1/2012 | 100.00000% | 82.50000% |
| 26105226450000 | 1PDP | LUKASSEN 14-34 | CABLE | J SAND | RECOVERY ENERGY, INC. | KIMBALL | NE | OIL | 12/1/2012 | 100.00000% | 78.00000% |
| 26105226250000 | 1PDP | WILKE 34-5,33-5,24-5,23-5 | DILL EAST | J SAND | RECOVERY ENERGY, INC. | KIMBALL | NE | OIL | 7/1/2012 | 87.50000% | 68.25000% |
| 49021209410000 | 1PDP | HANSON 42-26 | GOLDEN PRARIE | J SAND | RECOVERY ENERGY, INC. | LARAMIE | WY | OIL | 1/1/2013 | 90.00000% | 72.00000% |
| 49021207300000 | 1PDP | ANDERSON 21-34 | STATELINE | J SAND | RECOVERY ENERGY, INC. | LARAMIE | WY | OIL | 11/1/2012 | 74.00000% | 56.98000% |
| 49021206080000 | 1PDP | HOLGERSON 33A-33 | STATELINE | J SAND | RECOVERY ENERGY, INC. | LARAMIE | WY | OIL | 11/1/2012 | 100.00000% | 77.00000% |
| 49021206590000 | 1PDP | MALM 42-34 | STATELINE | J SAND | RECOVERY ENERGY, INC. | LARAMIE | WY | OIL | 10/1/2012 | 74.00001% | 56.98000% |
| 49021205960000 | 1PDP | OLIVERIUS 41-33 | STATELINE | J3 SAND | RECOVERY ENERGY, INC. | LARAMIE | WY | OIL | 11/1/2012 | 100.00000% | 76.99999% |
| 49021205940000 | 1PDP | OLIVERIUS 42-33 | STATELINE | J1 SAND | RECOVERY ENERGY, INC. | LARAMIE | WY | OIL | 10/1/2012 | 100.00000% | 77.00000% |
| 49021205950000 | 1PDP | WENZEL 12-34 | STATELINE | J SAND | RECOVERY ENERGY, INC. | LARAMIE | WY | OIL | 1/1/2013 | 100.00000% | 77.00000% |
| 49021209080000 | 1PDP | FORNSTROM 33-32 | WILDCAT | J SAND | EVERTSON OPERATING CO. INC. | LARAMIE | WY | OIL | 12/1/2012 | 0.00000% | 2.60000% |
| 49021209290000 | 1PDP | FORNSTROM 34A-32 | WILDCAT | J SAND | EVERTSON OPERATING CO. INC. | LARAMIE | WY | OIL | 12/1/2012 | 0.00000% | 2.60000% |
| 49021209060000 | 1PDP | FORNSTROM 43-32 | WILDCAT | J SAND | EVERTSON OPERATING CO. INC. | LARAMIE | WY | OIL | 12/1/2012 | 0.00000% | 2.60000% |
| | **PROVED UNDEVELOPED** | | | | | | | | | | |
| | 3PUD | LANG 11-34 | WATTENBERG | CODELL-NIOBRARA | RECOVERY ENERGY, INC. | WELD | CO | OIL | 7/1/2013 | 25.00000% | 20.37500% |
| | 3PUD | LANG 12-34 | WATTENBERG | CODELL-NIOBRARA | RECOVERY ENERGY, INC. | WELD | CO | OIL | 7/1/2013 | 25.00000% | 20.37500% |
| | 3PUD | LANG 21-34 | WATTENBERG | CODELL-NIOBRARA | RECOVERY ENERGY, INC. | WELD | CO | OIL | 7/1/2013 | 25.00000% | 20.37500% |
| | 3PUD | LANG 22-34 | WATTENBERG | CODELL-NIOBRARA | RECOVERY ENERGY, INC. | WELD | CO | OIL | 7/1/2013 | 25.00000% | 20.37500% |
| | 3PUD | LANG 2-2-34 | WATTENBERG | CODELL-NIOBRARA | RECOVERY ENERGY, INC. | WELD | CO | OIL | 7/1/2013 | 25.00000% | 20.37500% |
| | 3PUD | PALM 11-20 | ALBIN WEST | J-SAND | RECOVERY ENERGY, INC. | BANNER | NE | OIL | 7/1/2014 | 25.00000% | 20.62500% |
| | 3PUD | PALM 42-20 | ALBIN WEST | J-SAND | RECOVERY ENERGY, INC. | BANNER | NE | OIL | 8/1/2013 | 25.00000% | 20.62500% |
| | 3PUD | LARSON 24-20 | RANCHER | J-Sand | RECOVERY ENERGY, INC. | KIMBALL | NE | OIL | 3/1/2014 | 25.00000% | 21.87500% |
| | 3PUD | OLIVERIUS 32-33 | STATELINE | J-SAND | RECOVERY ENERGY, INC. | BANNER | NE | OIL | 7/1/2014 | 25.00000% | 19.25000% |
| | 3PUD | VRTATKO 44-22 | SURGE | J1-SAND | RECOVERY ENERGY, INC. | KIMBALL | NE | OIL | 3/1/2014 | 25.00000% | 19.37500% |
| | 3PUD | LUKASSEN 42-7 | TERRESTRIAL | WYKERT SAND | RECOVERY ENERGY, INC. | BANNER | NE | OIL | 7/1/2013 | 25.00000% | 18.75000% |
| | 3PUD | LUKASSEN 44-18 | TERRESTRIAL | WYKERT SAND | RECOVERY ENERGY, INC. | BANNER | NE | OIL | 7/1/2013 | 25.00000% | 18.75000% |
| | 3PUD | WILKE 44A-5 | WILKE | J-SAND | RECOVERY ENERGY, INC. | KIIMBALL | NE | OIL | 5/1/2014 | 25.00000% | 17.06250% |
| | 3PUD | MALM 32-34 | ALBIN WEST | J-SAND | RECOVERY ENERGY, INC. | LARAMIE | WY | OIL | 1/1/2014 | 25.00000% | 19.75000% |

# Oneline Summary
# Sorted by Reserve Category

# RECOVERY ENERGY, INC. REVISED
# RESERVES AND REVENUES AS OF
# 12/31/2012
# SORTED BY CATEGORY, STATE, FIELD, AND LEASE

| RESERVE CAT | FIELD | LEASE | COUNTY | STATE | NET OIL RESERVES MBBLS | NET GAS RESERVES MMCF | TOTAL REVENUE M$ | SEVERANCE TAX M$ | AD VAL TAX M$ | DIRECT OP EXPENSE M$ | TOTAL OP EXPENSE M$ | OPERATING REVENUE M$ | TOTAL INVESTMENT M$ | CASH FLOW UNDISC M$ | CASH FLOW DISC @ 10% M$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **PROVED DEVELOPED PRODUCING** | | | | | | | | | | | | | | | |
| 1PDP | PEACE PIPE | STATE-BRADBURY 13-36 | ARAPAHOE | CO | 1.5 | 76.3 | 1,217.4 | . | 121.7 | 327.4 | 449.1 | 768.3 | 46.9 | 721.4 | 581.6 |
| 1PDP | RED CLOUD | LEO PEIPER #1&3 | WASHINGTON | CO | 5.0 | . | 432.8 | . | 34.6 | 228.2 | 262.8 | 170.0 | 30.0 | 140.0 | 100.2 |
| 1PDP | TRAPPER | CIMYOTTE #6-21 | ADAMS | CO | 6.5 | 17.1 | 610.5 | . | 54.9 | 107.2 | 162.1 | 448.4 | . | 448.4 | 336.1 |
| 1PDP | WATTENBERG | SAWYER 32-2 | WELD | CO | 4.5 | 6.5 | 411.2 | . | 32.9 | 93.7 | 126.6 | 284.6 | . | 284.6 | 152.9 |
| 1PDP | WATTENBERG | SLW STATE PC BB18-65HN | WELD | CO | 11.0 | 42.9 | 1,069.8 | . | 85.6 | 44.0 | 129.6 | 940.2 | . | 940.2 | 557.8 |
| 1PDP | WATTENBERG | SLW STATE PC BB18-67HN | WELD | CO | 8.7 | 31.7 | 839.0 | . | 67.1 | 35.2 | 102.3 | 736.7 | . | 736.7 | 439.3 |
| 1PDP | WATTENBERG | VINCE STATE B13-63HN | WELD | CO | 2.7 | 11.6 | 263.4 | . | 21.1 | 12.0 | 33.1 | 230.4 | . | 230.4 | 132.1 |
| 1PDP | ALBIN WEST | PALM 21A-20, 43-20, 23-21 | BANNER | NE | 10.1 | . | 881.3 | 26.4 | 17.1 | 404.8 | 448.3 | 432.9 | . | 432.9 | 392.5 |
| 1PDP | ALBIN WEST | PALM EGLE 34-17 | BANNER | NE | 37.7 | . | 3,295.0 | 98.8 | 63.9 | 653.4 | 816.1 | 2,478.8 | . | 2,478.8 | 1,799.6 |
| 1PDP | CABLE | LUKASSEN 14-34 | KIMBALL | NE | 3.1 | . | 266.7 | 8.0 | 5.2 | 162.8 | 176.0 | 90.7 | . | 90.7 | 83.3 |
| 1PDP | DILL EAST | WILKE 34-5,33-5,24-5,23-5 | KIMBALL | NE | 7.8 | . | 677.2 | 20.3 | 13.1 | 415.8 | 449.3 | 227.9 | . | 227.9 | 214.1 |
| 1PDP | GOLDEN PRARIE | HANSON 42-26 | LARAMIE | WY | 35.4 | . | 3,093.1 | 198.0 | 209.3 | 772.2 | 1,179.5 | 1,913.6 | . | 1,913.6 | 1,419.5 |
| 1PDP | STATELINE | ANDERSON 21-34 | LARAMIE | WY | 0.4 | . | 38.4 | 2.5 | 2.6 | 26.0 | 31.1 | 7.3 | . | 7.3 | 7.1 |
| 1PDP | STATELINE | HOLGERSON 33A-33 | LARAMIE | WY | 4.2 | . | 365.8 | 23.4 | 24.8 | 189.2 | 237.4 | 128.5 | . | 128.5 | 117.1 |
| 1PDP | STATELINE | MALM 42-34 | LARAMIE | WY | 1.2 | . | 104.9 | 6.7 | 7.1 | 68.4 | 82.2 | 22.7 | . | 22.7 | 21.6 |
| 1PDP | STATELINE | OLIVERIUS 41-33 | LARAMIE | WY | 2.3 | . | 202.7 | 13.0 | 13.7 | 123.2 | 149.9 | 52.8 | . | 52.8 | 49.5 |
| 1PDP | STATELINE | OLIVERIUS 42-33 | LARAMIE | WY | 4.1 | . | 361.0 | 23.1 | 24.4 | 158.4 | 205.9 | 155.0 | . | 155.0 | 143.4 |
| 1PDP | STATELINE | WENZEL 12-34 | LARAMIE | WY | 61.0 | . | 5,325.9 | 340.9 | 360.4 | 849.2 | 1,550.5 | 3,775.4 | . | 3,775.4 | 2,888.7 |
| 1PDP | WILDCAT | FORNSTROM 33-32 | LARAMIE | WY | 1.3 | . | 117.3 | 7.5 | 7.9 | . | 15.5 | 101.9 | . | 101.9 | 68.0 |
| 1PDP | WILDCAT | FORNSTROM 34A-32 | LARAMIE | WY | 3.4 | . | 297.1 | 19.0 | 20.1 | . | 39.1 | 258.0 | . | 258.0 | 157.9 |
| 1PDP | WILDCAT | FORNSTROM 43-32 | LARAMIE | WY | 1.6 | . | 143.6 | 9.2 | 9.7 | . | 18.9 | 124.7 | . | 124.7 | 80.9 |
| **SUB TOTAL: PDP** | | | | | **213.3** | **186.0** | **20,014.0** | **796.8** | **1,197.4** | **4,671.0** | **6,665.2** | **13,348.8** | **76.9** | **13,271.9** | **9,743.2** |
| **PROVED UNDEVELOPED** | | | | | | | | | | | | | | | |
| 3PUD | WATTENBERG | LANG 11-34 | WELD | CO | 9.6 | 44.3 | 954.4 | . | 76.4 | 163.5 | 239.8 | 714.6 | 93.8 | 620.8 | 277.9 |
| 3PUD | WATTENBERG | LANG 12-34 | WELD | CO | 9.6 | 44.3 | 954.4 | . | 76.4 | 163.5 | 239.8 | 714.6 | 93.8 | 620.8 | 277.9 |
| 3PUD | WATTENBERG | LANG 21-34 | WELD | CO | 9.6 | 44.3 | 954.4 | . | 76.4 | 163.5 | 239.8 | 714.6 | 93.8 | 620.8 | 277.9 |
| 3PUD | WATTENBERG | LANG 22-34 | WELD | CO | 9.6 | 44.3 | 954.4 | . | 76.4 | 163.5 | 239.8 | 714.6 | 93.8 | 620.8 | 277.9 |
| 3PUD | WATTENBERG | LANG 2-2-34 | WELD | CO | 9.6 | 44.3 | 954.4 | . | 76.4 | 163.5 | 239.8 | 714.6 | 93.8 | 620.8 | 277.9 |
| 3PUD | ALBIN WEST | PALM 11-20 | BANNER | NE | 10.8 | . | 940.6 | 28.2 | 18.2 | 143.0 | 189.5 | 751.2 | . | 751.2 | 545.0 |
| 3PUD | ALBIN WEST | PALM 42-20 | BANNER | NE | 12.0 | . | 1,045.2 | 31.4 | 20.3 | 159.5 | 211.1 | 834.0 | . | 834.0 | 649.0 |
| 3PUD | RANCHER | LARSON 24-20 | KIMBALL | NE | 9.7 | . | 851.7 | 25.6 | 16.5 | 130.9 | 173.0 | 678.7 | . | 678.7 | 462.2 |

## RECOVERY ENERGY, INC. REVISED RESERVES AND REVENUES AS OF 12/31/2012
## SORTED BY CATEGORY, STATE, FIELD, AND LEASE

| RESERVE CAT | FIELD | LEASE | COUNTY | STATE | NET OIL RESERVES MBBLS | NET GAS RESERVES MMCF | TOTAL REVENUE M$ | SEVERANCE TAX M$ | AD VAL TAX M$ | DIRECT OP EXPENSE M$ | TOTAL OP EXPENSE M$ | OPERATING REVENUE M$ | TOTAL INVESTMENT M$ | CASH FLOW UNDISC M$ | CASH FLOW DISC @ 10% M$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3PUD | STATELINE | OLIVERIUS 32-33 | BANNER | NE | 7.7 | - | 672.7 | 43.1 | 45.5 | 68.2 | 156.8 | 515.9 | - | 515.9 | 407.9 |
| 3PUD | SURGE | VRTATKO 44-22 | KIMBALL | NE | 8.6 | - | 752.2 | 22.6 | 14.6 | 128.7 | 165.9 | 586.4 | - | 586.4 | 400.8 |
| 3PUD | TERRESTRIAL | LUKASSEN 42-7 | BANNER | NE | 10.6 | - | 923.4 | 27.7 | 17.9 | 250.8 | 296.4 | 627.0 | - | 627.0 | 411.0 |
| 3PUD | TERRESTRIAL | LUKASSEN 44-18 | BANNER | NE | 10.6 | - | 923.4 | 27.7 | 17.9 | 250.8 | 296.4 | 627.0 | - | 627.0 | 411.0 |
| 3PUD | WILKE | WILKE 44A-5 | KIIMBALL | NE | 7.7 | - | 670.8 | 20.1 | 13.0 | 112.2 | 145.3 | 525.5 | - | 525.5 | 392.3 |
| 3PUD | ALBIN WEST | MALM 32-34 | LARAMIE | WY | 12.0 | - | 1,045.9 | 31.4 | 20.3 | 167.2 | 218.9 | 827.0 | - | 827.0 | 610.2 |
| **SUB TOTAL: PUD** | | | | | **137.6** | **221.3** | **12,598.1** | **257.6** | **566.1** | **2,228.7** | **3,052.4** | **9,545.7** | **468.8** | **9,076.9** | **5,679.0** |
| **TOTAL PROVED** | | | | | **350.9** | **407.3** | **32,612.0** | **1,054.4** | **1,763.5** | **6,899.6** | **9,717.5** | **18,380.7** | **545.6** | **22,348.9** | **15,422.1** |

**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529

# Oneline Summary Sorted by Reserve Cateogory, Ranked by PV 10%

## RECOVERY ENERGY, INC. REVISED
## RESERVES AND REVENUES AS OF
## 12/31/2012
## SORTED BY CATEGORY AND RANKED BY PV 10

| RESERVE CAT | STATE | LEASE | COUNTY | FIELD | GROSS OIL RESERVES MBBLS | GROSS GAS RESERVES MMCF | NET OIL RESERVES MBBLS | NET GAS RESERVES MMCF | TOTAL REVENUE M$ | SEVERANCE TAX M$ | AD VAL TAX M$ | DIRECT OP EXPENSE M$ | TOTAL OP EXPENSE M$ | OPERATING REVENUE M$ | TOTAL INVESTMENT M$ | CASH FLOW UNDISC M$ | CASH FLOW DISC @ 10% M$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **PROVED DEVELOPED PRODUCING** | | | | | | | | | | | | | | | | | |
| 1PDP | WY | LARAMIE | STATELINE | WENZEL 12-34 | 79.2 | . | 61.0 | . | 5,325.9 | 340.9 | 360.4 | 849.2 | 1,550.5 | 3,775.4 | . | 3,775.4 | 2,888.7 |
| 1PDP | NE | BANNER | ALBIN WEST | PALM EGLE 34-17 | 45.7 | . | 37.7 | . | 3,295.0 | 98.8 | 63.9 | 653.4 | 816.1 | 2,478.8 | . | 2,478.8 | 1,799.6 |
| 1PDP | WY | LARAMIE | GOLDEN PRARIE | HANSON42-26 | 49.2 | . | 35.4 | . | 3,093.1 | 198.0 | 209.3 | 772.2 | 1,179.5 | 1,913.6 | . | 1,913.6 | 1,419.5 |
| 1PDP | CO | ARAPAHOE | PEACE PIPE | STATE-BRADBURY 13-36 | 3.0 | 273.3 | 1.5 | 76.3 | 1,217.4 | . | 121.7 | 327.4 | 449.1 | 768.3 | 46.9 | 721.4 | 581.6 |
| 1PDP | CO | WELD | WATTENBERG | SLW STATE PC BB18-65HN | 200.5 | 783.2 | 11.0 | 42.9 | 1,069.8 | . | 85.6 | 44.0 | 129.6 | 940.2 | . | 940.2 | 557.8 |
| 1PDP | CO | WELD | WATTENBERG | SLW STATE PC BB18-67HN | 185.8 | 680.0 | 8.7 | 31.7 | 839.0 | . | 67.1 | 35.2 | 102.3 | 736.7 | . | 736.7 | 439.3 |
| 1PDP | NE | BANNER | ALBIN WEST | PALM 21A-20, 43-20, 23-21 | 12.2 | . | 10.1 | . | 881.3 | 26.4 | 17.1 | 404.8 | 448.3 | 432.9 | . | 432.9 | 392.5 |
| 1PDP | CO | ADAMS | TRAPPER | CIMYOTTE #6-21 | 8.4 | 22.2 | 6.5 | 17.1 | 610.5 | . | 54.9 | 107.2 | 162.1 | 448.4 | . | 448.4 | 336.1 |
| 1PDP | NE | KIMBALL | DILL EAST | WILKE 34-5,33-5,24-5,23-5 | 11.4 | . | 7.8 | . | 677.2 | 20.3 | 13.1 | 415.8 | 449.3 | 227.9 | . | 227.9 | 214.1 |
| 1PDP | WY | LARAMIE | WILDCAT | FORNSTROM 34A-32 | 130.8 | . | 3.4 | . | 297.1 | 19.0 | 20.1 | . | 39.1 | 258.0 | . | 258.0 | 157.9 |
| 1PDP | CO | WELD | WATTENBERG | SAWYER 32-2 | 11.1 | 16.0 | 4.5 | 6.5 | 411.2 | . | 32.9 | 93.7 | 126.6 | 284.6 | . | 284.6 | 152.9 |
| 1PDP | WY | LARAMIE | STATELINE | OLIVERIUS42-33 | 5.4 | . | 4.1 | . | 361.0 | 23.1 | 24.4 | 158.4 | 205.9 | 155.0 | . | 155.0 | 143.4 |
| 1PDP | CO | WELD | WATTENBERG | VINCE STATE B13-63HN | 173.6 | 749.1 | 2.7 | 11.6 | 263.4 | . | 21.1 | 12.0 | 33.1 | 230.4 | . | 230.4 | 132.1 |
| 1PDP | WY | LARAMIE | STATELINE | HOLGERSON 33A-33 | 5.4 | . | 4.2 | . | 365.8 | 23.4 | 24.8 | 189.2 | 237.4 | 128.5 | . | 128.5 | 117.1 |
| 1PDP | CO | WASHINGTON | RED CLOUD | LEO PEIPER #1&3 | 6.4 | . | 5.0 | . | 432.8 | . | 34.6 | 228.2 | 262.8 | 170.0 | 30.0 | 140.0 | 100.2 |
| 1PDP | NE | KIMBALL | CABLE | LUKASSEN 14-34 | 3.9 | . | 3.1 | . | 266.7 | 8.0 | 5.2 | 162.8 | 176.0 | 90.7 | . | 90.7 | 83.3 |
| 1PDP | WY | LARAMIE | WILDCAT | FORNSTROM 43-32 | 63.2 | . | 1.6 | . | 143.6 | 9.2 | 9.7 | . | 18.9 | 124.7 | . | 124.7 | 80.9 |
| 1PDP | WY | LARAMIE | WILDCAT | FORNSTROM 33-32 | 51.7 | . | 1.3 | . | 117.3 | 7.5 | 7.9 | . | 15.5 | 101.9 | . | 101.9 | 68.0 |
| 1PDP | WY | LARAMIE | STATELINE | OLIVERIUS41-33 | 3.0 | . | 2.3 | . | 202.7 | 13.0 | 13.7 | 123.2 | 149.9 | 52.8 | . | 52.8 | 49.5 |
| 1PDP | WY | LARAMIE | STATELINE | MALM 42-34 | 2.1 | . | 1.2 | . | 104.9 | 6.7 | 7.1 | 68.4 | 82.2 | 22.7 | . | 22.7 | 21.6 |
| 1PDP | WY | LARAMIE | STATELINE | ANDERSON 21-34 | 0.8 | . | 0.4 | . | 38.4 | 2.5 | 2.6 | 26.0 | 31.1 | 7.3 | . | 7.3 | 7.1 |
| **SUB TOTAL: PDP** | | | | | **1,052.7** | **2,523.9** | **213.3** | **186.0** | **20,014.0** | **796.8** | **1,197.4** | **4,671.0** | **6,665.2** | **13,348.8** | **76.9** | **13,271.9** | **9,743.2** |
| **PROVED UNDEVELOPED** | | | | | | | | | | | | | | | | | |
| 3PUD | NE | BANNER | ALBIN WEST | PALM 42-20 | 58.0 | . | 12.0 | . | 1,045.2 | 31.4 | 20.3 | 159.5 | 211.1 | 834.0 | . | 834.0 | 649.0 |
| 3PUD | WY | LARAMIE | ALBIN WEST | MALM 32-34 | 60.6 | . | 12.0 | . | 1,045.9 | 31.4 | 20.3 | 167.2 | 218.9 | 827.0 | . | 827.0 | 610.2 |
| 3PUD | NE | BANNER | ALBIN WEST | PALM 11-20 | 52.2 | . | 10.8 | . | 940.6 | 28.2 | 18.2 | 143.0 | 189.5 | 751.2 | . | 751.2 | 545.0 |
| 3PUD | NE | KIMBALL | RANCHER | LARSON 24-20 | 44.6 | . | 9.7 | . | 851.7 | 25.6 | 16.5 | 130.9 | 173.0 | 678.7 | . | 678.7 | 462.2 |
| 3PUD | NE | BANNER | TERRESTRIAL | LUKASSEN 42-7 | 56.4 | . | 10.6 | . | 923.4 | 27.7 | 17.9 | 250.8 | 296.4 | 627.0 | . | 627.0 | 411.0 |
| 3PUD | NE | BANNER | TERRESTRIAL | LUKASSEN44-18 | 56.4 | . | 10.6 | . | 923.4 | 27.7 | 17.9 | 250.8 | 296.4 | 627.0 | . | 627.0 | 411.0 |
| 3PUD | NE | BANNER | STATELINE | OLIVERIUS 32-33 | 40.0 | . | 7.7 | . | 672.7 | 43.1 | 45.5 | 68.2 | 156.8 | 515.9 | . | 515.9 | 407.9 |
| 3PUD | NE | KIMBALL | SURGE | VRTATKO 44-22 | 44.4 | . | 8.6 | . | 752.2 | 22.6 | 14.6 | 128.7 | 165.9 | 586.4 | . | 586.4 | 400.8 |
| 3PUD | NE | KIIMBALL | WILKE | WILKE 44A-5 | 45.0 | . | 7.7 | . | 670.8 | 20.1 | 13.0 | 112.2 | 145.3 | 525.5 | . | 525.5 | 392.3 |
| 3PUD | CO | WELD | WATTENBERG | LANG 11-34 | 47.1 | 217.2 | 9.6 | 44.3 | 954.4 | . | 76.4 | 163.5 | 239.8 | 714.6 | 93.8 | 620.8 | 277.9 |
| 3PUD | CO | WELD | WATTENBERG | LANG 12-34 | 47.1 | 217.2 | 9.6 | 44.3 | 954.4 | . | 76.4 | 163.5 | 239.8 | 714.6 | 93.8 | 620.8 | 277.9 |
| 3PUD | CO | WELD | WATTENBERG | LANG 21-34 | 47.1 | 217.2 | 9.6 | 44.3 | 954.4 | . | 76.4 | 163.5 | 239.8 | 714.6 | 93.8 | 620.8 | 277.9 |

**RALPH E. DAVIS ASSOCIATES, INC.**

Texas Registered Engineering Firm F-1529

**REVISED AS OF APRIL 1, 2013**

## RECOVERY ENERGY, INC. REVISED
## RESERVES AND REVENUES AS OF
## 12/31/2012
## SORTED BY CATEGORY AND RANKED BY PV 10

| RESERVE CAT | STATE | LEASE | COUNTY | FIELD | GROSS OIL RESERVES MBBLS | GROSS GAS RESERVES MMCF | NET OIL RESERVES MBBLS | NET GAS RESERVES MMCF | TOTAL REVENUE M$ | SEVERANCE TAX M$ | AD VAL TAX M$ | DIRECT OP EXPENSE M$ | TOTAL OP EXPENSE M$ | OPERATING REVENUE M$ | TOTAL INVESTMENT M$ | CASH FLOW UNDISC M$ | DISC @ 1 M$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3PUD | CO | WELD | WATTENBERG | LANG 2-2-34 | 47.1 | 217.2 | 9.6 | 44.3 | 954.4 | - | 76.4 | 163.5 | 239.8 | 714.6 | 93.8 | 620.8 | 2 |
| 3PUD | CO | WELD | WATTENBERG | LANG 22-34 | 47.1 | 217.2 | 9.6 | 44.3 | 954.4 | - | 76.4 | 163.5 | 239.8 | 714.6 | 93.8 | 620.8 | 2 |
| **SUB TOTAL: PUD** | | | | | **693.0** | **1,086.2** | **137.6** | **221.3** | **12,598.1** | **257.6** | **566.1** | **2,228.7** | **3,052.4** | **9,545.7** | **468.8** | **9,076.9** | **5,** |
| **TOTAL PROVED** | | | | | **1,745.7** | **3,610.1** | **350.9** | **407.3** | **32,612.0** | **1,054.4** | **1,763.5** | **6,899.6** | **9,717.5** | **18,380.7** | **545.6** | **22,348.9** | **15,4** |

**RALPH E. DAVIS ASSOCIATES, INC.**

Texas Registered Engineering Firm F-1529

# Proved Developed Producing
# Individual Wells for Producing
# Properties w/ Production Curves

RECOVERY ENERGY
PROVED DEVELOPED PRODUCING
RESERVES AND REVENUES AS OF 12/3
REVISED EVALUATION AT 03/28 2013

DATE : 04/01/2013
TIME : 14:03:13
DBS : DEMO
SETTINGS : RED_JAN 13
SCENARIO: RED_JAN 13

## R E S E R V E S   A N D   E C O N O M I C S

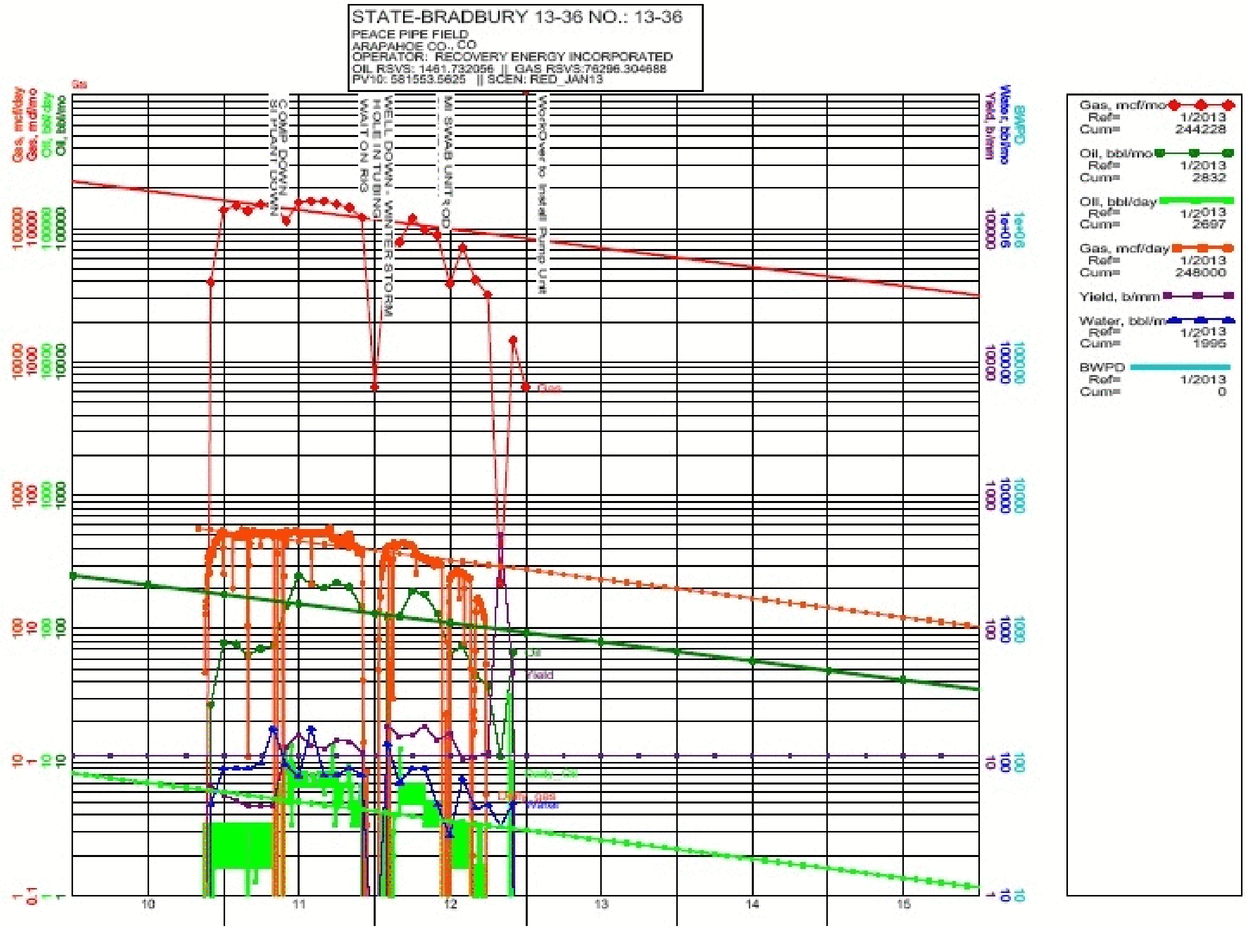
### AS OF DATE: 12/31/2012

| --END-- MO-YEAR | GROSS OIL PRODUCTION MBBLS | GROSS GAS PRODUCTION MMCF | NET OIL PRODUCTION MBBLS | NET GAS PRODUCTION MMCF | NET OIL PRICE $/BBL | NET GAS PRICE $/MCF | NET OIL SALES M$ | NET GAS SALES M$ | TOTAL NET SALES M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 197.939 | 638.405 | 51.927 | 50.921 | 87.370 | 2.668 | 4536.825 | 135.843 | 4897.542 |
| 12-2014 | 129.647 | 354.038 | 36.386 | 31.748 | 87.370 | 2.694 | 3179.041 | 85.544 | 3464.542 |
| 12-2015 | 95.000 | 239.715 | 25.459 | 22.380 | 87.370 | 2.697 | 2224.379 | 60.361 | 2428.709 |
| 12-2016 | 73.896 | 177.636 | 17.946 | 16.547 | 87.370 | 2.696 | 1567.923 | 44.612 | 1716.193 |
| 12-2017 | 60.615 | 138.560 | 13.331 | 12.499 | 87.370 | 2.693 | 1164.708 | 33.663 | 1273.004 |
| 12-2018 | 52.483 | 111.924 | 11.113 | 9.599 | 87.370 | 2.689 | 970.963 | 25.813 | 1050.512 |
| 12-2019 | 46.294 | 92.838 | 9.387 | 7.482 | 87.370 | 2.684 | 820.117 | 20.084 | 878.891 |
| 12-2020 | 41.396 | 78.672 | 8.015 | 5.917 | 87.370 | 2.679 | 700.229 | 15.850 | 743.937 |
| 12-2021 | 37.301 | 65.519 | 6.890 | 4.093 | 87.370 | 2.660 | 601.958 | 10.887 | 625.337 |
| 12-2022 | 33.758 | 54.960 | 5.917 | 2.615 | 87.370 | 2.626 | 516.941 | 6.868 | 523.809 |
| 12-2023 | 30.497 | 49.521 | 4.942 | 2.296 | 87.370 | 2.624 | 431.774 | 6.024 | 437.798 |
| 12-2024 | 27.904 | 45.014 | 4.338 | 2.033 | 87.370 | 2.622 | 379.027 | 5.332 | 384.359 |
| 12-2025 | 25.574 | 41.223 | 3.829 | 1.816 | 87.370 | 2.620 | 334.500 | 4.760 | 339.260 |
| 12-2026 | 23.412 | 37.871 | 3.351 | 1.541 | 87.370 | 2.614 | 292.789 | 4.028 | 296.817 |
| 12-2027 | 21.412 | 35.005 | 2.905 | 1.323 | 87.370 | 2.608 | 253.824 | 3.450 | 257.274 |
| S TOT | 897.129 | 2160.900 | 205.734 | 172.810 | 87.370 | 2.680 | 17974.994 | 463.119 | 19317.984 |
| AFTER | 155.559 | 362.971 | 7.572 | 13.207 | 87.370 | 2.605 | 661.588 | 34.401 | 695.989 |
| TOTAL | 1052.689 | 2523.871 | 213.306 | 186.017 | 87.370 | 2.675 | 18636.582 | 497.520 | 20013.975 |

| --END-- MO-YEAR | AD VALOREM TAX M$ | PRODUCTION TAX M$ | DIRECT OPER EXPENSE M$ | INTEREST PAID M$ | CAPITAL REPAYMENT M$ | EQUITY INVESTMENT M$ | FUTURE NET CASHFLOW M$ | CUMULATIVE CASHFLOW M$ | CUM. DISC. CASHFLOW M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 282.191 | 202.694 | 804.669 | 0.000 | 0.000 | 76.875 | 3531.113 | 3531.113 | 3375.591 |
| 12-2014 | 198.328 | 142.352 | 769.203 | 0.000 | 0.000 | 0.000 | 2354.660 | 5885.773 | 5423.761 |
| 12-2015 | 142.456 | 98.852 | 556.440 | 0.000 | 0.000 | 0.000 | 1630.962 | 7516.734 | 6712.760 |
| 12-2016 | 103.171 | 68.054 | 344.940 | 0.000 | 0.000 | 0.000 | 1200.027 | 8716.762 | 7574.643 |
| 12-2017 | 79.236 | 50.150 | 216.771 | 0.000 | 0.000 | 0.000 | 926.846 | 9643.608 | 8179.603 |
| 12-2018 | 64.990 | 41.107 | 213.194 | 0.000 | 0.000 | 0.000 | 731.221 | 10374.829 | 8613.465 |
| 12-2019 | 54.182 | 34.206 | 210.619 | 0.000 | 0.000 | 0.000 | 579.884 | 10954.713 | 8926.246 |
| 12-2020 | 45.813 | 28.824 | 208.764 | 0.000 | 0.000 | 0.000 | 460.536 | 11415.249 | 9152.071 |
| 12-2021 | 38.143 | 24.552 | 197.384 | 0.000 | 0.000 | 0.000 | 365.258 | 11780.507 | 9314.891 |
| 12-2022 | 31.533 | 21.109 | 179.096 | 0.000 | 0.000 | 0.000 | 292.071 | 12072.578 | 9433.246 |
| 12-2023 | 26.198 | 18.301 | 159.596 | 0.000 | 0.000 | 0.000 | 233.703 | 12306.281 | 9519.340 |
| 12-2024 | 23.214 | 15.982 | 159.596 | 0.000 | 0.000 | 0.000 | 185.567 | 12491.848 | 9581.493 |
| 12-2025 | 20.689 | 14.047 | 159.596 | 0.000 | 0.000 | 0.000 | 144.928 | 12636.776 | 9625.629 |
| 12-2026 | 18.163 | 12.418 | 155.627 | 0.000 | 0.000 | 0.000 | 110.609 | 12747.385 | 9656.256 |
| 12-2027 | 15.968 | 10.923 | 148.008 | 0.000 | 0.000 | 0.000 | 82.375 | 12829.760 | 9676.997 |
| S TOT | 1144.273 | 783.573 | 4483.504 | 0.000 | 0.000 | 76.875 | 12829.760 | 12829.760 | 9676.997 |
| AFTER | 53.133 | 13.219 | 187.457 | 0.000 | 0.000 | 0.000 | 442.180 | 13271.939 | 9743.167 |
| TOTAL | 1197.406 | 796.792 | 4670.961 | 0.000 | 0.000 | 76.875 | 13271.940 | 13271.939 | 9743.167 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 24.0 | 1.0 | LIFE, YRS. | 34.00 | 5.00 | 11160.462 |
| GROSS ULT., MB & MMF | 1768.762 | 3730.055 | DISCOUNT % | 10.00 | 8.00 | 10251.478 |
| GROSS CUM., MB & MMF | 716.073 | 1206.183 | UNDISCOUNTED PAYOUT, YRS. | 0.02 | 10.00 | 9743.169 |
| GROSS RES., MB & MMF | 1052.689 | 2523.872 | DISCOUNTED PAYOUT, YRS. | 0.02 | 12.00 | 9295.615 |
| NET RES., MB & MMF | 213.306 | 186.017 | UNDISCOUNTED NET/INVEST. | 173.64 | 15.00 | 8715.323 |
| NET REVENUE, M$ | 18636.578 | 497.520 | DISCOUNTED NET/INVEST. | 128.75 | 18.00 | 8221.428 |
| INITIAL PRICE, $ | 87.370 | 2.635 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 6803.890 |
| INITIAL N.I., PCT. | 40.176 | 5.931 | INITIAL W.I., PCT. | 27.804 | 60.00 | 5016.243 |
| | | | | | 80.00 | 4378.413 |
| | | | | | 260.00 | 2520.648 |

