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

FORM 10-K

(Mark One)
☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended February 28, 2011

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

For the transition period from ______ to _______

Commission file number 000-50107

DAYBREAK OIL AND GAS, INC.

(Exact name of registrant as specified in its charter)

Washington	**91-0626366**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
601 W. Main Ave., Suite 1012, Spokane, WA	**99201**
(Address of principal executive offices)	(Zip code)

Registrant's telephone number, including area code: **(509) 232-7674**

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

Securities registered pursuant to Section 12(g) of the Exchange Act: Common Stock, $.001 par value

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the 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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

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

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

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

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

The aggregate market value of the voting and non-voting stock held by non-affiliates of the registrant, based on the closing price of $0.0845 on August 31, 2010, as reported by the Over-the-Counter Bulletin Board was $3,658,312.

At May 26, 2011, the registrant had 48,791,599 outstanding shares of $0.001 par value common stock.

DOCUMENTS INCORPORATED BY REFERENCE:

Part III of this Form 10-K incorporates by reference certain portions of the registrant's definitive proxy statement on Schedule 14A, which will be filed with the Commission not later than 120 days after the close of the fiscal year covered by this report on Form 10-K, or if the Registrant's Schedule 14A is not filed within such period, will be included in an amendment to this Report on Form 10-K which will be filed within such 120 day period.

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

This annual report on Form 10-K contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These forward-looking statements are based on our current expectations, assumptions, estimates and projections for the future of our business and our industry and are not statements of historical fact. Words such as "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "plan," "predict," "project," "will" and similar expressions identify forward-looking statements. Examples of forward-looking statements include statements about the following:

- Our future operating results,
- Our future capital expenditures,
- Our expansion and growth of operations, and
- Our future investments in and acquisitions of oil and natural gas properties.

We have based these forward-looking statements on assumptions and analyses made in light of our experience and our perception of historical trends, current conditions, and expected future developments. However, you should be aware that these forward-looking statements are only our predictions and we cannot guarantee any such outcomes. Future events and actual results may differ materially from the results set forth in or implied in the forward-looking statements. Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, the following risks and uncertainties:

- General economic and business conditions,
- Exposure to market risks in our financial instruments,
- Fluctuations in worldwide prices and demand for oil and natural gas,
- Fluctuations in the levels of our oil and natural gas exploration and development activities,
- Our ability to find, acquire and develop oil and gas properties,
- Risks associated with oil and natural gas exploration and development activities,
- Competition for raw materials and customers in the oil and natural gas industry,
- Technological changes and developments in the oil and natural gas industry,
- Legislative and regulatory uncertainties, including proposed changes to federal tax law and climate change legislation, and potential environmental liabilities,
- Our ability to continue as a going concern,
- Our ability to secure additional capital to fund operations, and
- Other factors discussed elsewhere in this Form 10-K and in our other public filings, press releases, and discussions with Company management.

Should one or more of the risks or uncertainties described above or elsewhere in this Form 10-K occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically undertake no obligation to publicly update or revise any information contained in a forward-looking statement or any forward-looking statement in its entirety, whether as a result of new information, future events, or otherwise, except as required by law.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

PART I

ITEM 1. BUSINESS

Historical Background

Daybreak Oil and Gas, Inc. (referred to herein as “we,” “our,” “Daybreak” or the “Company”) was originally incorporated in the State of Washington on March 11, 1955 as Daybreak Uranium, Inc. The Company was established for the purpose of mineral exploration and development on claims or leased lands throughout the Western United States. In August 1955, we acquired the assets of Morning Sun Uranium, Inc. By the late 1950s, we had ceased to be a producing mining company and thereafter engaged in mineral exploration only. In May 1964, to reflect the diversity of our mineral holdings, we changed our name to Daybreak Mines, Inc. By February 1967, we had ceased all exploration operations. After that time, our activities were confined to annual assessment and maintenance work on our Idaho mineral properties and other general and administrative functions. In November 2004, we sold our last remaining mineral rights covering approximately 340 acres in Shoshone County, Idaho.

Effective March 1, 2005, we undertook a new business direction for the Company; that of an exploration and development company in the oil and gas industry. In October of 2005, to better reflect this new direction of the Company, our shareholders approved changing our name to Daybreak Oil and Gas, Inc. Our Common Stock is quoted on the OTC Bulletin Board (OTC:BB) market under the symbol DBRM.OB.

Our corporate office is located at 601 W. Main Ave., Suite 1012, Spokane, Washington 99201-0613. Our telephone number is (509) 232-7674. Our regional operations office is located at 1414 S. Friendswood Dr., Suite 215, Friendswood, Texas 77546. The telephone number of our office in Friendswood is (281) 996-4176.

Oil and Gas Overview

Our focus is to pursue oil and gas drilling opportunities through joint ventures with industry partners as a means of limiting our drilling risk. Prospects are generally brought to us by other oil and gas companies or individuals. We identify and evaluate prospective oil and gas properties to determine both the degree of risk and the commercial potential of the project. We seek projects that offer a mix of low risk with a potential of steady reliable revenue as well as projects with a higher risk, but that may also have a larger return. We strive to use modern 3-D seismic technology to help us identify potential oil and gas reservoirs and to mitigate our risk. We seek to maximize the value of our asset base by exploring and developing properties that have both production and reserve growth potential.

In some instances, we strive to be operator of our oil and gas properties. As the operator, we are more directly in control of the timing, costs of drilling, completion and production operations on our projects.

Competition

We compete with independent oil and gas companies for exploration prospects, property acquisitions and for the equipment and labor required to operate and develop these properties. Many of our competitors have substantially greater financial and other resources than we have. These competitors may be able to pay more for exploratory prospects and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can.

We conduct all of our drilling, exploration and production activities onshore in the United States. All of our oil and gas assets are located in the United States and all of our revenues are from sales to customers within the United States.

Significant Customers

At our property locations with continuing operations in California and discontinued operations in Alabama, we have oil and gas sales contracts with one dominant purchaser in each respective area. If these purchasers are unable to resell their products or if they lose a significant sales contract then we may incur difficulties in selling our oil and gas. The price we receive for oil sales is based on prices quoted on the New York Mercantile Exchange ("NYMEX") for spot West Texas Intermediate ("WTI") contracts, less deductions which vary by grade of crude oil sold. For the years ended February 28, 2011 and 2010, the monthly average discount from WTI pricing on oil sales in California was 7.9% and 11.7% respectively. At February 28, 2011, one customer represented 100.0% of crude oil and natural gas sales receivables.

The revenue from any single customer that exceeds 10% of total revenue is set forth in the table below.

			For the Year Ended February 28, 2011		For the Year Ended February 28, 2010	
Project	**Location**	**Customer**	**Revenue**	**Percentage**	**Revenue**	**Percentage**
East Slopes	California	Plains Marketing	$ 975,479	90.4%	$ 469,357	84.5%
Gilbertown*	Alabama	Hunt Crude Oil Supply	$ -0-	-0-%	$ 84,353	15.2%

*Discontinued operation, we did not have any revenue from the East Gilbertown Field during the year ended February 28, 2011.

Title to Properties

As is customary in the oil and natural gas industry, we make only a cursory review of title to undeveloped oil and natural gas leases at the time we acquire them. However, before drilling operations commence, we search the title, and remedy material defects, if any, before we actually begin drilling the well. To the extent title opinions or other investigations reflect title defects, we (rather than the seller or lessor of the undeveloped property) typically are obligated to cure any such title defects at our expense. If we are unable to remedy or cure any title defects, so that it would not be prudent for us to commence drilling operations on the property, we could suffer a loss of our entire investment in the property. We believe that we have good title to our oil and natural gas properties, some of which are subject to immaterial encumbrances, easements, and restrictions.

Regulation

The exploration and development of oil and gas properties are subject to various types of federal, state and local laws and regulations. These laws and regulations govern a wide range of matters, including the drilling and spacing of wells, allowable rates of production, restoration of surface areas, plugging and abandonment of wells and specific requirements for the operation of wells. Failure to comply with such laws and regulations can result in substantial penalties.

Laws and regulations relating to our business frequently change so we are unable to predict the future cost or impact of complying with such laws. Future laws and regulations, including changes to existing laws and regulations, could adversely affect our business. These regulatory burdens generally do not affect us any differently than they affect other companies in our industry with similar types, quantities and locations of production.

Operational Hazards and Insurance

Our operations are subject to the usual hazards incident to the drilling and production of oil and gas, such as blowouts, cratering, explosions, uncontrollable flows of oil, gas or well fluids, fires and pollution and other environmental risks. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operation. In addition, the presence of unanticipated pressures or irregularities in formations, miscalculations, or accidents may cause our drilling activities to be unsuccessful and result in a total loss of our investment.

We maintain insurance of various types to cover our operations with policy limits and retention liability customary in the industry. We believe the coverage and types of insurance we maintain are adequate. The occurrence of a significant adverse event, the risks of which are not fully covered by insurance, could have a material adverse effect on our financial condition and results of operations. We cannot give any assurances that we will be able to maintain adequate insurance in the future at rates we consider reasonable.

Employees and Consultants

At February 28, 2011, we had six full-time employees and one part-time employee. Additionally, we regularly use the services of three consultants on an as-needed basis for accounting, technical, oil field, geological, and administrative services. None of our employees are subject to a collective bargaining agreement. In our opinion, relations with our employees are good. We may hire more employees in the next fiscal year as needed. All other services are currently contracted for with independent contractors. We have not obtained "key man" life insurance on any of our officers or directors.

Long Term Success

Our success depends on the successful acquisition, exploration and development of commercial grade oil and gas properties as well as the prevailing prices for oil and natural gas to generate future revenues and operating cash flow. Oil and natural gas prices have been extremely volatile in recent years and are affected by many factors outside of our control. The volatile nature of the energy markets makes it difficult to estimate future prices of oil and natural gas; however, any prolonged period of depressed prices would have a material adverse effect on our results of operations and financial condition. Such pricing factors are largely beyond our control, and may result in fluctuations in our earnings. We believe there are significant opportunities available to us in the oil and gas exploration and development industry.

Availability of SEC Filings

You may read and copy any materials we file with the U.S. Securities and Exchange Commission (the "SEC") at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549, on official business days during the hours of 10:00 am to 3:00 pm. You can obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. The address of that site is http://www.sec.gov.

Website / Available Information

Our website can be found at www.daybreakoilandgas.com. Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed with or furnished to the SEC, pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 ("the Exchange Act") can be accessed free of charge on our web site at www.daybreakoilandgas.com under the "Shareholder/Financial" section of our web site within the "SEC Filings" subsection as soon as is reasonably practicable after we electronically file such material with, or otherwise furnish it to, the SEC.

We have adopted an Ethical Business Conduct Policy Statement to provide guidance to our directors, officers and employees on matters of business conduct and ethics, including compliance standards and procedures. We also have adopted a Code of Ethics for Senior Financial Officers that applies to our principal executive officer, principal financial officer, principal accounting officer and controller. Our Ethical Business Conduct Policy Statement and Code of Ethics for Senior Financial Officers are available under the "Shareholder/Financial" section of our web site at www.daybreakoilandgas.com within the heading "Corporate Governance." We intend to promptly disclose via a Current Report on Form 8-K or via an update to our web site, information on any amendment to or waiver of these codes with respect to our executive officers and directors. Waiver information disclosed via the web site will remain on the web site for at least 12 months after the initial disclosure of a waiver.

Our Corporate Governance Guidelines and the charters of our Audit Committee, Nominating and Corporate Governance Committee, and Compensation Committee are also available in the "Shareholder/Financial" section of our web site at www.daybreakoilandgas.com within the heading "Corporate Governance." In addition, copies of our Ethical Business Conduct Policy Statement, Code of Ethics for Senior Financial Officers, Corporate Governance Guidelines and the charters of the Committees referenced above are available at no cost to any shareholder who requests them by writing or telephoning us at the following address or telephone number:

Daybreak Oil and Gas, Inc.
601 W. Main Ave., Suite 1012
Spokane, WA 99201-0613
Attention: Corporate Secretary
Telephone: (509) 232-7674

Information contained on or connected to our web site is not incorporated by reference into this Annual Report on Form 10-K and should not be considered part of this report or any other filing that we make with the SEC.

ITEM 1A. RISK FACTORS

The following risk factors together with other information set forth in this Annual Report on Form 10-K, should be carefully considered by current and future investors in our securities. An investment in our securities involves substantial risks. If any of the following risks actually occur, our financial condition and our results of operations could be materially and adversely affected. Additional risks and uncertainties not presently known to us may also impair our business operations. In any such case, the trading price of our Common Stock could decline, and you could lose all, or a part, of your investment.

We have a limited operating history on which to base an investment decision.

We have a limited history of oil and gas production and have minimal proven reserves. To date, while we have positive cash flow from our continuing operations in California, we have not yet generated sustainable positive cash flow or earnings on a company-wide basis. We cannot provide any assurances that we will ever operate profitability. As a result of our limited operating history, we are more susceptible to business risks. These risks include unforeseen capital requirements, failure to establish business relationships, and competitive disadvantages against larger and more established companies.

The oil and gas business is highly competitive, placing Daybreak at an operating disadvantage.

We expect to be at a competitive disadvantage in (a) seeking to acquire suitable oil and or gas drilling prospects; (b) undertaking exploration and development; and (c) seeking additional financing. We base our preliminary decisions regarding the acquisition of oil and or gas prospects and undertaking of drilling ventures upon general and inferred geology and economic assumptions. This public information is also available to our competitors.

In addition, we compete with large oil and gas companies with longer operating histories and greater financial resources than us. These larger competitors, by reason of their size and greater financial strength, can more easily:

- access capital markets;
- recruit more qualified personnel;
- absorb the burden of any changes in laws and regulation in applicable jurisdictions;
- handle longer periods of reduced prices of gas and oil;
- acquire and evaluate larger volumes of critical information;
- compete for industry-offered business ventures.

These disadvantages could create negative results for our business plan and future operations.

Oil and gas prices are volatile. Declines in commodity prices in the past have adversely affected, and in the future may adversely affect, our financial condition, liquidity, results of operations, cash flows, access to capital markets, and ability to grow.

Our revenues, operating results, liquidity, cash flows, profitability and valuation of proved reserves depend substantially upon the market prices of oil and natural gas. Product prices affect our cash flow available for capital expenditures and our ability to access funds through the capital markets. If commodity prices decline in the future, the decline could have adverse effects on our reserves and availability of funds.

The prices we receive for our oil and natural gas depend upon factors beyond our control, including among others:

- changes in the supply of and demand for oil and natural gas
- market uncertainty
- the level of consumer product demands

- hurricanes and other weather conditions
- domestic governmental regulations and taxes
- the foreign supply of oil and natural gas
- overall domestic and foreign economic conditions.

These factors make it very difficult to predict future commodity price movements with any certainty. Oil prices and natural gas prices do not necessarily fluctuate in direct relation to each other.

Our ability to reach and maintain profitable operating results is dependant on our ability to find, acquire, and develop oil and gas properties.

Our future performance depends upon our ability to find, acquire, and develop oil and gas reserves that are economically recoverable. Without successful exploration and acquisition activities, we will not be able to develop reserves or generate production revenues to achieve and maintain profitable operating results. No assurance can be given that we will be able to find, acquire or develop these reserves on acceptable terms. We also cannot assure that commercial quantities of oil and gas deposits will be discovered that are sufficient to enable us to recover our exploration and development costs. Although certain management personnel have significant experience in the oil and gas industry, we have not yet established a history of locating and developing properties that have economically feasible oil and gas reserves.

Our oil and gas exploration and production, and related activities are subject to extensive environmental regulations, and to laws that can give rise to substantial liabilities from environmental contamination.