**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529




**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529

STATE-BRADBURY 13-36
FIELD: PEACE PIPE
COUNTY: ARAPAHOE STATE: CO
OPERATOR: RECOVERY ENERGY INCOR
1PDP

DATE : 04/01/2013
TIME : 14:03:09
DBS : DEMO
SETTINGS : RED_JAN 13
SCENARIO: RED_JAN 13

## R E S E R V E S A N D E C O N O M I C S

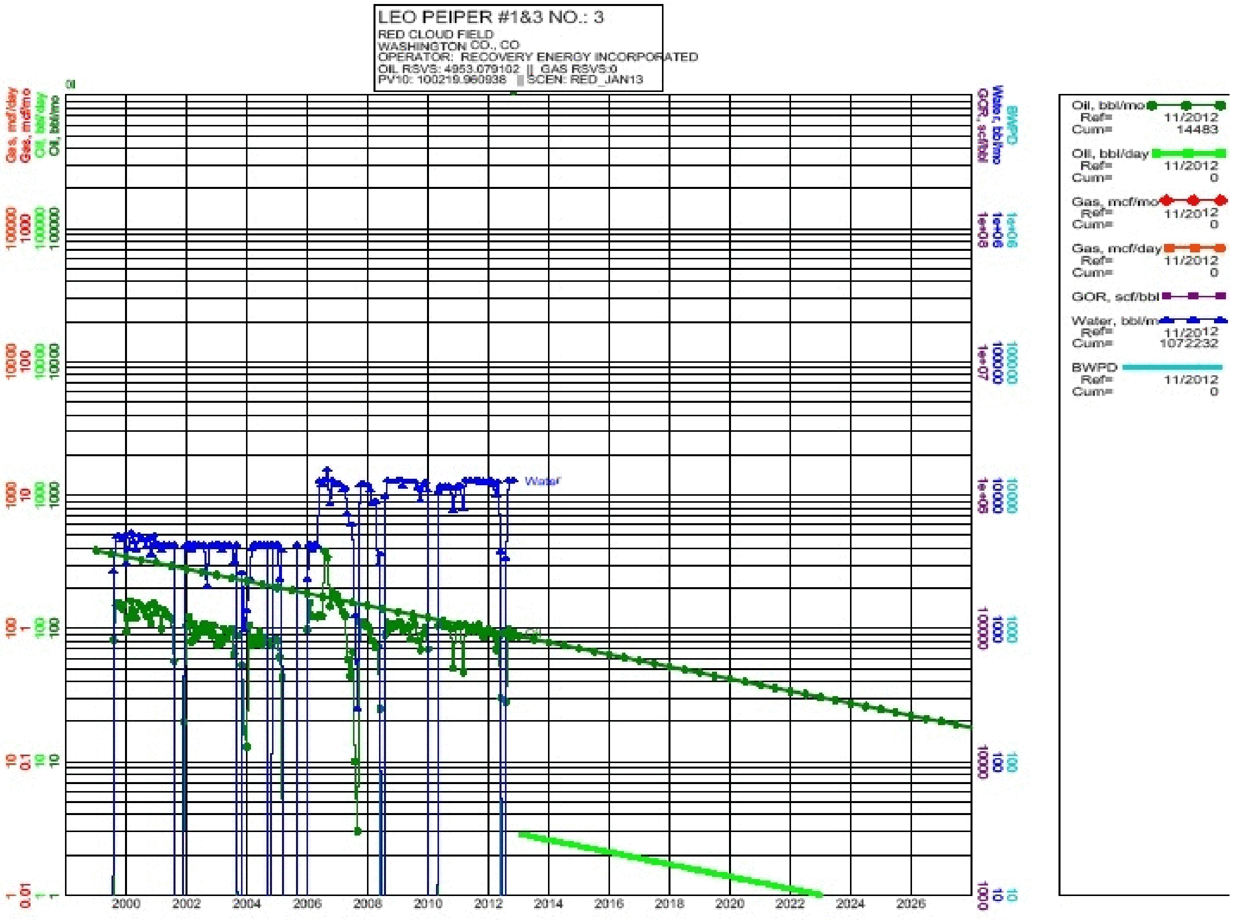
### AS OF DATE: 12/31/2012

| --END-- MO-YEAR | GROSS OIL PRODUCTION MBBLS | GROSS GAS PRODUCTION MMCF | NET OIL PRODUCTION MBBLS | NET GAS PRODUCTION MMCF | NET OIL PRICE $/BBL | NET GAS PRICE $/MCF | NET OIL SALES M$ | NET GAS SALES M$ | TOTAL NET SALES M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 0.776 | 69.860 | 0.374 | 19.500 | 87.370 | 2.750 | 32.640 | 53.624 | 311.138 |
| 12-2014 | 0.690 | 62.119 | 0.332 | 17.339 | 87.370 | 2.750 | 29.024 | 47.682 | 276.663 |
| 12-2015 | 0.497 | 44.726 | 0.239 | 12.484 | 87.370 | 2.750 | 20.897 | 34.331 | 199.198 |
| 12-2016 | 0.358 | 32.203 | 0.172 | 8.989 | 87.370 | 2.750 | 15.046 | 24.718 | 143.422 |
| 12-2017 | 0.258 | 23.186 | 0.124 | 6.472 | 87.370 | 2.750 | 10.833 | 17.797 | 103.264 |
| 12-2018 | 0.186 | 16.694 | 0.089 | 4.660 | 87.370 | 2.750 | 7.800 | 12.814 | 74.350 |
| 12-2019 | 0.134 | 12.020 | 0.064 | 3.355 | 87.370 | 2.750 | 5.616 | 9.226 | 53.532 |
| 12-2020 | 0.096 | 8.654 | 0.046 | 2.416 | 87.370 | 2.750 | 4.043 | 6.643 | 38.543 |
| 12-2021 | 0.043 | 3.881 | 0.021 | 1.083 | 87.370 | 2.750 | 1.813 | 2.979 | 17.283 |
| 12-2022 | | | | | | | | | |
| 12-2023 | | | | | | | | | |
| 12-2024 | | | | | | | | | |
| 12-2025 | | | | | | | | | |
| 12-2026 | | | | | | | | | |
| 12-2027 | | | | | | | | | |
| S TOT | 3.037 | 273.341 | 1.462 | 76.296 | 87.370 | 2.750 | 127.712 | 209.815 | 1217.395 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| TOTAL | 3.037 | 273.341 | 1.462 | 76.296 | 87.370 | 2.750 | 127.712 | 209.815 | 1217.**395** |

| --END-- MO-YEAR | AD VALOREM TAX M$ | PRODUCTION TAX M$ | DIRECT OPER EXPENSE M$ | INTEREST PAID M$ | CAPITAL REPAYMENT M$ | EQUITY INVESTMENT M$ | FUTURE NET CASHFLOW M$ | CUMULATIVE CASHFLOW M$ | CUM. DISC. CASHFLOW M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 31.114 | 0.000 | 55.993 | 0.000 | 0.000 | 46.875 | 177.157 | 177.157 | 165.876 |
| 12-2014 | 27.666 | 0.000 | 55.228 | 0.000 | 0.000 | 0.000 | 193.769 | 370.926 | 334.378 |
| 12-2015 | 19.920 | 0.000 | 45.644 | 0.000 | 0.000 | 0.000 | 133.634 | 504.560 | 440.034 |
| 12-2016 | 14.342 | 0.000 | 38.744 | 0.000 | 0.000 | 0.000 | 90.336 | 594.897 | 504.978 |
| 12-2017 | 10.326 | 0.000 | 33.775 | 0.000 | 0.000 | 0.000 | 59.162 | 654.059 | 543.655 |
| 12-2018 | 7.435 | 0.000 | 30.198 | 0.000 | 0.000 | 0.000 | 36.717 | 690.776 | 565.489 |
| 12-2019 | 5.353 | 0.000 | 27.623 | 0.000 | 0.000 | 0.000 | 20.556 | 711.332 | 576.615 |
| 12-2020 | 3.854 | 0.000 | 25.768 | 0.000 | 0.000 | 0.000 | 8.920 | 720.252 | 581.019 |
| 12-2021 | 1.728 | 0.000 | 14.388 | 0.000 | 0.000 | 0.000 | 1.167 | 721.419 | 581.554 |
| 12-2022 | | | | | | | | | |
| 12-2023 | | | | | | | | | |
| 12-2024 | | | | | | | | | |
| 12-2025 | | | | | | | | | |
| 12-2026 | | | | | | | | | |
| 12-2027 | | | | | | | | | |
| S TOT | 121.739 | 0.000 | 327.361 | 0.000 | 0.000 | 46.875 | 721.419 | 721.419 | 581.554 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 721.419 | 581.554 |
| TOTAL | 121.739 | 0.000 | 327.361 | 0.000 | 0.000 | 46.875 | 721.419 | 721.419 | 581.554 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 0.0 | 1.0 | LIFE, YRS. | 8.58 | 5.00 | 644.172 |
| GROSS ULT., MB & MMF | 5.869 | 517.569 | DISCOUNT % | 10.00 | 8.00 | 605.105 |
| GROSS CUM., MB & MMF | 2.832 | 244.228 | UNDISCOUNTED PAYOUT, YRS. | 0.21 | 10.00 | 581.554 |
| GROSS RES., MB & MMF | 3.037 | 273.341 | DISCOUNTED PAYOUT, YRS. | 0.22 | 12.00 | 559.752 |
| NET RES., MB & MMF | 1.462 | 76.296 | UNDISCOUNTED NET/INVEST. | 16.39 | 15.00 | 529.948 |
| NET REVENUE, M$ | 127.712 | 209.815 | DISCOUNTED NET/INVEST. | 13.51 | 18.00 | 503.173 |
| INITIAL PRICE, $ | 87.370 | 2.750 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 418.930 |
| INITIAL N.I., PCT. | 48.125 | 48.125 | INITIAL W.I., PCT. | 62.500 | 60.00 | 297.543 |
| | | | | | 80.00 | 250.833 |
| | | | | | 260.00 | 110.800 |

**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529




**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529

LEO PEIPER #1&3
FIELD: RED CLOUD
COUNTY: WASHINGTON STATE: CO
OPERATOR : RECOVERY ENERGY INCOR
1PDP

DATE : 04/01/2013
TIME : 14:03:09
DBS : DEMO
SETTINGS : RED_JAN 13
SCENARIO: RED_JAN 13

## R E S E R V E S   A N D   E C O N O M I C S

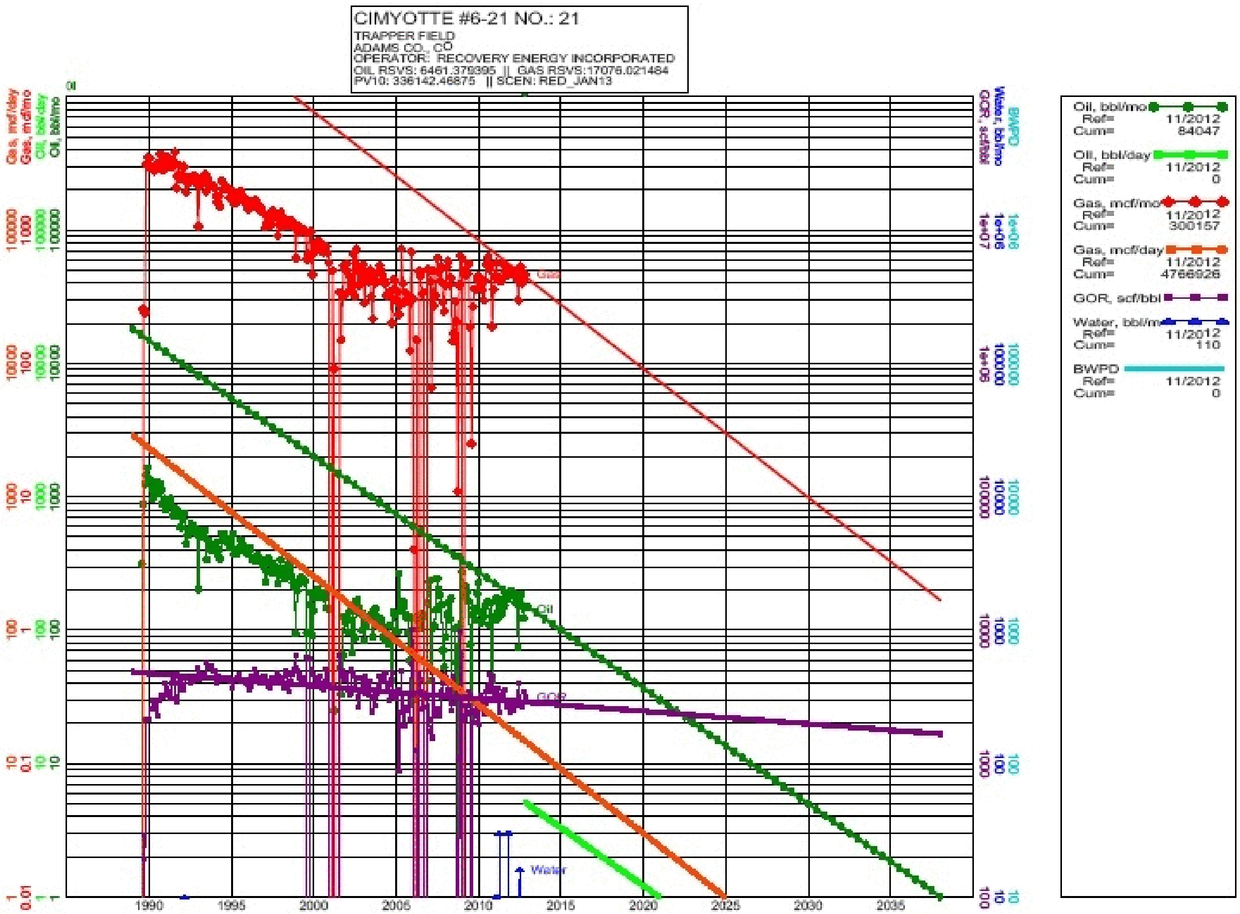
### AS OF DATE: 12/31/2012

| --END-- MO-YEAR | GROSS OIL PRODUCTION MBBLS | GROSS GAS PRODUCTION MMCF | NET OIL PRODUCTION MBBLS | NET GAS PRODUCTION MMCF | NET OIL PRICE $/BBL | NET GAS PRICE $/MCF | NET OIL SALES M$ | NET GAS SALES M$ | TOTAL NET SALES M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 0.911 | 0.000 | 0.711 | 0.000 | 87.370 | 0.000 | 62.085 | 0.000 | 62.085 |
| 12-2014 | 0.898 | 0.000 | 0.701 | 0.000 | 87.370 | 0.000 | 61.221 | 0.000 | 61.221 |
| 12-2015 | 0.808 | 0.000 | 0.631 | 0.000 | 87.370 | 0.000 | 55.092 | 0.000 | 55.092 |
| 12-2016 | 0.727 | 0.000 | 0.567 | 0.000 | 87.370 | 0.000 | 49.576 | 0.000 | 49.576 |
| 12-2017 | 0.655 | 0.000 | 0.511 | 0.000 | 87.370 | 0.000 | 44.612 | 0.000 | 44.612 |
| 12-2018 | 0.589 | 0.000 | 0.459 | 0.000 | 87.370 | 0.000 | 40.146 | 0.000 | 40.146 |
| 12-2019 | 0.530 | 0.000 | 0.413 | 0.000 | 87.370 | 0.000 | 36.126 | 0.000 | 36.126 |
| 12-2020 | 0.477 | 0.000 | 0.372 | 0.000 | 87.370 | 0.000 | 32.509 | 0.000 | 32.509 |
| 12-2021 | 0.429 | 0.000 | 0.335 | 0.000 | 87.370 | 0.000 | 29.254 | 0.000 | 29.254 |
| 12-2022 | 0.325 | 0.000 | 0.253 | 0.000 | 87.370 | 0.000 | 22.128 | 0.000 | 22.128 |
| 12-2023 | | | | | | | | | |
| 12-2024 | | | | | | | | | |
| 12-2025 | | | | | | | | | |
| 12-2026 | | | | | | | | | |
| 12-2027 | | | | | | | | | |
| S TOT | 6.350 | 0.000 | 4.953 | 0.000 | 87.370 | 0.000 | 432.751 | 0.000 | 432.751 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| TOTAL | 6.350 | 0.000 | 4.953 | 0.000 | 87.370 | 0.000 | 432.751 | 0.000 | 432.751 |

| --END-- MO-YEAR | AD VALOREM TAX M$ | PRODUCTION TAX M$ | DIRECT OPER EXPENSE M$ | INTEREST PAID M$ | CAPITAL REPAYMENT M$ | EQUITY INVESTMENT M$ | FUTURE NET CASHFLOW M$ | CUMULATIVE CASHFLOW M$ | CUM. DISC. CASHFLOW M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 4.967 | 0.000 | 21.450 | 0.000 | 0.000 | 30.000 | 5.669 | 5.669 | 4.160 |
| 12-2014 | 4.898 | 0.000 | 23.400 | 0.000 | 0.000 | 0.000 | 32.924 | 38.592 | 32.749 |
| 12-2015 | 4.407 | 0.000 | 23.400 | 0.000 | 0.000 | 0.000 | 27.284 | 65.877 | 54.290 |
| 12-2016 | 3.966 | 0.000 | 23.400 | 0.000 | 0.000 | 0.000 | 22.210 | 88.087 | 70.233 |
| 12-2017 | 3.569 | 0.000 | 23.400 | 0.000 | 0.000 | 0.000 | 17.643 | 105.730 | 81.750 |
| 12-2018 | 3.212 | 0.000 | 23.400 | 0.000 | 0.000 | 0.000 | 13.534 | 119.264 | 89.783 |
| 12-2019 | 2.890 | 0.000 | 23.400 | 0.000 | 0.000 | 0.000 | 9.836 | 129.100 | 95.094 |
| 12-2020 | 2.601 | 0.000 | 23.400 | 0.000 | 0.000 | 0.000 | 6.508 | 135.609 | 98.292 |
| 12-2021 | 2.340 | 0.000 | 23.400 | 0.000 | 0.000 | 0.000 | 3.514 | 139.122 | 99.865 |
| 12-2022 | 1.770 | 0.000 | 19.500 | 0.000 | 0.000 | 0.000 | 0.858 | 139.981 | 100.220 |
| 12-2023 | | | | | | | | | |
| 12-2024 | | | | | | | | | |
| 12-2025 | | | | | | | | | |
| 12-2026 | | | | | | | | | |
| 12-2027 | | | | | | | | | |
| S TOT | 34.620 | 0.000 | 228.150 | 0.000 | 0.000 | 30.000 | 139.981 | 139.981 | 100.220 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 139.981 | 100.220 |
| TOTAL | 34.620 | 0.000 | 228.150 | 0.000 | 0.000 | 30.000 | 139.981 | 139.981 | 100.220 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 9.83 | 5.00 | 117.537 |
| GROSS ULT., MB & MMF | 20.833 | 0.000 | DISCOUNT % | 10.00 | 8.00 | 106.639 |
| GROSS CUM., MB & MMF | 14.483 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.84 | 10.00 | 100.220 |
| GROSS RES., MB & MMF | 6.350 | 0.000 | DISCOUNTED PAYOUT, YRS. | 0.88 | 12.00 | 94.382 |
| NET RES., MB & MMF | 4.953 | 0.000 | UNDISCOUNTED NET/INVEST. | 5.67 | 15.00 | 86.567 |
| NET REVENUE, M$ | 432.751 | 0.000 | DISCOUNTED NET/INVEST. | 4.37 | 18.00 | 79.711 |
| INITIAL PRICE, $ | 87.370 | 0.000 | RATE-OF-RETURN, PCT. | 246.57 | 30.00 | 59.196 |
| INITIAL N.I., PCT. | 78.000 | 0.000 | INITIAL W.I., PCT. 100.000 | | 60.00 | 32.591 |
| | | | | | 80.00 | 23.324 |
| | | | | | 260.00 | -1.019 |

**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529




**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529

**CIMYOTTE #6-21**
**FIELD: TRAPPER**
**COUNTY: ADAMS STATE: CO**
**OPERATOR: RECOVERY ENERGY INCOR**
**1PDP**

**DATE : 04/01/2013**
**TIME : 14:03:09**
**DBS : DEMO**
**SETTINGS : RED_JAN 13**
**SCENARIO: RED_JAN 13**

## R E S E R V E S A N D E C O N O M I C S

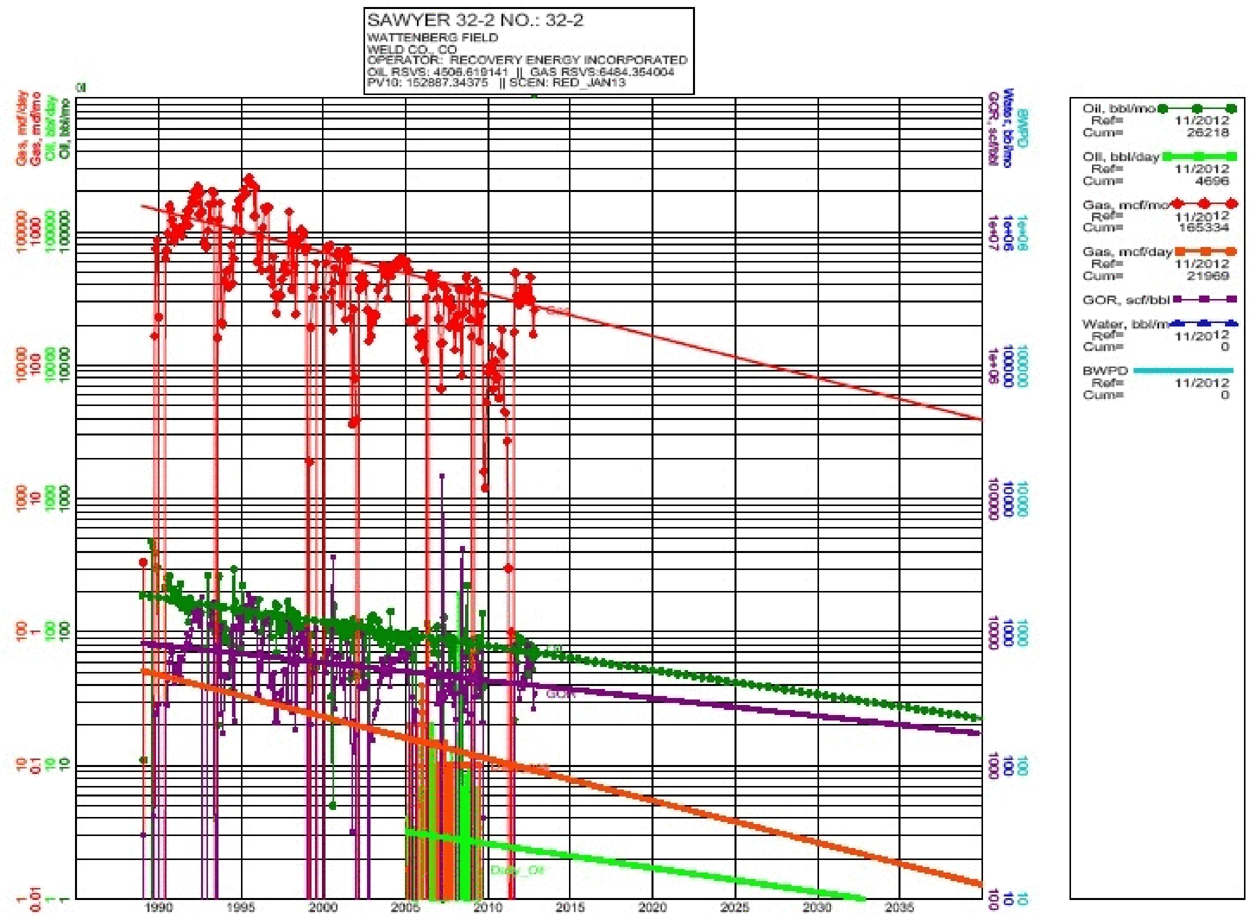
**AS OF DATE: 12/31/2012**

| --END-- MO-YEAR | GROSS OIL PRODUCTION MBBLS | GROSS GAS PRODUCTION MMCF | NET OIL PRODUCTION MBBLS | NET GAS PRODUCTION MMCF | NET OIL PRICE $/BBL | NET GAS PRICE $/MCF | NET OIL SALES M$ | NET GAS SALES M$ | TOTAL NET SALES M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 1.629 | 4.640 | 1.256 | 3.577 | 87.370 | 2.690 | 109.719 | 9.622 | 119.341 |
| 12-2014 | 1.334 | 3.717 | 1.028 | 2.865 | 87.370 | 2.690 | 89.827 | 7.707 | 97.534 |
| 12-2015 | 1.092 | 2.977 | 0.842 | 2.295 | 87.370 | 2.690 | 73.542 | 6.173 | 79.715 |
| 12-2016 | 0.894 | 2.385 | 0.689 | 1.838 | 87.370 | 2.690 | 60.209 | 4.945 | 65.154 |
| 12-2017 | 0.732 | 1.910 | 0.564 | 1.472 | 87.370 | 2.690 | 49.293 | 3.961 | 53.254 |
| 12-2018 | 0.599 | 1.530 | 0.462 | 1.179 | 87.370 | 2.690 | 40.356 | 3.173 | 43.529 |
| 12-2019 | 0.491 | 1.226 | 0.378 | 0.945 | 87.370 | 2.690 | 33.039 | 2.541 | 35.581 |
| 12-2020 | 0.402 | 0.982 | 0.310 | 0.757 | 87.370 | 2.690 | 27.049 | 2.036 | 29.085 |
| 12-2021 | 0.329 | 0.786 | 0.253 | 0.606 | 87.370 | 2.690 | 22.145 | 1.631 | 23.776 |
| 12-2022 | 0.269 | 0.630 | 0.208 | 0.486 | 87.370 | 2.690 | 18.130 | 1.306 | 19.437 |
| 12-2023 | 0.220 | 0.505 | 0.170 | 0.389 | 87.370 | 2.690 | 14.843 | 1.046 | 15.890 |
| 12-2024 | 0.180 | 0.404 | 0.139 | 0.312 | 87.370 | 2.690 | 12.152 | 0.838 | 12.990 |
| 12-2025 | 0.148 | 0.324 | 0.114 | 0.250 | 87.370 | 2.690 | 9.949 | 0.671 | 10.620 |
| 12-2026 | 0.063 | 0.137 | 0.049 | 0.105 | 87.370 | 2.690 | 4.276 | 0.284 | 4.560 |
| 12-2027 | | | | | | | | | |
| S TOT | 8.383 | 22.154 | 6.461 | 17.076 | 87.370 | 2.690 | 564.531 | 45.935 | 610.465 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| TOTAL | 8.383 | 22.154 | 6.461 | 17.076 | 87.370 | 2.690 | 564.531 | 45.935 | 610.465 |

| --END-- MO-YEAR | AD VALOREM TAX M$ | PRODUCTION TAX M$ | DIRECT OPER EXPENSE M$ | INTEREST PAID M$ | CAPITAL REPAYMENT M$ | EQUITY INVESTMENT M$ | FUTURE NET CASHFLOW M$ | CUMULATIVE CASHFLOW M$ | CUM. DISC. CASHFLOW M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 10.741 | 0.000 | 7.938 | 0.000 | 0.000 | 0.000 | 100.663 | 100.663 | 96.179 |
| 12-2014 | 8.778 | 0.000 | 7.938 | 0.000 | 0.000 | 0.000 | 80.818 | 181.481 | 166.380 |
| 12-2015 | 7.174 | 0.000 | 7.938 | 0.000 | 0.000 | 0.000 | 64.603 | 246.084 | 217.396 |
| 12-2016 | 5.864 | 0.000 | 7.938 | 0.000 | 0.000 | 0.000 | 51.352 | 297.435 | 254.263 |
| 12-2017 | 4.793 | 0.000 | 7.938 | 0.000 | 0.000 | 0.000 | 40.523 | 337.958 | 280.713 |
| 12-2018 | 3.918 | 0.000 | 7.938 | 0.000 | 0.000 | 0.000 | 31.673 | 369.631 | 299.508 |
| 12-2019 | 3.202 | 0.000 | 7.938 | 0.000 | 0.000 | 0.000 | 24.441 | 394.072 | 312.695 |
| 12-2020 | 2.618 | 0.000 | 7.938 | 0.000 | 0.000 | 0.000 | 18.529 | 412.601 | 321.785 |
| 12-2021 | 2.140 | 0.000 | 7.938 | 0.000 | 0.000 | 0.000 | 13.698 | 426.299 | 327.895 |
| 12-2022 | 1.749 | 0.000 | 7.938 | 0.000 | 0.000 | 0.000 | 9.749 | 436.049 | 331.850 |
| 12-2023 | 1.430 | 0.000 | 7.938 | 0.000 | 0.000 | 0.000 | 6.521 | 442.570 | 334.257 |
| 12-2024 | 1.169 | 0.000 | 7.938 | 0.000 | 0.000 | 0.000 | 3.883 | 446.453 | 335.562 |
| 12-2025 | 0.956 | 0.000 | 7.938 | 0.000 | 0.000 | 0.000 | 1.726 | 448.180 | 336.091 |
| 12-2026 | 0.410 | 0.000 | 3.969 | 0.000 | 0.000 | 0.000 | 0.180 | 448.360 | 336.142 |
| 12-2027 | | | | | | | | | |
| S TOT | 54.942 | 0.000 | 107.163 | 0.000 | 0.000 | 0.000 | 448.360 | 448.360 | 336.142 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 448.360 | 336.142 |
| TOTAL | 54.942 | 0.000 | 107.163 | 0.000 | 0.000 | 0.000 | 448.360 | 448.360 | 336.142 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 13.50 | 5.00 | 383.979 |
| GROSS ULT., MB & MMF | 92.734 | 323.189 | DISCOUNT % | 10.00 | 8.00 | 353.691 |
| GROSS CUM., MB & MMF | 84.352 | 301.036 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 336.142 |
| GROSS RES., MB & MMF | 8.383 | 22.154 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 320.363 |
| NET RES., MB & MMF | 6.461 | 17.076 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 299.497 |
| NET REVENUE, M$ | 564.531 | 45.935 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 281.429 |
| INITIAL PRICE, $ | 87.370 | 2.690 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 228.519 |
| INITIAL N.I., PCT. | 77.080 | 77.080 | INITIAL W.I., PCT. | 94.500 | 60.00 | 161.624 |
| | | | | | 80.00 | 138.363 |
| | | | | | 260.00 | 74.638 |

**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529




**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529

**SAWYER 32-2**
**FIELD: WATTENBERG**
**COUNTY: WELD STATE: CO**
**OPERATOR: RECOVERY ENERGY INCOR**
**1PDP**

**DATE : 04/01/2013**
**TIME : 14:03:09**
**DBS : DEMO**
**SETTINGS : RED_JAN 13**
**SCENARIO: RED_JAN 13**

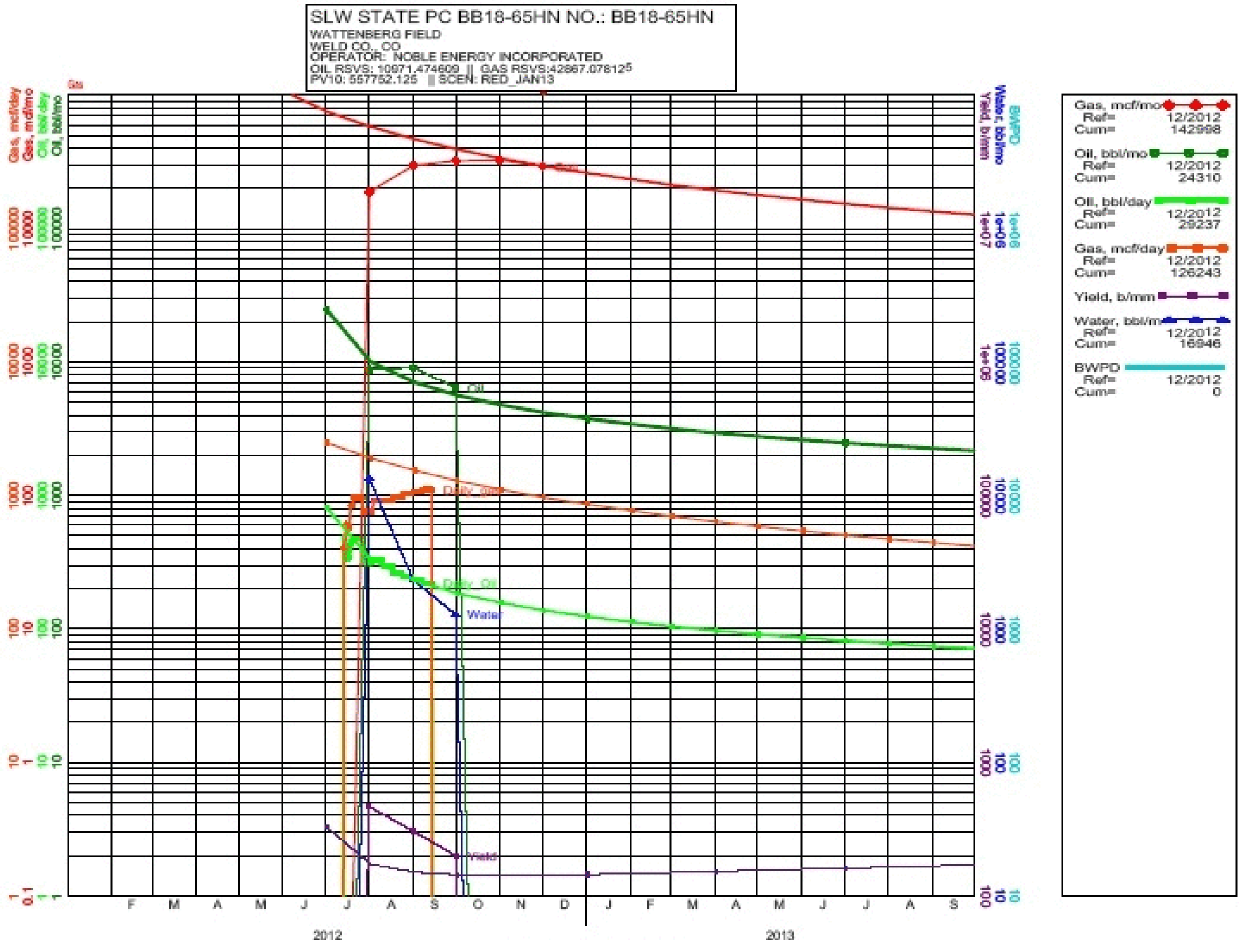
## R E S E R V E S A N D E C O N O M I C S

**AS OF DATE: 12/31/2012**

| --END-- MO-YEAR | GROSS OIL PRODUCTION MBBLS | GROSS GAS PRODUCTION -MMCF | NET OIL PRODUCTION MBBLS | NET GAS PRODUCTION MMCF | NET OIL PRICE $/BBL | NET GAS PRICE $/MCF | NET OIL SALES M$ | NET GAS SALES M$ | TOTAL NET SALES M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 0.816 | 2.933 | 0.331 | 1.189 | 87.370 | 2.690 | 28.908 | 3.198 | 32.106 |
| 12-2014 | 0.783 | 2.406 | 0.317 | 0.975 | 87.370 | 2.690 | 27.726 | 2.624 | 30.350 |
| 12-2015 | 0.751 | 1.975 | 0.304 | 0.800 | 87.370 | 2.690 | 26.592 | 2.153 | 28.745 |
| 12-2016 | 0.720 | 1.620 | 0.292 | 0.657 | 87.370 | 2.690 | 25.504 | 1.767 | 27.271 |
| 12-2017 | 0.691 | 1.329 | 0.280 | 0.539 | 87.370 | 2.690 | 24.461 | 1.450 | 25.911 |
| 12-2018 | 0.662 | 1.091 | 0.269 | 0.442 | 87.370 | 2.690 | 23.461 | 1.189 | 24.651 |
| 12-2019 | 0.635 | 0.895 | 0.258 | 0.363 | 87.370 | 2.690 | 22.502 | 0.976 | 23.478 |
| 12-2020 | 0.609 | 0.734 | 0.247 | 0.298 | 87.370 | 2.690 | 21.581 | 0.801 | 22.382 |
| 12-2021 | 0.584 | 0.603 | 0.237 | 0.244 | 87.370 | 2.690 | 20.699 | 0.657 | 21.356 |
| 12-2022 | 0.561 | 0.495 | 0.227 | 0.200 | 87.370 | 2.690 | 19.852 | 0.539 | 20.392 |
| 12-2023 | 0.538 | 0.406 | 0.218 | 0.164 | 87.370 | 2.690 | 19.041 | 0.442 | 19.483 |
| 12-2024 | 0.516 | 0.333 | 0.209 | 0.135 | 87.370 | 2.690 | 18.262 | 0.363 | 18.625 |
| 12-2025 | 0.495 | 0.273 | 0.200 | 0.111 | 87.370 | 2.690 | 17.515 | 0.298 | 17.813 |
| 12-2026 | 0.474 | 0.224 | 0.192 | 0.091 | 87.370 | 2.690 | 16.799 | 0.244 | 17.043 |
| 12-2027 | 0.455 | 0.184 | 0.184 | 0.075 | 87.370 | 2.690 | 16.112 | 0.201 | 16.312 |
| S TOT | 9.290 | 15.501 | 3.766 | 6.283 | 87.370 | 2.690 | 329.015 | 16.902 | 345.917 |
| AFTER | 1.828 | 0.496 | 0.741 | 0.201 | 87.370 | 2.690 | 64.729 | 0.540 | 65.269 |
| TOTAL | 11.118 | 15.997 | 4.507 | 6.484 | 87.370 | 2.690 | 393.743 | 17.443 | 411.186 |

| --END-- MO-YEAR | AD VALOREM TAX M$ | PRODUCTION TAX M$ | DIRECT OPER EXPENSE M$ | INTEREST PAID M$ | CAPITAL REPAYMENT M$ | EQUITY INVESTMENT M$ | FUTURE NET CASHFLOW M$ | CUMULATIVE CASHFLOW M$ | CUM. DISC. CASHFLOW M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 2.568 | 0.000 | 4.807 | 0.000 | 0.000 | 0.000 | 24.731 | 24.731 | 23.601 |
| 12-2014 | 2.428 | 0.000 | 4.807 | 0.000 | 0.000 | 0.000 | 23.115 | 47.846 | 43.655 |
| 12-2015 | 2.300 | 0.000 | 4.807 | 0.000 | 0.000 | 0.000 | 21.639 | 69.484 | 60.721 |
| 12-2016 | 2.182 | 0.000 | 4.807 | 0.000 | 0.000 | 0.000 | 20.283 | 89.767 | 75.264 |
| 12-2017 | 2.073 | 0.000 | 4.807 | 0.000 | 0.000 | 0.000 | 19.031 | 108.799 | 87.668 |
| 12-2018 | 1.972 | 0.000 | 4.807 | 0.000 | 0.000 | 0.000 | 17.872 | 126.670 | 98.258 |
| 12-2019 | 1.878 | 0.000 | 4.807 | 0.000 | 0.000 | 0.000 | 16.793 | 143.463 | 107.304 |
| 12-2020 | 1.791 | 0.000 | 4.807 | 0.000 | 0.000 | 0.000 | 15.785 | 159.248 | 115.034 |
| 12-2021 | 1.708 | 0.000 | 4.807 | 0.000 | 0.000 | 0.000 | 14.841 | 174.089 | 121.641 |
| 12-2022 | 1.631 | 0.000 | 4.807 | 0.000 | 0.000 | 0.000 | 13.954 | 188.043 | 127.288 |
| 12-2023 | 1.559 | 0.000 | 4.807 | 0.000 | 0.000 | 0.000 | 13.118 | 201.160 | 132.114 |
| 12-2024 | 1.490 | 0.000 | 4.807 | 0.000 | 0.000 | 0.000 | 12.328 | 213.488 | 136.237 |
| 12-2025 | 1.425 | 0.000 | 4.807 | 0.000 | 0.000 | 0.000 | 11.581 | 225.070 | 139.759 |
| 12-2026 | 1.363 | 0.000 | 4.807 | 0.000 | 0.000 | 0.000 | 10.873 | 235.943 | 142.765 |
| 12-2027 | 1.305 | 0.000 | 4.807 | 0.000 | 0.000 | 0.000 | 10.201 | 246.143 | 145.328 |
| S TOT | 27.673 | 0.000 | 72.100 | 0.000 | 0.000 | 0.000 | 246.143 | 246.143 | 145.328 |
| AFTER | 5.222 | 0.000 | 21.630 | 0.000 | 0.000 | 0.000 | 38.417 | 284.561 | 152.887 |
| TOTAL | 32.895 | 0.000 | 93.730 | 0.000 | 0.000 | 0.000 | 284.561 | 284.561 | 152.887 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 19.50 | 5.00 | 201.165 |
| GROSS ULT., MB & MMF | 37.475 | 181.878 | DISCOUNT % | 10.00 | 8.00 | 169.357 |
| GROSS CUM., MB & MMF | 26.357 | 165.882 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 152.887 |
| GROSS RES., MB & MMF | 11.118 | 15.997 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 139.222 |
| NET RES., MB & MMF | 4.507 | 6.484 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 122.708 |
| NET REVENUE, M$ | 393.743 | 17.443 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 109.736 |
| INITIAL PRICE, $ | 87.370 | 2.690 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 77.884 |
| INITIAL N.I., PCT. | 40.536 | 40.536 | INITIAL W.I., PCT. | 57.222 | 60.00 | 47.684 |
| | | | | | 80.00 | 39.079 |
| | | | | | 260.00 | 18.960 |




**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529

SLW STATE PC BB1865HN
FIELD: WATTENBERG
COUNTY: WELD STATE: CO
OPERATOR: NOBLE ENERGY INCORPOR
1PDP

DATE : 04/01/2013
TIME : 14:03:09
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO: RED_JAN13

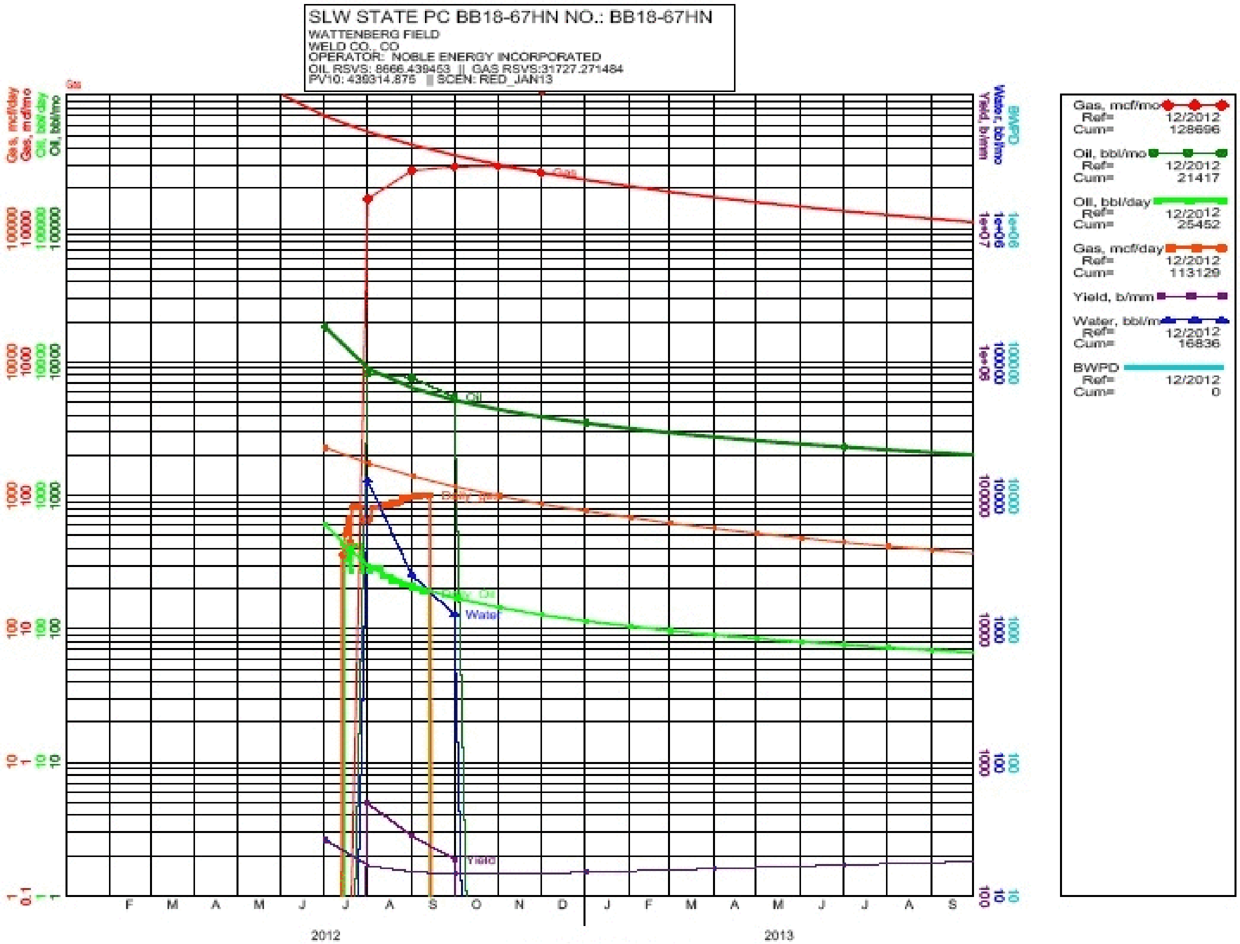
## R E S E R V E S A N D E C O N O M I C S