Our operations are subject to extensive federal, state and local environmental laws and regulations, which impose limitations on the discharge of pollutants into the environment, establish standards for the management, treatment, storage, transportation and disposal of hazardous materials and of solid and hazardous wastes, and impose obligations to investigate and remediate contamination in certain circumstances. Liabilities to investigate or remediate contamination, as well as other liabilities concerning hazardous materials or contamination such as claims for personal injury or property damage, may arise at many locations, including properties in which we have an ownership interest but no operational control, properties we formerly owned or operated, and sites where our wastes have been treated or disposed of, as well as at properties that we currently own or operate. Such liabilities may arise even where the contamination does not result from any noncompliance with applicable environmental laws. Under a number of environmental laws, such liabilities may also be joint and several, meaning that we could be held responsible for more than our share of the liability involved, or even the entire share. Environmental requirements generally have become more stringent in recent years, and compliance with those requirements more expensive.

We have incurred expenses in connection with environmental compliance, and we anticipate that we will continue to do so in the future. Failure to comply with extensive applicable environmental laws and regulations could result in significant civil or criminal penalties and remediation costs. Some of our properties may be affected by environmental contamination that may require investigation or remediation. In addition, claims are sometimes made or threatened against companies engaged in oil and gas exploration and production by owners of surface estates, adjoining properties or others alleging damage resulting from environmental contamination and other incidents of operation. Compliance with, and liabilities for remediation under, these laws and regulations, and liabilities concerning contamination or hazardous materials, may adversely affect our business, financial condition and results of operations.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of proposed legislation.

Legislation has been proposed that would, if enacted into law, make significant changes to United States federal income tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to: (1) the repeal of the percentage depletion allowance for oil and natural gas properties, (2) the elimination of current deductions for intangible drilling and development costs, (3) the elimination of the deduction for certain domestic production activities, and (4) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any such changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this legislation or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively impact the value of an investment in our Common Stock as well as affect our financial condition and results of operations.

The adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for the oil we produce.

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 federal Clean Air Act. The EPA's rules relating to emissions of greenhouse gases from large stationary sources of emissions are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent the EPA from implementing, or requiring state environmental agencies to implement, the rules. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States including petroleum refineries, as well as certain onshore oil and natural gas production facilities.

Moreover, 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 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. Although our current facilities are not subject to the EPA's greenhouse gases reporting rules, the EPA has indicated that it is evaluating whether the rule should be applied to oil and gas production activities, perhaps on a field-wide basis.

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 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.

To execute our business plan we will need to develop current projects and expand our operations requiring significant capital expenditures which we may be unable to fund.

We have a history of net losses and expect that our operating losses will continue over the next 12 months as we continue to implement our business plan. Our business plan contemplates the development of our current exploration projects and the expansion of our business by identifying, acquiring, and developing additional oil and gas properties.

We need to rely on external sources of financing to meet the capital requirements associated with the development of our current properties and the expansion of our oil and gas operations. We plan to obtain the funding we need through debt and equity markets. There is no assurance that we will be able to obtain additional funding when it is required or that it will be available to us on commercially acceptable terms.

We may make offers to acquire oil and gas properties in the ordinary course of our business. If these offers are accepted, our capital needs will increase substantially. If we fail to obtain the funding that we need when it is required, we may have to forego or delay potentially valuable opportunities to acquire new oil and gas properties. In addition, without the necessary funding, we may default on existing funding commitments to third parties and forfeit or dilute our rights in existing oil and gas property interests.

When we make the determination to invest in oil or gas properties we rely upon geological and engineering estimates which involve a high level of uncertainty.

Geologic and engineering data are used to determine the probability that a reservoir of oil or natural gas exists at a particular location. This data is also used to determine whether oil and natural gas are recoverable from a reservoir. Recoverability is ultimately subject to the accuracy of data including, but not limited to, geological characteristics of the reservoir, structure, reservoir fluid properties, the size and boundaries of the drainage area, reservoir pressure, and the anticipated rate of pressure depletion. Also the increasing costs of production operations may render some deposits uneconomic to extract.

The evaluation of these and other factors is based upon available seismic data, computer modeling, well tests and information obtained from production of oil and natural gas from adjacent or similar properties. There is a high degree of risk in proving the existence and recoverability of reserves. Actual recoveries of proved reserves can differ materially from original estimates. Accordingly, reserve estimates may be subject to downward adjustment. Actual production, revenue and expenditures will likely vary from estimates, and such variances may be material.

Our financial condition will deteriorate if we are unable to retain our interests in our leased oil and gas properties.

All of our properties are held under interests in oil and gas mineral leases. If we fail to meet the specific requirements of any lease, such lease may be terminated or otherwise expire. We cannot be assured that we will be able to meet our obligations under each lease. The termination or expiration of our "working interests" (interests created by the execution of an oil and gas lease) relating to these leases would impair our financial condition and results of operations.

We will need significant additional funds to meet capital calls, drilling and other production costs in our effort to explore, produce, develop and sell the natural gas and oil produced by our leases. We may not be able to obtain any such additional funds on acceptable terms.

Title deficiencies could render our oil and gas leases worthless; thus damaging the financial condition of our business.

The existence of a material title deficiency can render a lease worthless, resulting in a large expense to our business. We rely upon the judgment of oil and gas lease brokers who perform the field work and examine records in the appropriate governmental office before attempting to place a specific mineral interest under lease. This is a customary practice in the oil and gas industry.

We anticipate that we, or the person or company acting as "operator" (the individual or company responsible for the exploration, exploitation and production of an oil or natural gas well or lease, usually pursuant to the terms of a joint operating agreement among the various parties owning the working interest in the well) on the properties that we lease, will examine title prior to any well being drilled. Even after taking these precautions, deficiencies in the marketability of the title to the leases may still arise. Such deficiencies may render some leases worthless, negatively impacting our financial condition.

If we as operators, or the operator of our oil and gas projects fail to maintain adequate insurance, our business could be exposed to significant losses.

Our oil and gas projects are subject to risks inherent in the oil and gas industry. These risks involve explosions, uncontrollable flows of oil, gas or well fluids, pollution, fires, earthquakes and other environmental issues. These risks could result in substantial losses due to injury and loss of life, severe damage to and destruction of property and equipment, pollution and other environmental damage. As protection against these operating hazards we maintain insurance coverage to include physical damage and comprehensive general liability. However, we are not fully insured in all aspects of our business. The occurrence of a significant event on any project against which we are not adequately covered by insurance could have a material adverse effect on our financial position.

In the projects in which we are not the operator, we require the operator to maintain insurance of various types to cover our operations with policy limits and retention liability customary in the industry. The occurrence of a significant adverse event on any of these projects if they are not fully covered by insurance could result in the loss of all or part of our investment. The loss of any such project investment could have a material adverse effect on our financial condition and results of operations.

We may lose key management personnel which could endanger the future success of our oil and gas operations.

Our President and Chief Executive Officer, who is also acting as our interim principal finance and accounting officer; our Senior Vice-President, Exploration and two directors each have substantial experience in the oil and gas business. The loss of any of these individuals, could adversely affect our business. If one or more members of our management team dies, becomes disabled or voluntarily terminates employment with us, there is no assurance that a suitable or comparable substitute will be found.

We may be unable to continue as a going concern in which case our securities will have little or no value.

Our financial statements for the year ended February 28, 2011 were prepared on a going concern basis, which contemplates the realization of assets and the settlement of liabilities in the normal course of business. We have incurred net losses since inception which raises substantial doubt about our ability to continue as a going concern. In the event we are not able to continue operations, an investor will likely suffer a complete loss of their investment in our securities.

We have experienced significant operating losses in the past and there can be no assurance that we will become profitable in the future.

We have reported a net loss of approximately $1,215,747 for the year ended February 28, 2011, and we have an accumulated deficit through February 28, 2011 of $22,406,909. Without successful exploration and development of our properties any investment in Daybreak could become devalued or worthless.

In the past, we have disclosed material weakness in our internal controls and procedures which could erode investor confidence, jeopardize our ability to obtain insurance and limit our ability to attract qualified persons to serve at Daybreak.

As of the end of the reporting period, February 28, 2011, an evaluation was conducted by Daybreak management, including our Chief Executive Officer, also serving as our interim principal finance and accounting officer, as to the effectiveness of the design and operation of our internal controls over financial reporting pursuant to Rule 13a-15(e) of the Exchange Act. Based on that evaluation, our management concluded that our internal controls over financial reporting were effective as of February 28, 2011.

When the evaluation of our internal controls over financial reporting was conducted for the year ended February 28, 2009, a determination was made that our internal controls were not effective as of that date. This evaluation is more fully described in our Annual Report on Form 10-K for the year ended February 28, 2009.

We have since initiated the following changes in our internal control over financial reporting:

- developed an additional level of authoritative accounting resource and review to be used in the recognition of extraordinary non-cash transactions;
- additional training was designed to reinforce existing resources;
- management added an additional level of oversight for approval of non-routine non-cash transactions; and
- a third party was engaged to assist in efforts to document and test financial reporting controls.

Failure to comply with rules regarding internal controls and procedures may make it more difficult for us to obtain certain types of insurance, including director and officer liability insurance. We may be forced to accept reduced policy limits and coverage and/or incur substantially higher costs to obtain the same or similar coverage. The impact of these events could also make it more difficult for us to attract and retain qualified persons to serve on our Board of Directors, on committees of our Board of Directors, or as executive officers.

The market price of our Common Stock could be volatile, which may cause the investment value of our stock to decline.

Our Common Stock is quoted on the Over-the-Counter Bulletin Board (OTC:BB) market under the symbol DBRM.OB.

The Bulletin Board market is characterized by low trading volume. Because of this limited liquidity, shareholders may be unable to sell their shares at or above the cost of their purchase prices. The trading price of our shares has experienced wide fluctuations and these shares may be subject to similar fluctuations in the future.

The trading price of our Common Stock may be affected by a number of factors including events described in these risk factors, as well as our operating results, financial condition, announcements of drilling activities, general conditions in the oil and gas exploration and development industry, and other events or factors.

In recent years, broad stock market indices, in general, and smaller capitalization companies, in particular, have experienced substantial price fluctuations. In a volatile market, we may experience wide fluctuations in the market price of our Common Stock. These fluctuations may have a negative effect on the market price of our Common Stock.

Pursuant to SEC rules our Common Stock is classified as a "penny stock' increasing the risk of investment in these shares.

Our Common Stock is designated as a "penny stock" and thus may be more illiquid than shares traded on an exchange or on NASDAQ. Penny stocks generally are any non-NASDAQ or non-exchange listed equity securities with a price of less than $5.00, subject to certain exceptions.

The "penny stock" reporting and disclosure requirements may have the effect of reducing the level of trading activity in the secondary market for a stock that is subject to these rules. The market liquidity for the shares could be severely and adversely affected by limiting the ability of broker-dealers to sell these shares.

The resale of shares offered in private placements could depress the value of the shares.

Shares of our Common Stock have been offered and sold in private placements at significant discounts to the trading price of the Common Stock at the time of the offering. Sales of substantial amounts of Common Stock eligible for future sale in the public market, or the availability of shares for sale, including shares issued upon exercise of outstanding warrants, could adversely affect the prevailing market price of our Common Stock and our ability to raise capital by an offering of equity securities.

Privately placed issuances of our Common Stock, preferred stock and warrants have and may continue to dilute ownership interests which could have an adverse effect on our stock prices.

Our authorized capital stock consists of 200,000,000 shares of Common Stock and 10,000,000 shares of preferred stock. As of February 28, 2011, there were 48,791,599 shares of Common Stock and 906,565 shares of Series A Convertible Preferred stock outstanding.

Historically we have, and likely will continue to issue additional shares of our Common Stock in connection with the compensation of personnel, future acquisitions, private placements, or for other business purposes. Future issuances of substantial amounts of these equity securities could have a material adverse effect on the market price of our Common Stock, and would result in further dilution of the ownership interests of our existing shareholders.

Preferred Stock has been issued with greater rights than the Common Stock issued which may dilute and depress the investment value of the Common Stock investments.

The Board of Directors has the power to issue shares without shareholder approval, and such shares can be issued with such rights, preferences, and limitations as may be determined by our Board of Directors.

The rights of the holders of Common Stock are subject to and may be adversely affected by the rights and preferences afforded to the holders of these preferred shares. The rights and preferences of the issued preferred shares include:

- conversion into Common Stock of the Company anytime the preferred shareholder may wish;
- cumulative dividends in the amount of 6% of the original purchase price per annum, payable upon declaration by the board of directors;
- the ability to vote together with the Common Stock with a number of votes equal to the number of shares of Common Stock to be issued upon conversion of the Preferred Stock.

The issuance of these preferred shares could make it less likely that shareholders receive a premium for their shares of Common Stock as a result of any attempt to acquire the Company. Further, this issuance could adversely affect the market price of, and the voting and other rights, of the holders of outstanding shares of Common Stock.

We may seek to raise additional funds in the future through debt financing which may impose operational restrictions and may further dilute existing ownership interests.

We expect to seek to raise additional capital in the future to help fund our acquisition, development, and production of oil and natural gas reserves. Debt financing, if available, may require restrictive covenants which may limit our operating flexibility. Future debt financing may also involve debt instruments that are convertible into or exercisable for Common Stock. The conversion of the debt to equity financing may dilute the equity position of our existing shareholders.

The amount of our outstanding indebtedness continues to increase and our ability to make payments towards such indebtedness could have adverse consequences on future operations.

Our outstanding indebtedness at February 28, 2011 was $1,345,000, which constituted a $750,000 secured promissory note (“Loan”) and the $595,000 principal amount outstanding on the 12% Subordinated Notes (“Notes”). Our level of indebtedness affects our operations in a number of ways. The Loan and the Notes contain covenants that result in a substantial portion of our cash flow from operations being dedicated to the payment of interest on our indebtedness. Accordingly, these funds will not be available for other purposes, such as future exploration, development or acquisition activities. Our ability to meet our debt service obligations and reduce our total indebtedness will depend upon our future performance. Our future performance, in turn, is dependent upon many factors that are beyond our control such as general economic, financial and business conditions. We cannot guarantee that our future performance will not be adversely affected by such economic conditions and financial, business and other factors.

The Loan is secured by a Mortgage, Deed of Trust, Assignment of Production, Security Agreement and Financing Statement on the Sunday and Bear leases in the Company’s East Slopes Project. If the Company were to default on this Loan, the Company would lose two of its primary leases.

We do not anticipate paying dividends on our Common Stock which could devalue the market value of these securities.

We have not paid any cash dividends on our Common Stock since our inception. We do not anticipate paying cash dividends in the foreseeable future. Any dividends paid in the future will be at the complete discretion of our Board of Directors. For the foreseeable future, we anticipate that we will retain any revenues which we may generate from our operations. These retained revenues will be used to finance and develop the growth of the Company. Prospective investors should be aware that the absence of dividend payments could negatively affect the market value of our Common Stock.

ITEM 1B. UNRESOLVED STAFF COMMENTS

As a smaller reporting company, we are not required to provide the information otherwise required by this Item.

ITEM 2. PROPERTIES

During the year ended February 28, 2011, we were involved in an onshore oil project in Kern County, California. In the year ended February 28, 2010, we were involved in onshore oil and gas projects in Alabama, California and Louisiana. Our involvement in the Alabama and Louisiana projects has ended and information presented on these projects is intended to meet disclosure requirements or be for comparative purposes only. Unless otherwise noted, all of our discussion refers only to our continuing operations in California. We have not filed any estimates of total, proved net oil or gas reserves with any federal agency other than this report to the SEC for the fiscal year ended February 28, 2011. Throughout this Annual Report on Form 10-K, oil is shown in barrels ("Bbls"), and natural gas is shown in thousands of cubic feet ("Mcf") unless otherwise specified.