**AS OF DATE: 12/31/2012**

| --END-- MO-YEAR | GROSS OIL PRODUCTION MBBLS | GROSS GAS PRODUCTION MMCF | NET OIL PRODUCTION MBBLS | NET GAS PRODUCTION MMCF | NET OIL PRICE $/BBL | NET GAS PRICE $/MCF | NET OIL SALES M$ | NET GAS SALES M$ | TOTAL NET SALES M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 31.127 | 195.829 | 2.153 | 13.137 | 87.370 | 2.594 | 188.086 | 34.078 | 222.164 |
| 12-2014 | 19.665 | 100.543 | 1.053 | 5.235 | 87.370 | 2.594 | 91.996 | 13.579 | 105.575 |
| 12-2015 | 15.214 | 67.032 | 0.789 | 3.373 | 87.370 | 2.594 | 68.948 | 8.749 | 77.697 |
| 12-2016 | 12.701 | 49.954 | 0.659 | 2.513 | 87.370 | 2.594 | 57.561 | 6.520 | 64.081 |
| 12-2017 | 11.046 | 39.640 | 0.573 | 1.994 | 87.370 | 2.594 | 50.061 | 5.174 | 55.235 |
| 12-2018 | 9.857 | 32.756 | 0.511 | 1.648 | 87.370 | 2.594 | 44.671 | 4.275 | 48.946 |
| 12-2019 | 8.952 | 27.847 | 0.464 | 1.401 | 87.370 | 2.594 | 40.571 | 3.634 | 44.205 |
| 12-2020 | 8.221 | 24.176 | 0.426 | 1.216 | 87.370 | 2.594 | 37.256 | 3.155 | 40.412 |
| 12-2021 | 7.563 | 21.331 | 0.392 | 1.073 | 87.370 | 2.594 | 34.276 | 2.784 | 37.060 |
| 12-2022 | 6.958 | 19.064 | 0.361 | 0.959 | 87.370 | 2.594 | 31.534 | 2.488 | 34.022 |
| 12-2023 | 6.401 | 17.216 | 0.332 | 0.866 | 87.370 | 2.594 | 29.011 | 2.247 | 31.258 |
| 12-2024 | 5.889 | 15.683 | 0.305 | 0.789 | 87.370 | 2.594 | 26.690 | 2.047 | 28.737 |
| 12-2025 | 5.418 | 14.392 | 0.281 | 0.724 | 87.370 | 2.594 | 24.555 | 1.878 | 26.433 |
| 12-2026 | 4.985 | 13.289 | 0.259 | 0.669 | 87.370 | 2.594 | 22.591 | 1.734 | 24.325 |
| 12-2027 | 4.586 | 12.338 | 0.238 | 0.621 | 87.370 | 2.594 | 20.783 | 1.610 | 22.394 |
| S TOT | 158.584 | 651.090 | 8.797 | 36.220 | 87.370 | 2.594 | 768.590 | 93.954 | 862.544 |
| AFTER | 41.922 | 132.118 | 2.175 | 6.647 | 87.370 | 2.594 | 189.988 | 17.243 | 207.231 |
| TOTAL | 200.506 | 783.208 | 10.971 | 42.867 | 87.370 | 2.594 | 958.578 | 111.197 | 1069.775 |

| --END-- MO-YEAR | AD VALOREM TAX M$ | PRODUCTION TAX M$ | DIRECT OPER EXPENSE M$ | INTEREST PAID M$ | CAPITAL REPAYMENT M$ | EQUITY INVESTMENT M$ | FUTURE NET CASHFLOW M$ | CUMULATIVE CASHFLOW M$ | CUM. DISC. CASHFLOW M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 17.773 | 0.000 | 1.707 | 0.000 | 0.000 | 0.000 | 202.684 | 202.684 | 194.381 |
| 12-2014 | 8.446 | 0.000 | 1.316 | 0.000 | 0.000 | 0.000 | 95.813 | 298.497 | 277.794 |
| 12-2015 | 6.216 | 0.000 | 1.280 | 0.000 | 0.000 | 0.000 | 70.201 | 368.697 | 333.230 |
| 12-2016 | 5.126 | 0.000 | 1.280 | 0.000 | 0.000 | 0.000 | 57.674 | 426.371 | 374.616 |
| 12-2017 | 4.419 | 0.000 | 1.280 | 0.000 | 0.000 | 0.000 | 49.536 | 475.907 | 406.922 |
| 12-2018 | 3.916 | 0.000 | 1.280 | 0.000 | 0.000 | 0.000 | 43.750 | 519.657 | 432.856 |
| 12-2019 | 3.536 | 0.000 | 1.280 | 0.000 | 0.000 | 0.000 | 39.388 | 559.045 | 454.079 |
| 12-2020 | 3.233 | 0.000 | 1.280 | 0.000 | 0.000 | 0.000 | 35.898 | 594.943 | 471.662 |
| 12-2021 | 2.965 | 0.000 | 1.280 | 0.000 | 0.000 | 0.000 | 32.815 | 627.758 | 486.274 |
| 12-2022 | 2.722 | 0.000 | 1.280 | 0.000 | 0.000 | 0.000 | 30.020 | 657.778 | 498.426 |
| 12-2023 | 2.501 | 0.000 | 1.280 | 0.000 | 0.000 | 0.000 | 27.477 | 685.255 | 508.537 |
| 12-2024 | 2.299 | 0.000 | 1.280 | 0.000 | 0.000 | 0.000 | 25.158 | 710.412 | 516.953 |
| 12-2025 | 2.115 | 0.000 | 1.280 | 0.000 | 0.000 | 0.000 | 23.038 | 733.451 | 523.960 |
| 12-2026 | 1.946 | 0.000 | 1.280 | 0.000 | 0.000 | 0.000 | 21.099 | 754.549 | 529.793 |
| 12-2027 | 1.791 | 0.000 | 1.280 | 0.000 | 0.000 | 0.000 | 19.322 | 773.871 | 534.650 |
| S TOT | 69.004 | 0.000 | 19.669 | 0.000 | 0.000 | 0.000 | 773.871 | 773.871 | 534.650 |
| AFTER | 16.578 | 0.000 | 24.329 | 0.000 | 0.000 | 0.000 | 166.324 | 940.195 | 557.752 |
| TOTAL | 85.582 | 0.000 | 43.998 | 0.000 | 0.000 | 0.000 | 940.195 | 940.195 | 557.752 |

**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529




**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529

SLW STATE PC BB1867HN
FIELD: WATTENBERG
COUNTY: WELD STATE: CO
OPERATOR: NOBLE ENERGY INCORPOR
1PDP

DATE : 04/01/2013
TIME : 14:03:10
DBS : DEMO
SETTINGS : RED_JAN 13
SCENARIO: RED_JAN 13

## R E S E R V E S A N D E C O N O M I C S

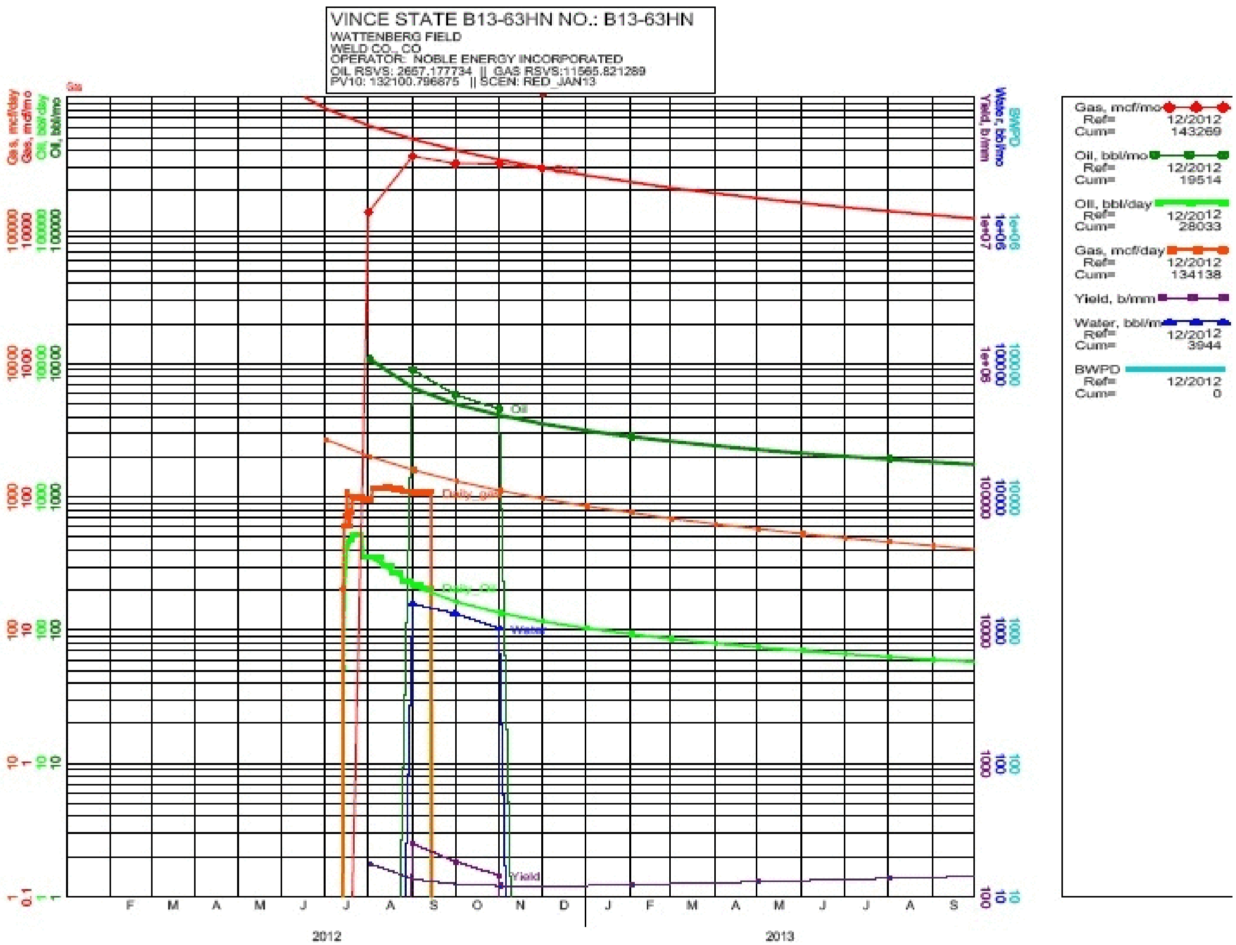
### AS OF DATE: 12/31/2012

| --END-- MO-YEAR | GROSS OIL PRODUCTION MBBLS | GROSS GAS PRODUCTION MMCF | NET OIL PRODUCTION MBBLS | NET GAS PRODUCTION MMCF | NET OIL PRICE $/BBL | NET GAS PRICE $/MCF | NET OIL SALES M$ | NET GAS SALES M$ | TOTAL NET SALES M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 28.995 | 173.266 | 1.714 | 9.935 | 87.370 | 2.580 | 149.745 | 25.632 | 175.377 |
| 12-2014 | 18.400 | 88.371 | 0.816 | 3.800 | 87.370 | 2.580 | 71.271 | 9.805 | 81.076 |
| 12-2015 | 14.253 | 58.783 | 0.632 | 2.528 | 87.370 | 2.580 | 55.210 | 6.522 | 61.732 |
| 12-2016 | 11.907 | 43.755 | 0.528 | 1.882 | 87.370 | 2.580 | 46.120 | 4.854 | 50.975 |
| 12-2017 | 10.359 | 34.695 | 0.459 | 1.492 | 87.370 | 2.580 | 40.126 | 3.849 | 43.975 |
| 12-2018 | 9.246 | 28.656 | 0.410 | 1.232 | 87.370 | 2.580 | 35.814 | 3.179 | 38.993 |
| 12-2019 | 8.399 | 24.353 | 0.372 | 1.047 | 87.370 | 2.580 | 32.533 | 2.702 | 35.235 |
| 12-2020 | 7.713 | 21.137 | 0.342 | 0.909 | 87.370 | 2.580 | 29.877 | 2.345 | 32.222 |
| 12-2021 | 7.096 | 18.645 | 0.315 | 0.802 | 87.370 | 2.580 | 27.487 | 2.069 | 29.556 |
| 12-2022 | 6.529 | 16.661 | 0.289 | 0.716 | 87.370 | 2.580 | 25.288 | 1.848 | 27.136 |
| 12-2023 | 6.006 | 15.044 | 0.266 | 0.647 | 87.370 | 2.580 | 23.265 | 1.669 | 24.934 |
| 12-2024 | 5.526 | 13.703 | 0.245 | 0.589 | 87.370 | 2.580 | 21.404 | 1.520 | 22.924 |
| 12-2025 | 5.084 | 12.573 | 0.225 | 0.541 | 87.370 | 2.580 | 19.691 | 1.395 | 21.086 |
| 12-2026 | 4.677 | 11.609 | 0.207 | 0.499 | 87.370 | 2.580 | 18.116 | 1.288 | 19.404 |
| 12-2027 | 4.303 | 10.777 | 0.191 | 0.463 | 87.370 | 2.580 | 16.667 | 1.196 | 17.862 |
| S TOT | 148.493 | 572.029 | 7.012 | 27.083 | 87.370 | 2.580 | 612.614 | 69.874 | 682.488 |
| AFTER | 37.324 | 108.004 | 1.655 | 4.645 | 87.370 | 2.580 | 144.573 | 11.983 | 156.556 |
| TOTAL | 185.818 | 680.033 | 8.666 | 31.727 | 87.370 | 2.580 | 757.187 | 81.856 | 839.043 |

| --END-- MO-YEAR | AD VALOREM TAX M$ | PRODUCTION TAX M$ | DIRECT OPER EXPENSE M$ | INTEREST PAID M$ | CAPITAL REPAYMENT M$ | EQUITY INVESTMENT M$ | FUTURE NET CASHFLOW M$ | CUMULATIVE CASHFLOW M$ | CUM. DISC. CASHFLOW M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 14.030 | 0.000 | 1.459 | 0.000 | 0.000 | 0.000 | 159.887 | 159.887 | 153.330 |
| 12-2014 | 6.486 | 0.000 | 1.094 | 0.000 | 0.000 | 0.000 | 73.496 | 233.383 | 217.228 |
| 12-2015 | 4.939 | 0.000 | 1.094 | 0.000 | 0.000 | 0.000 | 55.699 | 289.081 | 261.212 |
| 12-2016 | 4.078 | 0.000 | 1.094 | 0.000 | 0.000 | 0.000 | 45.803 | 334.884 | 294.079 |
| 12-2017 | 3.518 | 0.000 | 1.094 | 0.000 | 0.000 | 0.000 | 39.363 | 374.247 | 319.750 |
| 12-2018 | 3.119 | 0.000 | 1.094 | 0.000 | 0.000 | 0.000 | 34.780 | 409.026 | 340.367 |
| 12-2019 | 2.819 | 0.000 | 1.094 | 0.000 | 0.000 | 0.000 | 31.321 | 440.348 | 357.243 |
| 12-2020 | 2.578 | 0.000 | 1.094 | 0.000 | 0.000 | 0.000 | 28.550 | 468.898 | 371.227 |
| 12-2021 | 2.364 | 0.000 | 1.094 | 0.000 | 0.000 | 0.000 | 26.097 | 494.994 | 382.848 |
| 12-2022 | 2.171 | 0.000 | 1.094 | 0.000 | 0.000 | 0.000 | 23.871 | 518.865 | 392.511 |
| 12-2023 | 1.995 | 0.000 | 1.094 | 0.000 | 0.000 | 0.000 | 21.845 | 540.710 | 400.550 |
| 12-2024 | 1.834 | 0.000 | 1.094 | 0.000 | 0.000 | 0.000 | 19.996 | 560.706 | 407.239 |
| 12-2025 | 1.687 | 0.000 | 1.094 | 0.000 | 0.000 | 0.000 | 18.305 | 579.011 | 412.806 |
| 12-2026 | 1.552 | 0.000 | 1.094 | 0.000 | 0.000 | 0.000 | 16.757 | 595.769 | 417.439 |
| 12-2027 | 1.429 | 0.000 | 1.094 | 0.000 | 0.000 | 0.000 | 15.339 | 611.108 | 421.295 |
| S TOT | 54.599 | 0.000 | 16.781 | 0.000 | 0.000 | 0.000 | 611.108 | 611.108 | 421.295 |
| AFTER | 12.524 | 0.000 | 18.422 | 0.000 | 0.000 | 0.000 | 125.609 | 736.716 | 439.315 |
| TOTAL | 67.123 | 0.000 | 35.203 | 0.000 | 0.000 | 0.000 | 736.716 | 736.716 | 439.315 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 31.83 | 5.00 | 542.272 |
| GROSS ULT., MB & MMF | 210.909 | 833.428 | DISCOUNT % | 10.00 | 8.00 | 473.898 |
| GROSS CUM., MB & MMF | 25.091 | 153.396 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 439.315 |
| GROSS RES., MB & MMF | 185.818 | 680.033 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 410.859 |
| NET RES., MB & MMF | 8.666 | 31.727 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 376.515 |
| NET REVENUE, M$ | 757.187 | 81.856 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 349.341 |
| INITIAL PRICE, $ | 87.370 | 2.580 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 280.022 |
| INITIAL N.I., PCT. | 5.911 | 5.911 | INITIAL W.I., PCT. | 6.756 | 60.00 | 205.567 |
| | | | | | 80.00 | 181.129 |
| | | | | | 260.00 | 111.830 |

**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529




**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529

**VINCE STATE B13-63HN**
**FIELD: WATTENBERG**
**COUNTY: WELD STATE: CO**
**OPERATOR: NOBLE ENERGY INCORPOR**
**1PDP**

**DATE : 04/01/2013**
**TIME : 14:03:10**
**DBS : DEMO**
**SETTINGS : RED_JAN 13**
**SCENARIO: RED_JAN 13**

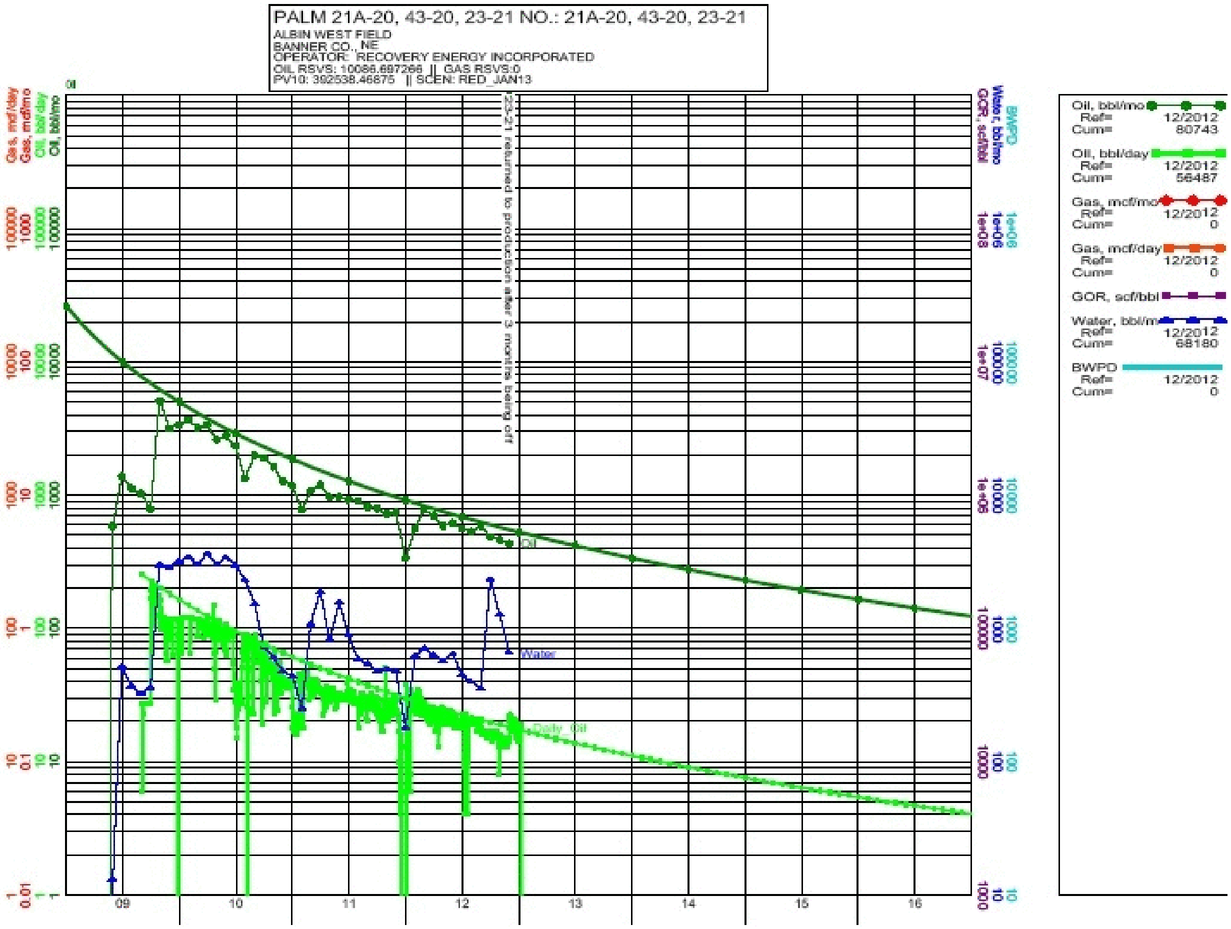
## R E S E R V E S A N D E C O N O M I C S

**AS OF DATE: 12/31/2012**

| --END-- MO-YEAR | GROSS OIL PRODUCTION MBBLS | GROSS GAS PRODUCTION MMCF | NET OIL PRODUCTION MBBLS | NET GAS PRODUCTION MMCF | NET OIL PRICE $/BBL | NET GAS PRICE $/MCF | NET OIL SALES M$ | NET GAS SALES M$ | TOTAL NET SALES M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 25.448 | 191.876 | 0.490 | 3.584 | 87.370 | 2.704 | 42.809 | 9.690 | 52.499 |
| 12-2014 | 15.803 | 96.881 | 0.256 | 1.534 | 87.370 | 2.704 | 22.401 | 4.147 | 26.548 |
| 12-2015 | 12.168 | 64.223 | 0.176 | 0.900 | 87.370 | 2.704 | 15.352 | 2.432 | 17.785 |
| 12-2016 | 10.135 | 47.720 | 0.146 | 0.668 | 87.370 | 2.704 | 12.787 | 1.807 | 14.595 |
| 12-2017 | 8.803 | 37.799 | 0.127 | 0.529 | 87.370 | 2.704 | 11.106 | 1.432 | 12.538 |
| 12-2018 | 7.848 | 31.197 | 0.113 | 0.437 | 87.370 | 2.704 | 9.901 | 1.182 | 11.083 |
| 12-2019 | 7.123 | 26.498 | 0.103 | 0.371 | 87.370 | 2.704 | 8.987 | 1.004 | 9.990 |
| 12-2020 | 6.550 | 22.989 | 0.095 | 0.322 | 87.370 | 2.704 | 8.264 | 0.871 | 9.135 |
| 12-2021 | 6.084 | 20.273 | 0.088 | 0.284 | 87.370 | 2.704 | 7.675 | 0.768 | 8.443 |
| 12-2022 | 5.694 | 18.111 | 0.082 | 0.254 | 87.370 | 2.704 | 7.184 | 0.686 | 7.870 |
| 12-2023 | 5.351 | 16.350 | 0.077 | 0.229 | 87.370 | 2.704 | 6.752 | 0.619 | 7.371 |
| 12-2024 | 5.030 | 14.890 | 0.073 | 0.209 | 87.370 | 2.704 | 6.346 | 0.564 | 6.910 |
| 12-2025 | 4.728 | 13.661 | 0.068 | 0.191 | 87.370 | 2.704 | 5.966 | 0.517 | 6.483 |
| 12-2026 | 4.445 | 12.611 | 0.064 | 0.177 | 87.370 | 2.704 | 5.608 | 0.478 | 6.085 |
| 12-2027 | 4.178 | 11.706 | 0.060 | 0.164 | 87.370 | 2.704 | 5.271 | 0.443 | 5.715 |
| S TOT | 129.390 | 626.786 | 2.019 | 9.852 | 87.370 | 2.704 | 176.410 | 26.640 | 203.050 |
| AFTER | 44.186 | 122.354 | 0.638 | 1.714 | 87.370 | 2.704 | 55.747 | 4.634 | 60.382 |
| TOTAL | 173.576 | 749.140 | 2.657 | 11.566 | 87.370 | 2.704 | 232.158 | 31.274 | 263.432 |

| --END-- MO-YEAR | AD VALOREM TAX M$ | PRODUCTION TAX M$ | DIRECT OPER EXPENSE M$ | INTEREST PAID M$ | CAPITAL REPAYMENT M$ | EQUITY INVESTMENT M$ | FUTURE NET CASHFLOW M$ | CUMULATIVE CASHFLOW M$ | CUM. DISC. CASHFLOW M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 4.200 | 0.000 | 0.475 | 0.000 | 0.000 | 0.000 | 47.824 | 47.824 | 45.879 |
| 12-2014 | 2.124 | 0.000 | 0.396 | 0.000 | 0.000 | 0.000 | 24.028 | 71.852 | 66.840 |
| 12-2015 | 1.423 | 0.000 | 0.356 | 0.000 | 0.000 | 0.000 | 16.005 | 87.857 | 79.480 |
| 12-2016 | 1.168 | 0.000 | 0.356 | 0.000 | 0.000 | 0.000 | 13.071 | 100.928 | 88.860 |
| 12-2017 | 1.003 | 0.000 | 0.356 | 0.000 | 0.000 | 0.000 | 11.178 | 112.106 | 96.150 |
| 12-2018 | 0.887 | 0.000 | 0.356 | 0.000 | 0.000 | 0.000 | 9.840 | 121.946 | 101.983 |
| 12-2019 | 0.799 | 0.000 | 0.356 | 0.000 | 0.000 | 0.000 | 8.835 | 130.781 | 106.744 |
| 12-2020 | 0.731 | 0.000 | 0.356 | 0.000 | 0.000 | 0.000 | 8.048 | 138.828 | 110.685 |
| 12-2021 | 0.675 | 0.000 | 0.356 | 0.000 | 0.000 | 0.000 | 7.411 | 146.240 | 113.985 |
| 12-2022 | 0.630 | 0.000 | 0.356 | 0.000 | 0.000 | 0.000 | 6.884 | 153.124 | 116.772 |
| 12-2023 | 0.590 | 0.000 | 0.356 | 0.000 | 0.000 | 0.000 | 6.425 | 159.548 | 119.135 |
| 12-2024 | 0.553 | 0.000 | 0.356 | 0.000 | 0.000 | 0.000 | 6.001 | 165.550 | 121.143 |
| 12-2025 | 0.519 | 0.000 | 0.356 | 0.000 | 0.000 | 0.000 | 5.608 | 171.157 | 122.848 |
| 12-2026 | 0.487 | 0.000 | 0.356 | 0.000 | 0.000 | 0.000 | 5.242 | 176.400 | 124.297 |
| 12-2027 | 0.457 | 0.000 | 0.356 | 0.000 | 0.000 | 0.000 | 4.901 | 181.301 | 125.529 |
| S TOT | 16.244 | 0.000 | 5.505 | 0.000 | 0.000 | 0.000 | 181.301 | 181.301 | 125.529 |
| AFTER | 4.831 | 0.000 | 6.476 | 0.000 | 0.000 | 0.000 | 49.075 | 230.376 | 132.101 |
| TOTAL | 21.075 | 0.000 | 11.981 | 0.000 | 0.000 | 0.000 | 230.376 | 230.376 | 132.101 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 33.17 | 5.00 | 164.745 |
| GROSS ULT., MB & MMF | 196.425 | 920.075 | DISCOUNT % | 10.00 | 8.00 | 142.894 |
| GROSS CUM., MB & MMF | 22.849 | 170.935 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 132.101 |
| GROSS RES., MB & MMF | 173.576 | 749.140 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 123.347 |
| NET RES., MB & MMF | 2.657 | 11.566 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 112.923 |
| NET REVENUE, M$ | 232.158 | 31.274 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 104.773 |
| INITIAL PRICE, $ | 87.370 | 2.704 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 84.256 |
| INITIAL N.I., PCT. | 1.925 | 1.925 | INITIAL W.I., PCT. | 2.200 | 60.00 | 62.303 |
| | | | | | 80.00 | 55.029 |
| | | | | | 260.00 | 34.060 |




**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529

PALM 21A-20, 43-20, 23-21
FIELD: ALBIN WEST
COUNTY: BANNER STATE: NE
OPERATOR: RECOVERY ENERGY INCOR
1PDP

DATE : 04/01/2013
TIME : 14:03:10
DBS : DEMO
SETTINGS : RED_JAN 13
SCENARIO: RED_JAN 13

## R E S E R V E S A N D E C O N O M I C S

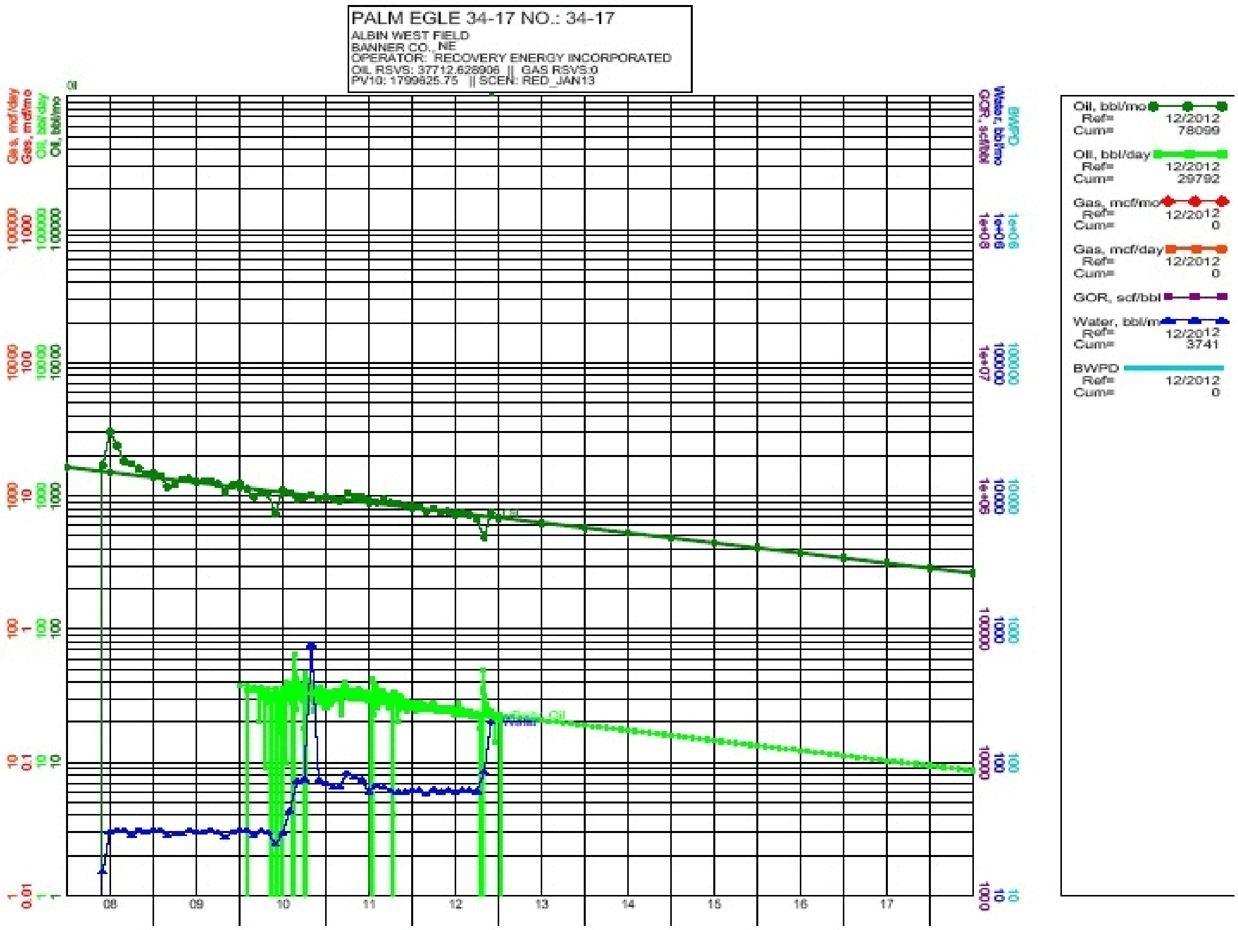
**AS OF DATE: 12/31/2012**

| --END-- MO-YEAR | GROSS OIL PRODUCTION MBBLS | GROSS GAS PRODUCTION MMCF | NET OIL PRODUCTION MBBLS | NET GAS PRODUCTION MMCF | NET OIL PRICE $/BBL | NET GAS PRICE $/MCF | NET OIL SALES M$ | NET GAS SALES M$ | TOTAL NET SALES M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 5.076 | 0.000 | 4.188 | 0.000 | 87.370 | 0.000 | 365.866 | 0.000 | 365.866 |
| 12-2014 | 3.346 | 0.000 | 2.761 | 0.000 | 87.370 | 0.000 | 241.190 | 0.000 | 241.190 |
| 12-2015 | 2.342 | 0.000 | 1.932 | 0.000 | 87.370 | 0.000 | 168.829 | 0.000 | 168.829 |
| 12-2016 | 1.462 | 0.000 | 1.206 | 0.000 | 87.370 | 0.000 | 105.389 | 0.000 | 105.389 |
| 12-2017 | | | | | | | | | |
| 12-2018 | | | | | | | | | |
| 12-2019 | | | | | | | | | |
| 12-2020 | | | | | | | | | |
| 12-2021 | | | | | | | | | |
| 12-2022 | | | | | | | | | |
| 12-2023 | | | | | | | | | |
| 12-2024 | | | | | | | | | |
| 12-2025 | | | | | | | | | |
| 12-2026 | | | | | | | | | |
| 12-2027 | | | | | | | | | |
| S TOT | 12.226 | 0.000 | 10.087 | 0.000 | 87.370 | 0.000 | 881.275 | 0.000 | 881.275 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| TOTAL | 12.226 | 0.000 | 10.087 | 0.000 | 87.370 | 0.000 | 881.275 | 0.000 | 881.275 |

| --END-- MO-YEAR | AD VALOREM TAX M$ | PRODUCTION TAX M$ | DIRECT OPER EXPENSE M$ | INTEREST PAID M$ | CAPITAL REPAYMENT M$ | EQUITY INVESTMENT M$ | FUTURE NET CASHFLOW M$ | CUMULATIVE CASHFLOW M$ | CUM. DISC. CASHFLOW M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 7.098 | 10.976 | 105.600 | 0.000 | 0.000 | 0.000 | 242.192 | 242.192 | 232.186 |
| 12-2014 | 4.679 | 7.236 | 105.600 | 0.000 | 0.000 | 0.000 | 123.676 | 365.868 | 340.024 |
| 12-2015 | 3.275 | 5.065 | 105.600 | 0.000 | 0.000 | 0.000 | 54.889 | 420.757 | 383.623 |
| 12-2016 | 2.045 | 3.162 | 88.000 | 0.000 | 0.000 | 0.000 | 12.183 | 432.940 | 392.538 |
| 12-2017 | | | | | | | | | |
| 12-2018 | | | | | | | | | |
| 12-2019 | | | | | | | | | |
| 12-2020 | | | | | | | | | |
| 12-2021 | | | | | | | | | |
| 12-2022 | | | | | | | | | |
| 12-2023 | | | | | | | | | |
| 12-2024 | | | | | | | | | |
| 12-2025 | | | | | | | | | |
| 12-2026 | | | | | | | | | |
| 12-2027 | | | | | | | | | |
| S TOT | 17.097 | 26.438 | 404.800 | 0.000 | 0.000 | 0.000 | 432.940 | 432.940 | 392.538 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 432.940 | 392.538 |
| TOTAL | 17.097 | 26.438 | 404.800 | 0.000 | 0.000 | 0.000 | 432.940 | 432.940 | 392.538 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 2.0 | 0.0 | LIFE, YRS. | 3.83 | 5.00 | 411.446 |
| GROSS ULT., MB & MMF | 93.396 | 0.000 | DISCOUNT % | 10.00 | 8.00 | 399.821 |
| GROSS CUM., MB & MMF | 81.170 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 392.538 |
| GROSS RES., MB & MMF | 12.226 | 0.000 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 385.599 |
| NET RES., MB & MMF | 10.087 | 0.000 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 375.782 |
| NET REVENUE, M$ | 881.275 | 0.000 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 366.615 |
| INITIAL PRICE, $ | 87.370 | 0.000 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 335.306 |
| INITIAL N.I., PCT. | 82.500 | 0.000 | INITIAL W.I., PCT. 100.000 | | 60.00 | 281.820 |
| | | | | | 80.00 | 257.795 |
| | | | | | 260.00 | 169.311 |

**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529




**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529

**PALM EGLE 34-17**
**FIELD: ALBIN WEST**
**COUNTY: BANNER STATE: NE**
**OPERATOR: RECOVERY ENERGY INCOR**
**1PDP**

**DATE : 04/01/2013**
**TIME : 14:03:10**
**DBS : DEMO**
**SETTINGS : RED_JAN 13**
**SCENARIO: RED_JAN 13**

**R E S E R V E S A N D E C O N O M I C S**

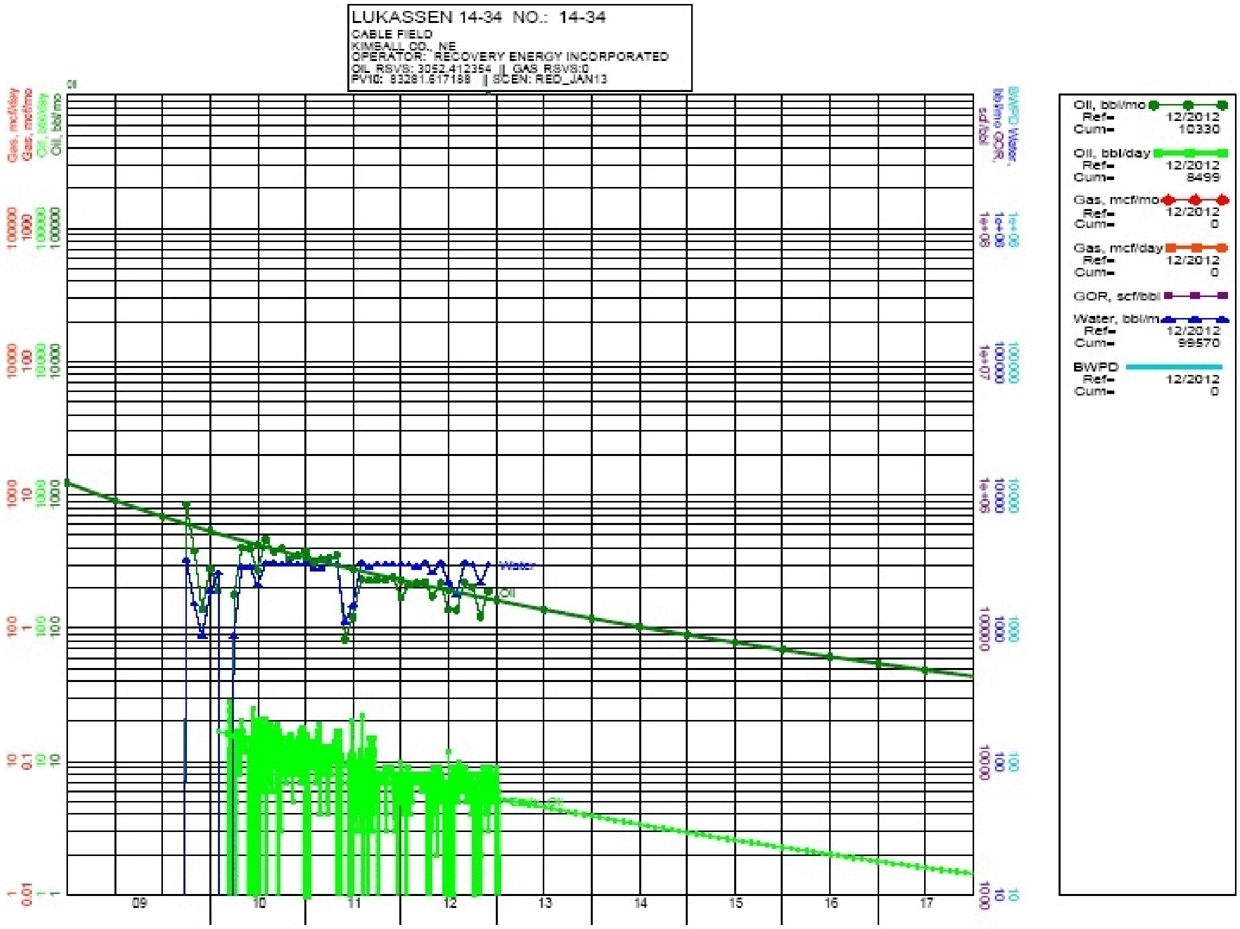
**AS OF DATE: 12/31/2012**

| --END-- MO-YEAR | GROSS OIL PRODUCTION MBBLS | GROSS GAS PRODUCTION MMCF | NET OIL PRODUCTION MBBLS | NET GAS PRODUCTION MMCF | NET OIL PRICE $/BBL | NET GAS PRICE $/MCF | NET OIL SALES M$ | NET GAS SALES M$ | TOTAL NET SALES M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 7.900 | 0.000 | 6.518 | 0.000 | 87.370 | 0.000 | 569.455 | 0.000 | 569.455 |
| 12-2014 | 6.636 | 0.000 | 5.475 | 0.000 | 87.370 | 0.000 | 478.343 | 0.000 | 478.343 |
| 12-2015 | 5.574 | 0.000 | 4.599 | 0.000 | 87.370 | 0.000 | 401.808 | 0.000 | 401.808 |
| 12-2016 | 4.683 | 0.000 | 3.863 | 0.000 | 87.370 | 0.000 | 337.518 | 0.000 | 337.518 |
| 12-2017 | 3.933 | 0.000 | 3.245 | 0.000 | 87.370 | 0.000 | 283.515 | 0.000 | 283.515 |
| 12-2018 | 3.304 | 0.000 | 2.726 | 0.000 | 87.370 | 0.000 | 238.153 | 0.000 | 238.153 |
| 12-2019 | 2.775 | 0.000 | 2.290 | 0.000 | 87.370 | 0.000 | 200.049 | 0.000 | 200.049 |
| 12-2020 | 2.331 | 0.000 | 1.923 | 0.000 | 87.370 | 0.000 | 168.041 | 0.000 | 168.041 |
| 12-2021 | 1.958 | 0.000 | 1.616 | 0.000 | 87.370 | 0.000 | 141.154 | 0.000 | 141.154 |
| 12-2022 | 1.645 | 0.000 | 1.357 | 0.000 | 87.370 | 0.000 | 118.570 | 0.000 | 118.570 |
| 12-2023 | 1.382 | 0.000 | 1.140 | 0.000 | 87.370 | 0.000 | 99.598 | 0.000 | 99.598 |
| 12-2024 | 1.161 | 0.000 | 0.958 | 0.000 | 87.370 | 0.000 | 83.663 | 0.000 | 83.663 |
| 12-2025 | 0.975 | 0.000 | 0.804 | 0.000 | 87.370 | 0.000 | 70.277 | 0.000 | 70.277 |
| 12-2026 | 0.819 | 0.000 | 0.676 | 0.000 | 87.370 | 0.000 | 59.032 | 0.000 | 59.032 |
| 12-2027 | 0.635 | 0.000 | 0.524 | 0.000 | 87.370 | 0.000 | 45.777 | 0.000 | 45.777 |
| S TOT | 45.712 | 0.000 | 37.713 | 0.000 | 87.370 | 0.000 | 3294.953 | 0.000 | 3294.953 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| TOTAL | 45.712 | 0.000 | 37.713 | 0.000 | 87.370 | 0.000 | 3294.953 | 0.000 | 3294.953 |

| --END-- MO-YEAR | AD VALOREM TAX M$ | PRODUCTION TAX M$ | DIRECT OPER EXPENSE M$ | INTEREST PAID M$ | CAPITAL REPAYMENT M$ | EQUITY INVESTMENT M$ | FUTURE NET CASHFLOW M$ | CUMULATIVE CASHFLOW M$ | CUM. DISC. CASHFLOW M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 11.047 | 17.084 | 43.800 | 0.000 | 0.000 | 0.000 | 497.524 | 497.524 | 475.259 |
| 12-2014 | 9.280 | 14.350 | 43.800 | 0.000 | 0.000 | 0.000 | 410.912 | 908.437 | 832.107 |
| 12-2015 | 7.795 | 12.054 | 43.800 | 0.000 | 0.000 | 0.000 | 338.158 | 1246.595 | 1099.085 |
| 12-2016 | 6.548 | 10.126 | 43.800 | 0.000 | 0.000 | 0.000 | 277.045 | 1523.640 | 1297.937 |
| 12-2017 | 5.500 | 8.505 | 43.800 | 0.000 | 0.000 | 0.000 | 225.710 | 1749.350 | 1445.222 |
| 12-2018 | 4.620 | 7.145 | 43.800 | 0.000 | 0.000 | 0.000 | 182.588 | 1931.938 | 1553.544 |
| 12-2019 | 3.881 | 6.001 | 43.800 | 0.000 | 0.000 | 0.000 | 146.366 | 2078.304 | 1632.489 |
| 12-2020 | 3.260 | 5.041 | 43.800 | 0.000 | 0.000 | 0.000 | 115.940 | 2194.244 | 1689.345 |
| 12-2021 | 2.738 | 4.235 | 43.800 | 0.000 | 0.000 | 0.000 | 90.381 | 2284.625 | 1729.643 |
| 12-2022 | 2.300 | 3.557 | 43.800 | 0.000 | 0.000 | 0.000 | 68.912 | 2353.538 | 1757.582 |
| 12-2023 | 1.932 | 2.988 | 43.800 | 0.000 | 0.000 | 0.000 | 50.878 | 2404.416 | 1776.339 |
| 12-2024 | 1.623 | 2.510 | 43.800 | 0.000 | 0.000 | 0.000 | 35.730 | 2440.146 | 1788.321 |
| 12-2025 | 1.363 | 2.108 | 43.800 | 0.000 | 0.000 | 0.000 | 23.005 | 2463.150 | 1795.340 |
| 12-2026 | 1.145 | 1.771 | 43.800 | 0.000 | 0.000 | 0.000 | 12.316 | 2475.467 | 1798.764 |
| 12-2027 | 0.888 | 1.373 | 40.150 | 0.000 | 0.000 | 0.000 | 3.366 | 2478.833 | 1799.626 |
| S TOT | 63.922 | 98.849 | 653.350 | 0.000 | 0.000 | 0.000 | 2478.833 | 2478.833 | 1799.626 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 2478.833 | 1799.626 |
| TOTAL | 63.922 | 98.849 | 653.350 | 0.000 | 0.000 | 0.000 | 2478.833 | 2478.833 | 1799.626 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 14.92 | 5.00 | 2084.613 |
| GROSS ULT., MB & MMF | 74.310 | 0.000 | DISCOUNT % | 10.00 | 8.00 | 1903.357 |
| GROSS CUM., MB & MMF | 28.598 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 1799.626 |
| GROSS RES., MB & MMF | 45.712 | 0.000 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 1707.175 |
| NET RES., MB & MMF | 37.713 | 0.000 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 1586.138 |
| NET REVENUE, M$ | 3294.953 | 0.000 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 1482.463 |
| INITIAL PRICE, $ | 87.370 | 0.000 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 1185.055 |
| INITIAL N.I., PCT. | 82.500 | 0.000 | INITIAL W.I., PCT. | 100.000 | 60.00 | 822.200 |