California (East Slopes Project, East Slopes North Project and Expanded AMI Project)

Kern and Tulare Counties. In May 2005, we agreed to jointly explore an area of mutual interest ("AMI") in the southeastern part of the San Joaquin Basin near Bakersfield, California. As our exploration work has continued, this project has been divided into three major areas referred to as the "East Slopes Project" and the "East Slopes North Project", both located in Kern County, and the "Expanded AMI Project" located in Tulare County. Drilling targets are porous and permeable sandstone reservoirs which exist at depths of 1,200 feet to 4,000 feet.

East Slopes Project, Kern County, California. On September 17, 2010, the Company exercised a preferential right to acquire an additional 16.67% working interest from another working interest owner in the East Slopes Project. Since the purchase of the additional working interest our average monthly revenue from the five wells affected by this purchase has increased by approximately 75.8% or $19,345 per month over the last six months of the year ended February 28, 2011. With this purchase of additional working interest and the completion of two additional wells in October 2010, the average net revenue interest in our eleven producing wells in Kern County, California is now 29.85%. Our average working interest is 40.15% for these same wells.

The installation of electrical power service to our permanent production facilities for the Sunday, Bear and Black property locations was completed in September 2010. In March 2011, we completed the installation of electrical service to our production facilities and wells at the Dyer Creek Field location. Our 3-D seismic data evaluation is continuing and the reprocessing of the data to enhance the quality of prospects is expected to yield more than the current eight to ten exploration prospects already identified on this acreage. Refer to the discussion below for additional information on our producing properties in the East Slopes Project area.

We believe the Company is now well positioned to expand its operations in the East Slopes Project. We currently have production from five reservoirs at our Bear, Sunday, Black, Ball and Dyer Creek locations. The Sunday and Bear locations each have four producing wells. The Black reservoir is the smallest of all currently producing reservoirs, and we will most likely drill only one or two more development wells. The Dyer Creek and Ball reservoirs were put on production in late October 2010. There are several other similar prospects on trend with the Bear, Black and Dyer Creek reservoirs exhibiting the same seismic characteristics. Some of these prospects, if successful, would utilize the Company's existing production facilities. In addition to the current field development, there are several other exploratory prospects that have been identified from the seismic data, which we plan to drill in the future.

Sunday Property

In November 2008, we made our initial oil discovery drilling the Sunday #1 well. The well was put on production in January 2009. Production is from the Vedder sand at approximately 2,000 feet. During 2009, we drilled three development wells including one horizontal well. The Sunday reservoir is estimated to be approximately 34.6 acres in size with the potential for at least three more development wells to be drilled in the future. With the acquisition of the additional 16.67% working interest in the East Slopes Project in September 2010, we have a 41.67% working interest with a 29.0% net revenue interest in the Sunday #1 well. We continue to have a 37.5% working interest with a 27% net revenue interest in each of the Sunday #2 and #3 wells. In the Sunday #4H well, we own a 37.5% working interest with a 30.1% net revenue interest.

Bear Property

In February 2009, we made our second oil discovery drilling the Bear #1 well which is approximately one mile northwest of our Sunday discovery. The well was put on production in May 2009. Production is from the Vedder sand at approximately 2,200 feet. In December 2009, we began a development program by drilling and completing the Bear #2 well. In April 2010, we successfully drilled and completed the Bear #3 and the Bear #4 wells. The Bear reservoir is estimated to be approximately 62 acres in size with the potential for at least three more development wells to be drilled in the future including one planned for the summer of 2011. With the acquisition of the additional 16.67% working interest in the East Slopes Project in September 2010, we have a 41.67% working interest with a 29.0% net revenue interest in each of the Bear wells in this property.

Black Property

The Black property was acquired through a farm-in arrangement with a local operator. The Black location is just south of the Bear location on the same fault system. The Black #1 well was completed and put on production in January 2010. Production is from the Vedder sand at 2,150 feet. The Black reservoir is estimated to be approximately 13.4 acres in size with the potential for at least two more development wells to be drilled in the future. We have a 37.5% working interest with a 29.8% net revenue interest at this property.

Sunday Central Processing and Storage Facility

The oil produced from our acreage is considered heavy oil. The oil ranges from 14° to 16° API gravity. All of our oil from the Sunday, Bear and Black locations is processed, stored and sold from the Sunday Central Processing and Storage Facility. The oil must be heated to separate and remove water to prepare it to be sold. We constructed these facilities during the summer and fall of 2009 and at the same time established electrical service for our field by constructing three miles of power lines. As a result, our average operating costs have been reduced from over $32 per barrel to below $20 per barrel of oil after accounting for the loss of certain oil processing credits that ceased with our purchase of an additional 16.67% working interest in September 2010. By having this central facility and permanent electrical power available, we are ensuring that our operating expenses are kept to a minimum.

Ball Property

The Ball #1-11 well was put on production in late October 2010. Our 3-D seismic indicates a reservoir approximately 37.5 acres in size with the potential for at least two development wells to be drilled in the future including one in the summer of 2011. Production from the Ball #1-11 well is being processed at the Dyer Creek production facility. We have a 41.67% working interest with a 34.69% net revenue interest at this property.

Dyer Creek Property

The Dyer Creek #67X-11 well was also put on production in late October 2010. This well is producing from the Vedder sand and is located to the north of the Bear reservoir on the same trapping fault. The Dyer Creek reservoir has the potential for at least one development well in the future. Production from the Dyer Creek #67X-11 well is also being processed at the Dyer Creek production facility. We have a 41.67% working interest with a 34.69% net revenue interest at this property.

Dyer Creek Processing and Storage Facility

The Dyer Creek Processing and Storage Facility serves the Dyer Creek and Ball properties and includes previously abandoned infrastructure that we have refurbished. We have completed the installation of electrical service to this location, thereby reducing operating costs by eliminating the use of rental equipment. Our oil processing costs at this facility should now decline significantly. The oil produced into this facility has similar API gravity to the oil at the Sunday production facility and the oil must also be heated to separate and remove water in preparation for sale.

Bull Run Prospect

This prospect is located in the southern portion of our acreage position. The drilling targets are the Etchegoin and Santa Margarita sands located between 800 and 1,200 feet deep. We plan to drill an exploratory well on this prospect during the summer of 2011. Based on wells drilled by previous operators and our recently reprocessed 3-D seismic data, we estimate that the Bull Run Prospect is approximately 280 acres in size with a gross reserve potential of 6 million barrels of oil. The Bull Run wells will require a pilot steam flood and additional production facilities. We have a 41.67% working interest in this prospect.

Glide-Kendall Prospect

This prospect is located in the southern portion of our acreage position. The drilling targets are the Olcese and Eocene sands between 1,000 and 2,000 feet deep. We plan to drill an exploratory well in the fall of 2011. We estimate that the Glide Kendall prospect is 200 acres in size with a gross reserve potential of 500,000 barrels of oil. We have a 41.67% working interest in this prospect.

Sherman Prospect

This prospect is located in the southern portion of our acreage position. The drilling targets are the Olcese and Etchegoin sands between 1,000 and 2,000 feet deep. We plan to drill an exploratory well in early 2012. We estimate that the Sherman Prospect is 100 acres in size with a gross reserve potential of 300,000 barrels of oil. We have a 41.67% working interest in this prospect.

Baker Prospect

This prospect is located in the northern portion of our acreage position approximately one mile south of our Sunday property. This drilling target is the Vedder sand which is approximately 2,000 feet deep. We plan to drill an exploratory well in early 2012. We estimate that the Baker prospect is 70 acres in size with a gross reserve potential of 200,000 barrels of oil. We have a 41.67% working interest in this prospect.

Breckenridge-Chimney Prospect

This prospect is located in the central portion of our acreage position. The drilling targets are the Vedder and Eocene sands between 2,000 and 2,500 feet deep. We plan to drill an exploratory well in 2012. We estimate that the Breckenridge-Chimney prospect is 60 acres in size with a gross reserve potential of 1.5 million barrels of oil. We have a 41.67% working interest in this prospect.

Tobias Prospect

This prospect is located in the central portion of our acreage position. The drilling targets are the Vedder and Eocene sands between 2,000 and 2,500 feet deep. We plan to drill an exploratory well in 2012. We estimate that the Tobias prospect is 60 acres in size with a gross reserve potential of 700,000 barrels of oil. We have a 41.67% working interest in this prospect.

We plan to spend approximately $1,800,000 in new capital investments within the East Slopes Project area in the current fiscal year.

Production, Revenue and LOE

Our net production volume, net revenue and net lease operating expenses ("LOE") by property location for the three months and years ended February 28, 2010 and February 28, 2011 in Kern County, California is set forth in the table below. Due to certain oil processing credits that we received from December 2009 through August 2010, our overall production costs for the Sunday #1 well and all four Bear wells during that time period were significantly less than the overall production costs for the other Sunday wells and the Black #1 well. These oil processing credits ended September 1, 2010 with our acquisition of a portion of a third party's working interest in this project. Initial LOE costs for the Ball and Dyer Creek locations were higher than average during the first four months of production because of the use of rental equipment to supply power to the wells and production facilities. Electrical power installation has now been completed for these wells and the associated production facility.

Location	Three Months Ended February 28, 2011	Three Months Ended February 28, 2010	Twelve Months Ended February 28, 2011	Twelve Months Ended February 28, 2010
Sunday				
Production (Bbls)	1,585	1,843	6,852	5,812
Revenue	$ 133,390	$ 125,930	$ 505,888	$ 359,921
LOE Costs	$ 15,605	$ 12,397	$ 67,650	$ 135,137
Bear				
Production (Bbls)	1,354	649	4,365	1,470
Revenue	$ 114,110	44,635	$ 330,196	95,778
LOE Costs	$ 15,645	$ 677	$ 26,710	$ 81,695
Black				
Production (Bbls)	252	$ 198	1,077	198
Revenue	$ 21,179	$ 13,659	$ 79,903	$ 13,659
LOE Costs	$ 4,349	$ 1,514	$ 15,466	$ 1,514
Ball				
Production (Bbls)	230	—	277	—
Revenue	$ 19,270	$ —	$ 22,970	$ —
LOE Costs	$ 10,862	$ —	$ 16,901	$ —
Dyer Creek				
Production (Bbls)	384	—	438	—
Revenue	$ 32,426	$ —	$ 36,522	$ —
LOE Costs	$ 10,245	$ —	$ 15,442	$ —
Infrastructure Costs	$ 5,818	$ 4,319	$ 31,065	$ 22,261
Total				
Production (Bbls)	3,805	2,690	13,009	7,480
Revenue	$ 320,375	$ 184,224	$ 975,479	$ 469,358
LOE Costs	$ 62,524	$ 18,907	$ 173,234	$ 240,607
Average Sales Price	$ 84.20	$ 68.50	$ 74.98	$ 62.75
Average LOE Cost	$ 16.43	$ 7.03	$ 13.32	$ 32.17

Reserves

All of our estimated proved reserves of 237,820 barrels of oil at March 1, 2011 were derived from engineering reports prepared by Lonquist & Co. LLC (“Lonquist”) of Austin and Houston, Texas in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC.

Lonquist is an independent petroleum engineering consulting firm registered in the State of Texas, and Tereasa Montemayor, a Senior Petroleum Engineer, is the technical person at Lonquist primarily responsible for evaluating the proved reserves covered by their report. Ms. Montemayor graduated from the University of Texas at Austin with a degree in Petroleum Engineering. She is a member in good standing of the Society of Petroleum Engineers and has over 23 years experience in evaluating oil and gas reserves. Ms. Montemayor has been employed by Lonquist for over four years, most recently as a reservoir engineer since 2009. The services provided by Lonquist are not audits of our reserves but instead consist of complete engineering evaluations of the respective properties. For more information about the evaluations performed by Lonquist, refer to the copy of their report filed as an exhibit to this Annual Report on Form 10-K.

Our internal controls over the reserve reporting process are designed to result in accurate and reliable estimates in compliance with applicable regulations and guidance. Internal reserve preparation for the Company is performed by Robert Martin, the Senior Vice-President - Exploration. Mr. Martin is a 1977 graduate of McGill University in Montreal, Quebec, Canada with an Honors Bachelor of Science Degree in Geological Science and is a member, in good standing, of the Association of Professional Engineers Geologists and Geophysicists of Alberta (APEGGA) and entitled to the designation “Professional Geologist” in Alberta. Mr. Martin has over 30 years of experience in petroleum exploration and management.

Although we believe that the estimates of reserves prepared by Mr. Martin have been prepared in accordance with professional engineering standards consistent with SEC and FASB guidelines, we engage an independent petroleum engineering consultant to prepare an annual evaluation of our estimated proved reserves. We provide to Lonquist for their analysis all pertinent data needed to properly evaluate our reserves. Mr. Martin consults regularly with Lonquist during the reserve estimation process to review properties, assumptions, and any new data available. Additionally, the Company’s senior management reviewed and approved all Daybreak reserve report information contained in this Annual Report on Form 10-K.

Under current SEC standards, proved reserves are 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, and under existing economic conditions, operating methods, and government regulations. The term “reasonable certainty” implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

In order to establish reasonable certainty with respect to our estimated proved reserves, we employ technologies that have been demonstrated to yield results with consistency and repeatability. The technical data used in the estimation of our proved reserves include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available downhole and production data, seismic data and well test data. Generally, oil and gas reserves are estimated using, as appropriate, one or more of these available methods: production decline curve analysis, analogy to similar reservoirs or volumetric calculations. Reserves attributable to producing wells with sufficient production history are estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing wells with limited production history and for undeveloped locations are estimated using performance from analogous wells in the surrounding area and technical data to assess the reservoir continuity. In some instances, particularly in connection with exploratory discoveries, analogous performance data is not available, requiring us to rely primarily on volumetric calculations to determine reserve quantities. Volumetric calculations are primarily based on data derived from geologic-based seismic interpretation, open-hole logs and completion flow data. When using production decline curve analysis or analogy to estimate proved reserves, we limit our estimates to the quantities of oil and gas derived through volumetric calculations.

The accuracy of any reserve estimate is a function of the quality of available geological, geophysical, engineering and economic data, the precision of the engineering and geological interpretation and judgment. The estimates of reserves and future cash flows are based on various assumptions and are inherently imprecise. Although we believe these estimates are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from these estimates. Also, the use of a 10% discount factor for reporting purposes may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which our business or the oil and natural gas industry in general are subject.

Our estimated quantities of proved oil reserves as of February 28, 2011 are set forth in the table below. All of our proved reserves are located in Kern County, California.

Reserve Category	Oil (Bbl)
Developed	88,840
Undeveloped	148,980
Total Proved	237,820

Changes in our estimated proved developed oil reserves for the year ended February 28, 2011 are set forth in the table below.

	Proved Reserves (Bbl)
Balance as of February 28, 2010	38,647
Extensions and discoveries	23,507
Revisions	21,549
Purchases of minerals-in-place	18,146
Production	(13,009)
Balance as of February 28, 2011	88,840

Extensions and discoveries. Extensions and discoveries for the year ended February 28, 2011 added 23,507 barrels of oil of proved reserves, replacing 180.7% of our fiscal year production. These additions resulted primarily from our development drilling program in the Bear Field and new discoveries in the Ball Field. Of the total reserve additions, proved developed reserves accounted for 100% of the extensions and discoveries.

Revisions. Net upward revisions of 21,549 barrels of oil resulted from new information derived by additional interpretation of existing 3-D seismic data.

Purchases of minerals-in-place. In September 2010, we acquired from a third party an additional 16.67% working interest in five producing oil wells in Kern County, California. This purchase resulted in a 18,146 barrel increase in our proved oil reserves.