**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529




**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529

LUKASSEN 14-34
FIELD: CABLE
COUNTY: KIMBALL STATE: NE
OPERATOR: RECOVERY ENERGY INCOR
1PDP

DATE : 04/01/2013
TIME : 14:03:11
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO : RED_JAN13

## RESERVES AND ECONOMICS

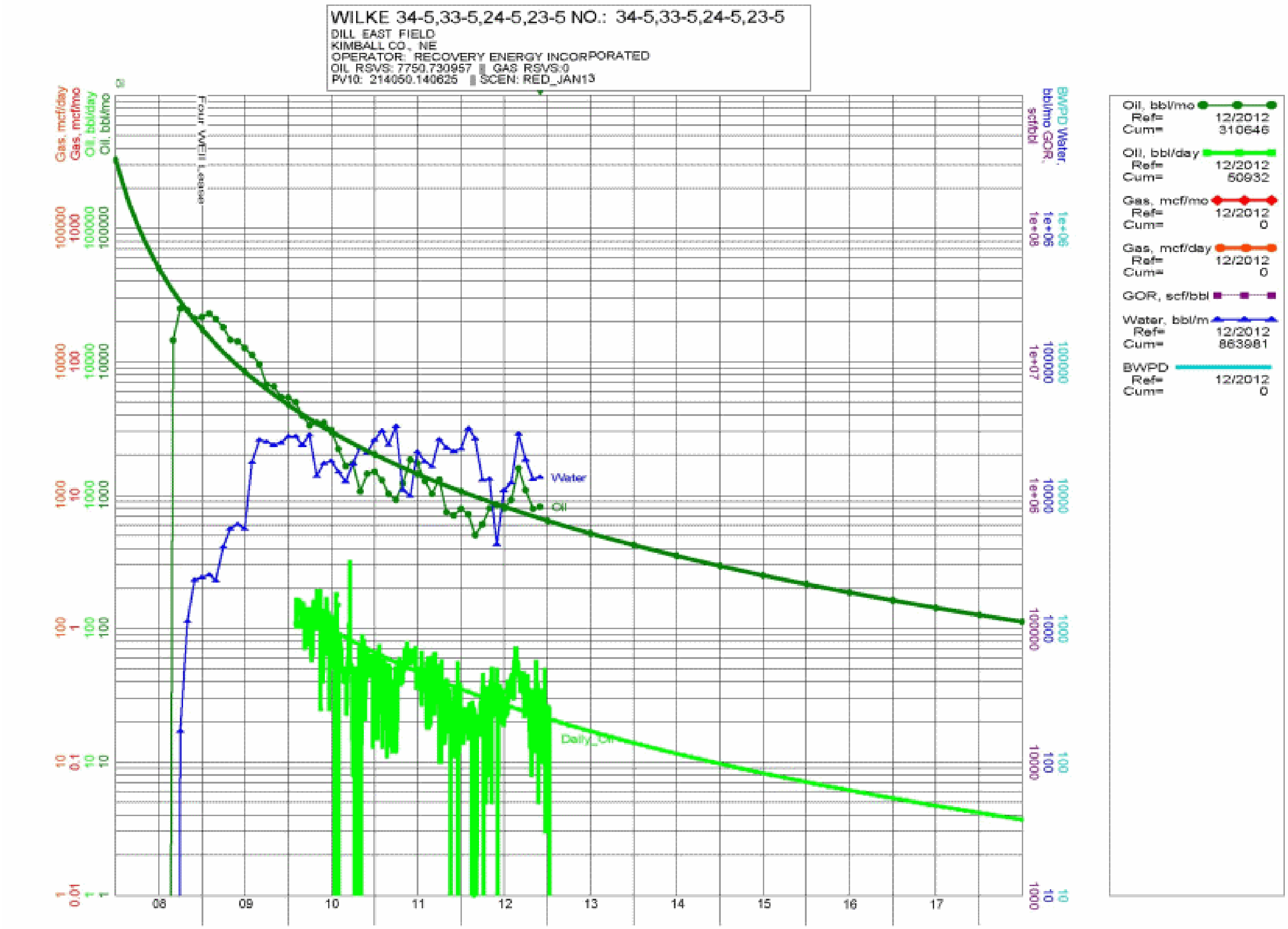
### AS OF DATE: 12/31/2012

| --END-- MO-YEAR | GROSS OIL PRODUCTION | GROSS GAS PRODUCTION | NET OIL PRODUCTION | NET GAS PRODUCTION | NET OIL PRICE | NET GAS PRICE | NET OIL SALES | NET GAS SALES | TOTAL NET SALES |
|---|---|---|---|---|---|---|---|---|---|
| ------- | ---MBBLS--- | ----MMCF--- | ---MBBLS--- | ----MMCF--- | ---$/BBL--- | ---$/MCF--- | -----M$---- | -----M$---- | -----M$---- |
| 12-2013 | 1.665 | 0.000 | 1.299 | 0.000 | 87.370 | 0.000 | 113.468 | 0.000 | 113.468 |
| 12-2014 | 1.237 | 0.000 | 0.965 | 0.000 | 87.370 | 0.000 | 84.276 | 0.000 | 84.276 |
| 12-2015 | 0.943 | 0.000 | 0.736 | 0.000 | 87.370 | 0.000 | 64.290 | 0.000 | 64.290 |
| 12-2016 | 0.068 | 0.000 | 0.053 | 0.000 | 87.370 | 0.000 | 4.656 | 0.000 | 4.656 |
| 12-2017 | | | | | | | | | |
| 12-2018 | | | | | | | | | |
| 12-2019 | | | | | | | | | |
| 12-2020 | | | | | | | | | |
| 12-2021 | | | | | | | | | |
| 12-2022 | | | | | | | | | |
| 12-2023 | | | | | | | | | |
| 12-2024 | | | | | | | | | |
| 12-2025 | | | | | | | | | |
| 12-2026 | | | | | | | | | |
| 12-2027 | | | | | | | | | |
| S TOT | 3.913 | 0.000 | 3.052 | 0.000 | 87.370 | 0.000 | 266.689 | 0.000 | 266.689 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| TOTAL | 3.913 | 0.000 | 3.052 | 0.000 | 87.370 | 0.000 | 266.689 | 0.000 | 266.689 |

| --END-- MO-YEAR | AD VALOREM TAX | PRODUCTION TAX | DIRECT OPER EXPENSE | INTEREST PAID | CAPITAL REPAYMENT | EQUITY INVESTMENT | FUTURE NET CASHFLOW | CUMULATIVE CASHFLOW | CUM. DISC. CASHFLOW |
|---|---|---|---|---|---|---|---|---|---|
| ------- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- |
| 12-2013 | 2.201 | 3.404 | 52.800 | 0.000 | 0.000 | 0.000 | 55.062 | 55.062 | 52.772 |
| 12-2014 | 1.635 | 2.528 | 52.800 | 0.000 | 0.000 | 0.000 | 27.313 | 82.375 | 76.610 |
| 12-2015 | 1.247 | 1.929 | 52.800 | 0.000 | 0.000 | 0.000 | 8.314 | 90.689 | 83.262 |
| 12-2016 | 0.090 | 0.140 | 4.400 | 0.000 | 0.000 | 0.000 | 0.026 | 90.715 | 83.282 |
| 12-2017 | | | | | | | | | |
| 12-2018 | | | | | | | | | |
| 12-2019 | | | | | | | | | |
| 12-2020 | | | | | | | | | |
| 12-2021 | | | | | | | | | |
| 12-2022 | | | | | | | | | |
| 12-2023 | | | | | | | | | |
| 12-2024 | | | | | | | | | |
| 12-2025 | | | | | | | | | |
| 12-2026 | | | | | | | | | |
| 12-2027 | | | | | | | | | |
| S TOT | 5.174 | 8.001 | 162.800 | 0.000 | 0.000 | 0.000 | 90.715 | 90.715 | 83.282 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 90.715 | 83.282 |
| TOTAL | 5.174 | 8.001 | 162.800 | 0.000 | 0.000 | 0.000 | 90.715 | 90.715 | 83.282 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| | --------- | --------- | | | ------ | -------- |
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 3.08 | 5.00 | 86.784 |
| GROSS ULT., MB & MMF | 14.408 | 0.000 | DISCOUNT % | 10.00 | 8.00 | 84.636 |
| GROSS CUM., MB & MMF | 10.494 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 83.282 |
| GROSS RES., MB & MMF | 3.913 | 0.000 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 81.985 |
| NET RES., MB & MMF | 3.052 | 0.000 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 80.140 |
| NET REVENUE, M$ | 266.689 | 0.000 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 78.407 |
| INITIAL PRICE, $ | 87.370 | 0.000 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 72.401 |
| INITIAL N.I., PCT. | 78.000 | 0.000 | INITIAL W.I., PCT. | 100.000 | 60.00 | 61.817 |

| | |
|---|---|
| **80.00** | **56.920** |
| **260.00** | **38.079** |



RALPH E. DAVIS ASSOCIATES, INC.
Texas Registered Engineering Firm F-1529

WILKE 34-5,33-5,24-5,23-5
FIELD: DILL EAST
COUNTY: KIMBALL STATE: NE
OPERATOR: RECOVERY ENERGY INCOR
1PDP

DATE : 04/01/2013
TIME : 14:03:11
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO : RED_JAN13

## RESERVES AND ECONOMICS

### AS OF DATE: 12/31/2012

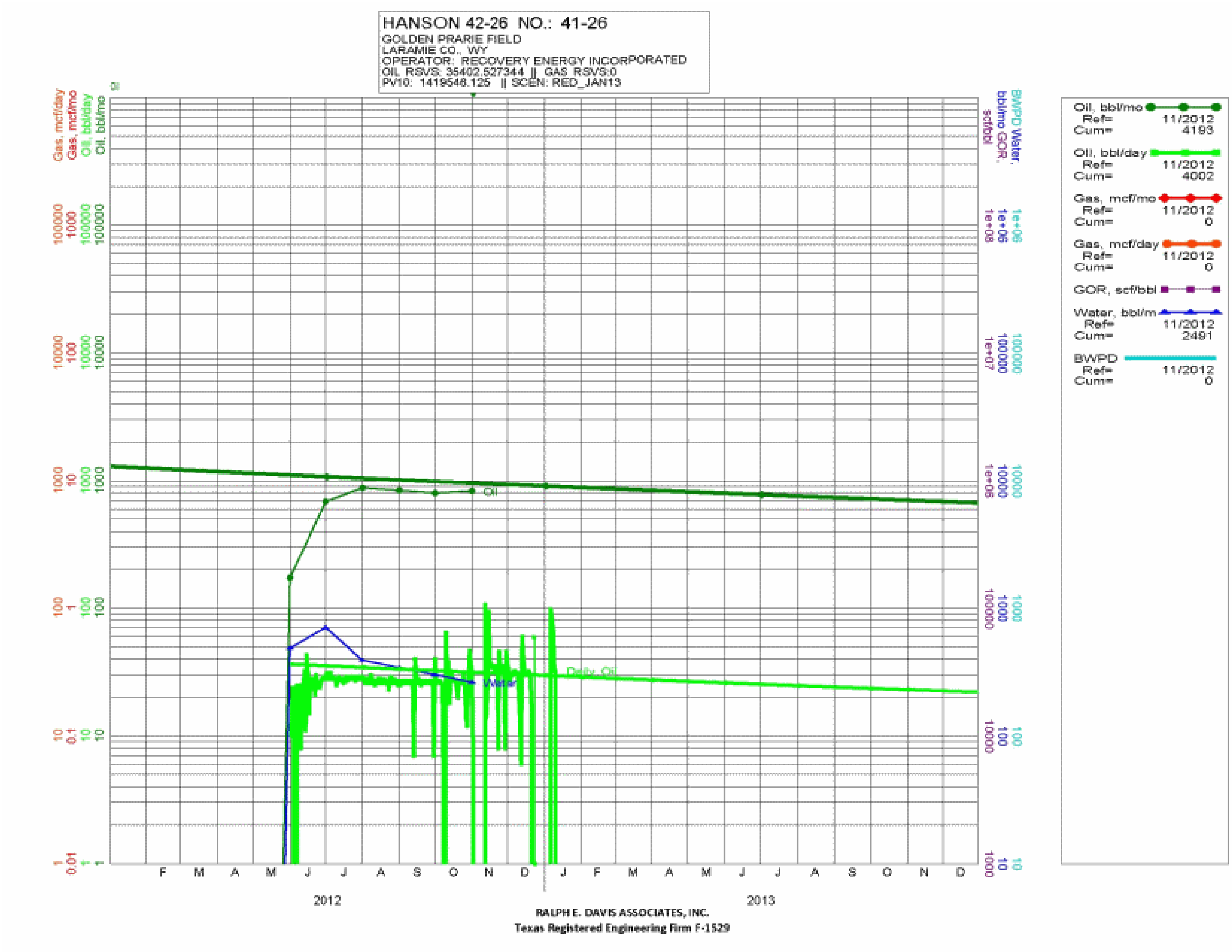
| --END-- MO-YEAR | GROSS OIL PRODUCTION | GROSS GAS PRODUCTION | NET OIL PRODUCTION | NET GAS PRODUCTION | NET OIL PRICE | NET GAS PRICE | NET OIL SALES | NET GAS SALES | TOTAL NET SALES |
|---|---|---|---|---|---|---|---|---|---|
| ------- | ---MBBLS--- | ----MMCF--- | ---MBBLS--- | ----MMCF--- | ---$/BBL--- | ---$/MCF--- | -----M$---- | -----M$---- | -----M$---- |
| 12-2013 | 6.268 | 0.000 | 4.278 | 0.000 | 87.370 | 0.000 | 373.772 | 0.000 | 373.772 |
| 12-2014 | 4.240 | 0.000 | 2.894 | 0.000 | 87.370 | 0.000 | 252.809 | 0.000 | 252.809 |
| 12-2015 | 0.849 | 0.000 | 0.579 | 0.000 | 87.370 | 0.000 | 50.600 | 0.000 | 50.600 |
| 12-2016 | | | | | | | | | |
| 12-2017 | | | | | | | | | |
| 12-2018 | | | | | | | | | |
| 12-2019 | | | | | | | | | |
| 12-2020 | | | | | | | | | |
| 12-2021 | | | | | | | | | |
| 12-2022 | | | | | | | | | |
| 12-2023 | | | | | | | | | |
| 12-2024 | | | | | | | | | |
| 12-2025 | | | | | | | | | |
| 12-2026 | | | | | | | | | |
| 12-2027 | | | | | | | | | |
| S TOT | 11.356 | 0.000 | 7.751 | 0.000 | 87.370 | 0.000 | 677.181 | 0.000 | 677.181 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| TOTAL | 11.356 | 0.000 | 7.751 | 0.000 | 87.370 | 0.000 | 677.181 | 0.000 | 677.181 |

| --END-- MO-YEAR | AD VALOREM TAX | PRODUCTION TAX | DIRECT OPER EXPENSE | INTEREST PAID | CAPITAL REPAYMENT | EQUITY INVESTMENT | FUTURE NET CASHFLOW | CUMULATIVE CASHFLOW | CUM. DISC. CASHFLOW |
|---|---|---|---|---|---|---|---|---|---|
| ------- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- |
| 12-2013 | 7.251 | 11.213 | 184.800 | 0.000 | 0.000 | 0.000 | 170.508 | 170.508 | 163.758 |
| 12-2014 | 4.904 | 7.584 | 184.800 | 0.000 | 0.000 | 0.000 | 55.520 | 226.028 | 212.492 |
| 12-2015 | 0.982 | 1.518 | 46.200 | 0.000 | 0.000 | 0.000 | 1.901 | 227.929 | 214.050 |
| 12-2016 | | | | | | | | | |
| 12-2017 | | | | | | | | | |
| 12-2018 | | | | | | | | | |
| 12-2019 | | | | | | | | | |
| 12-2020 | | | | | | | | | |
| 12-2021 | | | | | | | | | |
| 12-2022 | | | | | | | | | |
| 12-2023 | | | | | | | | | |
| 12-2024 | | | | | | | | | |
| 12-2025 | | | | | | | | | |
| 12-2026 | | | | | | | | | |
| 12-2027 | | | | | | | | | |
| S TOT | 13.137 | 20.315 | 415.800 | 0.000 | 0.000 | 0.000 | 227.929 | 227.929 | 214.050 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 227.929 | 214.050 |
| TOTAL | 13.137 | 20.315 | 415.800 | 0.000 | 0.000 | 0.000 | 227.929 | 227.929 | 214.050 |

| | OIL | GAS |
|---|---|---|
| | --------- | --------- |
| GROSS WELLS | 4.0 | 0.0 |
| GROSS ULT., MB & MMF | 61.324 | 0.000 |
| GROSS CUM., MB & MMF | 49.967 | 0.000 |
| GROSS RES., MB & MMF | 11.356 | 0.000 |
| NET RES., MB & MMF | 7.751 | 0.000 |
| NET REVENUE, M$ | 677.181 | 0.000 |
| INITIAL PRICE, $ | 87.370 | 0.000 |
| INITIAL N.I., PCT. | 68.250 | 0.000 |

| | |
|---|---|
| LIFE, YRS. | 2.25 |
| DISCOUNT % | 10.00 |
| UNDISCOUNTED PAYOUT, YRS. | 0.00 |
| DISCOUNTED PAYOUT, YRS. | 0.00 |
| UNDISCOUNTED NET/INVEST. | 0.00 |
| DISCOUNTED NET/INVEST. | 0.00 |
| RATE-OF-RETURN, PCT. | 260.00 |
| INITIAL W.I., PCT. | 87.500 |

| P.W. % | P.W., M$ |
|---|---|
| ------ | -------- |
| 5.00 | 220.652 |
| 8.00 | 216.616 |
| 10.00 | 214.050 |
| 12.00 | 211.577 |
| 15.00 | 208.030 |
| 18.00 | 204.665 |
| 30.00 | 192.763 |
| 60.00 | 170.747 |
| 80.00 | 160.048 |
| 260.00 | 115.116 |



HANSON 42-26 NO.: 41-26
GOLDEN PRARIE FIELD
LARAMIE CO., WY
OPERATOR: RECOVERY ENERGY INCORPORATED
OIL RSVS: 35402.527344 || GAS RSVS:0
PV10: 1419546.125 || SCEN: RED_JAN13
Oil, bbl/mo
Ref= 11/2012
Cum= 4193
Oil, bbl/day
Ref= 11/2012
Cum= 4002
Gas, mcf/mo
Ref= 11/2012
Cum= 0
Gas, mcf/day
Ref= 11/2012
Cum= 0
GOR, scf/bbl
Water, bbl/m
Ref= 11/2012
Cum= 2491
BWPD
Ref= 11/2012
Cum= 0
2012
2013
RALPH E. DAVIS ASSOCIATES, INC.
Texas Registered Engineering Firm F-1529

HANSON 42-26
FIELD: GOLDEN PRARIE
COUNTY: LARAMIE     STATE: WY
OPERATOR: RECOVERY ENERGY INCOR
1PDP

DATE : 04/01/2013
TIME : 14:03:11
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO : RED_JAN13

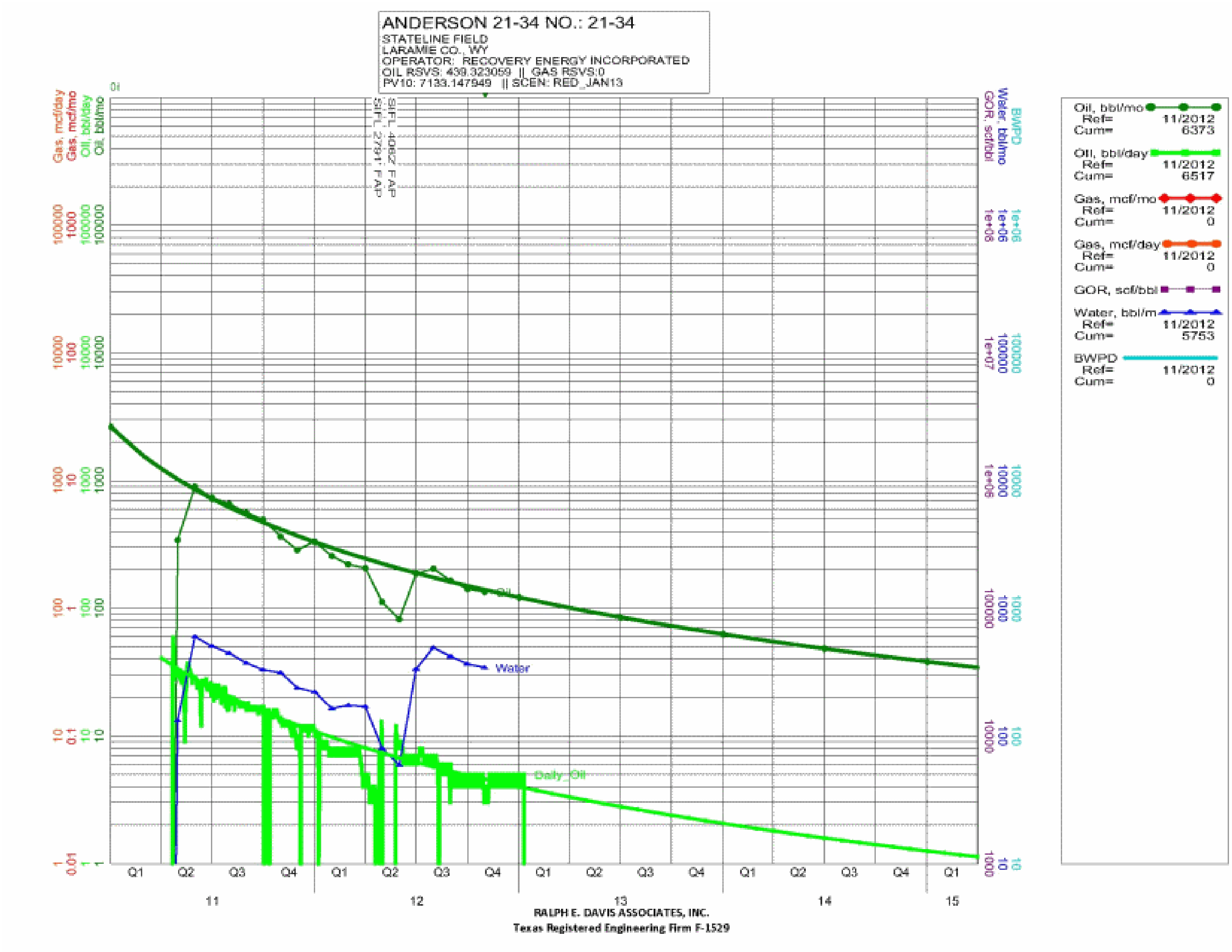
## RESERVES AND ECONOMICS

AS OF DATE: 12/31/2012

| --END-- MO-YEAR | GROSS OIL PRODUCTION | GROSS GAS PRODUCTION | NET OIL PRODUCTION | NET GAS PRODUCTION | NET OIL PRICE | NET GAS PRICE | NET OIL SALES | NET GAS SALES | TOTAL NET SALES |
|---|---|---|---|---|---|---|---|---|---|
| ------- | ---MBBLS--- | ----MMCF--- | ---MBBLS--- | ----MMCF--- | ---$/BBL--- | ---$/MCF--- | -----M$---- | -----M$---- | -----M$---- |
| 12-2013 | 9.332 | 0.000 | 6.719 | 0.000 | 87.370 | 0.000 | 587.019 | 0.000 | 587.019 |
| 12-2014 | 7.053 | 0.000 | 5.078 | 0.000 | 87.370 | 0.000 | 443.689 | 0.000 | 443.689 |
| 12-2015 | 5.528 | 0.000 | 3.980 | 0.000 | 87.370 | 0.000 | 347.774 | 0.000 | 347.774 |
| 12-2016 | 4.456 | 0.000 | 3.208 | 0.000 | 87.370 | 0.000 | 280.325 | 0.000 | 280.325 |
| 12-2017 | 3.673 | 0.000 | 2.644 | 0.000 | 87.370 | 0.000 | 231.026 | 0.000 | 231.026 |
| 12-2018 | 3.082 | 0.000 | 2.219 | 0.000 | 87.370 | 0.000 | 193.862 | 0.000 | 193.862 |
| 12-2019 | 2.625 | 0.000 | 1.890 | 0.000 | 87.370 | 0.000 | 165.127 | 0.000 | 165.127 |
| 12-2020 | 2.264 | 0.000 | 1.630 | 0.000 | 87.370 | 0.000 | 142.434 | 0.000 | 142.434 |
| 12-2021 | 1.974 | 0.000 | 1.421 | 0.000 | 87.370 | 0.000 | 124.189 | 0.000 | 124.189 |
| 12-2022 | 1.737 | 0.000 | 1.251 | 0.000 | 87.370 | 0.000 | 109.292 | 0.000 | 109.292 |
| 12-2023 | 1.541 | 0.000 | 1.110 | 0.000 | 87.370 | 0.000 | 96.966 | 0.000 | 96.966 |
| 12-2024 | 1.377 | 0.000 | 0.992 | 0.000 | 87.370 | 0.000 | 86.647 | 0.000 | 86.647 |
| 12-2025 | 1.239 | 0.000 | 0.892 | 0.000 | 87.370 | 0.000 | 77.919 | 0.000 | 77.919 |
| 12-2026 | 1.120 | 0.000 | 0.807 | 0.000 | 87.370 | 0.000 | 70.467 | 0.000 | 70.467 |
| 12-2027 | 1.018 | 0.000 | 0.733 | 0.000 | 87.370 | 0.000 | 64.053 | 0.000 | 64.053 |
| S TOT | 48.020 | 0.000 | 34.575 | 0.000 | 87.370 | 0.000 | 3020.788 | 0.000 | 3020.788 |
| AFTER | 1.150 | 0.000 | 0.828 | 0.000 | 87.370 | 0.000 | 72.331 | 0.000 | 72.331 |
| TOTAL | 49.170 | 0.000 | 35.403 | 0.000 | 87.370 | 0.000 | 3093.119 | 0.000 | 3093.119 |

| --END-- MO-YEAR | AD VALOREM TAX | PRODUCTION TAX | DIRECT OPER EXPENSE | INTEREST PAID | CAPITAL REPAYMENT | EQUITY INVESTMENT | FUTURE NET CASHFLOW | CUMULATIVE CASHFLOW | CUM. DISC. CASHFLOW |
|---|---|---|---|---|---|---|---|---|---|
| ------- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- |
| 12-2013 | 39.725 | 37.569 | 47.520 | 0.000 | 0.000 | 0.000 | 462.205 | 462.205 | 442.013 |
| 12-2014 | 30.026 | 28.396 | 47.520 | 0.000 | 0.000 | 0.000 | 337.747 | 799.952 | 735.561 |
| 12-2015 | 23.535 | 22.258 | 47.520 | 0.000 | 0.000 | 0.000 | 254.462 | 1054.414 | 936.576 |
| 12-2016 | 18.970 | 17.941 | 47.520 | 0.000 | 0.000 | 0.000 | 195.893 | 1250.307 | 1077.237 |
| 12-2017 | 15.634 | 14.786 | 47.520 | 0.000 | 0.000 | 0.000 | 153.086 | 1403.393 | 1177.157 |
| 12-2018 | 13.119 | 12.407 | 47.520 | 0.000 | 0.000 | 0.000 | 120.815 | 1524.209 | 1248.842 |
| 12-2019 | 11.175 | 10.568 | 47.520 | 0.000 | 0.000 | 0.000 | 95.864 | 1620.073 | 1300.549 |
| 12-2020 | 9.639 | 9.116 | 47.520 | 0.000 | 0.000 | 0.000 | 76.159 | 1696.231 | 1337.894 |
| 12-2021 | 8.404 | 7.948 | 47.520 | 0.000 | 0.000 | 0.000 | 60.316 | 1756.548 | 1364.782 |
| 12-2022 | 7.396 | 6.995 | 47.520 | 0.000 | 0.000 | 0.000 | 47.381 | 1803.929 | 1383.986 |
| 12-2023 | 6.562 | 6.206 | 47.520 | 0.000 | 0.000 | 0.000 | 36.678 | 1840.607 | 1397.502 |
| 12-2024 | 5.864 | 5.545 | 47.520 | 0.000 | 0.000 | 0.000 | 27.718 | 1868.325 | 1406.790 |
| 12-2025 | 5.273 | 4.987 | 47.520 | 0.000 | 0.000 | 0.000 | 20.139 | 1888.464 | 1412.928 |
| 12-2026 | 4.769 | 4.510 | 47.520 | 0.000 | 0.000 | 0.000 | 13.669 | 1902.133 | 1416.717 |
| 12-2027 | 4.335 | 4.099 | 47.520 | 0.000 | 0.000 | 0.000 | 8.099 | 1910.232 | 1418.762 |
| S TOT | 204.425 | 193.330 | 712.800 | 0.000 | 0.000 | 0.000 | 1910.232 | 1910.232 | 1418.762 |
| AFTER | 4.895 | 4.629 | 59.400 | 0.000 | 0.000 | 0.000 | 3.407 | 1913.639 | 1419.546 |
| TOTAL | 209.320 | 197.960 | 772.200 | 0.000 | 0.000 | 0.000 | 1913.639 | 1913.639 | 1419.546 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| | --------- | --------- | | | ------ | -------- |
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 16.25 | 5.00 | 1626.358 |
| GROSS ULT., MB & MMF | 49.170 | 0.000 | DISCOUNT % | 10.00 | 8.00 | 1494.783 |
| GROSS CUM., MB & MMF | 0.000 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 1419.546 |
| GROSS RES., MB & MMF | 49.170 | 0.000 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 1352.488 |
| NET RES., MB & MMF | 35.403 | 0.000 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 1264.629 |
| NET REVENUE, M$ | 3093.119 | 0.000 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 1189.245 |
| INITIAL PRICE, $ | 87.370 | 0.000 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 971.572 |
| INITIAL N.I., PCT. | 72.000 | 0.000 | INITIAL W.I., PCT. | 90.000 | 60.00 | 699.663 |
| | | | | | 80.00 | 604.724 |
| | | | | | 260.00 | 338.447 |


ANDERSON 21-34 NO.: 21-34
STATELINE FIELD
LARAMIE CO., WY
OPERATOR: RECOVERY ENERGY INCORPORATED
OIL RSVS: 439.323059 || GAS RSVS:0
PV10: 7133.147949 || SCEN: RED_JAN13
SIFL 4062' FAP
SIFL 2791' FAP
Gas, mcf/day
Gas, mcf/mo
Oil, bbl/day
Oil, bbl/mo
BWPD
Water, bbl/mo
GOR, scf/bbl
Oil
Water
Daily_Oil
Oil, bbl/mo
Ref= 11/2012
Cum= 6373
Oil, bbl/day
Ref= 11/2012
Cum= 6517
Gas, mcf/mo
Ref= 11/2012
Cum= 0
Gas, mcf/day
Ref= 11/2012
Cum= 0
GOR, scf/bbl
Water, bbl/m
Ref= 11/2012
Cum= 5753
BWPD
Ref= 11/2012
Cum= 0
Q1 Q2 Q3 Q4 Q1 Q2 Q3 Q4 Q1 Q2 Q3 Q4 Q1 Q2 Q3 Q4 Q1
11 12 13 14 15
RALPH E. DAVIS ASSOCIATES, INC.
Texas Registered Engineering Firm F-1529

ANDERSON 21-34
FIELD: STATELINE
COUNTY: LARAMIE      STATE: WY
OPERATOR: RECOVERY ENERGY INCOR
1PDP

DATE : 04/01/2013
TIME : 14:03:11
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO : RED_JAN13

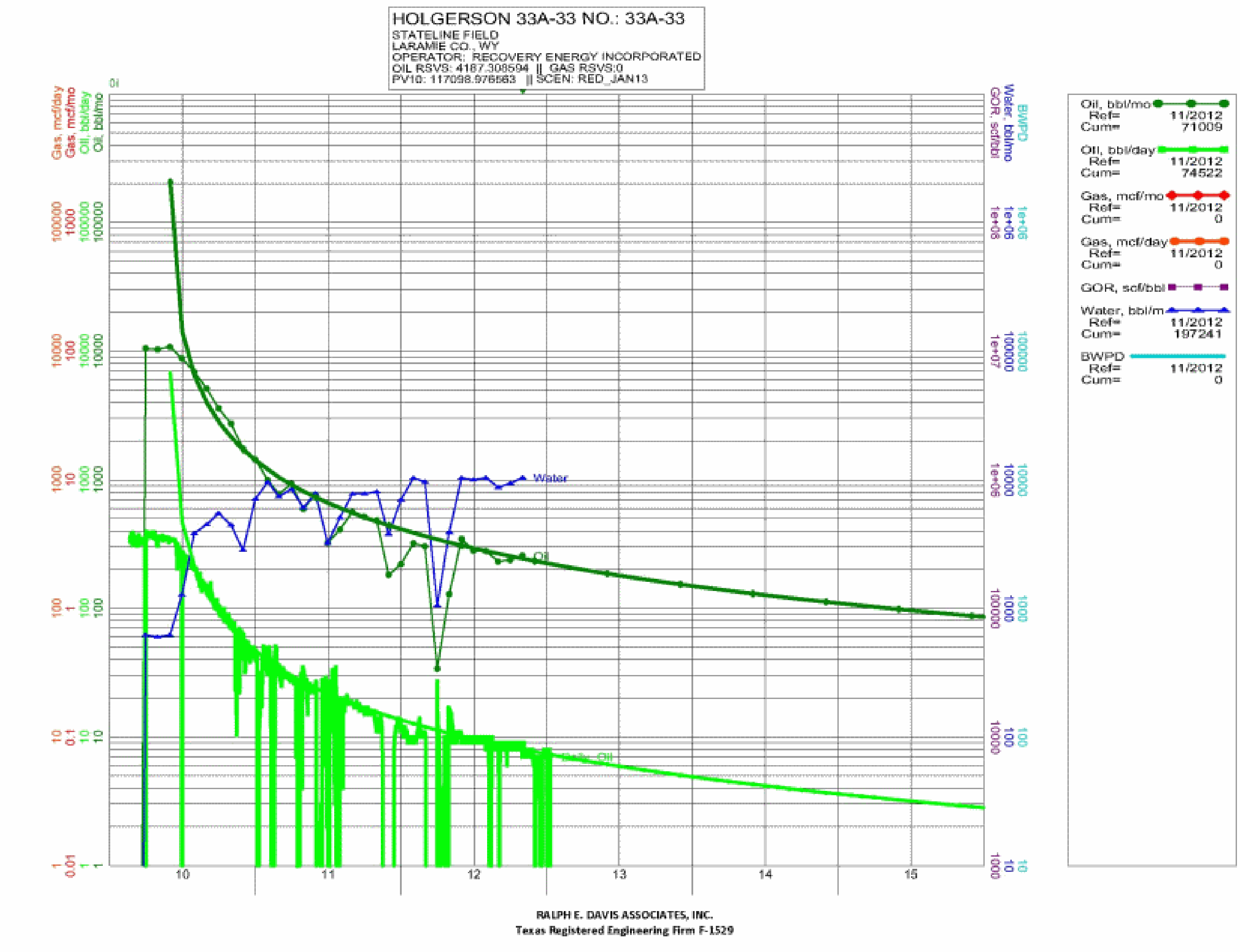
## RESERVES AND ECONOMICS

AS OF DATE: 12/31/2012

| --END-- MO-YEAR | GROSS OIL PRODUCTION | GROSS GAS PRODUCTION | NET OIL PRODUCTION | NET GAS PRODUCTION | NET OIL PRICE | NET GAS PRICE | NET OIL SALES | NET GAS SALES | TOTAL NET SALES |
|---|---|---|---|---|---|---|---|---|---|
| ------- | ---MBBLS--- | ----MMCF--- | ---MBBLS--- | ----MMCF--- | ---$/BBL--- | ---$/MCF--- | -----M$---- | -----M$---- | -----M$---- |
| 12-2013 | 0.771 | 0.000 | 0.439 | 0.000 | 87.370 | 0.000 | 38.384 | 0.000 | 38.384 |
| 12-2014 | | | | | | | | | |
| 12-2015 | | | | | | | | | |
| 12-2016 | | | | | | | | | |
| 12-2017 | | | | | | | | | |
| 12-2018 | | | | | | | | | |
| 12-2019 | | | | | | | | | |
| 12-2020 | | | | | | | | | |
| 12-2021 | | | | | | | | | |
| 12-2022 | | | | | | | | | |
| 12-2023 | | | | | | | | | |
| 12-2024 | | | | | | | | | |
| 12-2025 | | | | | | | | | |
| 12-2026 | | | | | | | | | |
| 12-2027 | | | | | | | | | |
| S TOT | 0.771 | 0.000 | 0.439 | 0.000 | 87.370 | 0.000 | 38.384 | 0.000 | 38.384 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| TOTAL | 0.771 | 0.000 | 0.439 | 0.000 | 87.370 | 0.000 | 38.384 | 0.000 | 38.384 |

| --END-- MO-YEAR | AD VALOREM TAX | PRODUCTION TAX | DIRECT OPER EXPENSE | INTEREST PAID | CAPITAL REPAYMENT | EQUITY INVESTMENT | FUTURE NET CASHFLOW | CUMULATIVE CASHFLOW | CUM. DISC. CASHFLOW |
|---|---|---|---|---|---|---|---|---|---|
| ------- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- |
| 12-2013 | 2.598 | 2.457 | 26.048 | 0.000 | 0.000 | 0.000 | 7.282 | 7.282 | 7.133 |
| 12-2014 | | | | | | | | | |
| 12-2015 | | | | | | | | | |
| 12-2016 | | | | | | | | | |
| 12-2017 | | | | | | | | | |
| 12-2018 | | | | | | | | | |
| 12-2019 | | | | | | | | | |
| 12-2020 | | | | | | | | | |
| 12-2021 | | | | | | | | | |
| 12-2022 | | | | | | | | | |
| 12-2023 | | | | | | | | | |
| 12-2024 | | | | | | | | | |
| 12-2025 | | | | | | | | | |
| 12-2026 | | | | | | | | | |
| 12-2027 | | | | | | | | | |
| S TOT | 2.598 | 2.457 | 26.048 | 0.000 | 0.000 | 0.000 | 7.282 | 7.282 | 7.133 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 7.282 | 7.133 |
| TOTAL | 2.598 | 2.457 | 26.048 | 0.000 | 0.000 | 0.000 | 7.282 | 7.282 | 7.133 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| | --------- | --------- | | | ------ | -------- |
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 0.67 | 5.00 | 7.205 |
| GROSS ULT., MB & MMF | 7.404 | 0.000 | DISCOUNT % | 10.00 | 8.00 | 7.161 |
| GROSS CUM., MB & MMF | 6.633 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 7.133 |
| GROSS RES., MB & MMF | 0.771 | 0.000 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 7.106 |
| NET RES., MB & MMF | 0.439 | 0.000 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 7.065 |
| NET REVENUE, M$ | 38.384 | 0.000 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 7.027 |
| INITIAL PRICE, $ | 87.370 | 0.000 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 6.884 |
| INITIAL N.I., PCT. | 56.980 | 0.000 | INITIAL W.I., PCT. | 74.000 | 60.00 | 6.592 |
| | | | | | 80.00 | 6.435 |
| | | | | | 260.00 | 5.620 |



HOLGERSON 33A-33 NO.: 33A-33
STATELINE FIELD
LARAMIE CO., WY
OPERATOR: RECOVERY ENERGY INCORPORATED
OIL RSVS: 4187.308594 || GAS RSVS:0
PV10: 117098.976563 || SCEN: RED_JAN13
Gas, mcf/day
Gas, mcf/mo
Oil, bbl/day
Oil, bbl/mo
BWPD
Water, bbl/mo
GOR, scf/bbl
Water
Oil
Daily Oil
Oil, bbl/mo
Ref= 11/2012
Cum= 71009
Oil, bbl/day
Ref= 11/2012
Cum= 74522
Gas, mcf/mo
Ref= 11/2012
Cum= 0
Gas, mcf/day
Ref= 11/2012
Cum= 0
GOR, scf/bbl
Water, bbl/m
Ref= 11/2012
Cum= 197241
BWPD
Ref= 11/2012
Cum= 0
10
11
12
13
14
15
RALPH E. DAVIS ASSOCIATES, INC.
Texas Registered Engineering Firm F-1529

HOLGERSON 33A-33
FIELD: STATELINE
COUNTY: LARAMIE STATE: WY
OPERATOR: RECOVERY ENERGY INCOR
1PDP

DATE : 04/01/2013
TIME : 14:03:12
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO : RED_JAN13

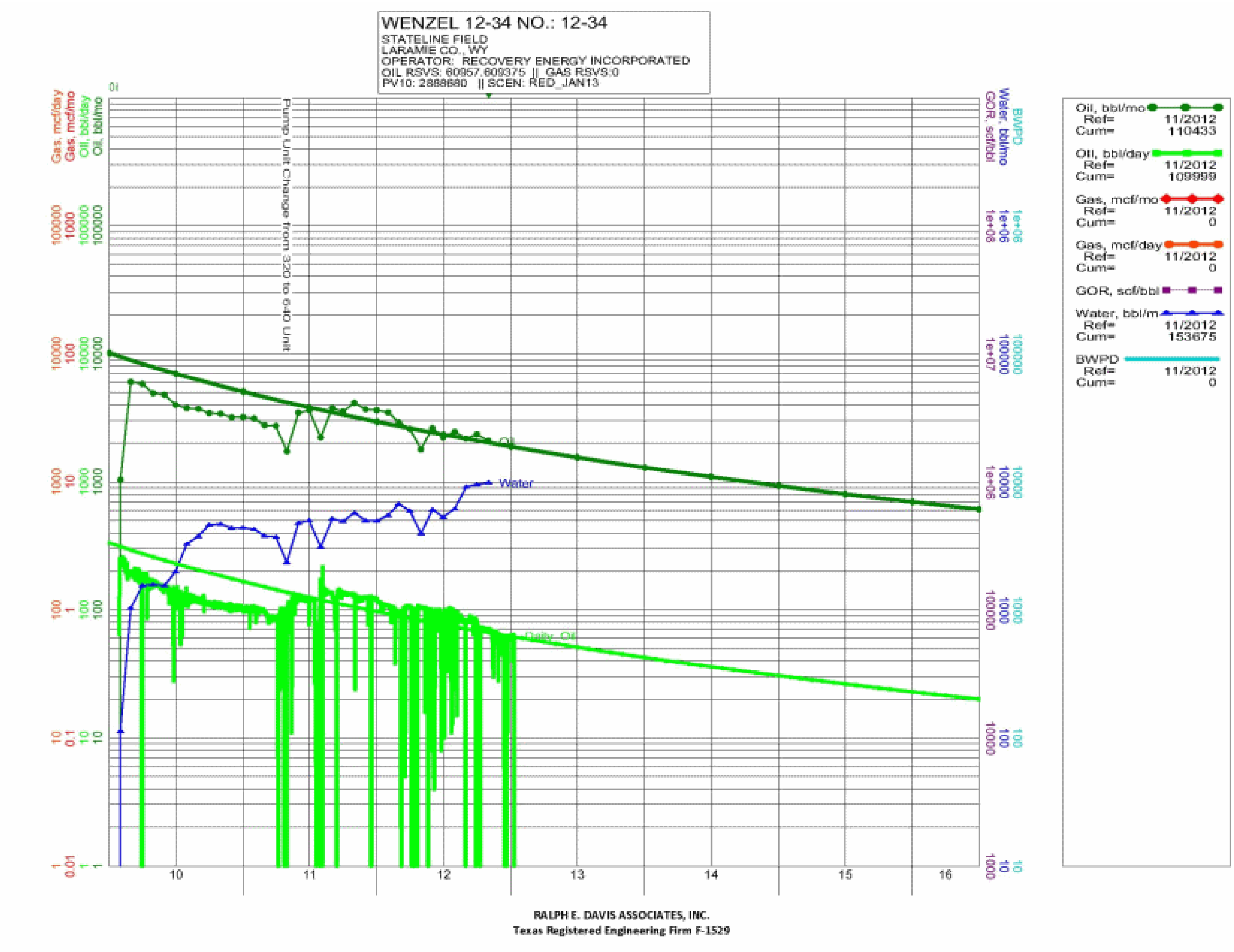
## RESERVES AND ECONOMICS

### AS OF DATE: 12/31/2012

| --END-- MO-YEAR | GROSS OIL PRODUCTION | GROSS GAS PRODUCTION | NET OIL PRODUCTION | NET GAS PRODUCTION | NET OIL PRICE | NET GAS PRICE | NET OIL SALES | NET GAS SALES | TOTAL NET SALES |
|---|---|---|---|---|---|---|---|---|---|
| ------- | ---MBBLS--- | ----MMCF--- | ---MBBLS--- | ----MMCF--- | ---$/BBL--- | ---$/MCF--- | -----M$---- | -----M$---- | -----M$---- |
| 12-2013 | 2.183 | 0.000 | 1.681 | 0.000 | 87.370 | 0.000 | 146.857 | 0.000 | 146.857 |
| 12-2014 | 1.530 | 0.000 | 1.178 | 0.000 | 87.370 | 0.000 | 102.933 | 0.000 | 102.933 |
| 12-2015 | 1.161 | 0.000 | 0.894 | 0.000 | 87.370 | 0.000 | 78.134 | 0.000 | 78.134 |
| 12-2016 | 0.564 | 0.000 | 0.434 | 0.000 | 87.370 | 0.000 | 37.920 | 0.000 | 37.920 |
| 12-2017 | | | | | | | | | |
| 12-2018 | | | | | | | | | |
| 12-2019 | | | | | | | | | |
| 12-2020 | | | | | | | | | |
| 12-2021 | | | | | | | | | |
| 12-2022 | | | | | | | | | |
| 12-2023 | | | | | | | | | |
| 12-2024 | | | | | | | | | |
| 12-2025 | | | | | | | | | |
| 12-2026 | | | | | | | | | |
| 12-2027 | | | | | | | | | |
| S TOT | 5.438 | 0.000 | 4.187 | 0.000 | 87.370 | 0.000 | 365.845 | 0.000 | 365.845 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| TOTAL | 5.438 | 0.000 | 4.187 | 0.000 | 87.370 | 0.000 | 365.845 | 0.000 | 365.845 |

| --END-- MO-YEAR | AD VALOREM TAX | PRODUCTION TAX | DIRECT OPER EXPENSE | INTEREST PAID | CAPITAL REPAYMENT | EQUITY INVESTMENT | FUTURE NET CASHFLOW | CUMULATIVE CASHFLOW | CUM. DISC. CASHFLOW |
|---|---|---|---|---|---|---|---|---|---|
| ------- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- |
| 12-2013 | 9.938 | 9.399 | 52.800 | 0.000 | 0.000 | 0.000 | 74.720 | 74.720 | 71.660 |
| 12-2014 | 6.966 | 6.588 | 52.800 | 0.000 | 0.000 | 0.000 | 36.580 | 111.300 | 103.567 |
| 12-2015 | 5.288 | 5.001 | 52.800 | 0.000 | 0.000 | 0.000 | 15.046 | 126.346 | 115.531 |
| 12-2016 | 2.566 | 2.427 | 30.800 | 0.000 | 0.000 | 0.000 | 2.127 | 128.473 | 117.099 |
| 12-2017 | | | | | | | | | |
| 12-2018 | | | | | | | | | |
| 12-2019 | | | | | | | | | |
| 12-2020 | | | | | | | | | |
| 12-2021 | | | | | | | | | |
| 12-2022 | | | | | | | | | |
| 12-2023 | | | | | | | | | |
| 12-2024 | | | | | | | | | |
| 12-2025 | | | | | | | | | |
| 12-2026 | | | | | | | | | |
| 12-2027 | | | | | | | | | |
| S TOT | 24.758 | 23.414 | 189.200 | 0.000 | 0.000 | 0.000 | 128.473 | 128.473 | 117.099 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 128.473 | 117.099 |
| TOTAL | 24.758 | 23.414 | 189.200 | 0.000 | 0.000 | 0.000 | 128.473 | 128.473 | 117.099 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| | --------- | --------- | | | ------ | -------- |
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 3.58 | 5.00 | 122.435 |
| GROSS ULT., MB & MMF | 80.427 | 0.000 | DISCOUNT % | 10.00 | 8.00 | 119.157 |
| GROSS CUM., MB & MMF | 74.989 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 117.099 |
| GROSS RES., MB & MMF | 5.438 | 0.000 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 115.135 |
| NET RES., MB & MMF | 4.187 | 0.000 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 112.351 |
| NET REVENUE, M$ | 365.845 | 0.000 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 109.746 |
| INITIAL PRICE, $ | 87.370 | 0.000 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 100.804 |
| INITIAL N.I., PCT. | 77.000 | 0.000 | INITIAL W.I., PCT. | 100.000 | 60.00 | 85.362 |
| | | | | | 80.00 | 78.352 |
| | | | | | 260.00 | 52.111 |


WENZEL 12-34 NO.: 12-34
STATELINE FIELD
LARAMIE CO., WY
OPERATOR: RECOVERY ENERGY INCORPORATED
OIL RSVS: 60957.609375 || GAS RSVS:0
PV10: 2888680 || SCEN: RED_JAN13
Gas, mcf/day
Gas, mcf/mo
Oil, bbl/day
Oil, bbl/mo
BWPD
Water, bbl/mo
GOR, scf/bbl
Pump Unit Change from 320 to 640 Unit
Oil
Water
Daily Oil
Oil, bbl/mo
Ref= 11/2012
Cum= 110433
Oil, bbl/day
Ref= 11/2012
Cum= 109999
Gas, mcf/mo
Ref= 11/2012
Cum= 0
Gas, mcf/day
Ref= 11/2012
Cum= 0
GOR, scf/bbl
Water, bbl/m
Ref= 11/2012
Cum= 153675
BWPD
Ref= 11/2012
Cum= 0
10
11
12
13
14
15
16
RALPH E. DAVIS ASSOCIATES, INC.
Texas Registered Engineering Firm F-1529

MALM 42-34
FIELD: STATELINE
COUNTY: LARAMIE STATE: WY
OPERATOR: RECOVERY ENERGY INCOR
1PDP

DATE : 04/01/2013
TIME : 14:03:12
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO : RED_JAN13

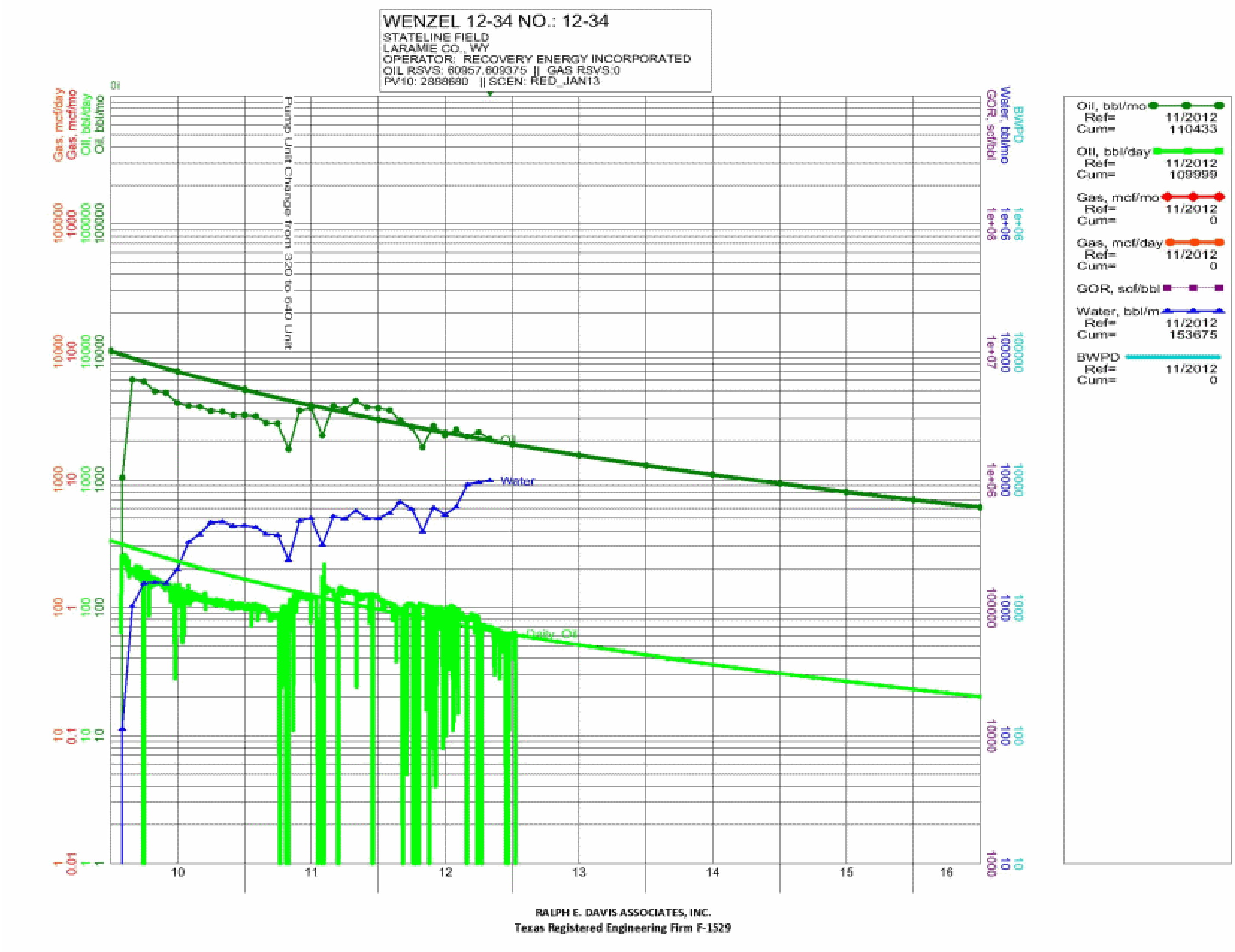
**RESERVES AND ECONOMICS**

**AS OF DATE: 12/31/2012**

| --END-- MO-YEAR | GROSS OIL PRODUCTION | GROSS GAS PRODUCTION | NET OIL PRODUCTION | NET GAS PRODUCTION | NET OIL PRICE | NET GAS PRICE | NET OIL SALES | NET GAS SALES | TOTAL NET SALES |
|---|---|---|---|---|---|---|---|---|---|
| ------- | ---MBBLS--- | ----MMCF--- | ---MBBLS--- | ----MMCF--- | ---$/BBL--- | ---$/MCF--- | -----M$---- | -----M$---- | -----M$---- |
| 12-2013 | 1.338 | 0.000 | 0.762 | 0.000 | 87.370 | 0.000 | 66.611 | 0.000 | 66.611 |
| 12-2014 | 0.770 | 0.000 | 0.439 | 0.000 | 87.370 | 0.000 | 38.314 | 0.000 | 38.314 |
| 12-2015 | | | | | | | | | |
| 12-2016 | | | | | | | | | |
| 12-2017 | | | | | | | | | |
| 12-2018 | | | | | | | | | |
| 12-2019 | | | | | | | | | |
| 12-2020 | | | | | | | | | |
| 12-2021 | | | | | | | | | |
| 12-2022 | | | | | | | | | |
| 12-2023 | | | | | | | | | |
| 12-2024 | | | | | | | | | |
| 12-2025 | | | | | | | | | |
| 12-2026 | | | | | | | | | |
| 12-2027 | | | | | | | | | |
| S TOT | 2.108 | 0.000 | 1.201 | 0.000 | 87.370 | 0.000 | 104.925 | 0.000 | 104.925 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| TOTAL | 2.108 | 0.000 | 1.201 | 0.000 | 87.370 | 0.000 | 104.925 | 0.000 | 104.925 |

| --END-- MO-YEAR | AD VALOREM TAX | PRODUCTION TAX | DIRECT OPER EXPENSE | INTEREST PAID | CAPITAL REPAYMENT | EQUITY INVESTMENT | FUTURE NET CASHFLOW | CUMULATIVE CASHFLOW | CUM. DISC. CASHFLOW |
|---|---|---|---|---|---|---|---|---|---|
| ------- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- |
| 12-2013 | 4.508 | 4.263 | 39.072 | 0.000 | 0.000 | 0.000 | 18.768 | 18.768 | 18.032 |
| 12-2014 | 2.593 | 2.452 | 29.304 | 0.000 | 0.000 | 0.000 | 3.965 | 22.733 | 21.550 |
| 12-2015 | | | | | | | | | |
| 12-2016 | | | | | | | | | |
| 12-2017 | | | | | | | | | |
| 12-2018 | | | | | | | | | |
| 12-2019 | | | | | | | | | |
| 12-2020 | | | | | | | | | |
| 12-2021 | | | | | | | | | |
| 12-2022 | | | | | | | | | |
| 12-2023 | | | | | | | | | |
| 12-2024 | | | | | | | | | |
| 12-2025 | | | | | | | | | |
| 12-2026 | | | | | | | | | |
| 12-2027 | | | | | | | | | |
| S TOT | 7.101 | 6.715 | 68.376 | 0.000 | 0.000 | 0.000 | 22.733 | 22.733 | 21.550 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 22.733 | 21.550 |
| TOTAL | 7.101 | 6.715 | 68.376 | 0.000 | 0.000 | 0.000 | 22.733 | 22.733 | 21.550 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| | --------- | --------- | | | ------ | -------- |
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 1.75 | 5.00 | 22.116 |
| GROSS ULT., MB & MMF | 6.601 | 0.000 | DISCOUNT % | 10.00 | 8.00 | 21.770 |
| GROSS CUM., MB & MMF | 4.493 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 21.550 |
| GROSS RES., MB & MMF | 2.108 | 0.000 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 21.337 |
| NET RES., MB & MMF | 1.201 | 0.000 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 21.030 |
| NET REVENUE, M$ | 104.925 | 0.000 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 20.738 |
| INITIAL PRICE, $ | 87.370 | 0.000 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 19.694 |
| INITIAL N.I., PCT. | 56.980 | 0.000 | INITIAL W.I., PCT. | 74.000 | 60.00 | 17.716 |
| | | | | | 80.00 | 16.732 |
| | | | | | 260.00 | 12.408 |


WENZEL 12-34 NO.: 12-34
STATELINE FIELD
LARAMIE CO., WY
OPERATOR: RECOVERY ENERGY INCORPORATED
OIL RSVS: 60957.609375 || GAS RSVS:0
PV10: 2888680 || SCEN: RED_JAN13
Pump Unit Change from 320 to 640 Unit
Oil
Water
Daily Oil
Oil, bbl/mo
Ref= 11/2012
Cum= 110433
Oil, bbl/day
Ref= 11/2012
Cum= 109999
Gas, mcf/mo
Ref= 11/2012
Cum= 0
Gas, mcf/day
Ref= 11/2012
Cum= 0
GOR, scf/bbl
Water, bbl/m
Ref= 11/2012
Cum= 153675
BWPD
Ref= 11/2012
Cum= 0
RALPH E. DAVIS ASSOCIATES, INC.
Texas Registered Engineering Firm F-1529

WENZEL 12-34
FIELD: STATELINE
COUNTY: LARAMIE STATE: WY
OPERATOR: RECOVERY ENERGY INCOR
1PDP

DATE : 04/01/2013
TIME : 14:03:12
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO : RED_JAN13

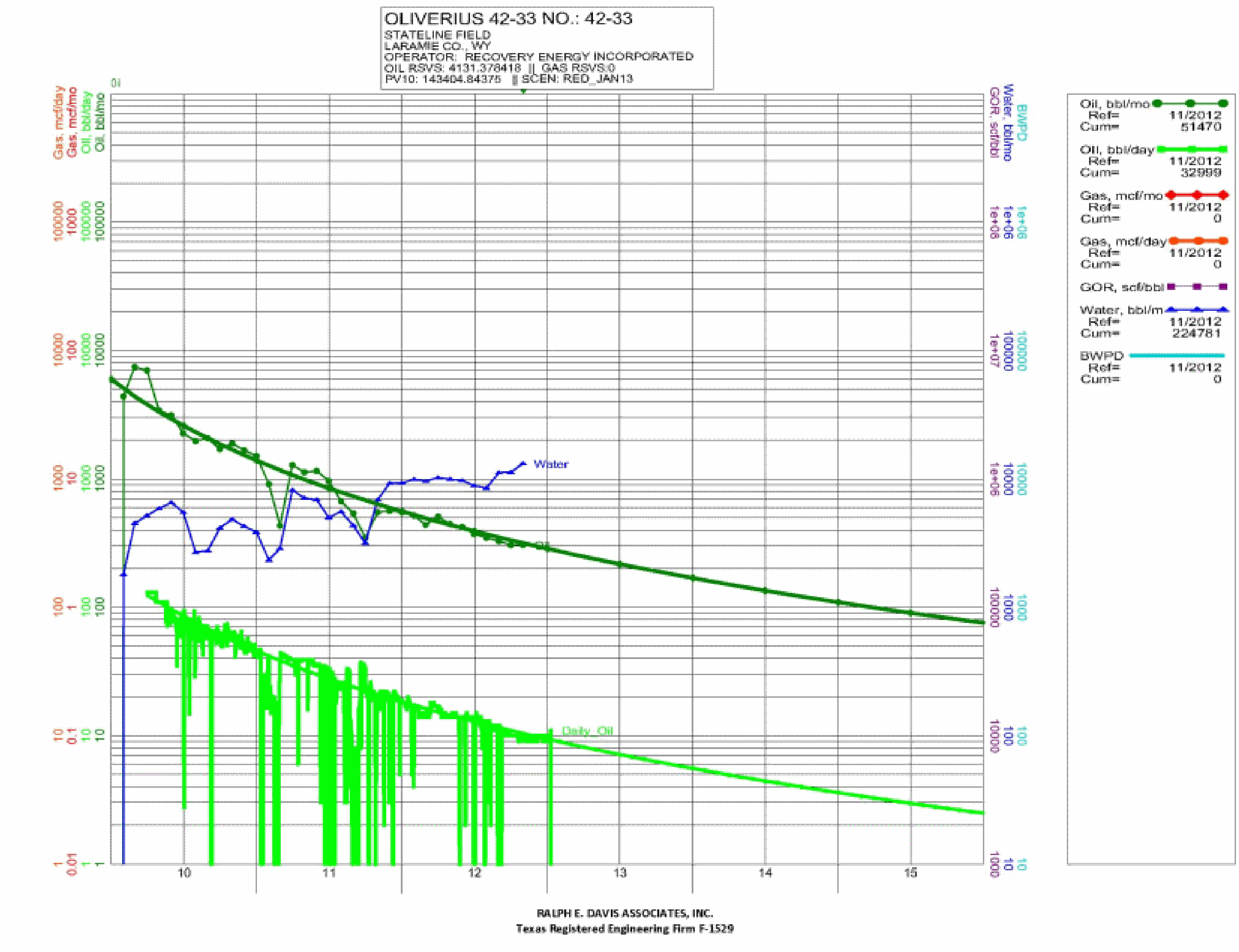
## RESERVES AND ECONOMICS

### AS OF DATE: 12/31/2012

| --END-- MO-YEAR | GROSS OIL PRODUCTION | GROSS GAS PRODUCTION | NET OIL PRODUCTION | NET GAS PRODUCTION | NET OIL PRICE | NET GAS PRICE | NET OIL SALES | NET GAS SALES | TOTAL NET SALES |
|---|---|---|---|---|---|---|---|---|---|
| ------- | ---MBBLS--- | ----MMCF--- | ---MBBLS--- | ----MMCF--- | ---$/BBL--- | ---$/MCF--- | -----M$---- | -----M$---- | -----M$---- |
| 12-2013 | 18.769 | 0.000 | 14.452 | 0.000 | 87.370 | 0.000 | 1262.696 | 0.000 | 1262.696 |
| 12-2014 | 13.187 | 0.000 | 10.154 | 0.000 | 87.370 | 0.000 | 887.135 | 0.000 | 887.135 |
| 12-2015 | 9.681 | 0.000 | 7.454 | 0.000 | 87.370 | 0.000 | 651.266 | 0.000 | 651.266 |
| 12-2016 | 7.354 | 0.000 | 5.662 | 0.000 | 87.370 | 0.000 | 494.725 | 0.000 | 494.725 |
| 12-2017 | 5.741 | 0.000 | 4.421 | 0.000 | 87.370 | 0.000 | 386.225 | 0.000 | 386.225 |
| 12-2018 | 4.583 | 0.000 | 3.529 | 0.000 | 87.370 | 0.000 | 308.345 | 0.000 | 308.345 |
| 12-2019 | 3.728 | 0.000 | 2.871 | 0.000 | 87.370 | 0.000 | 250.804 | 0.000 | 250.804 |
| 12-2020 | 3.081 | 0.000 | 2.372 | 0.000 | 87.370 | 0.000 | 207.249 | 0.000 | 207.249 |
| 12-2021 | 2.580 | 0.000 | 1.987 | 0.000 | 87.370 | 0.000 | 173.595 | 0.000 | 173.595 |
| 12-2022 | 2.187 | 0.000 | 1.684 | 0.000 | 87.370 | 0.000 | 147.123 | 0.000 | 147.123 |
| 12-2023 | 1.873 | 0.000 | 1.442 | 0.000 | 87.370 | 0.000 | 125.977 | 0.000 | 125.977 |
| 12-2024 | 1.618 | 0.000 | 1.246 | 0.000 | 87.370 | 0.000 | 108.855 | 0.000 | 108.855 |
| 12-2025 | 1.409 | 0.000 | 1.085 | 0.000 | 87.370 | 0.000 | 94.822 | 0.000 | 94.822 |
| 12-2026 | 1.237 | 0.000 | 0.952 | 0.000 | 87.370 | 0.000 | 83.197 | 0.000 | 83.197 |
| 12-2027 | 1.092 | 0.000 | 0.841 | 0.000 | 87.370 | 0.000 | 73.474 | 0.000 | 73.474 |
| S TOT | 78.120 | 0.000 | 60.152 | 0.000 | 87.370 | 0.000 | 5255.487 | 0.000 | 5255.487 |
| AFTER | 1.046 | 0.000 | 0.806 | 0.000 | 87.370 | 0.000 | 70.380 | 0.000 | 70.380 |
| TOTAL | 79.166 | 0.000 | 60.958 | 0.000 | 87.370 | 0.000 | 5325.867 | 0.000 | 5325.867 |

| --END-- MO-YEAR | AD VALOREM TAX | PRODUCTION TAX | DIRECT OPER EXPENSE | INTEREST PAID | CAPITAL REPAYMENT | EQUITY INVESTMENT | FUTURE NET CASHFLOW | CUMULATIVE CASHFLOW | CUM. DISC. CASHFLOW |
|---|---|---|---|---|---|---|---|---|---|
| ------- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- | -----M$---- |
| 12-2013 | 85.450 | 80.813 | 52.800 | 0.000 | 0.000 | 0.000 | 1043.633 | 1043.633 | 998.551 |
| 12-2014 | 60.035 | 56.777 | 52.800 | 0.000 | 0.000 | 0.000 | 717.523 | 1761.156 | 1622.450 |
| 12-2015 | 44.073 | 41.681 | 52.800 | 0.000 | 0.000 | 0.000 | 512.712 | 2273.868 | 2027.630 |
| 12-2016 | 33.479 | 31.662 | 52.800 | 0.000 | 0.000 | 0.000 | 376.783 | 2650.651 | 2298.271 |
| 12-2017 | 26.137 | 24.718 | 52.800 | 0.000 | 0.000 | 0.000 | 282.570 | 2933.221 | 2482.763 |
| 12-2018 | 20.867 | 19.734 | 52.800 | 0.000 | 0.000 | 0.000 | 214.944 | 3148.165 | 2610.332 |
| 12-2019 | 16.973 | 16.051 | 52.800 | 0.000 | 0.000 | 0.000 | 164.980 | 3313.145 | 2699.341 |
| 12-2020 | 14.025 | 13.264 | 52.800 | 0.000 | 0.000 | 0.000 | 127.160 | 3440.305 | 2761.709 |
| 12-2021 | 11.748 | 11.110 | 52.800 | 0.000 | 0.000 | 0.000 | 97.937 | 3538.242 | 2805.377 |
| 12-2022 | 9.956 | 9.416 | 52.800 | 0.000 | 0.000 | 0.000 | 74.951 | 3613.193 | 2835.761 |
| 12-2023 | 8.525 | 8.063 | 52.800 | 0.000 | 0.000 | 0.000 | 56.589 | 3669.783 | 2856.619 |
| 12-2024 | 7.366 | 6.967 | 52.800 | 0.000 | 0.000 | 0.000 | 41.721 | 3711.504 | 2870.602 |
| 12-2025 | 6.417 | 6.069 | 52.800 | 0.000 | 0.000 | 0.000 | 29.536 | 3741.040 | 2879.605 |
| 12-2026 | 5.630 | 5.325 | 52.800 | 0.000 | 0.000 | 0.000 | 19.442 | 3760.482 | 2884.997 |
| 12-2027 | 4.972 | 4.702 | 52.800 | 0.000 | 0.000 | 0.000 | 11.000 | 3771.482 | 2887.775 |
| S TOT | 355.654 | 336.351 | 792.000 | 0.000 | 0.000 | 0.000 | 3771.482 | 3771.482 | 2887.775 |
| AFTER | 4.763 | 4.504 | 57.200 | 0.000 | 0.000 | 0.000 | 3.913 | 3775.395 | 2888.680 |
| TOTAL | 360.416 | 340.856 | 849.200 | 0.000 | 0.000 | 0.000 | 3775.395 | 3775.395 | 2888.680 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| | --------- | --------- | | | ------ | -------- |
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 16.08 | 5.00 | 3264.100 |
| GROSS ULT., MB & MMF | 192.398 | 0.000 | DISCOUNT % | 10.00 | 8.00 | 3026.062 |
| GROSS CUM., MB & MMF | 113.232 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 2888.680 |
| GROSS RES., MB & MMF | 79.166 | 0.000 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 2765.386 |
| NET RES., MB & MMF | 60.958 | 0.000 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 2602.547 |
| NET REVENUE, M$ | 5325.867 | 0.000 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 2461.562 |
| INITIAL PRICE, $ | 87.370 | 0.000 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 2047.021 |
| INITIAL N.I., PCT. | 77.000 | 0.000 | INITIAL W.I., PCT. | 100.000 | 60.00 | 1510.634 |
| | | | | | 80.00 | 1317.627 |
| | | | | | 260.00 | 757.853 |



OLIVERIUS 42-33 NO.: 42-33
STATELINE FIELD
LARAMIE CO., WY
OPERATOR: RECOVERY ENERGY INCORPORATED
OIL RSVS: 4131.378418 || GAS RSVS:0
PV10: 143404.84375 || SCEN: RED_JAN13
Oil, bbl/mo Ref= 11/2012 Cum= 51470
Oil, bbl/day Ref= 11/2012 Cum= 32999
Gas, mcf/mo Ref= 11/2012 Cum= 0
Gas, mcf/day Ref= 11/2012 Cum= 0
GOR, scf/bbl
Water, bbl/m Ref= 11/2012 Cum= 224781
BWPD Ref= 11/2012 Cum= 0
Water
Daily_Oil
RALPH E. DAVIS ASSOCIATES, INC.
Texas Registered Engineering Firm F-1529

OLIVERIUS 42-33
FIELD: STATELINE
COUNTY: LARAMIE STATE: WY
OPERATOR: RECOVERY ENERGY INCOR
1PDP

DATE : 04/01/2013
TIME : 14:03:12
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO : RED_JAN13

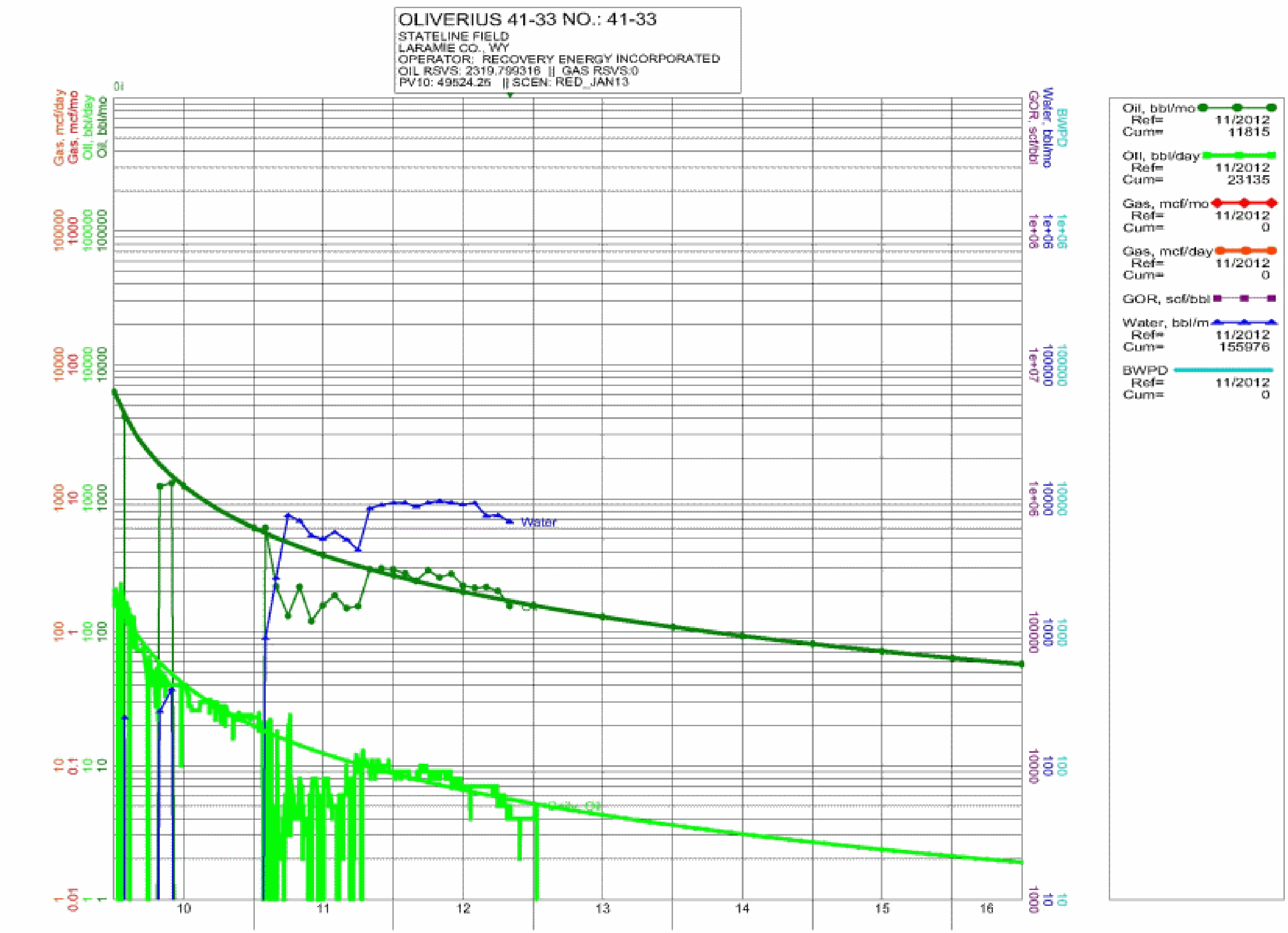
## RESERVES AND ECONOMICS

### AS OF DATE: 12/31/2012

| --END-- MO-YEAR | GROSS OIL PRODUCTION ---MBBLS--- | GROSS GAS PRODUCTION ----MMCF--- | NET OIL PRODUCTION ---MBBLS--- | NET GAS PRODUCTION ----MMCF--- | NET OIL PRICE ---$/BBL--- | NET GAS PRICE ---$/MCF--- | NET OIL SALES ----M$---- | NET GAS SALES -----M$---- | TOTAL NET SALES ----M$---- |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 2.641 | 0.000 | 2.034 | 0.000 | 87.370 | 0.000 | 177.695 | 0.000 | 177.695 |
| 12-2014 | 1.633 | 0.000 | 1.257 | 0.000 | 87.370 | 0.000 | 109.836 | 0.000 | 109.836 |
| 12-2015 | 1.091 | 0.000 | 0.840 | 0.000 | 87.370 | 0.000 | 73.428 | 0.000 | 73.428 |
| 12-2016 | | | | | | | | | |
| 12-2017 | | | | | | | | | |
| 12-2018 | | | | | | | | | |
| 12-2019 | | | | | | | | | |
| 12-2020 | | | | | | | | | |
| 12-2021 | | | | | | | | | |
| 12-2022 | | | | | | | | | |
| 12-2023 | | | | | | | | | |
| 12-2024 | | | | | | | | | |
| 12-2025 | | | | | | | | | |
| 12-2026 | | | | | | | | | |
| 12-2027 | | | | | | | | | |
| S TOT | 5.365 | 0.000 | 4.131 | 0.000 | 87.370 | 0.000 | 360.959 | 0.000 | 360.959 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| TOTAL | 5.365 | 0.000 | 4.131 | 0.000 | 87.370 | 0.000 | 360.959 | 0.000 | 360.959 |

| --END-- MO-YEAR | AD VALOREM TAX -----M$---- | PRODUCTION TAX -----M$---- | DIRECT OPER EXPENSE -----M$---- | INTEREST PAID -----M$---- | CAPITAL REPAYMENT -----M$---- | EQUITY INVESTMENT -----M$---- | FUTURE NET CASHFLOW -----M$---- | CUMULATIVE CASHFLOW -----M$---- | CUM. DISC. CASHFLOW -----M$---- |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 12.025 | 11.372 | 52.800 | 0.000 | 0.000 | 0.000 | 101.497 | 101.497 | 97.420 |
| 12-2014 | 7.433 | 7.030 | 52.800 | 0.000 | 0.000 | 0.000 | 42.574 | 144.071 | 134.619 |
| 12-2015 | 4.969 | 4.699 | 52.800 | 0.000 | 0.000 | 0.000 | 10.959 | 155.030 | 143.405 |
| 12-2016 | | | | | | | | | |
| 12-2017 | | | | | | | | | |
| 12-2018 | | | | | | | | | |
| 12-2019 | | | | | | | | | |
| 12-2020 | | | | | | | | | |
| 12-2021 | | | | | | | | | |
| 12-2022 | | | | | | | | | |
| 12-2023 | | | | | | | | | |
| 12-2024 | | | | | | | | | |
| 12-2025 | | | | | | | | | |
| 12-2026 | | | | | | | | | |
| 12-2027 | | | | | | | | | |
| S TOT | 24.427 | 23.101 | 158.400 | 0.000 | 0.000 | 0.000 | 155.030 | 155.030 | 143.405 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 155.030 | 143.405 |
| TOTAL | 24.427 | 23.101 | 158.400 | 0.000 | 0.000 | 0.000 | 155.030 | 155.030 | 143.405 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 3.00 | 5.00 | 148.895 |
| GROSS ULT., MB & MMF | 38.983 | 0.000 | DISCOUNT % | 10.00 | 8.00 | 145.530 |
| GROSS CUM., MB & MMF | 33.617 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 143.405 |
| GROSS RES., MB & MMF | 5.365 | 0.000 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 141.367 |
| NET RES., MB & MMF | 4.131 | 0.000 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 138.463 |
| NET REVENUE, M$ | 360.959 | 0.000 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 135.728 |
| INITIAL PRICE, $ | 87.370 | 0.000 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 126.206 |
| INITIAL N.I., PCT. | 77.000 | 0.000 | INITIAL W.I., PCT. | 100.000 | 60.00 | 109.227 |
| | | | | | 80.00 | 101.272 |
| | | | | | 260.00 | 69.906 |