The following table summarizes changes in our estimated proved undeveloped reserves for the year ended February 28, 2011.

	Proved Undeveloped Reserves (Bbl)
Balance as of February 28, 2010	23,507
Extensions and discoveries	148,980
Revisions	—
Reclassified to proved developed	(23,507)
Balance as of February 28, 2011	148,980

We added 148,980 barrels of proved undeveloped oil reserves from extensions and discoveries in Kern County, California. We also converted 23,507 barrels of proved undeveloped reserves to proved developed reserves as of February 28, 2011. We have no amounts of proved undeveloped reserves that have remained undeveloped for a period greater than five years.

East Slopes North Project, Kern County, California. This acreage is located immediately north of our East Slopes Project area in Kern County, California. We have currently dropped plans to hold this acreage and conduct a seismic survey on this acreage while we concentrate on developing additional prospects in the East Slopes Project.

Tulare County, California. The Expanded AMI Project, also located in the San Joaquin Basin, is in Tulare County and is a separate project area from the East Slopes Project in Kern County. We have currently dropped plans to hold and develop this acreage while we concentrate on developing additional prospects in the East Slopes Project.

Alabama (East Gilbertown Field) – Discontinued Operations

Choctaw County. In December 2006, we acquired a working interest in an existing oilfield project, the East Gilbertown Field, which produces relatively heavy oil (approximately 18° API). During the year ended February 28, 2010 we made the decision to exit this project. On March 15, 2010, we finalized the sale to a third party of our 12.5% working interest in this field. For the year ended February 28, 2011, we did not receive any oil sales revenue from this project. In connection with the sale, the Company recognized a gain from sale of oil and gas properties for the year ended February 28, 2011 of $10,285 which is presented under “Discontinued Operations” in the Statement of Operations. This sale has allowed us to focus on projects that better meet our corporate goals and objectives.

Louisiana (Krotz Springs Field) – Past Operations

St. Landry Parish. The Krotz Springs Field is a gas play with production coming from a Cockfield Sands reservoir. When production commenced in May of 2007, the unitized field operator of the Krotz Springs Field became the operator of this well. During the year ended February 28, 2010, we withdrew from this project and effectively ended all further involvement in this project. In the year ended February 28, 2011 we received approximately $104,017 from the Field Operator as a one-time adjustment to gas sales revenue that occurred from May 2007 through December 2009. This revenue is included in the “Oil and Gas Sales” caption on the Statement of Operations.

Summary Operating Data

The production volume shown in the following table is our net share of annual production in each project for the past three fiscal years. One barrel of oil equivalent (“BOE”) is roughly equivalent to 6,000 cubic feet or 6 Mcf of gas. Our involvement in the Alabama and Louisiana projects has ended and information presented on these discontinued projects is intended to only meet disclosure requirements. We do not have any fixed delivery commitment for oil or gas at any project.

	For the Year Ended February 28,		
	2011	2010	2009
Oil and Gas Production Data:			
Oil (Bbls)			
California	13,009	7,480	44
Alabama	—	1,739	2,344
Louisiana	—	—	24
Subtotal	13,009	9,219	2,412
Gas (Mcf)			
Louisiana	—	1,327	14,882
Total (BOE)			
California	13,009	7,480	44
Alabama	—	1,739	2,344
Louisiana	—	221	2,504
Total	13,009	9,440	4,892

The oil and gas sales revenue shown in the table below is our net share of annual revenue in each project for the past three fiscal years.

	For the Year Ended February 28,		
	2011	2010	2009
Oil and Gas Revenue:			
California	$ 975,479	$ 469,357	$ 1,290
Alabama	—	84,353	148,741
Louisiana*	104,017	2,085	51,881
Total	$ 1,079,496	$ 555,795	$ 201,912

*During the year ended February 28, 2011 we received approximately $104,017 from the field operator in Louisiana as a one-time adjustment to gas sales revenue that occurred from May 2007 through December 2009.

The table below shows the average sales price we received for oil and natural gas in aggregate from each project area on a BOE basis for the past three fiscal years.

	For the Year Ended February 28,		
	2011	2010	2009
Average Price:			
Oil (BOE)			
California	$ 74.98	$ 62.75	$ 29.13
Alabama	$ —	$ 48.51	$ 63.44
Louisiana	$ —	$ 8.70	$ 20.98
Average	$ 74.98	$ 51.95	$ 41.47

The table below shows the average cost of production for the past three fiscal years on a BOE basis.

	For the Year Ended February 28,		
	2011	2010	2009
Average Production Costs (BOE):			
California	$ 13.32	$ 32.17	$ 354.08
Alabama	$ —	$ 52.14	$ 39.43
Louisiana	$ —	$ 115.39	$ 15.66
Overall Average	$ 13.32	$ 33.40	$ 26.01

The table below shows the developed and undeveloped oil and gas lease acreage held by us as of February 28, 2011. Undeveloped acres are on lease acreage that wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas. Gross acres are the total number of acres in which we have an interest. Net acres are the sum of our fractional interests owned in the gross acres.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
California	440	185	20,760	8,650	21,200	8,835

The table below summarizes our productive oil and gas wells as of February 28, 2011. Productive wells are producing wells and wells capable of production. Gross wells are the total number of wells in which we have an interest. Net wells are the sum of our fractional interests owned in the gross wells.

Property Location	Gross	Net
Kern County, California	11	4.4
Total	11	4.4

The table below shows our exploratory and development well drilling activity for the past three fiscal years. We had no drilling activity in either of our Alabama or Louisiana projects during this time.

	For the Year Ended February 28, 2011		For the Year Ended February 28, 2010		For the Year Ended February 28, 2009	
Property Location	Productive	Dry	Productive	Dry	Productive	Dry
Kern County, California						
Exploratory	2	—	1	—	2	2
Developmental	2	—	4	—	—	—
Total	4	—	5	—	2	2

ITEM 3. LEGAL PROCEEDINGS

Neither the Company, nor any of our officers or directors is a party to any material legal proceeding or litigation, and such persons know of no material legal proceeding or contemplated or threatened litigation. There are no judgments against us or our officers or directors. None of our officers or directors has been convicted of a felony or misdemeanor relating to securities or performance in corporate office.

ITEM 4. REMOVED AND RESERVED

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our Common Stock is quoted in the over-the-counter market on the OTC Bulletin Board under the symbol "DBRM.OB". The following table shows the high and low closing sales prices for our Common Stock for the two most recent fiscal years. The quotations reflect inter-dealer prices, without retail mark-up, mark-down or commission and may not represent actual transactions. The information is derived from information received from online stock quotation services.

	Year Ended February 28, 2011		Year Ended February 28, 2010	
	High	Low	High	Low
First Quarter	0.12	0.09	0.12	0.07
Second Quarter	0.10	0.07	0.15	0.09
Third Quarter	0.13	0.07	0.14	0.10
Fourth Quarter	0.13	0.085	0.14	0.10

As of May 26, 2011, the Company had 2,221 shareholders of record. This number does not include an indeterminate number of shareholders whose shares are held by brokers in street name.

Transfer Agent

The transfer agent for our Common Stock is Computershare Trust Company, N.A., 250 Royall Street, Canton, MA 02021. Their web site address is: www.computershare.com.

Dividend Policy

The Company has not declared or paid cash dividends or made distributions in the past, and the Company does not anticipate that it will pay cash dividends or make distributions in the foreseeable future.

Sales of Unregistered Securities

Subordinated Notes

On January 13, 2010, we commenced a private placement of 12% Subordinated Notes (the "Notes"). We sold $595,000 of Notes to 13 accredited investors through the closing date of March 16, 2010. One of the accredited investors, a related party, is our Company President and Chief Executive Officer. The terms and conditions of the related party Note were identical to the terms and conditions of other participants' Notes.

Interest on the Notes accrues at 12% per annum, payable semi-annually. The note principal is payable in full at the expiration of the term of the Notes, which is January 29, 2015. Should the Board of Directors, on January 29, 2015, decide that the payment of the principal and any unpaid interest would impair the financial condition or operations of the Company, the Company may then elect a mandatory conversion of the unpaid principal and interest into the Company's Common Stock at a conversion rate equal to 75% of the average closing price of the Company's Common Stock over the 20 consecutive trading days preceding December 31, 2014.

Two Common Stock purchase warrants were issued for every dollar raised through the private placement resulting in a total of 1,190,000 warrants being issued through March 16, 2010. The warrants expire on January 29, 2015 and have an exercise price of $0.14. The fair value of the warrants issued with the Notes, as determined by the Black-Scholes option pricing model, was $116,557 using the following weighted-average assumptions: a risk free interest rate of 2.33%; volatility of 147.6%; and dividend yield of 0.0%. The fair value of the warrants was recognized as a discount to debt and is being amortized over the term of the Notes. Amortization expense for the year ended February 28, 2011 amounted to $16, 234. Unamortized debt discount amounted to $99,106 as of February 28, 2011. The Company analyzed the Notes and warrants for derivative accounting consideration and determined that derivative accounting does not apply to these instruments.

Proceeds from the fundraising were used to meet operating expenses and fund a portion of our development drilling program in Kern County, California. This offering of securities was made pursuant to a private placement held under Regulation D promulgated under the Securities Act of 1933, as amended.

Common Stock Issuances

On September 17, 2010, we exercised a preferential right to acquire an additional 16.67% working interest in the East Slopes Project in Kern County, California from another working interest owner. The Company financed the additional working interest by issuing, to an accredited third party, a one-year convertible secured promissory note for the principal amount of $750,000 (the “Loan”), subject to an annual interest rate of 10% per annum, which was prepaid at closing. Interest expense related to the Loan for the year ended February 28, 2011 was $37,500. Unamortized interest expense amounted to $37,500 as of February 28, 2011.

We issued 250,000 shares of the Company’s Common Stock to the third party as a loan origination fee. These shares were issued on October 8, 2010. The closing price of the Company’s Common Stock on September 17, 2010 was $0.095 and the stock issuance was valued at $23,750 which was deferred and is being amortized over the term of the Loan. Amortization expense for the year ended February 28, 2011 was $11,875. Unamortized loan origination fee expense amounted to $11,875 as of February 28, 2011.

The Company analyzed the share issuance for derivative accounting consideration and determined that derivative accounting does not apply to this transaction. The shares were issued in reliance on an exemption from registration provided by Section 4(2) of the Securities Act of 1933, as amended.

Private Placement Sale

On May 22, 2008, Daybreak closed an unregistered offering of its Common Stock through a private placement under the securities transaction exemption Regulation D Rule 506 of the Securities Act of 1933. Shares were offered at $0.25 per share to “accredited investors” only as defined in Regulation D under the Securities Act of 1933. For the year ended February 28, 2009, a total of 60,000 shares of unregistered Common Stock were sold directly by the Company to two accredited investors for $15,000. Net proceeds were used to meet leasehold expenses in California and general and administrative (“G&A”) expenses.

Common Stock Warrants

For the year ended February 28, 2011, a total of 39,550 warrants expired. These warrants were issued to a placement agent from a private placement of our Common Stock that occurred in the year ended February 28, 2008.

During the year ended February 28, 2011, a total of 210,000 warrants were issued by the Company. A total of 60,000 warrants were issued as a part of the private placement of the Subordinated Notes discussed above. The remaining 150,000 warrants were issued to a consultant for services rendered and expire on April 16, 2015 with an exercise price of $0.14. The fair value of the warrants issued to the consultant, as determined by the Black-Scholes option pricing model, was $14,600 using the following assumptions: a risk free interest rate of 2.49%; volatility of 143.5%; and dividend yield of 0.0%.

There were no warrants exercised during the year ended February 28, 2011. As of February 28, 2011 and 2010, there were 9,927,145 and 9,756,695 warrants issued and outstanding, respectively.

Warrants outstanding and exercisable as of February 28, 2011 are set forth in the table below:

Description	Warrants	Exercise Price	Remaining Life (Years)	Exercisable Warrants Remaining
Spring 2006 Common Stock Private Placement	4,013,602	$ 2.00	0.25	4,013,602
Placement Agent Warrants - Spring 2006 PP	802,721	$ 0.75	2.25	802,721
Placement Agent Warrants - Spring 2006 PP	401,361	$ 2.00	2.25	401,361
July 2006 Preferred Stock Private Placement	2,799,530	$ 2.00	0.50	2,799,530
Placement Agent Warrants - July 2006 PP	419,930	$ 1.00	2.50	419,930
Convertible Debenture Term Extension	150,001	$ 2.00	0.75	150,001
12% Subordinated Notes	1,190,000	$ 0.14	3.75	1,190,000
Warrants Issued for Services	150,000	$ 0.14	4.25	150,000
	9,927,145			9,927,145

The outstanding warrants as of February 28, 2011, have a weighted average exercise price of $1.61; a weighted average remaining life of 1.14 years; and an intrinsic value of $-0-.

Securities Authorized for Issuance under Equity Compensation Plan

The table below sets forth information regarding outstanding restricted stock awards for the fiscal year ended February 28, 2011. The Company has not awarded any restricted stock units. The Company has no qualified or nonqualified stock option plans and has no outstanding stock options.

Equity Compensation Plan Information

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans approved by security holders	—	—	—
Equity compensation plans not approved by security holders(1)	3,000,000	$ 0.10	1,000,000(2)
Total	**3,000,000**	**$ 0.10**	**1,000,000(2)**

(1) On April 6, 2009, the Board of Directors approved the 2009 Restricted Stock and Restricted Stock Unit Plan, as described in detail below, under the heading “2009 Restricted Stock and Restricted Stock Unit Plan.”

(2) Reflects initial 4,000,000 shares in the 2009 Restricted Stock and Restricted Stock Unit Plan, reduced by (i) 900,000 shares of restricted stock awarded to the Company’s non-employee directors in recognition of their leadership and contribution during the restructuring and transformation of the Company during the year ended February 28, 2009; (ii) 1,000,000 shares of restricted stock awarded to our current President and Chief Executive Officer and our former interim President and Chief Executive Officer in recognition of past service as executive officers during the year ended February 28, 2009; (iii) 425,000 and 625,000 shares of restricted stock awarded to employees during the years ended February 28, 2011 and 2010 respectively; and (iv) 25,000 shares of restricted stock awarded to non-employee directors under our director compensation plan for the years ended February 28, 2011 and 2010 respectively.

2009 Restricted Stock and Restricted Stock Unit Plan

On April 6, 2009, the Board of Directors approved the 2009 Restricted Stock and Restricted Stock Unit Plan (the "2009 Plan"), allowing the executive officers, directors, consultants and employees of the Company and its affiliates ("Plan Participants") to be eligible to receive restricted stock and restricted stock units awards, as a means of providing Plan Participants with a continuing proprietary interest in the Company. There are no predeterminations established for restricted stock or restricted stock units to be awarded to our named executive officers or employees.

We believe that awards of this type further align the interests of our employees and our shareholders by providing significant incentives for these employees to achieve and maintain high levels of performance. Restricted stock and restricted stock units also enhance our ability to attract and retain the services of qualified individuals.

Under the 2009 Plan, we may grant up to 4,000,000 shares. The Board delegated the administration of the 2009 Plan to the Compensation Committee. The Compensation Committee has the power and authority to select Plan Participants and grant awards of restricted stock and restricted stock units ("Awards") to such Plan Participants pursuant to the terms of the 2009 Plan. Awards may be in the form of actual shares of restricted Common Stock or hypothetical restricted Common Stock Units having a value equal to the fair market value of an identical number of shares of Common Stock. Unless otherwise provided by the Compensation Committee in an individual Award agreement, Awards under the 2009 Plan vest 25% on each of the first four anniversaries of the date of grant and the unvested portion of any Award will terminate and be forfeited upon termination of the Plan Participant's employment or service.

Subject to the terms of the 2009 Plan and the applicable Award agreement, the recipients of restricted stock generally will have the rights and privileges of a shareholder with respect to the restricted stock, including the right to vote the shares and to receive dividends, if applicable. The recipients of restricted stock units will not have the rights and privileges of a shareholder with respect to the shares underlying the restricted stock unit award until the award vests and the shares are received. The Compensation Committee may, at its discretion, withhold dividends attributed to any particular share of restricted stock, and any dividends so withheld will be distributed to the Plan Participant upon the release of restrictions on such shares in cash, or at the sole discretion of the Compensation Committee, in shares of Common Stock having a fair market value equal to the amount of such dividends. Awards under the 2009 Plan may not be assigned, alienated, pledged, attached, sold or otherwise transferred or encumbered by a Plan Participant other than by will or by the laws of descent and distribution.

Change in Control

Unless otherwise provided in an Award agreement, in the event of a Change in Control (as defined in the 2009 Plan) of the Company, the Compensation Committee may provide that the restrictions pertaining to all or any portion of a particular outstanding Award will expire at a time prior to the change in control. To the extent practicable, any actions taken by the Compensation Committee to accelerate vesting will occur in a manner and at a time that will allow affected Plan Participants to participate in the change in control transaction with respect to the Common Stock subject to their Awards.

Amendment and Termination

The Board at any time, and from time to time, may amend or terminate the 2009 Plan; provided, however, that such amendment or termination shall not be effective unless approved by the Company's shareholders to the extent shareholder approval is necessary to comply with any applicable tax or regulatory requirements. In addition, any such amendment or termination that would materially and adversely affect the rights of any Plan Participant shall not to that extent be effective without the consent of the affected Plan Participant. The Compensation Committee at any time, and from time to time, may amend the terms of any one or more Awards; provided, however, that the Compensation Committee may not effect any amendment which would materially and adversely affect the rights of any Plan Participant under any Award without the consent of such Plan Participant.

At February 28, 2011, a total of 1,000,000 shares remained available for issuance pursuant to the 2009 Plan. A summary of the 2009 Plan issuances is set forth in the table below:

Grant Date	Shares Awarded	Vesting Period	Shares Vested	Shares Outstanding (Unvested)
4/7/2009	1,900,000	3 Years	633,331	1,266,669
7/16/2009	25,000	3 Years	8,330	16,670
7/16/2009	625,000	4 Years	156,250	468,750
7/22/2010	25,000	3 Years	—	25,000
7/22/2010	425,000	4 Years	—	425,000
	3,000,000		797,911	2,202,089

For the year ended February 28, 2011, we recognized compensation expense related to the above restricted stock grants of $88,508. Unamortized compensation expense amounted to $133,272 as of February 28, 2011.

Common Stock

The Company is authorized to issue 200,000,000 shares of Common Stock with a par value of $0.001 of which 48,791,599 shares were issued and outstanding as of February 28, 2011. In comparison, at February 28, 2010, a total of 47,785,599 shares were issued and outstanding. This increase of 1,006,000 shares was due to the conversion of 102,000 shares of Series A Preferred Stock to 306,000 shares of Common Stock; the issuance of 250,000 shares in conjunction with the Loan to a third party as a part of our acquisition of additional working interest in Kern County, California; and the granting of restricted stock awards to non-employee directors (25,000 shares) and employees (425,000 shares) of the Company. All shares of Common Stock are equal to each other with respect to voting, liquidation, dividend and other rights. Owners of shares of Common Stock are entitled to one vote for each share of Common Stock owned at any shareholders' meeting. Holders of shares of Common Stock are entitled to receive such dividends as may be declared by the Board of Directors out of funds legally available therefore; and upon liquidation, are entitled to participate pro rata in a distribution of assets available for such a distribution to shareholders.

There are no conversion, preemptive, or other subscription rights or privileges with respect to any shares of our Common Stock. Our stock does not have cumulative voting rights, which means that the holders of more than 50% of the shares voting in an election of directors may elect all of the directors if they choose to do so. In such event, the holders of the remaining shares aggregating less than 50% would not be able to elect any directors.

Preferred Stock

The Company is authorized to issue up to 10,000,000 shares of Preferred Stock with a par value of $0.001. Our Preferred Stock may be entitled to preference over the Common Stock with respect to the distribution of assets of the Company in the event of liquidation, dissolution, or winding-up of the Company, whether voluntarily or involuntarily, or in the event of any other distribution of assets of the Company among its shareholders for the purpose of winding-up its affairs. The authorized but unissued shares of Preferred Stock may be divided into and issued in designated series from time to time by one or more resolutions adopted by the Board of Directors. The directors in their sole discretion shall have the power to determine the relative powers, preferences, and rights of each series of Preferred Stock.

On June 30, 2006, the Board of Directors designated 2,400,000 of these Preferred Stock shares as Series A Convertible Preferred Stock. In July 2006, we completed a private placement of the Series A Convertible Preferred Stock that resulted in the issuance of 1,399,765 shares to 100 accredited investors. At February 28, 2011, there were 906,565 shares issued and outstanding, that had not been converted into our Common Stock. During the year ended February 28, 2011, there were a total of 102,000 shares of Series A Convertible Preferred Stock that were converted to 306,000 shares of our Common Stock.

As of February 28, 2011, 30 accredited investors have converted 493,200 Series A Convertible Preferred shares into 1,479,600 shares of Daybreak Common Stock. Conversions of Series A Convertible Preferred that have occurred since the Series A Convertible Preferred was first issued in July 2006 are set forth in the table below.

Fiscal Period	Shares of Series A Preferred Converted to Common Stock	Shares of Common Stock Issued from Conversion	Number of Accredited Investors
Year Ended February 29, 2008	102,300	306,900	10
Year Ended February 28, 2009	237,000	711,000	12
Year Ended February 28, 2010	51,900	155,700	4
Year Ended February 28, 2011	102,000	306,000	4
Totals	493,200	1,479,600	30

Series A Convertible Preferred Stock

The following is a summary of the rights and preferences of the Series A Convertible Preferred Stock.

Conversion:

The preferred shareholder shall have the right to convert the Series A Convertible Preferred Stock into the Company's Common Stock at any time. Each share of Series A Convertible Preferred Stock is convertible into three shares of Common Stock.

Automatic Conversion:

The Series A Convertible Preferred Stock shall be automatically converted into Common Stock if the Common Stock into which the Series A Convertible Preferred Stock are convertible are registered with the SEC and at any time after the effective date of the registration statement the Company's Common Stock closes at or above $3.00 per share for 20 out of 30 trading days.

Dividend:

Holders of Series A Convertible Preferred Stock shall be paid dividends, in the amount of 6% of the original purchase price per annum. Dividends may be paid in cash or Common Stock at the discretion of the Company. Dividends are cumulative from the date of the final closing of the private placement, whether or not in any dividend period or periods we have assets legally available for the payment of such dividends. Accumulations of dividends on shares of Series A Convertible Preferred Stock do not bear interest. Dividends are payable upon declaration by the Board of Directors.

Cumulative dividends earned for each fiscal year since issuance are set forth in the table below.

Fiscal Year Ended	Shareholders at Period End	Accumulated Dividends
February 28, 2007	100	$ 155,333
February 29, 2008	90	242,165
February 28, 2009	78	209,974
February 28, 2010	74	190,460
February 28, 2011	70	173,893
		$ 971,825

Voting Rights:

The holders of the Series A Convertible Preferred Stock will vote together with the Common Stock and not as a separate class except as specifically provided or as otherwise required by law. Each share of the Series A Convertible Preferred Stock shall have a number of votes equal to the number of shares of Common Stock then issuable upon conversion of such shares of Series A Convertible Preferred Stock.

ITEM 6. SELECTED FINANCIAL DATA

As a smaller reporting company, we are not required to provide the information otherwise required by this Item.

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

The following management's discussion and analysis ("MD&A") is management's assessment of the historical financial and operating results of Daybreak during the period covered by the financial statements. This MD&A should be read in conjunction with the audited financial statements and the related notes and other information included elsewhere in this Annual Report on Form 10-K.

Safe Harbor Provision

Certain statements contained in our Management's Discussion and Analysis of Financial Condition and Results of Operations are intended to be covered by the safe harbor provided for under Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Exchange Act. All statements other than statements of historical facts contained in this MD&A report, including statements regarding our current expectations and projections about future results, intentions, plans and beliefs, business strategy, performance, prospects and opportunities, are inherently uncertain and are forward-looking statements. For more information about forward looking statements, please refer to the section labeled "Cautionary Statement About Forward-Looking Statements" at the beginning of this Annual Report on Form 10-K.

Introduction and Overview

We are an independent oil and natural gas exploration, development and production company. Our basic business model is to increase shareholder value by finding and developing oil and gas reserves through exploration and development activities, and selling the production from those reserves at a profit. To be successful, we must, over time, be able to find oil and gas reserves and then sell the resulting production at a price that is sufficient to cover our finding costs, operating expenses, administrative costs and interest expense, plus offer us a return on our capital investment.

We have a limited operating history of oil and gas production and minimal proven reserves, production and cash flow. To date, we have had limited revenues and have not been able to generate sustainable positive earnings on a Company-wide basis. Our management cannot provide any assurances that Daybreak will ever operate profitably. As a result of our limited operating history, we are more susceptible to the numerous business, investment and industry risks that have been described in Item 1A. Risk Factors of this Annual Report on Form 10-K.

Our longer-term success depends on, among many other factors, the acquisition and drilling of commercial grade oil and gas properties and on the prevailing sales prices for oil and natural gas along with associated operating expenses. The volatile nature of the energy markets makes it difficult to estimate future prices of oil and natural gas; however, any prolonged period of depressed prices would have a material adverse effect on our results of operations and financial condition.

Our operations are focused on identifying and evaluating prospective oil and gas properties and funding projects that we believe have the potential to produce oil or gas in commercial quantities. We are currently in the process of developing a multi-well oilfield project in Kern County, California.

During the past three fiscal years, we have been involved in the drilling and completion of eleven wells that have achieved commercial production in Kern County, California. To improve our overall cash flow, we have changed our focus to concentrate on operations in California and have divested our interests in Alabama and Louisiana.

Liquidity and Capital Resources

Our primary financial resource is our base of oil reserves. Our ability to fund our capital expenditure program is dependent upon the price levels we receive from our oil sales; the success of our exploration and development program in Kern County, California; and the availability of capital resource financing. In the next fiscal year, we plan on spending approximately $1,800,000 in new capital investments, however our actual expenditures may vary significantly from this estimate if our plans for exploration and development activities change during the year. Factors such as changes in operating margins and the availability of capital resources could increase or decrease our ultimate level of expenditures during the next fiscal year.

The changes in our capital resources at February 28, 2011 compared with February 28, 2010 are:

	February 28, 2011	February 28, 2010	Increase (Decrease)	Percentage Change
Cash	$ 57,380	$ 247,951	$ (190,571)	(76.9%)
Current Assets	$ 593,275	$ 1,070,541	$ (477,266)	(44.6%)
Total Assets	$ 3,313,180	$ 3,010,036	$ 303,144	10.1%
Current Liabilities	$ 2,672,124	$ 1,388,339	$ 1,283,785	92.5%
Total Liabilities	$ 3,223,140	$ 1,896,601	$ 1,326,539	69.9%
Working Capital Deficit	$ (2,078,849)	$ (317,798)	$ 1,761,051	554.1%

Our working capital deficit increased by $1,761,051, from ($317,798) as of February 28, 2010 to ($2,078,849) as of February 28, 2011. This increase in the deficit was due to the amount of successful drilling activity that we undertook in California; the refurbishing of a production facility and power installation cost for the production facilities utilized by our wells in California; and the assumption of the debt created through the default of certain original working interest partners in the East Slopes Project. The use of these associated production facilities has lowered our operating costs substantially and should assist us in maintaining a positive cash flow from our East Slope operations in Kern County, California during the next fiscal year.

We have repositioned Daybreak to better meet our corporate goals and objectives by disposing of assets that impeded our cash flow and growth in the East Slopes Project. In the last few years we have disposed of properties in Alabama, Louisiana and Texas. These actions have allowed us to move forward with our drilling and exploration program in Kern County.

Our business is capital intensive. Our ability to grow is dependent upon favorably obtaining outside capital and generating cash flows from operating activities necessary to fund our investment activities. There is no assurance that we will be able to achieve profitability. Since our future operations will continue to be dependent on successful exploration and development activities and our ability to seek and secure capital from external sources, should we be unable to achieve sustainable profitability this could cause any equity investment in the Company to become worthless.

Major sources of funds in the past for us have included the debt or equity markets. While we have achieved positive cash flow from operations in Kern County, California, we will have to rely on these capital markets to fund future operations and growth. Our business model is focused on acquiring exploration or development properties as well as existing production. Our ability to generate future revenues and operating cash flow will depend on successful exploration, and/or acquisition of oil and gas producing properties, which may very likely require us to continue to raise equity or debt capital from outside sources.

Daybreak has ongoing capital commitments to develop certain leases pursuant to their underlying terms. Failure to meet such ongoing commitments may result in the loss of the right to participate in future drilling on certain leases or the loss of the lease itself. These ongoing capital commitments may also cause us to seek additional capital from sources outside of the Company. The current uncertainty in the credit and capital markets, and the economic downturn, may restrict our ability to obtain needed capital.

We anticipate it will be necessary to rely on additional funding from the capital markets in the current fiscal year.

Cash Flows

Changes in the net funds provided by or (used in) each of our operating, investing and financing activities are set forth in the table below:

	February 28, 2011	February 28, 2010	Increase (Decrease)	Percentage Change
Net cash provided by (used in) operating activities	$ 184,673	$ (2,699,671)	$ 2,884,344	106.8%
Net cash provided by (used in) investing activities	$ (1,155,244)	$ 99,812	$ (1,255,056)	(1257.4%)
Net cash provided by financing activities	$ 780,000	$ 565,000	$ 215,000	38.1%

Cash Flow Used in Operating Activities

Cash flow from operating activities is derived from the production of our oil reserves and changes in the balances of receivables, payables, or other non-oil property asset account balances. For the year ended February 28, 2011, we had a positive cash flow from operating activities of $184,673, in comparison to a negative cash flow of ($2,699,671) for the year ended February 28, 2010. This change of $2,884,344 was the result of an increase in oil revenues; a reduction in operating expenses; collections of outstanding receivable amounts on assets held for sale; and an increase in our payables balances. Variations in cash flow from operating activities may impact our level of exploration and development expenditures.

Our expenditures consist primarily of exploration and drilling costs; production costs; geological, geophysical and engineering services and acquisition of mineral leases. Our expenses also consist of consulting and professional services, employee compensation, legal, accounting, travel and other G&A expenses which we have incurred in order to address necessary organizational activities.

Cash Flow Provided by Investing Activities

Cash flow from investing activities is derived from changes in oil and gas property balances and Other Assets account balances. Cash used in investing activities for the year ended February 28, 2011 was ($1,155,244), an increase of $1,255,056 from the $99,812 provided by investing activities for the year ended February 28, 2010. This change primarily reflects the purchase of additional working interest in five of our producing wells and the successful drilling and completion of four additional wells all in our East Slopes Project in Kern County, California. We converted two Operator bonds in Alabama and Louisiana that were no longer needed since our involvement in any projects in those states has now ceased. This conversion resulted in a decrease of approximately $275,000 plus accrued interest in the Other Assets account balance.