RALPH E. DAVIS ASSOCIATES, INC.
Texas Registered Engineering Firm F-1529

OLIVERIUS 41-33
FIELD: STATELINE
COUNTY: LARAMIE STATE: WY
OPERATOR: RECOVERY ENERGY INCOR
1PDP

DATE : 04/01/2013
TIME : 14:03:10
DBS : DEMO
SETTINGS : RED_JAN 13
SCENARIO: RED_JAN 13

## R E S E R V E S A N D E C O N O M I C S

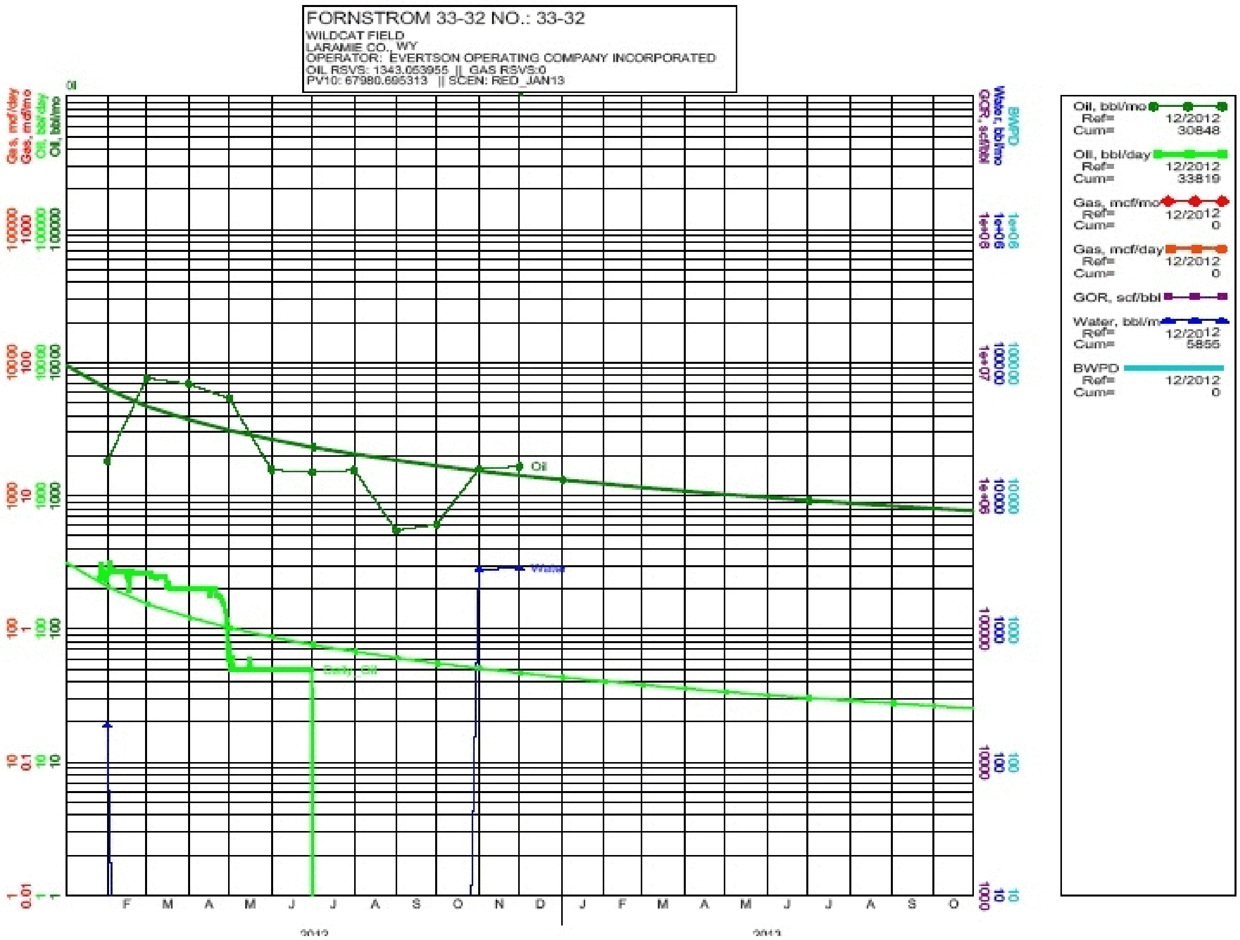
### AS OF DATE: 12/31/2012

| --END-- MO-YEAR | GROSS OIL PRODUCTION MBBLS | GROSS GAS PRODUCTION MMCF | NET OIL PRODUCTION MBBLS | NET GAS PRODUCTION MMCF | NET OIL PRICE $/BBL | NET GAS PRICE $/MCF | NET OIL SALES M$ | NET GAS SALES M$ | TOTAL NET SALES M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 1.573 | 0.000 | 1.211 | 0.000 | 87.370 | 0.000 | 105.790 | 0.000 | 105.790 |
| 12-2014 | 1.128 | 0.000 | 0.869 | 0.000 | 87.370 | 0.000 | 75.916 | 0.000 | 75.916 |
| 12-2015 | 0.312 | 0.000 | 0.240 | 0.000 | 87.370 | 0.000 | 20.975 | 0.000 | 20.975 |
| 12-2016 | | | | | | | | | |
| 12-2017 | | | | | | | | | |
| 12-2018 | | | | | | | | | |
| 12-2019 | | | | | | | | | |
| 12-2020 | | | | | | | | | |
| 12-2021 | | | | | | | | | |
| 12-2022 | | | | | | | | | |
| 12-2023 | | | | | | | | | |
| 12-2024 | | | | | | | | | |
| 12-2025 | | | | | | | | | |
| 12-2026 | | | | | | | | | |
| 12-2027 | | | | | | | | | |
| S TOT | 3.013 | 0.000 | 2.320 | 0.000 | 87.370 | 0.000 | 202.681 | 0.000 | 202.681 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| TOTAL | 3.013 | 0.000 | 2.320 | 0.000 | 87.370 | 0.000 | 202.681 | 0.000 | 202.681 |

| --END-- MO-YEAR | AD VALOREM TAX M$ | PRODUCTION TAX M$ | DIRECT OPER EXPENSE M$ | INTEREST PAID M$ | CAPITAL REPAYMENT M$ | EQUITY INVESTMENT M$ | FUTURE NET CASHFLOW M$ | CUMULATIVE CASHFLOW M$ | CUM. DISC. CASHFLOW M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 7.159 | 6.771 | 52.800 | 0.000 | 0.000 | 0.000 | 39.061 | 39.061 | 37.514 |
| 12-2014 | 5.137 | 4.859 | 52.800 | 0.000 | 0.000 | 0.000 | 13.120 | 52.181 | 49.023 |
| 12-2015 | 1.419 | 1.342 | 17.600 | 0.000 | 0.000 | 0.000 | 0.613 | 52.793 | 49.524 |
| 12-2016 | | | | | | | | | |
| 12-2017 | | | | | | | | | |
| 12-2018 | | | | | | | | | |
| 12-2019 | | | | | | | | | |
| 12-2020 | | | | | | | | | |
| 12-2021 | | | | | | | | | |
| 12-2022 | | | | | | | | | |
| 12-2023 | | | | | | | | | |
| 12-2024 | | | | | | | | | |
| 12-2025 | | | | | | | | | |
| 12-2026 | | | | | | | | | |
| 12-2027 | | | | | | | | | |
| S TOT | 13.716 | 12.972 | 123.200 | 0.000 | 0.000 | 0.000 | 52.793 | 52.793 | 49.524 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 52.793 | 49.524 |
| TOTAL | 13.716 | 12.972 | 123.200 | 0.000 | 0.000 | 0.000 | 52.793 | 52.793 | 49.524 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 2.33 | 5.00 | 51.079 |
| GROSS ULT., MB & MMF | 15.156 | 0.000 | DISCOUNT % | 10.00 | 8.00 | 50.128 |
| GROSS CUM., MB & MMF | 12.143 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 49.524 |
| GROSS RES., MB & MMF | 3.013 | 0.000 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 48.942 |
| NET RES., MB & MMF | 2.320 | 0.000 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 48.108 |
| NET REVENUE, M$ | 202.681 | 0.000 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 47.318 |
| INITIAL PRICE, $ | 87.370 | 0.000 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 44.523 |
| INITIAL N.I., PCT. | 77.000 | 0.000 | INITIAL W.I., PCT. | 100.000 | 60.00 | 39.370 |
| | | | | | 80.00 | 36.872 |
| | | | | | 260.00 | 26.437 |

**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529




**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529

FORNSTROM 33-32
FIELD: WILDCAT
COUNTY: LARAMIE STATE: WY
OPERATOR: EVERTSON OPERATING CO
1PDP

DATE : 04/01/2013
TIME : 14:03:13
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO : RED_JAN13

## R E S E R V E S A N D E C O N O M I C S

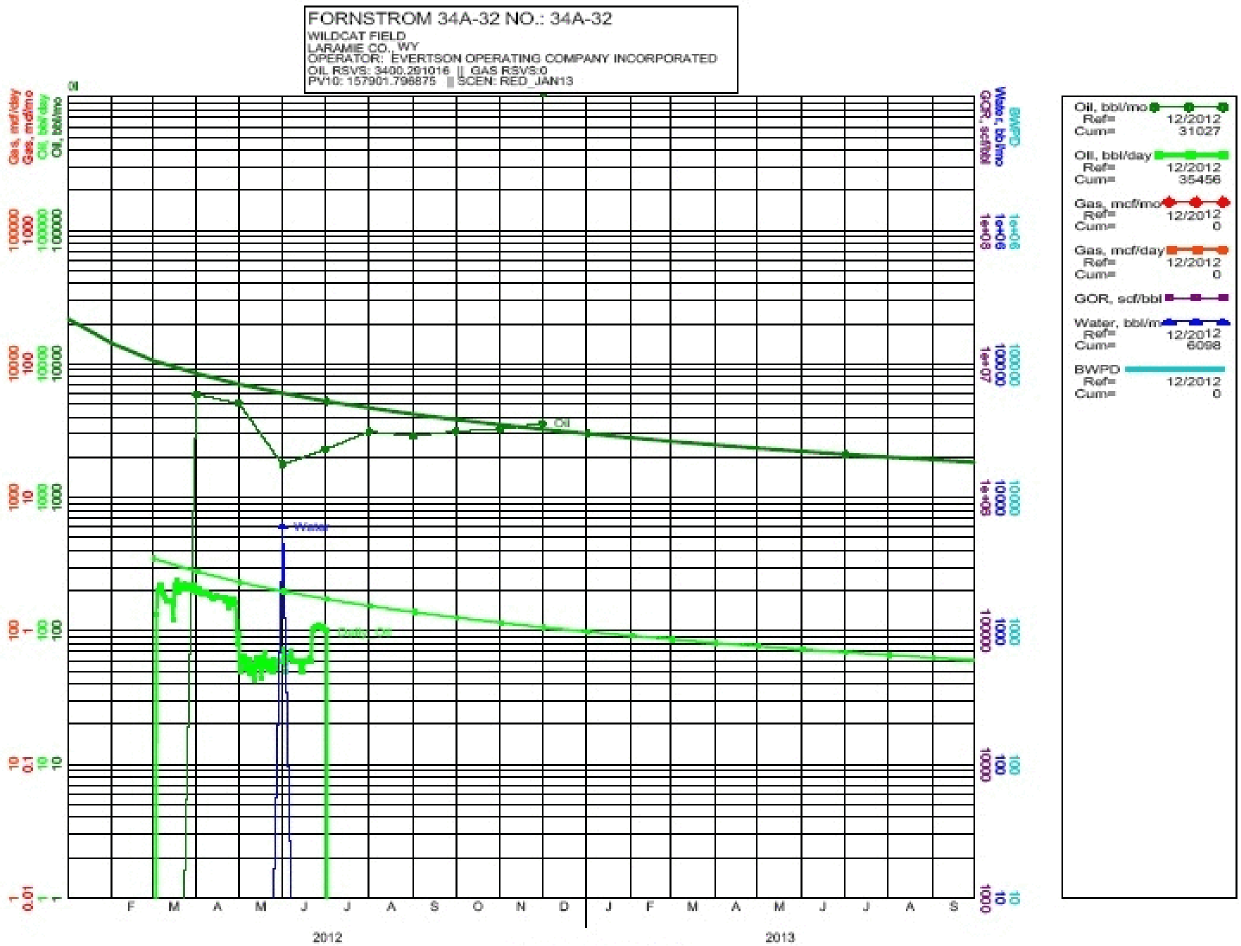
### AS OF DATE: 12/31/2012

| --END-- MO-YEAR | GROSS OIL PRODUCTION | GROSS GAS PRODUCTION | NET OIL PRODUCTION | NET GAS PRODUCTION | NET OIL PRICE | NET GAS PRICE | NET OIL SALES | NET GAS SALES | TOTAL NET SALES |
|---|---|---|---|---|---|---|---|---|---|
| ------- | ---MBBLS--- | ----MMCF--- | ---MBBLS--- | ----MMCF--- | ---$/BBL--- | ---$/MCF--- | -----M$---- | -----M$---- | -----M$---- |
| 12-2013 | 11.438 | 0.000 | 0.297 | 0.000 | 87.370 | 0.000 | 25.983 | 0.000 | 25.983 |
| 12-2014 | 7.029 | 0.000 | 0.183 | 0.000 | 87.370 | 0.000 | 15.967 | 0.000 | 15.967 |
| 12-2015 | 5.094 | 0.000 | 0.132 | 0.000 | 87.370 | 0.000 | 11.572 | 0.000 | 11.572 |
| 12-2016 | 4.000 | 0.000 | 0.104 | 0.000 | 87.370 | 0.000 | 9.087 | 0.000 | 9.087 |
| 12-2017 | 3.295 | 0.000 | 0.086 | 0.000 | 87.370 | 0.000 | 7.485 | 0.000 | 7.485 |
| 12-2018 | 2.803 | 0.000 | 0.073 | 0.000 | 87.370 | 0.000 | 6.367 | 0.000 | 6.367 |
| 12-2019 | 2.439 | 0.000 | 0.063 | 0.000 | 87.370 | 0.000 | 5.540 | 0.000 | 5.540 |
| 12-2020 | 2.159 | 0.000 | 0.056 | 0.000 | 87.370 | 0.000 | 4.905 | 0.000 | 4.905 |
| 12-2021 | 1.937 | 0.000 | 0.050 | 0.000 | 87.370 | 0.000 | 4.401 | 0.000 | 4.401 |
| 12-2022 | 1.757 | 0.000 | 0.046 | 0.000 | 87.370 | 0.000 | 3.991 | 0.000 | 3.991 |
| 12-2023 | 1.607 | 0.000 | 0.042 | 0.000 | 87.370 | 0.000 | 3.651 | 0.000 | 3.651 |
| 12-2024 | 1.478 | 0.000 | 0.038 | 0.000 | 87.370 | 0.000 | 3.358 | 0.000 | 3.358 |
| 12-2025 | 1.360 | 0.000 | 0.035 | 0.000 | 87.370 | 0.000 | 3.089 | 0.000 | 3.089 |
| 12-2026 | 1.251 | 0.000 | 0.033 | 0.000 | 87.370 | 0.000 | 2.842 | 0.000 | 2.842 |
| 12-2027 | 1.151 | 0.000 | 0.030 | 0.000 | 87.370 | 0.000 | 2.615 | 0.000 | 2.615 |
| S TOT | 48.798 | 0.000 | 1.269 | 0.000 | 87.370 | 0.000 | 110.852 | 0.000 | 110.852 |
| AFTER | 2.857 | 0.000 | 0.074 | 0.000 | 87.370 | 0.000 | 6.491 | 0.000 | 6.491 |
| TOTAL | 51.656 | 0.000 | 1.343 | 0.000 | 87.370 | 0.000 | 117.343 | 0.000 | 117.343 |

| --END-- MO-YEAR | AD VALOREM TAX | PRODUCTION TAX | DIRECT OPER EXPENSE | INTEREST PAID | CAPITAL REPAYMENT | EQUITY INVESTMENT | FUTURE NET CASHFLOW | CUMULATIVE CASHFLOW | CUM. DISC. CASHFLOW |
|---|---|---|---|---|---|---|---|---|---|
| ------- | -----MS------ | -----MS------ | -----MS------ | -----MS------ | -----MS------ | -----MS------ | -----MS------ | -----MS------ | -----MS------ |
| 12-2013 | 1.758 | 1.663 | 0.000 | 0.000 | 0.000 | 0.000 | 22.562 | 22.562 | 21.624 |
| 12-2014 | 1.081 | 1.022 | 0.000 | 0.000 | 0.000 | 0.000 | 13.864 | 36.426 | 33.682 |
| 12-2015 | 0.783 | 0.741 | 0.000 | 0.000 | 0.000 | 0.000 | 10.048 | 46.474 | 41.620 |
| 12-2016 | 0.615 | 0.582 | 0.000 | 0.000 | 0.000 | 0.000 | 7.890 | 54.364 | 47.283 |
| 12-2017 | 0.507 | 0.479 | 0.000 | 0.000 | 0.000 | 0.000 | 6.500 | 60.864 | 51.524 |
| 12-2018 | 0.431 | 0.407 | 0.000 | 0.000 | 0.000 | 0.000 | 5.528 | 66.393 | 54.802 |
| 12-2019 | 0.375 | 0.355 | 0.000 | 0.000 | 0.000 | 0.000 | 4.811 | 71.203 | 57.394 |
| 12-2020 | 0.332 | 0.314 | 0.000 | 0.000 | 0.000 | 0.000 | 4.259 | 75.462 | 59.481 |
| 12-2021 | 0.298 | 0.282 | 0.000 | 0.000 | 0.000 | 0.000 | 3.821 | 79.284 | 61.183 |
| 12-2022 | 0.270 | 0.255 | 0.000 | 0.000 | 0.000 | 0.000 | 3.465 | 82.749 | 62.585 |
| 12-2023 | 0.247 | 0.234 | 0.000 | 0.000 | 0.000 | 0.000 | 3.171 | 85.920 | 63.752 |
| 12-2024 | 0.227 | 0.215 | 0.000 | 0.000 | 0.000 | 0.000 | 2.916 | 88.835 | 64.727 |
| 12-2025 | 0.209 | 0.198 | 0.000 | 0.000 | 0.000 | 0.000 | 2.682 | 91.517 | 65.543 |
| 12-2026 | 0.192 | 0.182 | 0.000 | 0.000 | 0.000 | 0.000 | 2.468 | 93.985 | 66.225 |
| 12-2027 | 0.177 | 0.167 | 0.000 | 0.000 | 0.000 | 0.000 | 2.270 | 96.255 | 66.796 |
| S TOT | 7.502 | 7.095 | 0.000 | 0.000 | 0.000 | 0.000 | 96.255 | 96.255 | 66.796 |
| AFTER | 0.439 | 0.415 | 0.000 | 0.000 | 0.000 | 0.000 | 5.636 | 101.892 | 67.981 |
| TOTAL | 7.941 | 7.510 | 0.000 | 0.000 | 0.000 | 0.000 | 101.892 | 101.892 | 67.981 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 17.92 | 5.00 | 81.119 |
| GROSS ULT., MB & MMF | 83.872 | 0.000 | DISCOUNT % | 10.00 | 8.00 | 72.589 |
| GROSS CUM., MB & MMF | 32.216 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 67.981 |
| GROSS RES., MB & MMF | 51.656 | 0.000 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 64.033 |
| NET RES., MB & MMF | 1.343 | 0.000 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 59.079 |
| NET REVENUE, M$ | 117.343 | 0.000 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 55.017 |
| INITIAL PRICE, $ | 87.370 | 0.000 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 44.151 |
| INITIAL N.I., PCT. | 2.600 | 0.000 | INITIAL W.I., PCT. | 0.000 | 60.00 | 31.903 |
| | | | | | 80.00 | 27.818 |
| | | | | | 260.00 | 16.371 |

**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529




**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529

FORNSTROM 34A-32
FIELD: WILDCAT
COUNTY: LARAMIE STATE: WY
OPERATOR: EVERTSON OPERATING CO
1PDP

DATE : 04/01/2013
TIME : 14:03:13
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO : RED_JAN13

## R E S E R V E S A N D E C O N O M I C S

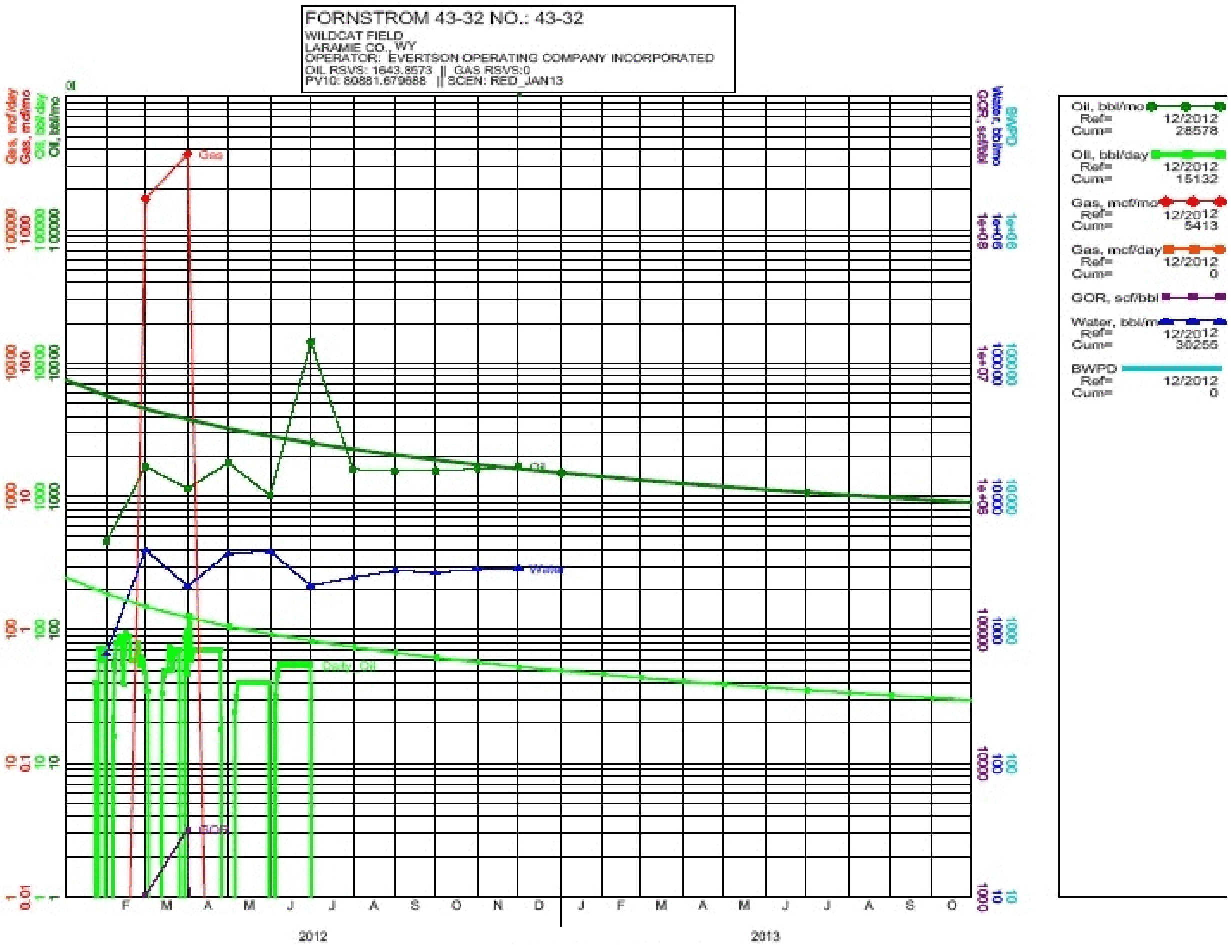
**AS OF DATE: 12/31/2012**

| GROSS OIL PRODUCTION ---MBBLS--- | GROSS GAS PRODUCTION MMCF--- | NET OIL PRODUCTION ---MBBLS--- | NET GAS PRODUCTION ---MMCF--- | NET OIL PRICE ---$/BBL--- | NET GAS PRICE ---$/MCF--- | NET OIL SALES ---M$-- | NET GAS SALES ---M$-- | TOTAL NET SALES --M$-- |
|---|---|---|---|---|---|---|---|---|
| 26.018 | 0.000 | 0.676 | 0.000 | 87.370 | 0.000 | 59.103 | 0.000 | 59.103 |
| 15.988 | 0.000 | 0.416 | 0.000 | 87.370 | 0.000 | 36.318 | 0.000 | 36.318 |
| 11.587 | 0.000 | 0.301 | 0.000 | 87.370 | 0.000 | 26.321 | 0.000 | 26.321 |
| 9.099 | 0.000 | 0.237 | 0.000 | 87.370 | 0.000 | 20.669 | 0.000 | 20.669 |
| 7.495 | 0.000 | 0.195 | 0.000 | 87.370 | 0.000 | 17.027 | 0.000 | 17.027 |
| 6.375 | 0.000 | 0.166 | 0.000 | 87.370 | 0.000 | 14.482 | 0.000 | 14.482 |
| 5.548 | 0.000 | 0.144 | 0.000 | 87.370 | 0.000 | 12.602 | 0.000 | 12.602 |
| 4.911 | 0.000 | 0.128 | 0.000 | 87.370 | 0.000 | 11.157 | 0.000 | 11.157 |
| 4.407 | 0.000 | 0.115 | 0.000 | 87.370 | 0.000 | 10.010 | 0.000 | 10.010 |
| 3.996 | 0.000 | 0.104 | 0.000 | 87.370 | 0.000 | 9.078 | 0.000 | 9.078 |
| 3.656 | 0.000 | 0.095 | 0.000 | 87.370 | 0.000 | 8.305 | 0.000 | 8.305 |
| 3.362 | 0.000 | 0.087 | 0.000 | 87.370 | 0.000 | 7.637 | 0.000 | 7.637 |
| 3.093 | 0.000 | 0.080 | 0.000 | 87.370 | 0.000 | 7.026 | 0.000 | 7.026 |
| 2.846 | 0.000 | 0.074 | 0.000 | 87.370 | 0.000 | 6.464 | 0.000 | 6.464 |
| 2.618 | 0.000 | 0.068 | 0.000 | 87.370 | 0.000 | 5.947 | 0.000 | 5.947 |
| 110.999 | 0.000 | 2.886 | 0.000 | 87.370 | 0.000 | 252.148 | 0.000 | 252.148 |
| 19.781 | 0.000 | 0.514 | 0.000 | 87.370 | 0.000 | 44.935 | 0.000 | 44.935 |
| 130.780 | 0.000 | 3.400 | 0.000 | 87.370 | 0.000 | 297.083 | 0.000 | 297.083 |

| AD VALOREM TAX -----MS------ | PRODUCTION TAX -----MS------ | DIRECT OPER EXPENSE -----MS------ | INTEREST PAID -----MS------ | CAPITAL REPAYMENT -----MS------ | EQUITY INVESTMENT -----MS------ | FUTURE NET CASHFLOW -----MS------ | CUMULATIVE CASHFLOW -----MS------ | CUM. DISC. CASHFLOW -----MS------ |
|---|---|---|---|---|---|---|---|---|
| 4.000 | 3.783 | 0.000 | 0.000 | 0.000 | 0.000 | 51.321 | 51.321 | 49.188 |
| 2.458 | 2.324 | 0.000 | 0.000 | 0.000 | 0.000 | 31.536 | 82.857 | 76.615 |
| 1.781 | 1.685 | 0.000 | 0.000 | 0.000 | 0.000 | 22.855 | 105.713 | 94.670 |
| 1.399 | 1.323 | 0.000 | 0.000 | 0.000 | 0.000 | 17.947 | 123.660 | 107.553 |
| 1.152 | 1.090 | 0.000 | 0.000 | 0.000 | 0.000 | 14.785 | 138.445 | 117.198 |
| 0.980 | 0.927 | 0.000 | 0.000 | 0.000 | 0.000 | 12.575 | 151.020 | 124.654 |
| 0.853 | 0.807 | 0.000 | 0.000 | 0.000 | 0.000 | 10.943 | 161.963 | 130.552 |
| 0.755 | 0.714 | 0.000 | 0.000 | 0.000 | 0.000 | 9.688 | 171.650 | 135.298 |
| 0.677 | 0.641 | 0.000 | 0.000 | 0.000 | 0.000 | 8.692 | 180.342 | 139.169 |
| 0.614 | 0.581 | 0.000 | 0.000 | 0.000 | 0.000 | 7.883 | 188.225 | 142.360 |
| 0.562 | 0.532 | 0.000 | 0.000 | 0.000 | 0.000 | 7.212 | 195.437 | 145.014 |
| 0.517 | 0.489 | 0.000 | 0.000 | 0.000 | 0.000 | 6.632 | 202.069 | 147.232 |
| 0.476 | 0.450 | 0.000 | 0.000 | 0.000 | 0.000 | 6.101 | 208.170 | 149.088 |
| 0.437 | 0.414 | 0.000 | 0.000 | 0.000 | 0.000 | 5.613 | 213.783 | 150.640 |
| 0.402 | 0.381 | 0.000 | 0.000 | 0.000 | 0.000 | 5.164 | 218.947 | 151.938 |
| 17.064 | 16.137 | 0.000 | 0.000 | 0.000 | 0.000 | 218.947 | 218.947 | 151.938 |
| 3.041 | 2.876 | 0.000 | 0.000 | 0.000 | 0.000 | 39.018 | 257.966 | 157.902 |
| 20.104 | 19.013 | 0.000 | 0.000 | 0.000 | 0.000 | 257.966 | 257.966 | 157.902 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 27.83 | 5.00 | 193.470 |
| GROSS ULT., MB & MMF | 164.919 | 0.000 | DISCOUNT % | 10.00 | 8.00 | 169.971 |
| GROSS CUM., MB & MMF | 34.139 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 157.902 |
| GROSS RES., MB & MMF | 130.780 | 0.000 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 147.875 |
| NET RES., MB & MMF | 3.400 | 0.000 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 135.651 |
| NET REVENUE, M$ | 297.083 | 0.000 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 125.880 |
| INITIAL PRICE, $ | 87.370 | 0.000 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 100.526 |
| INITIAL N.I., PCT. | 2.600 | 0.000 | INITIAL W.I., PCT. | 0.000 | 60.00 | 72.569 |
| | | | | | 80.00 | 63.276 |
| | | | | | 260.00 | 37.239 |

**RALPH E. DAVIS ASSOCIATES, INC.**




**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529

FORNSTROM 43-32
FIELD: WILDCAT
COUNTY: LARAMIE STATE: WY
OPERATOR: EVERTSON OPERATING CO
1PDP

DATE : 04/01/2013
TIME : 14:03:13
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO : RED_JAN13

## R E S E R V E S A N D E C O N O M I C S

### AS OF DATE: 12/31/2012

| GROSS OIL PRODUCTION ---MBBLS--- | GROSS GAS PRODUCTION --MMCF--- | NET OIL PRODUCTION ---MBBLS--- | NET GAS PRODUCTION --MMCF--- | NET OIL PRICE ---$/BBL--- | NET GAS PRICE ---$/MCF--- | NET OIL SALES ---M$--- | NET GAS SALES ---M$-- | TOTAL NET SALES ---M$-- |
|---|---|---|---|---|---|---|---|---|
| 13.264 | 0.000 | 0.345 | 0.000 | 87.370 | 0.000 | 30.132 | 0.000 | 30.132 |
| 8.298 | 0.000 | 0.216 | 0.000 | 87.370 | 0.000 | 18.849 | 0.000 | 18.849 |
| 6.053 | 0.000 | 0.157 | 0.000 | 87.370 | 0.000 | 13.750 | 0.000 | 13.750 |
| 4.768 | 0.000 | 0.124 | 0.000 | 87.370 | 0.000 | 10.830 | 0.000 | 10.830 |
| 3.934 | 0.000 | 0.102 | 0.000 | 87.370 | 0.000 | 8.936 | 0.000 | 8.936 |
| 3.349 | 0.000 | 0.087 | 0.000 | 87.370 | 0.000 | 7.607 | 0.000 | 7.607 |
| 2.915 | 0.000 | 0.076 | 0.000 | 87.370 | 0.000 | 6.622 | 0.000 | 6.622 |
| 2.581 | 0.000 | 0.067 | 0.000 | 87.370 | 0.000 | 5.863 | 0.000 | 5.863 |
| 2.316 | 0.000 | 0.060 | 0.000 | 87.370 | 0.000 | 5.261 | 0.000 | 5.261 |
| 2.100 | 0.000 | 0.055 | 0.000 | 87.370 | 0.000 | 4.770 | 0.000 | 4.770 |
| 1.921 | 0.000 | 0.050 | 0.000 | 87.370 | 0.000 | 4.364 | 0.000 | 4.364 |
| 1.766 | 0.000 | 0.046 | 0.000 | 87.370 | 0.000 | 4.013 | 0.000 | 4.013 |
| 1.625 | 0.000 | 0.042 | 0.000 | 87.370 | 0.000 | 3.692 | 0.000 | 3.692 |
| 1.495 | 0.000 | 0.039 | 0.000 | 87.370 | 0.000 | 3.396 | 0.000 | 3.396 |
| 1.376 | 0.000 | 0.036 | 0.000 | 87.370 | 0.000 | 3.125 | 0.000 | 3.125 |
| 57.760 | 0.000 | 1.502 | 0.000 | 87.370 | 0.000 | 131.210 | 0.000 | 131.210 |
| 5.465 | 0.000 | 0.142 | 0.000 | 87.370 | 0.000 | 12.414 | 0.000 | 12.414 |
| 63.225 | 0.000 | 1.644 | 0.000 | 87.370 | 0.000 | 143.624 | 0.000 | 143.624 |

| AD VALOREM TAX -----MS------ | PRODUCTION TAX -----MS------ | DIRECT OPER EXPENSE -----MS------ | INTEREST PAID -----MS------ | CAPITAL REPAYMENT -----MS------ | EQUITY INVESTMENT -----MS------ | FUTURE NET CASHFLOW -----MS------ | CUMULATIVE CASHFLOW -----MS------ | CUM. DISC. CASHFLOW -----MS------ |
|---|---|---|---|---|---|---|---|---|
| 2.039 | 1.928 | 0.000 | 0.000 | 0.000 | 0.000 | 26.164 | 26.164 | 25.071 |
| 1.276 | 1.206 | 0.000 | 0.000 | 0.000 | 0.000 | 16.367 | 42.531 | 39.305 |
| 0.931 | 0.880 | 0.000 | 0.000 | 0.000 | 0.000 | 11.940 | 54.471 | 48.736 |
| 0.733 | 0.693 | 0.000 | 0.000 | 0.000 | 0.000 | 9.404 | 63.875 | 55.487 |
| 0.605 | 0.572 | 0.000 | 0.000 | 0.000 | 0.000 | 7.759 | 71.635 | 60.549 |
| 0.515 | 0.487 | 0.000 | 0.000 | 0.000 | 0.000 | 6.605 | 78.240 | 64.465 |
| 0.448 | 0.424 | 0.000 | 0.000 | 0.000 | 0.000 | 5.750 | 83.990 | 67.564 |
| 0.397 | 0.375 | 0.000 | 0.000 | 0.000 | 0.000 | 5.091 | 89.081 | 70.058 |
| 0.356 | 0.337 | 0.000 | 0.000 | 0.000 | 0.000 | 4.568 | 93.649 | 72.093 |
| 0.323 | 0.305 | 0.000 | 0.000 | 0.000 | 0.000 | 4.142 | 97.791 | 73.769 |
| 0.295 | 0.279 | 0.000 | 0.000 | 0.000 | 0.000 | 3.789 | 101.581 | 75.164 |
| 0.272 | 0.257 | 0.000 | 0.000 | 0.000 | 0.000 | 3.484 | 105.065 | 76.329 |
| 0.250 | 0.236 | 0.000 | 0.000 | 0.000 | 0.000 | 3.206 | 108.271 | 77.304 |
| 0.230 | 0.217 | 0.000 | 0.000 | 0.000 | 0.000 | 2.949 | 111.220 | 78.120 |
| 0.211 | 0.200 | 0.000 | 0.000 | 0.000 | 0.000 | 2.713 | 113.933 | 78.802 |
| 8.879 | 8.397 | 0.000 | 0.000 | 0.000 | 0.000 | 113.933 | 113.933 | 78.802 |
| 0.840 | 0.795 | 0.000 | 0.000 | 0.000 | 0.000 | 10.780 | 124.712 | 80.882 |
| 9.719 | 9.192 | 0.000 | 0.000 | 0.000 | 0.000 | 124.712 | 124.712 | 80.882 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 20.08 | 5.00 | 97.487 |
| GROSS ULT., MB & MMF | 93.360 | 0.000 | DISCOUNT % | 10.00 | 8.00 | 86.652 |
| GROSS CUM., MB & MMF | 30.135 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 80.882 |
| GROSS RES., MB & MMF | 63.225 | 0.000 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 75.985 |
| NET RES., MB & MMF | 1.644 | 0.000 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 69.897 |
| NET REVENUE, M$ | 143.624 | 0.000 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 64.950 |
| INITIAL PRICE, $ | 87.370 | 0.000 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 51.876 |
| INITIAL N.I., PCT. | 2.600 | 0.000 | INITIAL W.I., PCT. | 0.000 | 60.00 | 37.317 |
| | | | | | 80.00 | 32.484 |
| | | | | | 260.00 | 19.001 |

**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529

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# Proved Undeveloped
# Individual Wells for
# Non-Producing Properties

RECOVERY ENERGY
PROVED UNDEVELOPED
RESERVES AND REVENUES AS OF 12/3
REVISED EVALUATION AT 03/28/2013

DATE : 04/01/2013
TIME : 14:03:16
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO : RED_JAN13

## R E S E R V E S A N D E C O N O M I C S

### AS OF DATE: 12/31/2012

| GROSS OIL PRODUCTION ---MBBLS--- | GROSS GAS PRODUCTION MMCF--- | NET OIL PRODUCTION ---MBBLS--- | NET GAS PRODUCTION --MMCF--- | NET OIL PRICE ---$/BBL--- | NET GAS PRICE ---$/MCF--- | NET OIL SALES ---M$-- | NET GAS SALES ---M$-- | TOTAL NET SALES ---M$-- |
|---|---|---|---|---|---|---|---|---|
| 33.687 | 28.512 | 6.712 | 5.809 | 87.370 | 2.620 | 586.390 | 15.220 | 601.610 |
| 123.638 | 64.032 | 24.378 | 13.047 | 87.370 | 2.620 | 2129.907 | 34.182 | 2164.089 |
| 100.698 | 61.238 | 19.836 | 12.477 | 87.370 | 2.620 | 1733.070 | 32.690 | 1765.760 |
| 67.317 | 47.456 | 13.283 | 9.669 | 87.370 | 2.620 | 1160.554 | 25.333 | 1185.888 |
| 50.230 | 40.602 | 9.924 | 8.273 | 87.370 | 2.620 | 867.067 | 21.674 | 888.741 |
| 48.196 | 64.732 | 9.581 | 13.189 | 87.370 | 2.620 | 837.070 | 34.556 | 871.625 |
| 40.184 | 63.859 | 7.999 | 13.011 | 87.370 | 2.620 | 698.889 | 34.090 | 732.979 |
| 32.119 | 52.968 | 6.395 | 10.792 | 87.370 | 2.620 | 558.751 | 28.276 | 587.027 |
| 27.573 | 47.275 | 5.492 | 9.632 | 87.370 | 2.620 | 479.812 | 25.237 | 505.049 |
| 23.323 | 43.273 | 4.648 | 8.817 | 87.370 | 2.620 | 406.128 | 23.100 | 429.228 |
| 17.831 | 40.080 | 3.565 | 8.166 | 87.370 | 2.620 | 311.504 | 21.395 | 332.900 |
| 14.070 | 37.383 | 2.801 | 7.617 | 87.370 | 2.620 | 244.744 | 19.956 | 264.700 |
| 11.862 | 35.032 | 2.355 | 7.138 | 87.370 | 2.620 | 205.774 | 18.701 | 224.475 |
| 9.929 | 32.919 | 1.968 | 6.707 | 87.370 | 2.620 | 171.910 | 17.573 | 189.483 |
| 8.656 | 30.943 | 1.717 | 6.305 | 87.370 | 2.620 | 150.025 | 16.518 | 166.543 |
| 609.315 | 690.304 | 120.655 | 140.650 | 87.370 | 2.620 | 10541.596 | 368.502 | 10910.098 |
| 83.726 | 395.901 | 16.901 | 80.665 | 87.370 | 2.620 | 1476.615 | 211.342 | 1687.958 |
| 693.041 | 1086.205 | 137.555 | 221.314 | 87.370 | 2.620 | 12018.211 | 579.844 | 12598.056 |

| AD VALOREM TAX -----MS------ | PRODUCTION TAX -----MS------ | DIRECT OPER EXPENSE -----MS------ | INTEREST PAID -----MS------ | CAPITAL REPAYMENT -----MS------ | EQUITY INVESTMENT -----MS------ | FUTURE NET CASHFLOW -----MS------ | CUMULATIVE CASHFLOW -----MS------ | CUM. DISC. CASHFLOW -----MS------ |
|---|---|---|---|---|---|---|---|---|
| 27.449 | 10.238 | 28.450 | 0.000 | 0.000 | 0.000 | 535.474 | 535.474 | 499.256 |
| 78.074 | 61.712 | 116.300 | 0.000 | 0.000 | 250.000 | 1658.004 | 2193.478 | 1927.422 |
| 63.354 | 51.522 | 138.300 | 0.000 | 0.000 | 0.000 | 1512.585 | 3706.062 | 3124.600 |
| 40.996 | 32.289 | 138.300 | 0.000 | 0.000 | 0.000 | 974.303 | 4680.365 | 3824.857 |
| 30.671 | 23.032 | 138.300 | 0.000 | 0.000 | 0.000 | 696.737 | 5377.102 | 4279.834 |
| 37.713 | 17.688 | 138.300 | 0.000 | 0.000 | 218.750 | 459.173 | 5836.275 | 4550.696 |
| 32.438 | 13.831 | 133.900 | 0.000 | 0.000 | 0.000 | 552.810 | 6389.085 | 4849.090 |
| 25.023 | 10.861 | 125.100 | 0.000 | 0.000 | 0.000 | 426.043 | 6815.129 | 5057.976 |
| 21.552 | 9.333 | 125.100 | 0.000 | 0.000 | 0.000 | 349.064 | 7164.193 | 5213.524 |
| 18.849 | 7.668 | 122.900 | 0.000 | 0.000 | 0.000 | 279.811 | 7444.003 | 5327.001 |
| 16.070 | 5.229 | 110.800 | 0.000 | 0.000 | 0.000 | 200.801 | 7644.804 | 5401.018 |
| 14.019 | 3.543 | 86.600 | 0.000 | 0.000 | 0.000 | 160.538 | 7805.342 | 5454.753 |
| 12.623 | 2.641 | 72.300 | 0.000 | 0.000 | 0.000 | 136.911 | 7942.253 | 5496.412 |
| 11.403 | 1.859 | 54.700 | 0.000 | 0.000 | 0.000 | 121.520 | 8063.773 | 5530.018 |
| 10.474 | 1.410 | 45.900 | 0.000 | 0.000 | 0.000 | 108.758 | 8172.532 | 5557.357 |
| 440.709 | 252.856 | 1575.250 | 0.000 | 0.000 | 468.750 | 8172.532 | 8172.532 | 5557.357 |
| 125.355 | 4.793 | 653.425 | 0.000 | 0.000 | 0.000 | 904.385 | 9076.917 | 5678.957 |
| 566.064 | 257.649 | 2228.675 | 0.000 | 0.000 | 468.750 | 9076.917 | 9076.917 | 5678.957 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 14.0 | 0.0 | LIFE, YRS. | 42.42 | 5.00 | 6950.415 |
| GROSS ULT., MB & MMF | 693.041 | 1086.205 | DISCOUNT % | 10.00 | 8.00 | 6122.896 |
| GROSS CUM., MB & MMF | 0.000 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 5678.958 |
| GROSS RES., MB & MMF | 693.041 | 1086.205 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 5297.981 |
| NET RES., MB & MMF | 137.555 | 221.314 | UNDISCOUNTED NET/INVEST. | 20.36 | 15.00 | 4816.507 |
| NET REVENUE, M$ | 12018.210 | 579.844 | DISCOUNTED NET/INVEST. | 17.40 | 18.00 | 4416.851 |
| INITIAL PRICE, $ | 87.370 | 2.620 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 3316.077 |
| INITIAL N.I., PCT. | 19.923 | 20.375 | INITIAL W.I., PCT. | 25.000 | 60.00 | 2025.678 |
| | | | | | 80.00 | 1598.573 |
| | | | | | 260.00 | 534.344 |

LANG 11-34
FIELD: WATTENBERG
COUNTY: WELD STATE: CO
OPERATOR: RECOVERY ENERGY COMPA
3PUD

DATE : 04/01/2013
TIME : 14:03:14
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO : RED_JAN13