Cash Flow Provided by Financing Activities

Cash flow from financing activities is derived from changes in long-term liability account balances or in equity account balances excluding retained earnings. Cash flow provided by financing activities was $780,000 for the year ended February 28, 2011. This is in comparison to $565,000 provided by financing activities for the year ended February 28, 2010. The $750,000 in funds that was borrowed for the purchase of the additional working interest in our East Slopes Project and the remaining $30,000 from the private placement of 12% Subordinated Notes are the two components of our financing activities. Both of these borrowings are described below. We anticipate it will be necessary to rely on additional funding from the capital markets in the current fiscal year.

12% Subordinated Notes

On January 13, 2010, we commenced a private placement of 12% Subordinated Notes (“the Notes”). On March 16, 2010, the Company closed its private placement of Notes to 13 accredited investors resulting in total gross proceeds of $595,000. Interest on the Notes accrues at 12% per annum, payable semi-annually. The note principal is payable in full at the expiration of the term of the Notes, which is January 29, 2015. Should the Board of Directors, on January 29, 2015, decide that the payment of the principal and any unpaid interest would impair the financial condition or operations of the Company, the Company may then elect a mandatory conversion of the unpaid principal and interest into the Company’s Common Stock at a conversion rate equal to 75% of the average closing price of the Company’s Common Stock over the 20 consecutive trading days preceding December 31, 2014.

In conjunction with the Notes private placement a total of 1,190,000 common stock purchase warrants were issued at a rate of two warrants for every dollar raised through the private placement. The warrants have an exercise price of $0.14 and expire on January 29, 2015. The fair value of the warrants, as determined by the Black-Scholes option pricing model, was $116,557 using the following weighted average assumptions: a risk free interest rate of 2.33%; volatility of 147.6%; and dividend yield of 0.0%. The fair value of the warrants was recognized as a discount to debt and is being amortized over the term of the Notes using the effective interest method. Amortization expense for the year ended February 28, 2011 amounted to $16,234. Unamortized debt discount amounted to $99,106 as of February 28, 2011.

Proceeds from the Notes were used to meet operating expenses and fund a portion of our development drilling program in Kern County, California. This offering of securities was made pursuant to a private placement held under Regulation D promulgated under the Securities Act of 1933, as amended.

One-Year Note Payable

On September 17, 2010, we exercised a preferential right to acquire an additional 16.67% working interest in our East Slopes Project from another working interest owner. We financed the additional working interest purchase by issuing, to a third party, a one-year convertible secured promissory note for the principal amount of $750,000 (the “Loan”), subject to an annual interest rate of 10% per annum, which was prepaid at closing. The third party may convert up to 50% of the unpaid principal balance into the Company’s Common Stock at a conversion price of $0.16 per share at any time prior to the Loan being paid in full. Interest expense related to the Loan for the year ended February 28, 2011 was $37,500. Unamortized interest expense amounted to $37,500 as of February 28, 2011.

We issued 250,000 shares of the Company’s Common Stock to the third party as a loan origination fee. The fair value of these shares amounted to $23,750 which was deferred and is being amortized over the term of the Loan. Amortization expense for the year ended February 28, 2011 was $11,875. Unamortized loan origination fee expense amounted to $11,875 as of February 28, 2011.

The Loan is secured by a Mortgage, Deed of Trust, Assignment of Production, Security Agreement and Financing Statement on the Sunday and Bear leases in our East Slope Project. Furthermore, as a condition precedent to the Loan, we entered into a Technical and Consulting Services Agreement with the third party, whereby we will provide operating, engineering and technical consulting to the third party for a one-year period for the purpose of evaluating 22 wells in Hutchinson County, Texas for the third party.

As additional consideration for the Loan we executed an Assignment of Net Profits Interest in favor of the third party, whereby we assigned two percent of the net profits realized by us on our leases in the East Slopes Project. The fair value of the two percent net profits interest was determined to be $60,210 and has been recognized as a discount to the debt to be amortized over the term of the Loan. Amortization expense for the year ended February 28, 2011 amounted to $30,105. Unamortized debt discount amounted to $30,105 as of February 28, 2011.

Warrants Issued for Services

During the year ended February 28, 2011, a total of 150,000 warrants were issued to a consultant for services. These warrants have an exercise price of $0.14 and expire on April 16, 2015. The fair value of the warrants, as determined by the Black-Scholes option pricing model, was $14,600 using the following assumptions: a risk free interest rate of 2.49%; volatility of 143.5%; and dividend yield of 0.0%.

Changes in Financial Condition

We maintain our cash balance by increasing or decreasing our exploration and drilling expenditures as limited by availability of cash from operations or from financing activities. The cash balance for the year ended February 28, 2011 declined to $57,380. This was a decrease of $190,571 from the cash balance at February 28, 2010, of $247,951. This decrease was primarily due to successful drilling activities and the refurbishing of production facilities for the Ball and Dyer Creek wells in California and on-going G&A expenses.

Restricted Stock and Restricted Stock Unit Plan

On April 6, 2009, the Board approved the Restricted Stock and Restricted Stock Unit Plan (the “2009 Plan”) allowing the executive officers, directors, consultants and employees of Daybreak and its affiliates to be eligible to receive restricted stock and restricted stock unit awards. Subject to adjustment, the total number of shares of Daybreak’s Common Stock that will be available for the grant of awards under the 2009 Plan may not exceed 4,000,000 shares; provided, that, for purposes of this limitation, any stock subject to an award that is forfeited in accordance with the provisions of the 2009 Plan will again become available for issuance under the 2009 Plan.

We believe that awards of this type further align the interests of our employees and our shareholders by providing significant incentives for these employees to achieve and maintain high levels of performance. Restricted stock and restricted stock units also enhance our ability to attract and retain the services of qualified individuals.

On April 7, 2009, the Compensation Committee of the Board awarded 1,000,000 restricted shares of our Common Stock to a current and a former executive officer of Daybreak. These shares were granted pursuant to the 2009 Plan and fully vest equally over a period of three years.

On April 7, 2009, the Compensation Committee of the Board awarded 900,000 restricted shares of our Common Stock to the five non-employee Directors of Daybreak. These shares were granted pursuant to the 2009 Plan and fully vest equally over a period of three years.

On July 16, 2009, the Compensation Committee of the Board awarded 25,000 restricted shares of our Common Stock to the five non-employee Directors as a part of our director compensation plan. These shares were granted pursuant to the 2009 Plan and fully vest equally over a period of three years.

On July 16, 2009, the Compensation Committee of the Board awarded 625,000 restricted shares of our Common Stock to four employees of Daybreak. These shares were granted pursuant to the 2009 Plan and fully vest equally over a period of four years.

On July 22, 2010, the Compensation Committee of the Board awarded 25,000 restricted shares of our Common Stock to the five non-employee Directors as a part of our director compensation plan. These shares were granted pursuant to the 2009 Plan and fully vest equally over a period of three years.

On July 22, 2010, the Compensation Committee of the Board awarded 425,000 restricted shares of our Common Stock to five employees of Daybreak. These shares were granted pursuant to the 2009 Plan and fully vest equally over a period of four years.

At February 28, 2011, a total of 1,000,000 shares remained available for issuance pursuant to the 2009 Plan.

A summary of the 2009 Plan issuances is set forth in the table below:

Grant Date	Shares Awarded	Vesting Period	Shares Vested	Shares Outstanding (Unvested)
4/7/2009	1,900,000	3 Years	633,331	1,266,669
7/16/2009	25,000	3 Years	8,330	16,670
7/16/2009	625,000	4 Years	156,250	468,750
7/22/2010	25,000	3 Years	—	25,000
7/22/2010	425,000	4 Years	—	425,000
	3,000,000		797,911	2,202,089

For the year ended February 28, 2011, we recognized compensation expense related to the above restricted stock grants of $88,508. Unamortized compensation expense amounted to $133,272 as of February 28, 2011.

Oil Reserves

Daybreak's proved oil reserves increased 175,665 barrels of oil, or 282% to 237,820 barrels of oil for the year ended February 28, 2011 compared to 62,155 barrels of oil for the year ended February 28, 2010. Proved developed reserves increased by 50,192 barrels of oil, or 56%, to 88,840 barrels of oil for the year ended February 28, 2011, compared to 38,648 barrels of oil for the year ended February 28, 2010. Proved undeveloped reserves increased by 125,473 barrels of oil, or 84% to 148,980 barrels of oil for the year ended February 28, 2011, compared to 23,507 barrels of oil for the year ended February 28, 2010. Our reserves were fully engineered by Lonquist & Co. LLC ("Lonquist") of Austin and Houston, Texas in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC.

Results of Operations

Revenues from our East Slopes Project in Kern County, California for the year ended February 28, 2011 increased $506,122, or 107.8%, to $975,479 in comparison to revenues of $469,357 for the year ended February 28, 2010. The average price of a barrel of oil for the year ended February 28, 2011 was $74.98 in comparison to $62.75 for the year ended February 28, 2010. The increase of $12.23 in the average price of a barrel of oil accounted for $91,480 or 19.5% of the revenue increase for the year ended February 28, 2011. Oil production increased by 5,529 barrels, or 73.9%, for the year ended February 28, 2011 in comparison to the year ended February 28, 2010 and accounted for the other $414,641, or 80.5%, of the revenue increase for the year ended February 28, 2011.

Our loss from continuing operations declined to approximately $1.2 million for the year ended February 28, 2011 in comparison to the approximate $2.4 million loss from continuing operations for the year ended February 28, 2010. This decrease in the operating loss of approximately $1.2 million was due to an improvement in revenues of approximately $608,054, or 129%, and a decrease in operating expenses of approximately $696,644, or 24.5%, for the year ended February 28, 2011 in comparison to the year ended February 28, 2010.

Selected Financial Information

During the year ended February 28, 2011, we received oil sales revenue from eleven wells in our East Slopes Project in Kern County, California. Our commitment to improving corporate profitability remains unchanged, and we have reduced both the net loss from continuing operations and the overall net loss for the year ended February 28, 2011 in comparison to the year ended February 28, 2010. The net loss experienced for the year ended February 28, 2011 of approximately $1.2 million was an improvement of approximately $1.1 million, or 46.2%, from the net loss of approximately $2.3 million for the year ended February 28, 2010. The decline in our net loss for the year ended February 28, 2011 in comparison to the year ended February 28, 2010, is a result of both an increase in our oil sales revenue and a decrease in our overall expenses.

Our balance sheet at February 28, 2011 shows total assets of $3,313,180 comprised primarily of $57,380 in cash; accounts receivable (including oil sales, joint interest participants, production revenue and refunds) of $791,387; and oil and gas properties (net of Depreciation, Depletion, Amortization ("DD&A")) of $2,290,001. This compares with the February 28, 2010 balances for cash of $247,951; accounts receivable of $1,125,855; and, oil and gas properties of $1,210,799. The above changes can be attributed to the success of our exploratory and development drilling program and the acquisition of additional working interest in our East Slopes Project in Kern County.

At February 28, 2011, we had total liabilities of $3,223,140, comprised of accounts payable (including trade, related parties and liabilities associated with assets held for sale) of $1,952,229, short-term and long-term notes payable of $1,215,789 and $55,122 in asset retirement obligation ("ARO"), as compared with the February 28, 2010 balances for total liabilities of $1,896,601, comprised of $1,388,339 in accounts payable; $454,944 in notes payable and $53,318 in ARO.

Our Common Stock issued and outstanding increased by 1,006,000 shares to 48,791,599 for the year ended February 28, 2011 in comparison to 47,785,599 for the year ended February 28, 2010. This increase was a result of conversions from our Series A Convertible Preferred Stock (306,000 shares); awards of restricted stock made under the 2009 Plan (450,000) to executive officers, non-employee directors and employees; and loan origination fees (250,000). Series A Convertible Preferred Stock issued and outstanding decreased by 102,000 shares to 906,565 shares as of February 28, 2011, compared to 1,008,565 shares as of February 28, 2010.

Accumulated Deficit

Our financial statements for the year ended February 28, 2011 have been prepared on a going concern basis, which contemplates the realization of assets and the settlement of liabilities in the normal course of business. Our financial statements also state that the Company has incurred significant operating losses that raise substantial doubt about our ability to continue as a going concern. The accompanying financial statements do not include any adjustments that might result from this uncertainty. The increase in the accumulated deficit from $21,191,162 as of February 28, 2010, to $22,406,909 as of February 28, 2011 was due to the $1,215,747 net loss for the year ended February 28, 2011. The loss from continuing operations for the year ended February 28, 2011 decreased by $1,140,701 to $1,226,763, in comparison to the $2,367,464 loss from the year ended February 28, 2010. In effect, this was a decrease on our loss from continuing operations by approximately 48.2%. We expect to continue this trend of a decrease in the net operating loss in the current year because of increased production due to more wells producing and lower operating costs at our East Slopes Project.

Management Plans to Continue as a Going Concern

We continue to implement plans to enhance Daybreak's ability to continue as a going concern. The Company currently has a net revenue interest in eleven producing wells in our East Slopes Project located in Kern County, California. The revenue from these wells has created a steady and reliable source of revenue for the Company.

On September 17, 2010, the Company exercised a preferential right to acquire an additional 16.67% working interest from another working interest owner in the East Slopes Project. Since the purchase of the additional working interest our average monthly revenue from the five wells affected by this purchase has increased by 75.76%, or approximately $19,345 per month, over the last six months of the year ended February 28, 2011. With this purchase of additional working interest and the completion of two additional wells in October 2010 our average net revenue interest in our eleven producing wells in Kern County, California is now 29.85%. Our average working interest is 40.15% for these same wells.

We anticipate revenues will continue to increase as the Company participates in the drilling of more wells in the East Slopes Project. The Company plans to continue its development drilling program at a rate that is compatible with its cash flow and funding opportunities.

On January 13, 2010, we commenced a private placement of 12% Subordinated Notes. We sold $595,000 of Notes to 13 accredited investors. The private placement concluded on March 16, 2010. See the discussion above titled “12% Subordinated Notes” for more information on this private placement.

On September 17, 2010, we financed an additional working interest purchase in our East Slopes Project by issuing, to a third party, a one-year convertible secured promissory note for the principal amount of $750,000 (the “Loan”), subject to an annual interest rate of 10% per annum, which was prepaid at closing. See the discussion above titled “One Year Note Payable” for more information on this Loan.

On March 15, 2010, we finalized the sale of our 12.5% working interest in the East Gilbertown Field in Choctaw County, Alabama. This sale helped us by improving our cash reserves and allowed us to focus on our East Slopes Project.

As a result of these transactions and the results of our successful drilling activity, our liquidity will continue to improve. Our sources of funds in the past have included the debt or equity markets and, while the Company does have positive cash flow from its oil and gas properties, it has not yet established a positive cash flow on a company-wide basis. We anticipate it may be necessary to rely on additional funding from the private or public debt or equity markets in the future. However, we cannot offer any assurance that we will be successful in executing the aforementioned plans to continue as a going concern.

Fiscal Year 2011 Compared to Fiscal Year 2010 – Continuing Operations

This discussion comparing the year ended February 28, 2011 results with the year ended February 28, 2010 results covers our continuing operations in Kern County, California known as our East Slopes Project.

Kern County, California. The East Slopes Project is located in the southeastern part of the San Joaquin Basin near Bakersfield, California. Since January 2009, we have participated in the drilling of thirteen wells in this project. Eleven of those wells have been successful and have been placed on production. Drilling targets are porous and permeable sandstone reservoirs which exist at depths of 1,200 feet to 3,000 feet. Refer to our discussion in Item 2. Properties, in this Annual Report on Form 10-K for more information on our East Slopes Project.

St. Landry Parish. The Krotz Springs Field is a gas play with production coming from a Cockfield Sands reservoir. We were the operator for this project during the drilling and completion phases. When production commenced in May of 2007, the unitized field operator of the Krotz Springs Field became the operator of this well. In December 2009, we withdrew from this project and effectively ended all further involvement in this project.