## R E S E R V E S A N D E C O N O M I C S

### AS OF DATE: 12/31/2012

| GROSS OIL PRODUCTION ---MBBLS--- | GROSS GAS PRODUCTION MMCF--- | NET OIL PRODUCTION ---MBBLS--- | NET GAS PRODUCTION ---MMCF--- | NET OIL PRICE ---$/BBL--- | NET GAS PRICE ---$/MCF--- | NET OIL SALES ---M$-- | NET GAS SALES ---M$--- | TOTAL NET SALES ---M$--- |
|---|---|---|---|---|---|---|---|---|
| 2.754 | 5.702 | 0.561 | 1.162 | 87.370 | 2.620 | 49.027 | 3.044 | 52.071 |
| 4.042 | 12.806 | 0.823 | 2.609 | 87.370 | 2.620 | 71.946 | 6.836 | 78.782 |
| 3.025 | 12.248 | 0.616 | 2.495 | 87.370 | 2.620 | 53.850 | 6.538 | 60.388 |
| 2.182 | 9.491 | 0.445 | 1.934 | 87.370 | 2.620 | 38.845 | 5.067 | 43.911 |
| 1.780 | 8.120 | 0.363 | 1.655 | 87.370 | 2.620 | 31.682 | 4.335 | 36.016 |
| 3.185 | 12.946 | 0.649 | 2.638 | 87.370 | 2.620 | 56.689 | 6.911 | 63.600 |
| 2.861 | 12.772 | 0.583 | 2.602 | 87.370 | 2.620 | 50.939 | 6.818 | 57.757 |
| 2.210 | 10.594 | 0.450 | 2.158 | 87.370 | 2.620 | 39.342 | 5.655 | 44.997 |
| 1.896 | 9.455 | 0.386 | 1.926 | 87.370 | 2.620 | 33.746 | 5.047 | 38.793 |
| 1.691 | 8.655 | 0.345 | 1.763 | 87.370 | 2.620 | 30.107 | 4.620 | 34.727 |
| 1.542 | 8.016 | 0.314 | 1.633 | 87.370 | 2.620 | 27.444 | 4.279 | 31.723 |
| 1.423 | 7.477 | 0.290 | 1.523 | 87.370 | 2.620 | 25.330 | 3.991 | 29.321 |
| 1.323 | 7.006 | 0.270 | 1.428 | 87.370 | 2.620 | 23.547 | 3.740 | 27.287 |
| 1.235 | 6.584 | 0.252 | 1.341 | 87.370 | 2.620 | 21.989 | 3.515 | 25.503 |
| 1.157 | 6.189 | 0.236 | 1.261 | 87.370 | 2.620 | 20.602 | 3.304 | 23.906 |
| 32.305 | 138.061 | 6.582 | 28.130 | 87.370 | 2.620 | 575.084 | 73.700 | 648.784 |
| 14.795 | 79.180 | 3.014 | 16.133 | 87.370 | 2.620 | 263.370 | 42.268 | 305.639 |
| 47.100 | 217.241 | 9.597 | 44.263 | 87.370 | 2.620 | 838.454 | 115.969 | 954.423 |

| AD VALOREM TAX -----MS------ | PRODUCTION TAX -----MS------ | DIRECT OPER EXPENSE -----MS------ | INTEREST PAID -----MS------ | CAPITAL REPAYMENT -----MS------ | EQUITY INVESTMENT -----MS------ | FUTURE NET CASHFLOW -----MS------ | CUMULATIVE CASHFLOW -----MS------ | CUM. DISC. CASHFLOW -----MS------ |
|---|---|---|---|---|---|---|---|---|
| 4.166 | 0.000 | 1.950 | 0.000 | 0.000 | 0.000 | 45.956 | 45.956 | 42.971 |
| 6.303 | 0.000 | 3.900 | 0.000 | 0.000 | 50.000 | 18.579 | 64.535 | 58.782 |
| 4.831 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 51.657 | 116.192 | 99.650 |
| 3.513 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 36.498 | 152.691 | 125.859 |
| 2.881 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 29.235 | 181.926 | 144.933 |
| 5.088 | 0.000 | 3.900 | 0.000 | 0.000 | 43.750 | 10.862 | 192.788 | 151.042 |
| 4.621 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 49.236 | 242.024 | 177.630 |
| 3.600 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 37.498 | 279.522 | 196.012 |
| 3.103 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 31.790 | 311.312 | 210.173 |
| 2.778 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 28.049 | 339.361 | 221.529 |
| 2.538 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 25.285 | 364.646 | 230.835 |
| 2.346 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 23.075 | 387.721 | 238.554 |
| 2.183 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 21.204 | 408.925 | 245.003 |
| 2.040 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 19.563 | 428.488 | 250.411 |
| 1.912 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 18.093 | 446.582 | 254.958 |
| 51.903 | 0.000 | 56.550 | 0.000 | 0.000 | 93.750 | 446.582 | 446.582 | 254.958 |
| 24.451 | 0.000 | 106.925 | 0.000 | 0.000 | 0.000 | 174.263 | 620.844 | 277.891 |
| 76.354 | 0.000 | 163.475 | 0.000 | 0.000 | 93.750 | 620.844 | 620.844 | 277.891 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 42.42 | 5.00 | 389.009 |
| GROSS ULT., MB & MMF | 47.100 | 217.241 | DISCOUNT % | 10.00 | 8.00 | 314.170 |
| GROSS CUM., MB & MMF | 0.000 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 277.891 |
| GROSS RES., MB & MMF | 47.100 | 217.241 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 248.927 |
| NET RES., MB & MMF | 9.597 | 44.263 | UNDISCOUNTED NET/INVEST. | 7.62 | 15.00 | 215.156 |
| NET REVENUE, M$ | 838.454 | 115.969 | DISCOUNTED NET/INVEST. | 5.01 | 18.00 | 189.465 |
| INITIAL PRICE, $ | 87.370 | 2.620 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 128.935 |
| INITIAL N.I., PCT. | 20.375 | 20.375 | INITIAL W.I., PCT. | 25.000 | 60.00 | 74.287 |
| | | | | | 80.00 | 59.177 |
| | | | | | 260.00 | 24.476 |

**RALPH E. DAVIS ASSOCIATES, INC.**
**Texas Registered Engineering Firm F-1529**

LANG 12-34
FIELD: WATTENBERG
COUNTY: WELD STATE: CO
OPERATOR: RECOVERY ENERGY COMPA
3PUD

DATE : 04/01/2013
TIME : 14:03:14
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO : RED_JAN13

## R E S E R V E S A N D E C O N O M I C S

### AS OF DATE: 12/31/2012

| GROSS OIL PRODUCTION ---MBBLS--- | GROSS GAS PRODUCTION MMCF--- | NET OIL PRODUCTION ---MBBLS--- | NET GAS PRODUCTION ---MMCF--- | NET OIL PRICE ---$/BBL--- | NET GAS PRICE ---$/MCF--- | NET OIL SALES ---M$-- | NET GAS SALES ---M$--- | TOTAL NET SALES ---M$--- |
|---|---|---|---|---|---|---|---|---|
| 2.754 | 5.702 | 0.561 | 1.162 | 87.370 | 2.620 | 49.027 | 3.044 | 52.071 |
| 4.042 | 12.806 | 0.823 | 2.609 | 87.370 | 2.620 | 71.946 | 6.836 | 78.782 |
| 3.025 | 12.248 | 0.616 | 2.495 | 87.370 | 2.620 | 53.850 | 6.538 | 60.388 |
| 2.182 | 9.491 | 0.445 | 1.934 | 87.370 | 2.620 | 38.845 | 5.067 | 43.911 |
| 1.780 | 8.120 | 0.363 | 1.655 | 87.370 | 2.620 | 31.682 | 4.335 | 36.016 |
| 3.185 | 12.946 | 0.649 | 2.638 | 87.370 | 2.620 | 56.689 | 6.911 | 63.600 |
| 2.861 | 12.772 | 0.583 | 2.602 | 87.370 | 2.620 | 50.939 | 6.818 | 57.757 |
| 2.210 | 10.594 | 0.450 | 2.158 | 87.370 | 2.620 | 39.342 | 5.655 | 44.997 |
| 1.896 | 9.455 | 0.386 | 1.926 | 87.370 | 2.620 | 33.746 | 5.047 | 38.793 |
| 1.691 | 8.655 | 0.345 | 1.763 | 87.370 | 2.620 | 30.107 | 4.620 | 34.727 |
| 1.542 | 8.016 | 0.314 | 1.633 | 87.370 | 2.620 | 27.444 | 4.279 | 31.723 |
| 1.423 | 7.477 | 0.290 | 1.523 | 87.370 | 2.620 | 25.330 | 3.991 | 29.321 |
| 1.323 | 7.006 | 0.270 | 1.428 | 87.370 | 2.620 | 23.547 | 3.740 | 27.287 |
| 1.235 | 6.584 | 0.252 | 1.341 | 87.370 | 2.620 | 21.989 | 3.515 | 25.503 |
| 1.157 | 6.189 | 0.236 | 1.261 | 87.370 | 2.620 | 20.602 | 3.304 | 23.906 |
| 32.305 | 138.061 | 6.582 | 28.130 | 87.370 | 2.620 | 575.084 | 73.700 | 648.784 |
| 14.795 | 79.180 | 3.014 | 16.133 | 87.370 | 2.620 | 263.370 | 42.268 | 305.639 |
| 47.100 | 217.241 | 9.597 | 44.263 | 87.370 | 2.620 | 838.454 | 115.969 | 954.423 |

| AD VALOREM TAX -----MS------ | PRODUCTION TAX -----MS------ | DIRECT OPER EXPENSE -----MS------ | INTEREST PAID -----MS------ | CAPITAL REPAYMENT -----MS------ | EQUITY INVESTMENT -----MS------ | FUTURE NET CASHFLOW -----MS------ | CUMULATIVE CASHFLOW -----MS------ | CUM. DISC. CASHFLOW -----MS------ |
|---|---|---|---|---|---|---|---|---|
| 4.166 | 0.000 | 1.950 | 0.000 | 0.000 | 0.000 | 45.956 | 45.956 | 42.971 |
| 6.303 | 0.000 | 3.900 | 0.000 | 0.000 | 50.000 | 18.579 | 64.535 | 58.782 |
| 4.831 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 51.657 | 116.192 | 99.650 |
| 3.513 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 36.498 | 152.691 | 125.859 |
| 2.881 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 29.235 | 181.926 | 144.933 |
| 5.088 | 0.000 | 3.900 | 0.000 | 0.000 | 43.750 | 10.862 | 192.788 | 151.042 |
| 4.621 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 49.236 | 242.024 | 177.630 |
| 3.600 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 37.498 | 279.522 | 196.012 |
| 3.103 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 31.790 | 311.312 | 210.173 |
| 2.778 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 28.049 | 339.361 | 221.529 |
| 2.538 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 25.285 | 364.646 | 230.835 |
| 2.346 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 23.075 | 387.721 | 238.554 |
| 2.183 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 21.204 | 408.925 | 245.003 |
| 2.040 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 19.563 | 428.488 | 250.411 |
| 1.912 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 18.093 | 446.582 | 254.958 |
| 51.903 | 0.000 | 56.550 | 0.000 | 0.000 | 93.750 | 446.582 | 446.582 | 254.958 |
| 24.451 | 0.000 | 106.925 | 0.000 | 0.000 | 0.000 | 174.263 | 620.844 | 277.891 |
| 76.354 | 0.000 | 163.475 | 0.000 | 0.000 | 93.750 | 620.844 | 620.844 | 277.891 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 42.42 | 5.00 | 389.009 |
| GROSS ULT., MB & MMF | 47.100 | 217.241 | DISCOUNT % | 10.00 | 8.00 | 314.170 |
| GROSS CUM., MB & MMF | 0.000 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 277.891 |
| GROSS RES., MB & MMF | 47.100 | 217.241 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 248.927 |
| NET RES., MB & MMF | 9.597 | 44.263 | UNDISCOUNTED NET/INVEST. | 7.62 | 15.00 | 215.156 |
| NET REVENUE, M$ | 838.454 | 115.969 | DISCOUNTED NET/INVEST. | 5.01 | 18.00 | 189.465 |
| INITIAL PRICE, $ | 87.370 | 2.620 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 128.935 |
| INITIAL N.I., PCT. | 20.375 | 20.375 | INITIAL W.I., PCT. | 25.000 | 60.00 | 74.287 |
| | | | | | 80.00 | 59.177 |
| | | | | | 260.00 | 24.476 |

**RALPH E. DAVIS ASSOCIATES, INC.**
**Texas Registered Engineering Firm F-1529**

LANG 21-34
FIELD: WATTENBERG
COUNTY: WELD STATE: CO
OPERATOR: RECOVERY ENERGY COMPA
3PUD

DATE : 04/01/2013
TIME : 14:03:14
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO : RED_JAN13

## R E S E R V E S A N D E C O N O M I C S

### AS OF DATE: 12/31/2012

| GROSS OIL PRODUCTION ---MBBLS--- | GROSS GAS PRODUCTION MMCF--- | NET OIL PRODUCTION ---MBBLS--- | NET GAS PRODUCTION ---MMCF--- | NET OIL PRICE ---$/BBL--- | NET GAS PRICE ---$/MCF--- | NET OIL SALES ---M$-- | NET GAS SALES ---M$--- | TOTAL NET SALES ---M$--- |
|---|---|---|---|---|---|---|---|---|
| 2.754 | 5.702 | 0.561 | 1.162 | 87.370 | 2.620 | 49.027 | 3.044 | 52.071 |
| 4.042 | 12.806 | 0.823 | 2.609 | 87.370 | 2.620 | 71.946 | 6.836 | 78.782 |
| 3.025 | 12.248 | 0.616 | 2.495 | 87.370 | 2.620 | 53.850 | 6.538 | 60.388 |
| 2.182 | 9.491 | 0.445 | 1.934 | 87.370 | 2.620 | 38.845 | 5.067 | 43.911 |
| 1.780 | 8.120 | 0.363 | 1.655 | 87.370 | 2.620 | 31.682 | 4.335 | 36.016 |
| 3.185 | 12.946 | 0.649 | 2.638 | 87.370 | 2.620 | 56.689 | 6.911 | 63.600 |
| 2.861 | 12.772 | 0.583 | 2.602 | 87.370 | 2.620 | 50.939 | 6.818 | 57.757 |
| 2.210 | 10.594 | 0.450 | 2.158 | 87.370 | 2.620 | 39.342 | 5.655 | 44.997 |
| 1.896 | 9.455 | 0.386 | 1.926 | 87.370 | 2.620 | 33.746 | 5.047 | 38.793 |
| 1.691 | 8.655 | 0.345 | 1.763 | 87.370 | 2.620 | 30.107 | 4.620 | 34.727 |
| 1.542 | 8.016 | 0.314 | 1.633 | 87.370 | 2.620 | 27.444 | 4.279 | 31.723 |
| 1.423 | 7.477 | 0.290 | 1.523 | 87.370 | 2.620 | 25.330 | 3.991 | 29.321 |
| 1.323 | 7.006 | 0.270 | 1.428 | 87.370 | 2.620 | 23.547 | 3.740 | 27.287 |
| 1.235 | 6.584 | 0.252 | 1.341 | 87.370 | 2.620 | 21.989 | 3.515 | 25.503 |
| 1.157 | 6.189 | 0.236 | 1.261 | 87.370 | 2.620 | 20.602 | 3.304 | 23.906 |
| 32.305 | 138.061 | 6.582 | 28.130 | 87.370 | 2.620 | 575.084 | 73.700 | 648.784 |
| 14.795 | 79.180 | 3.014 | 16.133 | 87.370 | 2.620 | 263.370 | 42.268 | 305.639 |
| 47.100 | 217.241 | 9.597 | 44.263 | 87.370 | 2.620 | 838.454 | 115.969 | 954.423 |

| AD VALOREM TAX -----MS------ | PRODUCTION TAX -----MS------ | DIRECT OPER EXPENSE -----MS------ | INTEREST PAID -----MS------ | CAPITAL REPAYMENT -----MS------ | EQUITY INVESTMENT -----MS------ | FUTURE NET CASHFLOW -----MS------ | CUMULATIVE CASHFLOW -----MS------ | CUM. DISC. CASHFLOW -----MS------ |
|---|---|---|---|---|---|---|---|---|
| 4.166 | 0.000 | 1.950 | 0.000 | 0.000 | 0.000 | 45.956 | 45.956 | 42.971 |
| 6.303 | 0.000 | 3.900 | 0.000 | 0.000 | 50.000 | 18.579 | 64.535 | 58.782 |
| 4.831 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 51.657 | 116.192 | 99.650 |
| 3.513 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 36.498 | 152.691 | 125.859 |
| 2.881 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 29.235 | 181.926 | 144.933 |
| 5.088 | 0.000 | 3.900 | 0.000 | 0.000 | 43.750 | 10.862 | 192.788 | 151.042 |
| 4.621 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 49.236 | 242.024 | 177.630 |
| 3.600 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 37.498 | 279.522 | 196.012 |
| 3.103 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 31.790 | 311.312 | 210.173 |
| 2.778 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 28.049 | 339.361 | 221.529 |
| 2.538 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 25.285 | 364.646 | 230.835 |
| 2.346 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 23.075 | 387.721 | 238.554 |
| 2.183 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 21.204 | 408.925 | 245.003 |
| 2.040 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 19.563 | 428.488 | 250.411 |
| 1.912 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 18.093 | 446.582 | 254.958 |
| 51.903 | 0.000 | 56.550 | 0.000 | 0.000 | 93.750 | 446.582 | 446.582 | 254.958 |
| 24.451 | 0.000 | 106.925 | 0.000 | 0.000 | 0.000 | 174.263 | 620.844 | 277.891 |
| 76.354 | 0.000 | 163.475 | 0.000 | 0.000 | 93.750 | 620.844 | 620.844 | 277.891 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 42.42 | 5.00 | 389.009 |
| GROSS ULT., MB & MMF | 47.100 | 217.241 | DISCOUNT % | 10.00 | 8.00 | 314.170 |
| GROSS CUM., MB & MMF | 0.000 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 277.891 |
| GROSS RES., MB & MMF | 47.100 | 217.241 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 248.927 |
| NET RES., MB & MMF | 9.597 | 44.263 | UNDISCOUNTED NET/INVEST. | 7.62 | 15.00 | 215.156 |
| NET REVENUE, M$ | 838.454 | 115.969 | DISCOUNTED NET/INVEST. | 5.01 | 18.00 | 189.465 |
| INITIAL PRICE, $ | 87.370 | 2.620 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 128.935 |
| INITIAL N.I., PCT. | 20.375 | 20.375 | INITIAL W.I., PCT. | 25.000 | 60.00 | 74.287 |
| | | | | | 80.00 | 59.177 |
| | | | | | 260.00 | 24.476 |

**RALPH E. DAVIS ASSOCIATES, INC.**
**Texas Registered Engineering Firm F-1529**

LANG 2-2-34
FIELD: WATTENBERG
COUNTY: WELD STATE: CO
OPERATOR: RECOVERY ENERGY COMPA
3PUD

DATE : 04/01/2013
TIME : 14:03:14
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO : RED_JAN13

## R E S E R V E S A N D E C O N O M I C S

### AS OF DATE: 12/31/2012

| GROSS OIL PRODUCTION ---MBBLS--- | GROSS GAS PRODUCTION MMCF--- | NET OIL PRODUCTION ---MBBLS--- | NET GAS PRODUCTION ---MMCF--- | NET OIL PRICE ---$/BBL--- | NET GAS PRICE ---$/MCF--- | NET OIL SALES ---M$-- | NET GAS SALES ---M$--- | TOTAL NET SALES ---M$--- |
|---|---|---|---|---|---|---|---|---|
| 2.754 | 5.702 | 0.561 | 1.162 | 87.370 | 2.620 | 49.027 | 3.044 | 52.071 |
| 4.042 | 12.806 | 0.823 | 2.609 | 87.370 | 2.620 | 71.946 | 6.836 | 78.782 |
| 3.025 | 12.248 | 0.616 | 2.495 | 87.370 | 2.620 | 53.850 | 6.538 | 60.388 |
| 2.182 | 9.491 | 0.445 | 1.934 | 87.370 | 2.620 | 38.845 | 5.067 | 43.911 |
| 1.780 | 8.120 | 0.363 | 1.655 | 87.370 | 2.620 | 31.682 | 4.335 | 36.016 |
| 3.185 | 12.946 | 0.649 | 2.638 | 87.370 | 2.620 | 56.689 | 6.911 | 63.600 |
| 2.861 | 12.772 | 0.583 | 2.602 | 87.370 | 2.620 | 50.939 | 6.818 | 57.757 |
| 2.210 | 10.594 | 0.450 | 2.158 | 87.370 | 2.620 | 39.342 | 5.655 | 44.997 |
| 1.896 | 9.455 | 0.386 | 1.926 | 87.370 | 2.620 | 33.746 | 5.047 | 38.793 |
| 1.691 | 8.655 | 0.345 | 1.763 | 87.370 | 2.620 | 30.107 | 4.620 | 34.727 |
| 1.542 | 8.016 | 0.314 | 1.633 | 87.370 | 2.620 | 27.444 | 4.279 | 31.723 |
| 1.423 | 7.477 | 0.290 | 1.523 | 87.370 | 2.620 | 25.330 | 3.991 | 29.321 |
| 1.323 | 7.006 | 0.270 | 1.428 | 87.370 | 2.620 | 23.547 | 3.740 | 27.287 |
| 1.235 | 6.584 | 0.252 | 1.341 | 87.370 | 2.620 | 21.989 | 3.515 | 25.503 |
| 1.157 | 6.189 | 0.236 | 1.261 | 87.370 | 2.620 | 20.602 | 3.304 | 23.906 |
| 32.305 | 138.061 | 6.582 | 28.130 | 87.370 | 2.620 | 575.084 | 73.700 | 648.784 |
| 14.795 | 79.180 | 3.014 | 16.133 | 87.370 | 2.620 | 263.370 | 42.268 | 305.639 |
| 47.100 | 217.241 | 9.597 | 44.263 | 87.370 | 2.620 | 838.454 | 115.969 | 954.423 |

| AD VALOREM TAX -----MS------ | PRODUCTION TAX -----MS------ | DIRECT OPER EXPENSE -----MS------ | INTEREST PAID -----MS------ | CAPITAL REPAYMENT -----MS------ | EQUITY INVESTMENT -----MS------ | FUTURE NET CASHFLOW -----MS------ | CUMULATIVE CASHFLOW -----MS------ | CUM. DISC. CASHFLOW -----MS------ |
|---|---|---|---|---|---|---|---|---|
| 4.166 | 0.000 | 1.950 | 0.000 | 0.000 | 0.000 | 45.956 | 45.956 | 42.971 |
| 6.303 | 0.000 | 3.900 | 0.000 | 0.000 | 50.000 | 18.579 | 64.535 | 58.782 |
| 4.831 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 51.657 | 116.192 | 99.650 |
| 3.513 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 36.498 | 152.691 | 125.859 |
| 2.881 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 29.235 | 181.926 | 144.933 |
| 5.088 | 0.000 | 3.900 | 0.000 | 0.000 | 43.750 | 10.862 | 192.788 | 151.042 |
| 4.621 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 49.236 | 242.024 | 177.630 |
| 3.600 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 37.498 | 279.522 | 196.012 |
| 3.103 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 31.790 | 311.312 | 210.173 |
| 2.778 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 28.049 | 339.361 | 221.529 |
| 2.538 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 25.285 | 364.646 | 230.835 |
| 2.346 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 23.075 | 387.721 | 238.554 |
| 2.183 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 21.204 | 408.925 | 245.003 |
| 2.040 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 19.563 | 428.488 | 250.411 |
| 1.912 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 18.093 | 446.582 | 254.958 |
| 51.903 | 0.000 | 56.550 | 0.000 | 0.000 | 93.750 | 446.582 | 446.582 | 254.958 |
| 24.451 | 0.000 | 106.925 | 0.000 | 0.000 | 0.000 | 174.263 | 620.844 | 277.891 |
| 76.354 | 0.000 | 163.475 | 0.000 | 0.000 | 93.750 | 620.844 | 620.844 | 277.891 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 42.42 | 5.00 | 389.009 |
| GROSS ULT., MB & MMF | 47.100 | 217.241 | DISCOUNT % | 10.00 | 8.00 | 314.170 |
| GROSS CUM., MB & MMF | 0.000 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 277.891 |
| GROSS RES., MB & MMF | 47.100 | 217.241 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 248.927 |
| NET RES., MB & MMF | 9.597 | 44.263 | UNDISCOUNTED NET/INVEST. | 7.62 | 15.00 | 215.156 |
| NET REVENUE, M$ | 838.454 | 115.969 | DISCOUNTED NET/INVEST. | 5.01 | 18.00 | 189.465 |
| INITIAL PRICE, $ | 87.370 | 2.620 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 128.935 |
| INITIAL N.I., PCT. | 20.375 | 20.375 | INITIAL W.I., PCT. | 25.000 | 60.00 | 74.287 |
| | | | | | 80.00 | 59.177 |
| | | | | | 260.00 | 24.476 |

**RALPH E. DAVIS ASSOCIATES, INC.**
**Texas Registered Engineering Firm F-1529**

| | | |
|---|---|---|
| **LANG 22-34** | **DATE :** | **04/01/2013** |
| **FIELD: WATTENBERG** | **TIME :** | **14:03:14** |
| **COUNTY: WELD STATE: CO** | **DBS :** | **DEMO** |
| **OPERATOR: RECOVERY ENERGY COMPA** | **SETTINGS :** | **RED_JAN13** |
| **3PUD** | **SCENARIO :** | **RED_JAN13** |

## R E S E R V E S   A N D   E C O N O M I C S

**AS OF DATE: 12/31/2012**

| GROSS OIL PRODUCTION ---MBBLS--- | GROSS GAS PRODUCTION MMCF--- | NET OIL PRODUCTION ---MBBLS--- | NET GAS PRODUCTION ---MMCF--- | NET OIL PRICE ---$/BBL--- | NET GAS PRICE ---$/MCF--- | NET OIL SALES ----M$-- | NET GAS SALES --M$-- | TOTAL NET SALES ---M$-- |
|---|---|---|---|---|---|---|---|---|
| 2.754 | 5.702 | 0.561 | 1.162 | 87.370 | 2.620 | 49.027 | 3.044 | 52.071 |
| 4.042 | 12.806 | 0.823 | 2.609 | 87.370 | 2.620 | 71.946 | 6.836 | 78.782 |
| 3.025 | 12.248 | 0.616 | 2.495 | 87.370 | 2.620 | 53.850 | 6.538 | 60.388 |
| 2.182 | 9.491 | 0.445 | 1.934 | 87.370 | 2.620 | 38.845 | 5.067 | 43.911 |
| 1.780 | 8.120 | 0.363 | 1.655 | 87.370 | 2.620 | 31.682 | 4.335 | 36.016 |
| 3.185 | 12.946 | 0.649 | 2.638 | 87.370 | 2.620 | 56.689 | 6.911 | 63.600 |
| 2.861 | 12.772 | 0.583 | 2.602 | 87.370 | 2.620 | 50.939 | 6.818 | 57.757 |
| 2.210 | 10.594 | 0.450 | 2.158 | 87.370 | 2.620 | 39.342 | 5.655 | 44.997 |
| 1.896 | 9.455 | 0.386 | 1.926 | 87.370 | 2.620 | 33.746 | 5.047 | 38.793 |
| 1.691 | 8.655 | 0.345 | 1.763 | 87.370 | 2.620 | 30.107 | 4.620 | 34.727 |
| 1.542 | 8.016 | 0.314 | 1.633 | 87.370 | 2.620 | 27.444 | 4.279 | 31.723 |
| 1.423 | 7.477 | 0.290 | 1.523 | 87.370 | 2.620 | 25.330 | 3.991 | 29.321 |
| 1.323 | 7.006 | 0.270 | 1.428 | 87.370 | 2.620 | 23.547 | 3.740 | 27.287 |
| 1.235 | 6.584 | 0.252 | 1.341 | 87.370 | 2.620 | 21.989 | 3.515 | 25.503 |
| 1.157 | 6.189 | 0.236 | 1.261 | 87.370 | 2.620 | 20.602 | 3.304 | 23.906 |
| 32.305 | 138.061 | 6.582 | 28.130 | 87.370 | 2.620 | 575.084 | 73.700 | 648.784 |
| 14.795 | 79.180 | 3.014 | 16.133 | 87.370 | 2.620 | 263.370 | 42.268 | 305.639 |
| 47.100 | 217.241 | 9.597 | 44.263 | 87.370 | 2.620 | 838.454 | 115.969 | 954.423 |

| AD VALOREM TAX -----MS------ | PRODUCTION TAX -----MS------ | DIRECT OPER EXPENSE -----MS------ | INTEREST PAID -----MS------ | CAPITAL REPAYMENT -----MS------ | EQUITY INVESTMENT -----MS------ | FUTURE NET CASHFLOW -----MS------ | CUMULATIVE CASHFLOW -----MS------ | CUM. DISC. CASHFLOW -----MS------ |
|---|---|---|---|---|---|---|---|---|
| 4.166 | 0.000 | 1.950 | 0.000 | 0.000 | 0.000 | 45.956 | 45.956 | 42.971 |
| 6.303 | 0.000 | 3.900 | 0.000 | 0.000 | 50.000 | 18.579 | 64.535 | 58.782 |
| 4.831 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 51.657 | 116.192 | 99.650 |
| 3.513 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 36.498 | 152.691 | 125.859 |
| 2.881 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 29.235 | 181.926 | 144.933 |
| 5.088 | 0.000 | 3.900 | 0.000 | 0.000 | 43.750 | 10.862 | 192.788 | 151.042 |
| 4.621 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 49.236 | 242.024 | 177.630 |
| 3.600 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 37.498 | 279.522 | 196.012 |
| 3.103 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 31.790 | 311.312 | 210.173 |
| 2.778 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 28.049 | 339.361 | 221.529 |
| 2.538 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 25.285 | 364.646 | 230.835 |
| 2.346 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 23.075 | 387.721 | 238.554 |
| 2.183 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 21.204 | 408.925 | 245.003 |
| 2.040 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 19.563 | 428.488 | 250.411 |
| 1.912 | 0.000 | 3.900 | 0.000 | 0.000 | 0.000 | 18.093 | 446.582 | 254.958 |
| 51.903 | 0.000 | 56.550 | 0.000 | 0.000 | 93.750 | 446.582 | 446.582 | 254.958 |
| 24.451 | 0.000 | 106.925 | 0.000 | 0.000 | 0.000 | 174.263 | 620.844 | 277.891 |
| 76.354 | 0.000 | 163.475 | 0.000 | 0.000 | 93.750 | 620.844 | 620.844 | 277.891 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 42.42 | 5.00 | 389.009 |
| GROSS ULT., MB & MMF | 47.100 | 217.241 | DISCOUNT % | 10.00 | 8.00 | 314.170 |
| GROSS CUM., MB & MMF | 0.000 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 277.891 |
| GROSS RES., MB & MMF | 47.100 | 217.241 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 248.927 |
| NET RES., MB & MMF | 9.597 | 44.263 | UNDISCOUNTED NET/INVEST. | 7.62 | 15.00 | 215.156 |
| NET REVENUE, M$ | 838.454 | 115.969 | DISCOUNTED NET/INVEST. | 5.01 | 18.00 | 189.465 |
| INITIAL PRICE, $ | 87.370 | 2.620 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 128.935 |
| INITIAL N.I., PCT. | 20.375 | 20.375 | INITIAL W.I., PCT. | 25.000 | 60.00 | 74.287 |
| | | | | | 80.00 | 59.177 |
| | | | | | 260.00 | 24.476 |

PALM 11-20
FIELD: ALBIN WEST
COUNTY: BANNER STATE: NE
OPERATOR: RECOVERY ENERGY COMPA
3PUD

DATE : 04/01/2013
TIME : 14:03:15
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO : RED_JAN13

## R E S E R V E S A N D E C O N O M I C S

### AS OF DATE: 12/31/2012

| R | GROSS OIL PRODUCTION ---MBBLS--- | GROSS GAS PRODUCTION ---MMCF--- | NET OIL PRODUCTION ---MBBLS--- | NET GAS PRODUCTION --- MMCF--- | NET OIL PRICE ---$/BBL--- | NET GAS PRICE ---$/MCF--- | NET OIL SALES -- -M$--- | NET GAS SALES ---M$--- | TOTAL NET SALES -- -M$--- |
|---|---|---|---|---|---|---|---|---|---|
| | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| | 10.559 | 0.000 | 2.178 | 0.000 | 87.370 | 0.000 | 190.282 | 0.000 | 190.282 |
| | 13.693 | 0.000 | 2.824 | 0.000 | 87.370 | 0.000 | 246.748 | 0.000 | 246.748 |
| | 8.331 | 0.000 | 1.718 | 0.000 | 87.370 | 0.000 | 150.118 | 0.000 | 150.118 |
| | 5.508 | 0.000 | 1.136 | 0.000 | 87.370 | 0.000 | 99.258 | 0.000 | 99.258 |
| | 3.864 | 0.000 | 0.797 | 0.000 | 87.370 | 0.000 | 69.631 | 0.000 | 69.631 |
| | 2.833 | 0.000 | 0.584 | 0.000 | 87.370 | 0.000 | 51.059 | 0.000 | 51.059 |
| | 2.150 | 0.000 | 0.444 | 0.000 | 87.370 | 0.000 | 38.751 | 0.000 | 38.751 |
| | 1.678 | 0.000 | 0.346 | 0.000 | 87.370 | 0.000 | 30.230 | 0.000 | 30.230 |
| | 1.338 | 0.000 | 0.276 | 0.000 | 87.370 | 0.000 | 24.119 | 0.000 | 24.119 |
| | 1.088 | 0.000 | 0.224 | 0.000 | 87.370 | 0.000 | 19.608 | 0.000 | 19.608 |
| | 0.899 | 0.000 | 0.185 | 0.000 | 87.370 | 0.000 | 16.196 | 0.000 | 16.196 |
| | 0.258 | 0.000 | 0.053 | 0.000 | 87.370 | 0.000 | 4.648 | 0.000 | 4.648 |
| | | | | | | | | | |
| | | | | | | | | | |
| T | 52.200 | 0.000 | 10.766 | 0.000 | 87.370 | 0.000 | 940.647 | 0.000 | 940.647 |
| R | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| L | 52.200 | 0.000 | 10.766 | 0.000 | 87.370 | 0.000 | 940.647 | 0.000 | 940.647 |

| R | AD VALOREM TAX -----MS------ | PRODUCTION TAX -----MS------ | DIRECT OPER EXPENSE -----MS------ | INTEREST -----MS------ | CAPITAL REPAYMENT -----MS------ | EQUITY INVESTMENT -----MS------ | FUTURE NET CASHFLOW -----MS------ | CUMULATIVE CASHFLOW -----MS------ | TOTAL NET SALES ---M$--- |
|---|---|---|---|---|---|---|---|---|---|
| | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| | 3.691 | 5.708 | 6.600 | 0.000 | 0.000 | 0.000 | 174.282 | 174.282 | 147.713 |
| | 4.787 | 7.402 | 13.200 | 0.000 | 0.000 | 0.000 | 221.358 | 395.640 | 323.000 |
| | 2.912 | 4.504 | 13.200 | 0.000 | 0.000 | 0.000 | 129.502 | 525.142 | 416.164 |
| | 1.926 | 2.978 | 13.200 | 0.000 | 0.000 | 0.000 | 81.155 | 606.297 | 469.218 |
| | 1.351 | 2.089 | 13.200 | 0.000 | 0.000 | 0.000 | 52.991 | 659.288 | 500.703 |
| | 0.991 | 1.532 | 13.200 | 0.000 | 0.000 | 0.000 | 35.336 | 694.625 | 519.789 |
| | 0.752 | 1.163 | 13.200 | 0.000 | 0.000 | 0.000 | 23.636 | 718.261 | 531.395 |
| | 0.586 | 0.907 | 13.200 | 0.000 | 0.000 | 0.000 | 15.536 | 733.797 | 538.331 |
| | 0.468 | 0.724 | 13.200 | 0.000 | 0.000 | 0.000 | 9.728 | 743.525 | 542.282 |
| | 0.380 | 0.588 | 13.200 | 0.000 | 0.000 | 0.000 | 5.440 | 748.965 | 544.293 |
| | 0.314 | 0.486 | 13.200 | 0.000 | 0.000 | 0.000 | 2.196 | 751.161 | 545.035 |
| | 0.090 | 0.139 | 4.400 | 0.000 | 0.000 | 0.000 | 0.018 | 751.179 | 545.042 |
| | | | | | | | | | |
| | | | | | | | | | |
| T | 18.249 | 28.219 | 143.000 | 0.000 | 0.000 | 0.000 | 751.179 | 751.179 | 545.042 |
| R | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 751.179 | 545.042 |
| L | 18.249 | 28.219 | 143.000 | 0.000 | 0.000 | 0.000 | 751.179 | 751.179 | 545.042 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 12.33 | 5.00 | 634.966 |
| GROSS ULT., MB & MMF | 52.200 | 0.000 | DISCOUNT % | 10.00 | 8.00 | 578.408 |
| GROSS CUM., MB & MMF | 0.000 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 545.042 |
| GROSS RES., MB & MMF | 52.200 | 0.000 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 514.650 |
| NET RES., MB & MMF | 10.766 | 0.000 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 473.884 |
| NET REVENUE, M$ | 940.647 | 0.000 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 438.045 |
| INITIAL PRICE, $ | 87.370 | 0.000 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 330.342 |
| INITIAL N.I., PCT. | 20.625 | 0.000 | INITIAL W.I., PCT. | 25.000 | 60.00 | 190.497 |
| | | | | | 80.00 | 142.712 |
| | | | | | 260.00 | 31.360 |

PALM 42-20
FIELD: ALBIN WEST
COUNTY: BANNER STATE: NE
OPERATOR: RECOVERY ENERGY COMPA
3PUD

DATE : 04/01/2013
TIME : 14:03:15
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO : RED_JAN13

## R E S E R V E S A N D E C O N O M I C S

**AS OF DATE: 12/31/2012**

| OSS OIL UCTION BBLS--- | GROSS GAS PRODUCTION MMCF--- | NET OIL PRODUCTION ---MBBLS--- | NET GAS PRODUCTION MMCF--- | NET OIL PRICE ---$/BBL--- | NET GAS PRICE ---$/MCF--- | NET OIL SALES -- -M$---- | NET GAS SALES ---M$--- | TOTAL NET SALES ---M$--- |
|---|---|---|---|---|---|---|---|---|
| 9.143 | 0.000 | 1.886 | 0.000 | 87.370 | 0.000 | 164.761 | 0.000 | 164.761 |
| 15.054 | 0.000 | 3.105 | 0.000 | 87.370 | 0.000 | 271.279 | 0.000 | 271.279 |
| 9.437 | 0.000 | 1.946 | 0.000 | 87.370 | 0.000 | 170.057 | 0.000 | 170.057 |
| 6.371 | 0.000 | 1.314 | 0.000 | 87.370 | 0.000 | 114.814 | 0.000 | 114.814 |
| 4.539 | 0.000 | 0.936 | 0.000 | 87.370 | 0.000 | 81.794 | 0.000 | 81.794 |
| 3.368 | 0.000 | 0.695 | 0.000 | 87.370 | 0.000 | 60.692 | 0.000 | 60.692 |
| 2.580 | 0.000 | 0.532 | 0.000 | 87.370 | 0.000 | 46.496 | 0.000 | 46.496 |
| 2.028 | 0.000 | 0.418 | 0.000 | 87.370 | 0.000 | 36.550 | 0.000 | 36.550 |
| 1.629 | 0.000 | 0.336 | 0.000 | 87.370 | 0.000 | 29.347 | 0.000 | 29.347 |
| 1.331 | 0.000 | 0.275 | 0.000 | 87.370 | 0.000 | 23.986 | 0.000 | 23.986 |
| 1.104 | 0.000 | 0.228 | 0.000 | 87.370 | 0.000 | 19.902 | 0.000 | 19.902 |
| 0.928 | 0.000 | 0.191 | 0.000 | 87.370 | 0.000 | 16.729 | 0.000 | 16.729 |
| 0.486 | 0.000 | 0.100 | 0.000 | 87.370 | 0.000 | 8.757 | 0.000 | 8.757 |
| 58.000 | 0.000 | 11.962 | 0.000 | 87.370 | 0.000 | 1045.163 | 0.000 | 1045.163 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 58.000 | 0.000 | 11.962 | 0.000 | 87.370 | 0.000 | 1045.163 | 0.000 | 1045.163 |

| AD LOREM TAX -MS------ | PRODUCTION TAX | DIRECT OPER EXPENSE -----MS------ | INTEREST -----MS------ | CAPITAL REPAYMENT -----MS------ | EQUITY INVESTMENT | FUTURE NET CASHFLOW | CUMULATIVE CASHFLOW | CUM. DISC. CASHFLOW |
|---|---|---|---|---|---|---|---|---|
| 3.196 | 4.943 | 5.500 | 0.000 | 0.000 | 0.000 | 151.122 | 151.122 | 140.262 |
| 5.263 | 8.138 | 13.200 | 0.000 | 0.000 | 0.000 | 244.677 | 395.799 | 353.322 |
| 3.299 | 5.102 | 13.200 | 0.000 | 0.000 | 0.000 | 148.456 | 544.256 | 470.772 |
| 2.227 | 3.444 | 13.200 | 0.000 | 0.000 | 0.000 | 95.942 | 640.198 | 539.749 |
| 1.587 | 2.454 | 13.200 | 0.000 | 0.000 | 0.000 | 64.553 | 704.751 | 581.930 |
| 1.177 | 1.821 | 13.200 | 0.000 | 0.000 | 0.000 | 44.494 | 749.245 | 608.356 |
| 0.902 | 1.395 | 13.200 | 0.000 | 0.000 | 0.000 | 30.999 | 780.244 | 625.094 |
| 0.709 | 1.096 | 13.200 | 0.000 | 0.000 | 0.000 | 21.544 | 801.788 | 635.670 |
| 0.569 | 0.880 | 13.200 | 0.000 | 0.000 | 0.000 | 14.697 | 816.486 | 642.230 |
| 0.465 | 0.720 | 13.200 | 0.000 | 0.000 | 0.000 | 9.601 | 826.086 | 646.128 |
| 0.386 | 0.597 | 13.200 | 0.000 | 0.000 | 0.000 | 5.719 | 831.805 | 648.241 |
| 0.325 | 0.502 | 13.200 | 0.000 | 0.000 | 0.000 | 2.703 | 834.508 | 649.151 |
| 0.170 | 0.263 | 8.800 | 0.000 | 0.000 | 0.000 | -0.476 | 834.032 | 649.014 |
| 20.276 | 31.355 | 159.500 | 0.000 | 0.000 | 0.000 | 834.032 | 834.032 | 649.014 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 834.032 | 649.014 |
| 20.276 | 31.355 | 159.500 | 0.000 | 0.000 | 0.000 | 834.032 | 834.032 | 649.014 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 12.67 | 5.00 | 730.144 |
| GROSS ULT., MB & MMF | 58.000 | 0.000 | DISCOUNT % | 10.00 | 8.00 | 679.217 |
| GROSS CUM., MB & MMF | 0.000 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 649.014 |
| GROSS RES., MB & MMF | 58.000 | 0.000 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 621.379 |
| NET RES., MB & MMF | 11.962 | 0.000 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 584.085 |
| NET REVENUE, M$ | 1045.163 | 0.000 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 551.041 |
| INITIAL PRICE, $ | 87.370 | 0.000 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 449.673 |
| INITIAL N.I., PCT. | 20.625 | 0.000 | INITIAL W.I., PCT. | 25.000 | 60.00 | 309.376 |
| | | | | | 80.00 | 256.831 |
| | | | | | 260.00 | 104.754 |

LARSON 24-20
FIELD: RANCHER
COUNTY: KIMBALL STATE: NE
OPERATOR: RECOVERY ENERGY COMPA
3PUD

DATE : 04/01/2013
TIME : 14:03:15
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO : RED_JAN13