Revenues. The table below shows the revenues derived entirely from the sale of our share of oil and gas production from our continuing operations. Prior to February 2009, we had no revenues from our East Slopes Project.

The table set forth below shows our revenues for the year 2011 compared to the year 2010:

	2011	2010
California – East Slopes	$ 975,479	$ 469,357
Louisiana – Krotz Springs	104,017	2,085
Total Revenues	$ 1,079,496	$ 471,442

For the year ended February 28, 2011, the East Slopes Project represented 90.4% of total revenues. The Krotz Springs Field in Louisiana revenues represented 9.6% of total revenues. This Louisiana revenue represented a one-time adjustment by the unitized field operator to gas sales revenue earned from May 2007 through December 2009. For the year ended February 28, 2011, total revenues from continuing operations increased by $608,054, or 29.0%, in comparison with the year ended February 28, 2010. The revenues we recorded in California for the year ended February 28, 2011 represented an average net revenue interest of 29.85% in eleven producing wells.

The Daybreak net sales volume from eleven wells at our East Slopes Project for the year ended February 28, 2011 was 13,009 barrels, in comparison to 7,480 barrels from seven wells for the year ended February 28, 2010. We experienced twelve months of production from seven wells; ten months of production from two wells; and four months of production from the other two most recently drilled wells. This compares to 12 months of production from one well; ten months of production from a second well; eight months of production from two more wells; three months of production from one well; and one month of production for the final two wells for the year ended February 28, 2010. The average sales price of a barrel of oil for the year ended February 28, 2011 was $74.98, in comparison to $62.75 in the year ended February 28, 2010.

Costs and Expenses. Total operating expenses declined by 24.5%, or $696,644, for the year ended February 28, 2011, as compared to the year ended February 28, 2010. We experienced a decrease in every category of our operating expenses for the year ended February 28, 2011 even though we had more wells producing than in the prior year.

The table set forth below shows our costs and expenses for the year 2011 compared to the year 2010:

	For Year Ended February 28, 2011	For Year Ended February 28, 2010
Production Costs	$ 172,250	$ 269,820
Exploration and Drilling	184,255	301,912
DD&A	307,023	550,755
Gain on Write-Off of ARO	(8,324)	—
Bad debt expense (recovery)	(3,928)	113,528
G&A	1,494,969	1,606,874
Total Operating Expenses	$ 2,146,245	$ 2,842,889

Operating expenses incurred by the Company include production costs associated directly with the generation of oil and gas revenues (also including well workover projects and plugging and abandonment activities); unsuccessful exploratory drilling and lease rentals; DD&A charges; and G&A expenses (including legal and accounting expenses, director and management fees, investor relations expenses, and other G&A costs).

Production costs decreased $97,570, or 36.2%, for the year ended February 28, 2011 and relate directly to the eleven wells that were operating at our East Slopes Project during the year ended February 28, 2011, in comparison to the seven wells that we operated for the year ended February 28, 2010. The primary reason for this reduction in production costs is the full year utilization of our permanent production facilities, thus reducing our costs of preparing oil for sale by eliminating the need for rental equipment. Production costs represented 8.0% of total operating expenses.

Exploration and drilling expenses decreased $117,657, or 39.0%, for the year ended February 28, 2011, in comparison to the year ended February 28, 2010. The majority of this decrease was due to lower lease cost as we dropped acreage in California that was deemed to be lacking in drillable prospects. For the years ended February 28, 2011 and 2010, we did not drill any dry holes. Exploration and drilling expenses represented 8.6% of total operating expenses.

DD&A expenses decreased $243,732, or 44.3%, for the year ended February 28, 2011, in comparison to the year ended February 28, 2010. This decrease relates directly to lower amortization rates of our reserves as we have increased the amount of our proven reserves from our development drilling program in the East Slopes Project. Additionally, for the year ended February 28, 2010 we recorded impairment charges of $341,871. DD&A expenses represented 14.3% of total operating expenses.

Gain on write-off of ARO decreased by $8,324 for the year ended February 28, 2011. This gain was directly related to the write off of the asset retirement obligation of our Krotz Springs project in Louisiana. Gain on write-off of ARO represented (0.4%) of total operating expenses.

Bad debt expense decreased $117,456, or 103.5%, for the year ended February 28, 2011, in comparison to the year ended February 28, 2010. For the year ended February 28, 2011, we recovered $3,928 on accounts previously written off. Bad debt expense represented (0.2%) of total operating expense.

G&A costs decreased $111,905, or 7.0%, for the year ended February 28, 2011, in comparison to the year ended February 28, 2010. This decrease was due to increased efforts to limit our overall administrative costs. Significant reductions were achieved in travel and in shareholder meeting and communications expenses. These reductions were partially offset by an increase in insurance costs. Additionally, accounting and legal fees were reduced by approximately $48,443 for the year ended February 28, 2011.

Interest income decreased $11,361, or 84.2%, for the year ended February 28, 2011, in comparison to the year ended February 28. 2010. This decrease relates directly to lower average cash balances for the year ended February 28, 2011.

Interest expense increased by $152,636 for the year ended February 28, 2011, in comparison to the year ended February 28, 2010. The increase in interest expense is directly related to interest on short-term and long-term borrowing that occurred during the year ended February 28, 2011.

Due to the nature of our business, we expect that revenues, as well as all categories of expenses, will continue to fluctuate substantially quarter-to-quarter and year-to-year. Production costs will fluctuate according to the number and percentage ownership of producing wells, as well as the amount of revenues being contributed by such wells. Exploration and drilling expenses will be dependent upon the amount of capital that we have to invest in future development projects, as well as the success or failure of such projects. Likewise, the amount of DD&A expense will depend upon the factors cited above, as well as numerous other factors including general market conditions. An immediate goal for this current year is to improve cash flow to cover the current level of G&A expenses and to fund our development drilling in California.

Fiscal Year 2011 Compared to Fiscal Year 2010 – Discontinued Operations

This discussion comparing the year ended February 28, 2011 results with year ended February 28, 2010 results covers our discontinued operations in the East Gilbertown Field in Alabama.

Effective March 1, 2010, Daybreak assigned its interest in the East Gilbertown Field in Alabama to a third party. The cost and expense information for the years ended February 28, 2011 and 2010 reflects certain credits that result in this information being additions to revenue rather than deductions from revenue.

In accordance with the guidance governing accounting for impairment or disposal of long-lived assets, net results of operations for the East Gilbertown Field are set forth in the table below. The East Gilbertown Field information is presented on the Statement of Operations in the caption "Discontinued Operations" under the appropriate fiscal year.

	Year Ended February 28, 2011	Year Ended February 28, 2010
Oil sales revenue – East Gilbertown Field	$ —	— 84,353
Cost and expenses	731	23,246
Income (loss) from discontinued operations	$ 731	$ 107,599

Summary

We are continuing to execute the Company's business plan of developing Daybreak's acreage position in Kern County, California. The production and operating infrastructure is now in place and operating. We will continue to focus our efforts on drilling development wells, as well as drilling several exploration wells over the next year; which, coupled with the completion of our production and operating infrastructure and with the expectation for higher oil prices, will increase our net cash flow.

We anticipate the need to obtain funds for our future exploration and development activities through various methods, including issuing debt securities, equity securities, bank debt, or combinations of these instruments which could result in dilution to existing security holders and increased debt and leverage. We are pursuing financing alternatives; however, no assurance can be given that we will be able to obtain any additional financing on favorable terms, if at all.

Off-Balance Sheet Arrangements

As of February 28, 2011, we did not have any relationships with unconsolidated entities or financial partners, such as entities often referred to as structured finance or special purpose entities, which have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. As such, we are not materially exposed to any financing, liquidity, market or credit risk that could arise if we had engaged in such relationships.

Critical Accounting Policies

Management's discussion and analysis of our financial condition and results of operations are based on our financial statements, which have been prepared in conformity with accounting principles generally accepted in the United States of America. The preparation of these financial statements requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

On an ongoing basis, we evaluate our estimates, including those related to revenue recognition, bad debts, cancellation costs associated with long term commitments, investments, intangible assets, assets subject to disposal, income taxes, service contracts, contingencies and litigation. We base our estimates on historical experience and on various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making estimates and judgments about the carrying value of assets and liabilities that are not readily apparent from other sources. Estimates, by their nature, are based on judgment and available information. Therefore, actual results could differ from those estimates and could have a material impact on our financial statements, and it is possible that such changes could occur in the near term.

Oil and Gas Properties

We use the successful efforts method of accounting for oil and gas property acquisition, exploration, development, and production activities. Costs to acquire mineral interests in oil and gas properties, to drill and equip exploratory wells that find proved reserves, and to drill and equip development wells are capitalized as incurred. Costs to drill exploratory wells that are unsuccessful in finding proved reserves are expensed as incurred. In addition, the geological and geophysical costs, and costs of carrying and retaining unproved properties are expensed as incurred. Costs to operate and maintain wells and field equipment are expensed as incurred.

Capitalized proved property acquisition costs are amortized by field using the unit-of-production method based on proved reserves. Capitalized exploration well costs and development costs (plus estimated future dismantlement, surface restoration, and property abandonment costs, net of equipment salvage values) are amortized in a similar fashion (by field) based on their proved developed reserves. Support equipment and other property and equipment are depreciated over their estimated useful lives.

Pursuant to Financial Accounting Standards Board Codification ("ASC") Topic 360, *"Property, Plant and Equipment,"* we review proved oil and natural gas properties and other long-lived assets for impairment. These reviews are predicated by events and circumstances, such as downward revision of the reserve estimates or commodity prices, that indicate a decline in the recoverability of the carrying value of such properties. We estimate the future cash flows expected in connection with the properties and compare such future cash flows to the carrying amount of the properties to determine if the carrying amount is recoverable. When the carrying amounts of the properties exceed their estimated undiscounted future cash flows, the carrying amounts of the properties are reduced to their estimated fair value. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity prices, the timing of future production, future capital expenditures and a risk-adjusted discount rate. The charge is included in DD&A.

Unproved oil and gas properties that are individually significant are also periodically assessed for impairment of value. An impairment loss for unproved oil and gas properties is recognized at the time of impairment by providing an impairment allowance.

On the retirement or sale of a partial unit of proved property, the cost is charged to accumulated DD&A with a resulting gain or loss recognized in income.

Deposits and advances for services expected to be provided for exploration and development or for the acquisition of oil and gas properties are classified as long term other assets.

Revenue Recognition

We use the sales method to account for sales of crude oil and natural gas. Under this method, revenues are recognized based on actual volumes of oil and gas sold to purchasers. The volumes sold may differ from the volumes to which we are entitled based on our interests in the properties. These differences create imbalances, which are recognized as a liability only when the imbalance exceeds the estimate of remaining reserves. We had no significant imbalances as of February 28, 2011 and 2010.

Suspended Well Costs

We account for any suspended well costs in accordance with FASB ASC Topic 932, *"Extractive Activities – Oil and Gas"* ("ASC 932"). ASC 932 states that exploratory well costs should continue to be capitalized if: (1) a sufficient quantity of reserves are discovered in the well to justify its completion as a producing well and (2) sufficient progress is made in assessing the reserves and the economic and operating feasibility of the well. If the exploratory well costs do not meet both of these criteria, these costs should be expensed, net of any salvage value. Additional annual disclosures are required to provide information about management's evaluation of capitalized exploratory well costs.

In addition, ASC 932 requires annual disclosure of: (1) net changes from period to period of capitalized exploratory well costs for wells that are pending the determination of proved reserves, (2) the amount of exploratory well costs that have been capitalized for a period greater than one year after the completion of drilling and (3) an aging of exploratory well costs suspended for greater than one year, designating the number of wells the aging is related to. Further, the disclosures should describe the activities undertaken to evaluate the reserves and the projects, the information still required to classify the associated reserves as proved and the estimated timing for completing the evaluation.

Share Based Payments

Share based awards are accounted for under FASB Topic ASC 718, *"Compensation-Stock Compensation"* ("ASC 718"). ASC 718 requires compensation costs for all share based payments granted to be based on the grant date fair value. The value of the portion of the award that is ultimately expected to vest is recognized as expense ratably over the requisite service periods.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

As a smaller reporting company, we are not required to provide the information otherwise required by this Item.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Daybreak Oil and Gas, Inc.
Spokane, Washington

We have audited the accompanying balance sheets of Daybreak Oil and Gas, Inc. as of February 28, 2011 and 2010 and the related statements of operations, stockholders' 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 an audit 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 audits 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 financial statements referred to above present fairly, in all material respects, the financial position of Daybreak Oil and Gas, Inc. as of February 28, 2011 and 2010 and the results of its operations and its cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

The accompanying financial statements have been prepared assuming that Daybreak Oil and Gas, Inc. will continue as a going concern. As discussed in Note 2 to the financial statements, Daybreak Oil and Gas, Inc. suffered losses from operations and has negative operating cash flows, which raises substantial doubt about its ability to continue as a going concern. Management's plans regarding those matters are also described in Note 2. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

/s/ MaloneBailey, LLP
www.malonebailey.com
Houston, Texas

May 26, 2011

DAYBREAK OIL AND GAS, INC.
Balance Sheets
As of February 28, 2011 and 2010

	2011	2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 57,380	$ 247,951
Accounts receivable:		
Oil and gas sales	185,836	257,110
Joint interest participants, net of allowance for doubtful accounts of $33,346 and $16,237 respectively	163,551	215,648
Receivables associated with assets held for sale, net of allowance for doubtful accounts of $38,012 in 2010	—	303,097
Production revenue receivable	25,000	25,000
Refunds	91,632	—
Prepaid expenses and other current assets	69,876	21,735
Total current assets	593,275	1,070,541
OIL AND GAS PROPERTIES, net of accumulated depletion, depreciation, amortization, and impairment, of $871,666 and $1,783,258 respectively, successful efforts method		
Proved properties	1,837,431	1,189,566
Unproved properties	452,570	21,233
VEHICLES AND EQUIPMENT, net of accumulated depreciation of $31,329 and $29,841 respectively	—	1,488
PRODUCTION REVENUE RECEIVABLE - LONG TERM	325,000	325,000
OTHER ASSETS	104,904	402,208
Total assets	$ 3,313,180	$ 3,010,036
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable and other accrued liabilities	$ 1,790,382	$ 1,240,909
Accounts payable-related parties	156,370	31,898
Liabilities associated with assets held for sale	—	110,124
Accrued interest	5,477	5,408
Notes payable, net of discount, $30,105	719,895	—
Total current liabilities	2,672,124	1,388,339
LONG TERM LIABILITIES:		
Notes payable, net of discount of $99,106 and $110,056 respectively	495,894	454,944
Asset retirement obligation	55,122	53,318
Total liabilities	3,223,140	1,896,601
COMMITMENTS		
STOCKHOLDERS' EQUITY:		
Preferred stock - 10,000,000 shares authorized, $0.001 par value;	—	—
Series A Convertible Preferred stock - 2,400,000 shares authorized, $0.001 par value, 6% cumulative dividends; 906,565 shares and 1,008,565 shares issued and outstanding respectively	907	1,009
Common stock- 200,000,000 shares authorized; $0.001 par value, 48,791,599 and 47,785,599 shares issued and outstanding respectively	48,792	47,786
Additional paid-in capital	22,447,250	22,255,802
Accumulated deficit	(22,406,909)	(21,191,162)
Total stockholders' equity	90,040	1,113,435
Total liabilities and stockholders' equity	$ 3,313,180	$ 3,010,036

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

DAYBREAK OIL AND GAS, INC.
Statements of Operations
For the Years Ended February 28, 2011 and 2010