## R E S E R V E S A N D E C O N O M I C S

**AS OF DATE: 12/31/2012**

| ROSS OIL RODUCTION MBBLS | GROSS GAS PRODUCTION MMCF | NET OIL PRODUCTION MBBLS | NET GAS PRODUCTION MMCF | NET OIL PRICE $/BBL | NET GAS PRICE $/MCF | NET OIL SALES M$ | NET GAS SALES M$ | TOTAL NET SALES M$ |
|---|---|---|---|---|---|---|---|---|
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 8.757 | 0.000 | 1.916 | 0.000 | 87.370 | 0.000 | 167.366 | 0.000 | 167.366 |
| 7.545 | 0.000 | 1.650 | 0.000 | 87.370 | 0.000 | 144.199 | 0.000 | 144.199 |
| 5.858 | 0.000 | 1.281 | 0.000 | 87.370 | 0.000 | 111.956 | 0.000 | 111.956 |
| 4.837 | 0.000 | 1.058 | 0.000 | 87.370 | 0.000 | 92.451 | 0.000 | 92.451 |
| 4.146 | 0.000 | 0.907 | 0.000 | 87.370 | 0.000 | 79.245 | 0.000 | 79.245 |
| 3.644 | 0.000 | 0.797 | 0.000 | 87.370 | 0.000 | 69.648 | 0.000 | 69.648 |
| 3.261 | 0.000 | 0.713 | 0.000 | 87.370 | 0.000 | 62.326 | 0.000 | 62.326 |
| 2.958 | 0.000 | 0.647 | 0.000 | 87.370 | 0.000 | 56.537 | 0.000 | 56.537 |
| 2.359 | 0.000 | 0.516 | 0.000 | 87.370 | 0.000 | 45.078 | 0.000 | 45.078 |
| 1.137 | 0.000 | 0.249 | 0.000 | 87.370 | 0.000 | 21.736 | 0.000 | 21.736 |
| 0.061 | 0.000 | 0.013 | 0.000 | 87.370 | 0.000 | 1.159 | 0.000 | 1.159 |
| | | | | | | | | |
| | | | | | | | | |
| | | | | | | | | |
| 44.563 | 0.000 | 9.748 | 0.000 | 87.370 | 0.000 | 851.702 | 0.000 | 851.702 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 44.563 | 0.000 | 9.748 | 0.000 | 87.370 | 0.000 | 851.702 | 0.000 | 851.702 |

| AD VALOREM TAX M$ | PRODUCTION TAX M$ | DIRECT OPER EXPENSE M$ | INTEREST PAID M$ | CAPITAL REPAYMENT M$ | EQUITY INVESTMENT M$ | FUTURE NET CASHFLOW M$ | CUMULATIVE CASHFLOW M$ | CUM. DISC. CASHFLOW M$ |
|---|---|---|---|---|---|---|---|---|
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 3.247 | 5.021 | 11.000 | 0.000 | 0.000 | 0.000 | 148.098 | 148.098 | 127.720 |
| 2.797 | 4.326 | 13.200 | 0.000 | 0.000 | 0.000 | 123.876 | 271.973 | 225.621 |
| 2.172 | 3.359 | 13.200 | 0.000 | 0.000 | 0.000 | 93.226 | 365.199 | 292.558 |
| 1.794 | 2.774 | 13.200 | 0.000 | 0.000 | 0.000 | 74.684 | 439.883 | 341.289 |
| 1.537 | 2.377 | 13.200 | 0.000 | 0.000 | 0.000 | 62.130 | 502.013 | 378.134 |
| 1.351 | 2.089 | 13.200 | 0.000 | 0.000 | 0.000 | 53.007 | 555.020 | 406.707 |
| 1.209 | 1.870 | 13.200 | 0.000 | 0.000 | 0.000 | 46.047 | 601.067 | 429.269 |
| 1.097 | 1.696 | 13.200 | 0.000 | 0.000 | 0.000 | 40.544 | 641.612 | 447.327 |
| 0.875 | 1.352 | 13.200 | 0.000 | 0.000 | 0.000 | 29.651 | 671.263 | 459.400 |
| 0.422 | 0.652 | 13.200 | 0.000 | 0.000 | 0.000 | 7.462 | 678.725 | 462.191 |
| 0.022 | 0.035 | 1.100 | 0.000 | 0.000 | 0.000 | 0.002 | 678.728 | 462.191 |
| | | | | | | | | |
| | | | | | | | | |
| | | | | | | | | |
| 16.523 | 25.551 | 130.900 | 0.000 | 0.000 | 0.000 | 678.728 | 678.728 | 462.191 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 678.728 | 462.191 |
| 16.523 | 25.551 | 130.900 | 0.000 | 0.000 | 0.000 | 678.728 | 678.728 | 462.191 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 11.08 | 5.00 | 553.935 |
| GROSS ULT., MB & MMF | 44.563 | 0.000 | DISCOUNT % | 10.00 | 8.00 | 495.712 |
| GROSS CUM., MB & MMF | 0.000 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 462.191 |
| GROSS RES., MB & MMF | 44.563 | 0.000 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 432.214 |
| NET RES., MB & MMF | 9.748 | 0.000 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 392.861 |
| NET REVENUE, M$ | 851.702 | 0.000 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 359.099 |
| INITIAL PRICE, $ | 87.370 | 0.000 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 262.525 |
| INITIAL N.I., PCT. | 21.875 | 0.000 | INITIAL W.I., PCT. | 25.000 | 60.00 | 148.158 |
| | | | | | 80.00 | 111.635 |
| | | | | | 260.00 | 28.189 |

OLIVERIUS 32-33
FIELD: STATELINE
COUNTY: BANNER STATE: NE
OPERATOR: RECOVERY ENERGY COMPA
3PUD

DATE : 04/01/2013
TIME : 14:03:15
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO : RED_JAN13

## R E S E R V E S   A N D   E C O N O M I C S

### AS OF DATE: 12/31/2012

| GROSS OIL PRODUCTION MBBLS | GROSS GAS PRODUCTION MMCF | NET OIL PRODUCTION MBBLS | NET GAS PRODUCTION MMCF | NET OIL PRICE $/BBL | NET GAS PRICE $/MCF | NET OIL SALES M$ | NET GAS SALES M$ | TOTAL NET SALES M$ |
|---|---|---|---|---|---|---|---|---|
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 15.050 | 0.000 | 2.897 | 0.000 | 87.370 | 0.000 | 253.130 | 0.000 | 253.130 |
| 13.303 | 0.000 | 2.561 | 0.000 | 87.370 | 0.000 | 223.735 | 0.000 | 223.735 |
| 5.770 | 0.000 | 1.111 | 0.000 | 87.370 | 0.000 | 97.043 | 0.000 | 97.043 |
| 3.100 | 0.000 | 0.597 | 0.000 | 87.370 | 0.000 | 52.137 | 0.000 | 52.137 |
| 1.888 | 0.000 | 0.363 | 0.000 | 87.370 | 0.000 | 31.756 | 0.000 | 31.756 |
| 0.884 | 0.000 | 0.170 | 0.000 | 87.370 | 0.000 | 14.866 | 0.000 | 14.866 |
| 39.995 | 0.000 | 7.699 | 0.000 | 87.370 | 0.000 | 672.666 | 0.000 | 672.666 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 39.995 | 0.000 | 7.699 | 0.000 | 87.370 | 0.000 | 672.666 | 0.000 | 672.666 |

| AD VALOREM TAX M$ | PRODUCTION TAX M$ | DIRECT OPER EXPENSE M$ | INTEREST PAID M$ | CAPITAL REPAYMENT M$ | EQUITY INVESTMENT M$ | FUTURE NET CASHFLOW M$ | CUMULATIVE CASHFLOW M$ | CUM. DISC. CASHFLOW M$ |
|---|---|---|---|---|---|---|---|---|
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 17.130 | 16.200 | 6.600 | 0.000 | 0.000 | 0.000 | 213.200 | 213.200 | 180.946 |
| 15.141 | 14.319 | 13.200 | 0.000 | 0.000 | 0.000 | 181.075 | 394.275 | 324.845 |
| 6.567 | 6.211 | 13.200 | 0.000 | 0.000 | 0.000 | 71.065 | 465.339 | 376.102 |
| 3.528 | 3.337 | 13.200 | 0.000 | 0.000 | 0.000 | 32.072 | 497.411 | 397.122 |
| 2.149 | 2.032 | 13.200 | 0.000 | 0.000 | 0.000 | 14.375 | 511.786 | 405.693 |
| 1.006 | 0.951 | 8.800 | 0.000 | 0.000 | 0.000 | 4.108 | 515.894 | 407.949 |
| 45.521 | 43.051 | 68.200 | 0.000 | 0.000 | 0.000 | 515.894 | 515.894 | 407.949 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 515.894 | 407.949 |
| 45.521 | 43.051 | 68.200 | 0.000 | 0.000 | 0.000 | 515.894 | 515.894 | 407.949 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 6.67 | 5.00 | 456.988 |
| GROSS ULT., MB & MMF | 39.995 | 0.000 | DISCOUNT % | 10.00 | 8.00 | 426.530 |
| GROSS CUM., MB & MMF | 0.000 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 407.949 |
| GROSS RES., MB & MMF | 39.995 | 0.000 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 390.603 |
| NET RES., MB & MMF | 7.699 | 0.000 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 366.665 |
| NET REVENUE, M$ | 672.666 | 0.000 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 344.945 |
| INITIAL PRICE, $ | 87.370 | 0.000 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 275.407 |
| INITIAL N.I., PCT. | 19.250 | 0.000 | INITIAL W.I., PCT. | 25.000 | 60.00 | 173.470 |
| | | | | | 80.00 | 134.812 |
| | | | | | 260.00 | 33.665 |

VRTATKO 44-22
FIELD: SURGE
COUNTY: KIIMBALL STATE: NE
OPERATOR: RECOVERY ENERGY COMPA
3PUD

| | | |
|---|---|---|
| DATE | : | 04/01/2013 |
| TIME | : | 14:03:15 |
| DBS | : | DEMO |
| SETTINGS | : | RED_JAN13 |
| SCENARIO | : | RED_JAN13 |

## R E S E R V E S A N D E C O N O M I C S

**AS OF DATE: 12/31/2012**

| GROSS OIL PRODUCTION MBBLS | GROSS GAS PRODUCTION MMCF | NET OIL PRODUCTION MBBLS | NET GAS PRODUCTION MMCF | NET OIL PRICE $/BBL | NET GAS PRICE $/MCF | NET OIL SALES M$ | NET GAS SALES M$ | TOTAL NET SALES M$ |
|---|---|---|---|---|---|---|---|---|
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 8.757 | 0.000 | 1.697 | 0.000 | 87.370 | 0.000 | 148.238 | 0.000 | 148.238 |
| 7.545 | 0.000 | 1.462 | 0.000 | 87.370 | 0.000 | 127.719 | 0.000 | 127.719 |
| 5.858 | 0.000 | 1.135 | 0.000 | 87.370 | 0.000 | 99.161 | 0.000 | 99.161 |
| 4.837 | 0.000 | 0.937 | 0.000 | 87.370 | 0.000 | 81.885 | 0.000 | 81.885 |
| 4.146 | 0.000 | 0.803 | 0.000 | 87.370 | 0.000 | 70.188 | 0.000 | 70.188 |
| 3.644 | 0.000 | 0.706 | 0.000 | 87.370 | 0.000 | 61.688 | 0.000 | 61.688 |
| 3.261 | 0.000 | 0.632 | 0.000 | 87.370 | 0.000 | 55.203 | 0.000 | 55.203 |
| 2.958 | 0.000 | 0.573 | 0.000 | 87.370 | 0.000 | 50.076 | 0.000 | 50.076 |
| 2.359 | 0.000 | 0.457 | 0.000 | 87.370 | 0.000 | 39.926 | 0.000 | 39.926 |
| 1.073 | 0.000 | 0.208 | 0.000 | 87.370 | 0.000 | 18.156 | 0.000 | 18.156 |
| | | | | | | | | |
| | | | | | | | | |
| | | | | | | | | |
| | | | | | | | | |
| 44.438 | 0.000 | 8.610 | 0.000 | 87.370 | 0.000 | 752.242 | 0.000 | 752.242 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 44.438 | 0.000 | 8.610 | 0.000 | 87.370 | 0.000 | 752.242 | 0.000 | 752.242 |

| AD VALOREM TAX M$ | PRODUCTION TAX M$ | DIRECT OPER EXPENSE M$ | INTEREST PAID M$ | CAPITAL REPAYMENT M$ | EQUITY INVESTMENT M$ | FUTURE NET CASHFLOW M$ | CUMULATIVE CASHFLOW M$ | CUM. DISC. CASHFLOW M$ |
|---|---|---|---|---|---|---|---|---|
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 2.876 | 4.447 | 11.000 | 0.000 | 0.000 | 0.000 | 129.915 | 129.915 | 112.042 |
| 2.478 | 3.832 | 13.200 | 0.000 | 0.000 | 0.000 | 108.210 | 238.125 | 197.565 |
| 1.924 | 2.975 | 13.200 | 0.000 | 0.000 | 0.000 | 81.063 | 319.188 | 255.771 |
| 1.589 | 2.457 | 13.200 | 0.000 | 0.000 | 0.000 | 64.640 | 383.828 | 297.950 |
| 1.362 | 2.106 | 13.200 | 0.000 | 0.000 | 0.000 | 53.521 | 437.348 | 329.691 |
| 1.197 | 1.851 | 13.200 | 0.000 | 0.000 | 0.000 | 45.441 | 482.789 | 354.186 |
| 1.071 | 1.656 | 13.200 | 0.000 | 0.000 | 0.000 | 39.276 | 522.065 | 373.431 |
| 0.971 | 1.502 | 13.200 | 0.000 | 0.000 | 0.000 | 34.402 | 556.467 | 388.754 |
| 0.775 | 1.198 | 13.200 | 0.000 | 0.000 | 0.000 | 24.754 | 581.221 | 398.837 |
| 0.352 | 0.545 | 12.100 | 0.000 | 0.000 | 0.000 | 5.160 | 586.381 | 400.775 |
| | | | | | | | | |
| | | | | | | | | |
| | | | | | | | | |
| | | | | | | | | |
| 14.593 | 22.567 | 128.700 | 0.000 | 0.000 | 0.000 | 586.381 | 586.381 | 400.775 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 586.381 | 400.775 |
| 14.593 | 22.567 | 128.700 | 0.000 | 0.000 | 0.000 | 586.381 | 586.381 | 400.775 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 10.92 | 5.00 | 479.530 |
| GROSS ULT., MB & MMF | 44.438 | 0.000 | DISCOUNT % | 10.00 | 8.00 | 429.572 |
| GROSS CUM., MB & MMF | 0.000 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 400.775 |
| GROSS RES., MB & MMF | 44.438 | 0.000 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 374.999 |
| NET RES., MB & MMF | 8.610 | 0.000 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 341.125 |
| NET REVENUE, M$ | 752.242 | 0.000 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 312.031 |
| INITIAL PRICE, $ | 87.370 | 0.000 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 228.613 |
| INITIAL N.I., PCT. | 19.375 | 0.000 | INITIAL W.I., PCT. | 25.000 | 60.00 | 129.389 |
| | | | | | 80.00 | 97.588 |
| | | | | | 260.00 | 24.703 |

LUKASSEN 42-7 NE TERRESTRIAL WYK

| | | |
|---|---|---|
| DATE | : | 04/01/2013 |
| TIME | : | 14:03:15 |
| DBS | : | DEMO |
| SETTINGS | : | RED_JAN13 |
| SCENARIO | : | RED_JAN13 |

## R E S E R V E S A N D E C O N O M I C S

**AS OF DATE: 12/31/2012**

| GROSS OIL RODUCTION MBBLS | GROSS GAS PRODUCTION MMCF | NET OIL PRODUCTION MBBLS | NET GAS PRODUCTION MMCF | NET OIL PRICE $/BBL | NET GAS PRICE $/MCF | NET OIL SALES M$ | NET GAS SALES M$ | TOTAL NET SALES M$ |
|---|---|---|---|---|---|---|---|---|
| 5.387 | 0.000 | 1.010 | 0.000 | 87.370 | 0.000 | 88.246 | 0.000 | 88.246 |
| 7.474 | 0.000 | 1.401 | 0.000 | 87.370 | 0.000 | 122.439 | 0.000 | 122.439 |
| 5.653 | 0.000 | 1.060 | 0.000 | 87.370 | 0.000 | 92.600 | 0.000 | 92.600 |
| 4.722 | 0.000 | 0.885 | 0.000 | 87.370 | 0.000 | 77.352 | 0.000 | 77.352 |
| 4.132 | 0.000 | 0.775 | 0.000 | 87.370 | 0.000 | 67.689 | 0.000 | 67.689 |
| 3.704 | 0.000 | 0.694 | 0.000 | 87.370 | 0.000 | 60.677 | 0.000 | 60.677 |
| 3.334 | 0.000 | 0.625 | 0.000 | 87.370 | 0.000 | 54.610 | 0.000 | 54.610 |
| 3.000 | 0.000 | 0.563 | 0.000 | 87.370 | 0.000 | 49.149 | 0.000 | 49.149 |
| 2.700 | 0.000 | 0.506 | 0.000 | 87.370 | 0.000 | 44.234 | 0.000 | 44.234 |
| 2.430 | 0.000 | 0.456 | 0.000 | 87.370 | 0.000 | 39.810 | 0.000 | 39.810 |
| 2.187 | 0.000 | 0.410 | 0.000 | 87.370 | 0.000 | 35.829 | 0.000 | 35.829 |
| 1.968 | 0.000 | 0.369 | 0.000 | 87.370 | 0.000 | 32.246 | 0.000 | 32.246 |
| 1.772 | 0.000 | 0.332 | 0.000 | 87.370 | 0.000 | 29.022 | 0.000 | 29.022 |
| 1.594 | 0.000 | 0.299 | 0.000 | 87.370 | 0.000 | 26.120 | 0.000 | 26.120 |
| 1.435 | 0.000 | 0.269 | 0.000 | 87.370 | 0.000 | 23.508 | 0.000 | 23.508 |
| 51.492 | 0.000 | 9.655 | 0.000 | 87.370 | 0.000 | 843.532 | 0.000 | 843.532 |
| 4.876 | 0.000 | 0.914 | 0.000 | 87.370 | 0.000 | 79.882 | 0.000 | 79.882 |
| 56.368 | 0.000 | 10.569 | 0.000 | 87.370 | 0.000 | 923.414 | 0.000 | 923.414 |

| AD VALOREM TAX M$ | PRODUCTION TAX M$ | DIRECT OPER EXPENSE M$ | INTEREST PAID M$ | CAPITAL REPAYMENT M$ | EQUITY INVESTMENT M$ | FUTURE NET CASHFLOW M$ | CUMULATIVE CASHFLOW M$ | CUM. DISC. CASHFLOW M$ |
|---|---|---|---|---|---|---|---|---|
| 1.712 | 2.647 | 6.600 | 0.000 | 0.000 | 0.000 | 77.287 | 77.287 | 72.071 |
| 2.375 | 3.673 | 13.200 | 0.000 | 0.000 | 0.000 | 103.190 | 180.477 | 161.837 |
| 1.796 | 2.778 | 13.200 | 0.000 | 0.000 | 0.000 | 74.826 | 255.303 | 220.937 |
| 1.501 | 2.321 | 13.200 | 0.000 | 0.000 | 0.000 | 60.331 | 315.634 | 264.234 |
| 1.313 | 2.031 | 13.200 | 0.000 | 0.000 | 0.000 | 51.146 | 366.780 | 297.593 |
| 1.177 | 1.820 | 13.200 | 0.000 | 0.000 | 0.000 | 44.480 | 411.260 | 323.965 |
| 1.059 | 1.638 | 13.200 | 0.000 | 0.000 | 0.000 | 38.712 | 449.972 | 344.831 |
| 0.953 | 1.474 | 13.200 | 0.000 | 0.000 | 0.000 | 33.521 | 483.492 | 361.257 |
| 0.858 | 1.327 | 13.200 | 0.000 | 0.000 | 0.000 | 28.849 | 512.341 | 374.109 |
| 0.772 | 1.194 | 13.200 | 0.000 | 0.000 | 0.000 | 24.644 | 536.985 | 384.090 |
| 0.695 | 1.075 | 13.200 | 0.000 | 0.000 | 0.000 | 20.859 | 557.844 | 391.772 |
| 0.626 | 0.967 | 13.200 | 0.000 | 0.000 | 0.000 | 17.453 | 575.298 | 397.615 |
| 0.563 | 0.871 | 13.200 | 0.000 | 0.000 | 0.000 | 14.388 | 589.686 | 401.995 |
| 0.507 | 0.784 | 13.200 | 0.000 | 0.000 | 0.000 | 11.629 | 601.315 | 405.214 |
| 0.456 | 0.705 | 13.200 | 0.000 | 0.000 | 0.000 | 9.146 | 610.461 | 407.516 |
| 16.365 | 25.306 | 191.400 | 0.000 | 0.000 | 0.000 | 610.461 | 610.461 | 407.516 |
| 1.550 | 2.396 | 59.400 | 0.000 | 0.000 | 0.000 | 16.536 | 626.997 | 410.984 |
| 17.914 | 27.702 | 250.800 | 0.000 | 0.000 | 0.000 | 626.997 | 626.997 | 410.984 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| | - | - | | | -- | |
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 19.50 | 5.00 | 497.302 |
| GROSS ULT., MB & MMF | 56.368 | 0.000 | DISCOUNT % | 10.00 | 8.00 | 441.693 |
| GROSS CUM., MB & MMF | 0.000 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 410.984 |
| GROSS RES., MB & MMF | 56.368 | 0.000 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 384.286 |
| NET RES., MB & MMF | 10.569 | 0.000 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 350.263 |
| NET REVENUE, M$ | 923.414 | 0.000 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 321.932 |
| INITIAL PRICE, $ | 87.370 | 0.000 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 244.481 |
| INITIAL N.I., PCT. | 18.750 | 0.000 | INITIAL W.I., PCT. | 25.000 | 60.00 | 156.170 |
| | | | | | 80.00 | 127.309 |
| | | | | | 260.00 | 51.841 |

LUKASSEN 44-18 NE TERRESTRIAL WY

| | | |
|---|---|---|
| DATE | : | 04/01/2013 |
| TIME | : | 14:03:16 |
| DBS | : | DEMO |
| SETTINGS | : | RED_JAN13 |
| SCENARIO | : | RED_JAN13 |

## R E S E R V E S   A N D   E C O N O M I C S

### AS OF DATE: 12/31/2012

| GROSS OIL PRODUCTION MBBLS | GROSS GAS PRODUCTION MMCF | NET OIL PRODUCTION MBBLS | NET GAS PRODUCTION MMCF | NET OIL PRICE $/BBL | NET GAS PRICE $/MCF | NET OIL SALES M$ | NET GAS SALES M$ | TOTAL NET SALES M$ |
|---|---|---|---|---|---|---|---|---|
| 5.387 | 0.000 | 1.010 | 0.000 | 87.370 | 0.000 | 88.246 | 0.000 | 88.246 |
| 7.474 | 0.000 | 1.401 | 0.000 | 87.370 | 0.000 | 122.439 | 0.000 | 122.439 |
| 5.653 | 0.000 | 1.060 | 0.000 | 87.370 | 0.000 | 92.600 | 0.000 | 92.600 |
| 4.722 | 0.000 | 0.885 | 0.000 | 87.370 | 0.000 | 77.352 | 0.000 | 77.352 |
| 4.132 | 0.000 | 0.775 | 0.000 | 87.370 | 0.000 | 67.689 | 0.000 | 67.689 |
| 3.704 | 0.000 | 0.694 | 0.000 | 87.370 | 0.000 | 60.677 | 0.000 | 60.677 |
| 3.334 | 0.000 | 0.625 | 0.000 | 87.370 | 0.000 | 54.610 | 0.000 | 54.610 |
| 3.000 | 0.000 | 0.563 | 0.000 | 87.370 | 0.000 | 49.149 | 0.000 | 49.149 |
| 2.700 | 0.000 | 0.506 | 0.000 | 87.370 | 0.000 | 44.234 | 0.000 | 44.234 |
| 2.430 | 0.000 | 0.456 | 0.000 | 87.370 | 0.000 | 39.810 | 0.000 | 39.810 |
| 2.187 | 0.000 | 0.410 | 0.000 | 87.370 | 0.000 | 35.829 | 0.000 | 35.829 |
| 1.968 | 0.000 | 0.369 | 0.000 | 87.370 | 0.000 | 32.246 | 0.000 | 32.246 |
| 1.772 | 0.000 | 0.332 | 0.000 | 87.370 | 0.000 | 29.022 | 0.000 | 29.022 |
| 1.594 | 0.000 | 0.299 | 0.000 | 87.370 | 0.000 | 26.120 | 0.000 | 26.120 |
| 1.435 | 0.000 | 0.269 | 0.000 | 87.370 | 0.000 | 23.508 | 0.000 | 23.508 |
| 51.492 | 0.000 | 9.655 | 0.000 | 87.370 | 0.000 | 843.532 | 0.000 | 843.532 |
| 4.876 | 0.000 | 0.914 | 0.000 | 87.370 | 0.000 | 79.882 | 0.000 | 79.882 |
| 56.368 | 0.000 | 10.569 | 0.000 | 87.370 | 0.000 | 923.414 | 0.000 | 923.414 |

| AD VALOREM TAX M$ | PRODUCTION TAX M$ | DIRECT OPER EXPENSE M$ | INTEREST PAID M$ | CAPITAL REPAYMENT M$ | EQUITY INVESTMENT M$ | FUTURE NET CASHFLOW M$ | CUMULATIVE CASHFLOW M$ | CUM. DISC. CASHFLOW M$ |
|---|---|---|---|---|---|---|---|---|
| 1.712 | 2.647 | 6.600 | 0.000 | 0.000 | 0.000 | 77.287 | 77.287 | 72.071 |
| 2.375 | 3.673 | 13.200 | 0.000 | 0.000 | 0.000 | 103.190 | 180.477 | 161.837 |
| 1.796 | 2.778 | 13.200 | 0.000 | 0.000 | 0.000 | 74.826 | 255.303 | 220.937 |
| 1.501 | 2.321 | 13.200 | 0.000 | 0.000 | 0.000 | 60.331 | 315.634 | 264.234 |
| 1.313 | 2.031 | 13.200 | 0.000 | 0.000 | 0.000 | 51.146 | 366.780 | 297.593 |
| 1.177 | 1.820 | 13.200 | 0.000 | 0.000 | 0.000 | 44.480 | 411.260 | 323.965 |
| 1.059 | 1.638 | 13.200 | 0.000 | 0.000 | 0.000 | 38.712 | 449.972 | 344.831 |
| 0.953 | 1.474 | 13.200 | 0.000 | 0.000 | 0.000 | 33.521 | 483.492 | 361.257 |
| 0.858 | 1.327 | 13.200 | 0.000 | 0.000 | 0.000 | 28.849 | 512.341 | 374.109 |
| 0.772 | 1.194 | 13.200 | 0.000 | 0.000 | 0.000 | 24.644 | 536.985 | 384.090 |
| 0.695 | 1.075 | 13.200 | 0.000 | 0.000 | 0.000 | 20.859 | 557.844 | 391.772 |
| 0.626 | 0.967 | 13.200 | 0.000 | 0.000 | 0.000 | 17.453 | 575.298 | 397.615 |
| 0.563 | 0.871 | 13.200 | 0.000 | 0.000 | 0.000 | 14.388 | 589.686 | 401.995 |
| 0.507 | 0.784 | 13.200 | 0.000 | 0.000 | 0.000 | 11.629 | 601.315 | 405.214 |
| 0.456 | 0.705 | 13.200 | 0.000 | 0.000 | 0.000 | 9.146 | 610.461 | 407.516 |
| 16.365 | 25.306 | 191.400 | 0.000 | 0.000 | 0.000 | 610.461 | 610.461 | 407.516 |
| 1.550 | 2.396 | 59.400 | 0.000 | 0.000 | 0.000 | 16.536 | 626.997 | 410.984 |
| 17.914 | 27.702 | 250.800 | 0.000 | 0.000 | 0.000 | 626.997 | 626.997 | 410.984 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 19.50 | 5.00 | 497.302 |
| GROSS ULT., MB & MMF | 56.368 | 0.000 | DISCOUNT % | 10.00 | 8.00 | 441.693 |
| GROSS CUM., MB & MMF | 0.000 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 410.984 |
| GROSS RES., MB & MMF | 56.368 | 0.000 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 384.286 |
| NET RES., MB & MMF | 10.569 | 0.000 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 350.263 |
| NET REVENUE, M$ | 923.414 | 0.000 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 321.932 |
| INITIAL PRICE, $ | 87.370 | 0.000 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 244.481 |
| INITIAL N.I., PCT. | 18.750 | 0.000 | INITIAL W.I., PCT. | 25.000 | 60.00 | 156.170 |

| | |
|---|---|
| 80.00 | 127.309 |
| 260.00 | 51.841 |

WILKE 44A-5
FIELD: WILKE
COUNTY: KIIMBALL STATE: NE
OPERATOR: RECOVERY ENERGY COMPA
3PUD

DATE : 04/01/2013
TIME : 14:03:16
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO : RED_JAN13

## R E S E R V E S A N D E C O N O M I C S

### AS OF DATE: 12/31/2012

| --END-- MO-YEAR | GROSS OIL PRODUCTION MBBLS | GROSS GAS PRODUCTION MMCF | NET OIL PRODUCTION MBBLS | NET GAS PRODUCTION MMCF | NET OIL PRICE $/BBL | NET GAS PRICE $/MCF | NET OIL SALES M$ | NET GAS SALES M$ | TOTAL NET SALES M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 12-2014 | 11.887 | 0.000 | 2.028 | 0.000 | 87.370 | 0.000 | 177.206 | 0.000 | 177.206 |
| 12-2015 | 11.212 | 0.000 | 1.913 | 0.000 | 87.370 | 0.000 | 167.150 | 0.000 | 167.150 |
| 12-2016 | 6.995 | 0.000 | 1.193 | 0.000 | 87.370 | 0.000 | 104.272 | 0.000 | 104.272 |
| 12-2017 | 4.706 | 0.000 | 0.803 | 0.000 | 87.370 | 0.000 | 70.158 | 0.000 | 70.158 |
| 12-2018 | 3.344 | 0.000 | 0.571 | 0.000 | 87.370 | 0.000 | 49.854 | 0.000 | 49.854 |
| 12-2019 | 2.477 | 0.000 | 0.423 | 0.000 | 87.370 | 0.000 | 36.919 | 0.000 | 36.919 |
| 12-2020 | 1.894 | 0.000 | 0.323 | 0.000 | 87.370 | 0.000 | 28.240 | 0.000 | 28.240 |
| 12-2021 | 1.487 | 0.000 | 0.254 | 0.000 | 87.370 | 0.000 | 22.170 | 0.000 | 22.170 |
| 12-2022 | 0.997 | 0.000 | 0.170 | 0.000 | 87.370 | 0.000 | 14.868 | 0.000 | 14.868 |
| 12-2023 | | | | | | | | | |
| 12-2024 | | | | | | | | | |
| 12-2025 | | | | | | | | | |
| 12-2026 | | | | | | | | | |
| 12-2027 | | | | | | | | | |
| S TOT | 45.000 | 0.000 | 7.678 | 0.000 | 87.370 | 0.000 | 670.838 | 0.000 | 670.838 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| TOTAL | 45.000 | 0.000 | 7.678 | 0.000 | 87.370 | 0.000 | 670.838 | 0.000 | 670.838 |

| -END-- IO-YEAR | AD VALOREM TAX M$ | PRODUCTION TAX M$ | DIRECT OPER EXPENSE M$ | INTEREST PAID M$ | CAPITAL REPAYMENT M$ | EQUITY INVESTMENT M$ | FUTURE NET CASHFLOW M$ | CUMULATIVE CASHFLOW M$ | CUM. DISC. CASHFLOW M$ |
|---|---|---|---|---|---|---|---|---|---|
| 12-2013 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 12-2014 | 3.438 | 5.316 | 8.800 | 0.000 | 0.000 | 0.000 | 159.652 | 159.652 | 136.536 |
| 12-2015 | 3.243 | 5.015 | 13.200 | 0.000 | 0.000 | 0.000 | 145.693 | 305.345 | 251.891 |
| 12-2016 | 2.023 | 3.128 | 13.200 | 0.000 | 0.000 | 0.000 | 85.921 | 391.267 | 313.703 |
| 12-2017 | 1.361 | 2.105 | 13.200 | 0.000 | 0.000 | 0.000 | 53.492 | 444.759 | 348.677 |
| 12-2018 | 0.967 | 1.496 | 13.200 | 0.000 | 0.000 | 0.000 | 34.191 | 478.950 | 368.997 |
| 12-2019 | 0.716 | 1.108 | 13.200 | 0.000 | 0.000 | 0.000 | 21.895 | 500.845 | 380.827 |
| 12-2020 | 0.548 | 0.847 | 13.200 | 0.000 | 0.000 | 0.000 | 13.645 | 514.490 | 387.532 |
| 12-2021 | 0.430 | 0.665 | 13.200 | 0.000 | 0.000 | 0.000 | 7.875 | 522.365 | 391.053 |
| 12-2022 | 0.288 | 0.446 | 11.000 | 0.000 | 0.000 | 0.000 | 3.134 | 525.498 | 392.340 |
| 12-2023 | | | | | | | | | |
| 12-2024 | | | | | | | | | |
| 12-2025 | | | | | | | | | |
| 12-2026 | | | | | | | | | |
| 12-2027 | | | | | | | | | |
| S TOT | 13.014 | 20.125 | 112.200 | 0.000 | 0.000 | 0.000 | 525.498 | 525.498 | 392.340 |
| AFTER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 525.498 | 392.340 |
| TOTAL | 13.014 | 20.125 | 112.200 | 0.000 | 0.000 | 0.000 | 525.498 | 525.498 | 392.340 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| | - | - | | | -- | |
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 9.83 | 5.00 | 451.098 |
| GROSS ULT., MB & MMF | 45.000 | 0.000 | DISCOUNT % | 10.00 | 8.00 | 414.269 |
| GROSS CUM., MB & MMF | 0.000 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 392.340 |
| GROSS RES., MB & MMF | 45.000 | 0.000 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 372.232 |
| NET RES., MB & MMF | 7.678 | 0.000 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 345.052 |
| NET REVENUE, M$ | 670.838 | 0.000 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 320.953 |
| INITIAL PRICE, $ | 87.370 | 0.000 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 247.302 |
| INITIAL N.I., PCT. | 17.062 | 0.000 | INITIAL W.I., PCT. | 25.000 | 60.00 | 148.445 |
| | | | | | 80.00 | 113.570 |
| | | | | | 260.00 | 28.068 |

MALM 32-34
FIELD: ALBIN WEST
COUNTY: LARAMIE STATE: WY
OPERATOR: RECOVERY ENERGY COMPA
3PUD

DATE : 04/01/2013
TIME : 14:03:16
DBS : DEMO
SETTINGS : RED_JAN13
SCENARIO : RED_JAN13

## R E S E R V E S A N D E C O N O M I C S

### AS OF DATE: 12/31/2012

| GROSS OIL RODUCTION MBBLS | GROSS GAS PRODUCTION MMCF | NET OIL PRODUCTION MBBLS | NET GAS PRODUCTION MMCF | NET OIL PRICE $/BBL | NET GAS PRICE $/MCF | NET OIL SALES M$ | NET GAS SALES M$ | TOTAL NET SALES M$ |
|---|---|---|---|---|---|---|---|---|
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 18.417 | 0.000 | 3.637 | 0.000 | 87.370 | 0.000 | 317.801 | 0.000 | 317.801 |
| 11.533 | 0.000 | 2.278 | 0.000 | 87.370 | 0.000 | 199.011 | 0.000 | 199.011 |
| 7.781 | 0.000 | 1.537 | 0.000 | 87.370 | 0.000 | 134.263 | 0.000 | 134.263 |
| 5.540 | 0.000 | 1.094 | 0.000 | 87.370 | 0.000 | 95.596 | 0.000 | 95.596 |
| 4.109 | 0.000 | 0.812 | 0.000 | 87.370 | 0.000 | 70.903 | 0.000 | 70.903 |
| 3.147 | 0.000 | 0.622 | 0.000 | 87.370 | 0.000 | 54.301 | 0.000 | 54.301 |
| 2.473 | 0.000 | 0.488 | 0.000 | 87.370 | 0.000 | 42.673 | 0.000 | 42.673 |
| 1.985 | 0.000 | 0.392 | 0.000 | 87.370 | 0.000 | 34.256 | 0.000 | 34.256 |
| 1.622 | 0.000 | 0.320 | 0.000 | 87.370 | 0.000 | 27.992 | 0.000 | 27.992 |
| 1.346 | 0.000 | 0.266 | 0.000 | 87.370 | 0.000 | 23.223 | 0.000 | 23.223 |
| 1.131 | 0.000 | 0.223 | 0.000 | 87.370 | 0.000 | 19.518 | 0.000 | 19.518 |
| 0.961 | 0.000 | 0.190 | 0.000 | 87.370 | 0.000 | 16.591 | 0.000 | 16.591 |
| 0.564 | 0.000 | 0.111 | 0.000 | 87.370 | 0.000 | 9.727 | 0.000 | 9.727 |
| 60.610 | 0.000 | 11.970 | 0.000 | 87.370 | 0.000 | 1045.854 | 0.000 | 1045.854 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 60.610 | 0.000 | 11.970 | 0.000 | 87.370 | 0.000 | 1045.854 | 0.000 | 1045.854 |

| AD VALOREM TAX M$ | PRODUCTION TAX M$ | DIRECT OPER EXPENSE M$ | INTEREST PAID M$ | CAPITAL REPAYMENT M$ | EQUITY INVESTMENT M$ | FUTURE NET CASHFLOW M$ | CUMULATIVE CASHFLOW M$ | CUM. DISC. CASHFLOW M$ |
|---|---|---|---|---|---|---|---|---|
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 6.165 | 9.534 | 13.200 | 0.000 | 0.000 | 0.000 | 288.901 | 288.901 | 251.563 |
| 3.861 | 5.970 | 13.200 | 0.000 | 0.000 | 0.000 | 175.980 | 464.881 | 390.783 |
| 2.605 | 4.028 | 13.200 | 0.000 | 0.000 | 0.000 | 114.430 | 579.311 | 473.047 |
| 1.855 | 2.868 | 13.200 | 0.000 | 0.000 | 0.000 | 77.674 | 656.985 | 523.797 |
| 1.376 | 2.127 | 13.200 | 0.000 | 0.000 | 0.000 | 54.201 | 711.186 | 555.986 |
| 1.053 | 1.629 | 13.200 | 0.000 | 0.000 | 0.000 | 38.418 | 749.604 | 576.726 |
| 0.828 | 1.280 | 13.200 | 0.000 | 0.000 | 0.000 | 27.365 | 776.969 | 590.156 |
| 0.665 | 1.028 | 13.200 | 0.000 | 0.000 | 0.000 | 19.363 | 796.333 | 598.796 |
| 0.543 | 0.840 | 13.200 | 0.000 | 0.000 | 0.000 | 13.409 | 809.742 | 604.237 |
| 0.451 | 0.697 | 13.200 | 0.000 | 0.000 | 0.000 | 8.875 | 818.617 | 607.512 |
| 0.379 | 0.586 | 13.200 | 0.000 | 0.000 | 0.000 | 5.354 | 823.971 | 609.310 |
| 0.322 | 0.498 | 13.200 | 0.000 | 0.000 | 0.000 | 2.571 | 826.542 | 610.097 |
| 0.189 | 0.292 | 8.800 | 0.000 | 0.000 | 0.000 | 0.446 | 826.989 | 610.224 |
| 20.290 | 31.376 | 167.200 | 0.000 | 0.000 | 0.000 | 826.989 | 826.989 | 610.224 |
| 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 826.989 | 610.224 |
| 20.290 | 31.376 | 167.200 | 0.000 | 0.000 | 0.000 | 826.989 | 826.989 | 610.224 |

| | OIL | GAS | | | P.W. % | P.W., M$ |
|---|---|---|---|---|---|---|
| GROSS WELLS | 1.0 | 0.0 | LIFE, YRS. | 13.67 | 5.00 | 704.105 |

| | | | | | | |
|---|---|---|---|---|---|---|
| GROSS ULT., MB & MMF | 60.610 | 0.000 | DISCOUNT % | 10.00 | 8.00 | 644.949 |
| GROSS CUM., MB & MMF | 0.000 | 0.000 | UNDISCOUNTED PAYOUT, YRS. | 0.00 | 10.00 | 610.224 |
| GROSS RES., MB & MMF | 60.610 | 0.000 | DISCOUNTED PAYOUT, YRS. | 0.00 | 12.00 | 578.694 |
| NET RES., MB & MMF | 11.970 | 0.000 | UNDISCOUNTED NET/INVEST. | 0.00 | 15.00 | 536.526 |
| NET REVENUE, M$ | 1045.854 | 0.000 | DISCOUNTED NET/INVEST. | 0.00 | 18.00 | 499.548 |
| INITIAL PRICE, $ | 87.370 | 0.000 | RATE-OF-RETURN, PCT. | 260.00 | 30.00 | 388.582 |
| INITIAL N.I., PCT. | 19.750 | 0.000 | INITIAL W.I., PCT. | 25.000 | 60.00 | 242.569 |
| | | | | | 80.00 | 190.922 |
| | | | | | 260.00 | 57.542 |

**RALPH E. DAVIS ASSOCIATES, INC.**
Texas Registered Engineering Firm F-1529

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# Certificate of Qualifications

RALPH E. DAVIS
ASSOCIATES, INC.

# CERTIFICATE OF QUALIFICATION

I, Allen C. Barron, of 1717 St. James Place, Suite 460, Houston, Texas 77056 hereby certify:

1. I am an employee of Ralph E. Davis Associates, Inc., that has prepared an estimate of the oil and natural gas reserves on specific leaseholds in which Recovery Energy Company, Inc. has certain interests. The effective date of this evaluation is December 31, 2012.

2. I am Licensed Professional Engineer by the State of Texas, P.E. License number 48284.

3. I attended the University of Houston in Houston, Texas and graduated with a Bachelor of Science Degree in Chemical Engineering with a Petroleum Engineering option in 1968. I have in excess of forty-four years experience in the Petroleum Industry of which over thirty-four years of experience are in the conduct of evaluation and engineering studies relating to both domestic U.S. oil and gas fields and international energy assets.

4. I have prepared reserve evaluation studies and reserve audits for public and private companies for the purpose of reserve certification filings in foreign countries, domestic regulatory filings, financial disclosures and corporate strategic planning. I personally supervised and participated in the evaluation of the Recovery Energy Company, Inc. properties that are the subject of this report.

5. I do not have, nor do I expect to receive, any direct or indirect interest in the securities of Recovery Energy Company, Inc. or any affiliated companies.

6. A personal field inspection of the properties was not made, however, such an inspection was not considered necessary in view of the information available from public information, records and the files of the operator of the properties.

SIGNED: April 3, 2013

/s/ Allen C. Barron

Allen C. Barron, P.E.
President
Ralph E. Davis Associates, Inc.