	Years Ended	
	February 28, 2011	February 28, 2010
REVENUE:		
Oil and gas sales	$ 1,079,496	$ 471,442
OPERATING EXPENSES:		
Production costs	172,250	269,820
Exploration and drilling	184,255	301,912
Depreciation, depletion, amortization, and impairment	307,023	550,755
Gain on write-off of asset retirement obligation	(8,324)	—
Bad debt expense (recovery)	(3,928)	113,528
General and administrative	1,494,969	1,606,874
Total operating expenses	2,146,245	2,842,889
OPERATING LOSS	(1,066,749)	(2,371,447)
OTHER INCOME (EXPENSE):		
Interest income	2,126	13,487
Interest expense	(162,140)	(9,504)
Total other income (expense)	(160,014)	3,983
LOSS FROM CONTINUING OPERATIONS	(1,226,763)	(2,367,464)
DISCONTINUED OPERATIONS		
Income from discontinued operations (net of tax of $-0-)	731	107,599
Gain from sale of oil and gas properties (net of tax of $-0-)	10,285	—
INCOME FROM DISCONTINUED OPERATIONS	11,016	107,599
NET LOSS	(1,215,747)	(2,259,865)
Cumulative convertible preferred stock dividend requirement	(173,893)	(188,824)
NET LOSS AVAILABLE TO COMMON SHAREHOLDERS	$ (1,389,640)	$ (2,448,689)
NET INCOME (LOSS) PER COMMON SHARE		
Loss from continuing operations	$ (0.03)	$ (0.05)
Income from discontinued operations	0.00	0.00
NET LOSS PER COMMON SHARE - Basic and diluted	$ (0.03)	$ (0.05)
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING -		
Basic and diluted	48,300,733	47,207,830

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

DAYBREAK OIL AND GAS, INC.
Statements of Changes in Stockholders' Equity
For the Years Ended February 28, 2010 and 2011

	Series A Convertible Preferred Stock		Common Stock		Additional Paid-In Capital	Accumulated Deficit	Total
	Shares	Amount	Shares	Amount			
BALANCE, FEBRUARY 28, 2009	1,060,465	$ 1,061	45,079,899	$ 45,081	$ 22,047,360	$ (18,931,297)	$ 3,162,205
Issuance of common stock for:							
Company stock plan	—	—	2,550,000	2,550	75,596	—	78,146
Conversion of preferred stock	(51,900)	(52)	155,700	155	(103)	—	—
Issuance of warrants related to private placement	—	—	—	—	21,676	—	21,676
Warrants issued in connection with debt	—	—	—	—	111,273	—	111,273
Net loss	—	—	—	—	—	(2,259,865)	(2,259,865)
BALANCE, FEBRUARY 28, 2010	1,008,565	$ 1,009	47,785,599	$ 47,786	$ 22,255,802	$ (21,191,162)	$ 1,113,435
Issuance of common stock for:							
Company stock plan	—	—	450,000	450	88,058	—	88,508
Conversion of preferred stock	(102,000)	(102)	306,000	306	(204)	—	—
Loan origination fees			250,000	250	23,500	—	23,750
Debt discount on notes payable	—	—	—	—	65,494	—	65,494
Warrants issued in connection with fundraising	—	—	—	—	14,600	—	14,600
Net loss	—	—	—	—	—	(1,215,747)	(1,215,747)
BALANCE, FEBRUARY 28, 2011	906,565	$ 907	48,791,599	$ 48,792	$ 22,447,250	$ (22,406,909)	$ 90,040

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

DAYBREAK OIL AND GAS, INC.
Statements of Cash Flows
For the Years Ended February 28, 2011 and 2010

	Years Ended	
	February 28, 2011	February 28, 2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (1,215,747)	$ (2,259,865)
Adjustments to reconcile net loss to net cash used in operating activities:		
Stock compensation	88,508	78,146
Gain on write-off of asset retirement obligation	(8,324)	—
Gain on sale of oil and gas properties	(10,285)	—
Depreciation, depletion, and impairment expense	307,023	551,430
Amortization of debt discount	46,339	1,217
Amortization of loan origination fees	11,875	—
Bad debt expense (recovery)	(3,928)	113,528
Non cash interest income	(2,124)	(11,754)
Non cash general and administrative expense	—	21,676
Warrant expense for services	14,600	—
Changes in assets and liabilities:		
Accounts receivable - oil and gas sales	71,274	(243,379)
Accounts receivable - joint interest participants	56,025	(147,491)
Accounts receivable - refunds	(91,632)	—
Receivables associated with assets held for sale	303,097	—
Prepaid expenses and other current assets	(36,266)	(18,845)
Accounts payable and other accrued liabilities	529,697	(789,742)
Accounts payable - related parties	124,472	—
Accrued interest	69	5,408
Net cash provided by (used in) operating activities	184,673	(2,699,671)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Disposition of other assets	299,428	—
Additions to oil and gas properties	(1,454,672)	(662,688)
Proceeds from sale of oil and gas properties	—	762,500
Net cash provided by (used in) investing activities	(1,155,244)	99,812
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from issuance of notes payable	780,000	565,000
NET DECREASE IN CASH AND CASH EQUIVALENTS	(190,571)	(2,034,859)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	247,951	2,282,810
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 57,380	$ 247,951
CASH PAID FOR:		
Interest	$ 141,357	$ 4,096
Income taxes	$ —	$ —
SUPPLEMENTAL CASH FLOW INFORMATION:		
Acquisition of additional working interest through assumption of liability	$ —	$ 1,454,372
Unpaid additions to oil and gas properties	$ 271,979	$ 361,994
Addition to asset retirement obligation, net	$ 14,561	$ —
Discount on notes payable - Long term	$ 5,284	$ —
Discount on notes payable - Short term	$ 60,210	$ —
Conversion of preferred stock to common stock	$ 306	$ 155
Stock issued for loan origination fees	$ 23,750	$ —
Debt discount from warrants issued with debt	$ —	$ 111,273

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

NOTE 1 — ORGANIZATION:

Originally incorporated as Daybreak Uranium, Inc., ("Daybreak Uranium") under the laws of the State of Washington on March 11, 1955, Daybreak Uranium was organized to explore for, acquire, and develop mineral properties in the Western United States. During 2005, management of the Company decided to enter the oil and gas exploration and production industry. On October 25, 2005, the shareholders approved a name change from Daybreak Mines, Inc. to Daybreak Oil and Gas, Inc. (referred to herein as "Daybreak" or the "Company") to better reflect the business of the Company.

All of the Company's oil and gas production is sold under contracts that are market-sensitive. Accordingly, the Company's financial condition, results of operations, and capital resources are highly dependent upon prevailing market prices of, and demand for, oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond the control of the Company. These factors include the level of global demand for petroleum products, foreign supply of oil and gas, the establishment of and compliance with production quotas by oil-exporting countries, the relative strength of the U.S. dollar, weather conditions, the price and availability of alternative fuels, and overall economic conditions, both foreign and domestic.

NOTE 2 — GOING CONCERN:

Financial Condition

Daybreak's financial statements for the year ended February 28, 2011 have been prepared on a going concern basis, which contemplates the realization of assets and the settlement of liabilities in the normal course of business. Daybreak has incurred net losses since inception and has accumulated a deficit of $22,406,909 and a working capital deficit of $2,078,849, which raises substantial doubt about the Company's ability to continue as a going concern.

Management Plans to Continue as a Going Concern

The Company continues to implement plans to enhance its ability to continue as a going concern. Daybreak currently has a net revenue interest in eleven producing wells in its East Slopes Project located in Kern County, California (the "East Slopes Project"). The revenue from these wells has created a steady and reliable source of revenue for the Company.

On September 17, 2010, the Company exercised a preferential right to acquire an additional 16.67% working interest from another working interest owner in the East Slopes Project. Since the purchase of the additional working interest Daybreak's average monthly revenue from the five wells affected by this purchase has increased by 75.76% or approximately $19,345 per month over the last six months of the year ended February 28, 2011. With this purchase of additional working interest and the completion of two additional wells in October 2010 the Company's average net revenue interest in eleven producing wells in Kern County, California is now 29.85%. The Company's average working interest is 40.15% for these same wells.

Daybreak anticipates revenues will continue to increase as the Company participates in the drilling of more wells in the East Slopes Project. The Company plans to continue its development drilling program at a rate that is compatible with its cash flow and funding opportunities.

On January 13, 2010, Daybreak commenced a private placement of 12% Subordinated Notes. The Company sold $595,000 of Notes to 13 accredited investors. The private placement concluded on March 16, 2010.

On September 17, 2010, the Company financed an additional working interest purchase in its East Slopes Project by issuing, to a third party, a one-year convertible secured promissory note for the principal amount of $750,000 (the "Loan"), subject to an annual interest rate of 10% per annum, which was prepaid at closing.

On March 15, 2010, the Company finalized the sale of its 12.5% working interest in the East Gilbertown Field in Choctaw County, Alabama. This sale helped the Company by improving its cash reserves and allowed Daybreak to focus on its East Slopes Project.

Sources of funds in the past for the Company have included the debt or equity markets and, while the Company does have positive cash flow from its oil and gas properties, it has not yet established a positive cash flow on a company-wide basis. Daybreak anticipates it may be necessary to rely on additional funding from the private or public debt or equity markets in the future. However, the Company cannot offer any assurance that it will be successful in executing the aforementioned plans to continue as a going concern.

Daybreak's financial statements as of February 28, 2011 do not include any adjustments that might result from the inability to implement or execute Daybreak's plans to improve our ability to continue as a going concern.

NOTE 3 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Cash and Cash Equivalents

Cash equivalents include demand deposits with banks and all highly liquid investments with original maturities of three months or less.

The Company routinely maintains balances in financial institutions where deposits are guaranteed by the Federal Deposit Insurance Corporation ("FDIC"). As of February 28, 2011, the Company had no cash deposits in excess of FDIC insured limits at various financial institutions.

Accounts Receivable

The Company routinely assesses the recoverability of all material trade and other receivables. The Company accrues a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of any reserve may be reasonably estimated. Actual write-offs may exceed the recorded allowance. As of February 28, 2011 and 2010 the Company has recognized an allowance for doubtful accounts of $33,346 and $16,237 respectively.

Oil and Gas Properties

The Company uses the successful efforts method of accounting for oil and gas property acquisition, exploration, development, and production activities. Costs to acquire mineral interests in oil and gas properties, to drill and equip exploratory wells that find proved reserves, and to drill and equip development wells are capitalized as incurred. Costs to drill exploratory wells that are unsuccessful in finding proved reserves are expensed as incurred. In addition, the geological and geophysical costs, and costs of carrying and retaining unproved properties are expensed as incurred. Costs to operate and maintain wells and field equipment are expensed as incurred.

Capitalized proved property acquisition costs are amortized by field using the unit-of-production method based on estimated proved reserves. Capitalized exploration well costs and development costs (plus estimated future dismantlement, surface restoration, and property abandonment costs, net of equipment salvage values) are amortized in a similar fashion (by field) based on their estimated proved developed reserves. Support equipment and other property and equipment are depreciated over their estimated useful lives.

Pursuant to the provisions of Financial Accounting Standards B Codification ("ASC") Topic 360, *"Property, Plant and Equipment"* the Company reviews proved oil and natural gas properties and other long-lived assets for impairment. These reviews are predicated by events and circumstances, such as downward revision of the reserve estimates or commodity prices that indicate a decline in the recoverability of the carrying value of such properties. The Company estimates the future cash flows expected in connection with the properties and compares such future cash flows to the carrying amount of the properties to determine if the carrying amount is recoverable. When the carrying amounts of the properties exceed their estimated undiscounted future cash flows, the carrying amounts of the properties are reduced to their estimated fair value. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity prices, the timing of future production, future capital expenditures and a risk-adjusted discount rate. These estimates of future product prices may differ from current market prices of oil and gas. Any downward revisions to management's estimates of future production or product prices could result in an impairment of the Company's oil and gas properties in subsequent periods. Unproved oil and gas properties that are individually significant are also periodically assessed for impairment of value. An impairment loss for unproved oil and gas properties is recognized at the time of impairment by providing an impairment allowance.

Asset impairments of $-0- and $341,871 were recorded for the years ended February 28, 2011 and 2010, respectively which is included in Depreciation, Depletion, Amortization ("DD&A") in the statements of operations.

On the retirement or sale of a partial unit of proved property, the cost is charged to accumulated DD&A with a resulting gain or loss recognized in income.

Property and Equipment

Fixed assets are stated at cost. Depreciation on vehicles is provided using the straight line method over expected useful lives of three years. Depreciation on machinery and equipment is provided using the straight line method over expected useful life of three years. Depreciation of production facilities is recorded using the unit-of-production method based on estimated reserves.

Long Lived Assets

The Company reviews long-lived assets and identifiable intangibles whenever events or circumstances indicate that the carrying amounts of such assets may not be fully recoverable. The Company evaluates the recoverability of long-lived assets by measuring the carrying amounts of the assets against the estimated undiscounted cash flows associated with these assets. If this evaluation indicates that the future undiscounted cash flows of certain long-lived assets are not sufficient to recover the assets' carrying value, the assets are adjusted to their fair values (based upon discounted cash flows).

Fair Value of Financial Instruments

The carrying value of short-term financial instruments including cash, receivables, prepaid expenses, accounts payable, and other accrued liabilities approximated their fair values due to the relatively short period to maturity for these instruments. The long-term notes payable approximate fair value since the related rates of interest approximate current market rates.

Share Based Payments

Stock awards are accounted for under FASB ASC Topic 718, *"Compensation-Stock Compensation"* ("ASC 718"). Under ASC 718, compensation for all share-based payment awards is based on estimated fair value at the grant date. The value of the portion of the award that is ultimately expected to vest is recognized as expense on a straight-line basis over the requisite service periods, if any.

The Company estimates the fair value of stock purchase warrants ("Warrants") on the grant date using an option-pricing model. The Company uses the Black-Scholes option pricing model ("Black-Scholes Model") as its method of valuation for Warrant awards granted during the year. The Company's determination of fair value of Warrant awards on the date of grant using an option-pricing model is affected by the Company's stock price, as well as assumptions regarding a number of subjective variables. These variables include, but are not limited to, the Company's expected price volatility over the term of the awards and discount rates assumed.

Loss per Share of Common Stock

Basic loss per share of Common Stock is calculated by dividing net loss available to common stockholders by the weighted average number of common shares issued and outstanding during the year. Diluted net loss per share is computed based on the weighted average number of common shares outstanding, increased by dilutive Common Stock equivalents. Common Stock equivalents are excluded from the calculations when their effect is anti-dilutive.

Concentration of Credit Risk

Substantially all of the Company's accounts receivable result from crude oil and natural gas sales or joint interest billings to its working interest partners. This concentration of customers and joint interest owners may impact the Company's overall credit risk as these entities could be affected by similar changes in economic conditions as well as other related factors. Accounts receivable are generally not collateralized. Allowances for doubtful accounts at February 28, 2011 and 2010 relate to amounts due from joint interest owners.

At the Company's Kern County, California project, there is only one buyer for the purchase of oil production. At February 28, 2011, one customer represented 100.0% of crude oil sales receivable.

A table disclosing the total amount of revenues from any single customer that exceeds 10% of total revenues follows:

			For the Year Ended February 28, 2011		For the Year Ended February 28, 2010	
Project	**Location**	**Customer**	**Revenue**	**Percentage**	**Revenue**	**Percentage**
East Slopes	California	Plains Marketing	$ 975,479	90.4%	$ 469,357	84.5%
Gilbertown*	Alabama	Hunt Crude Oil Supply	$ -0-	-0-%	$ 84,353	15.2%

* Discontinued operation, we did not have any revenue from the East Gilbertown Field during the year ended February 28, 2011

Revenue Recognition

The Company uses the sales method to account for sales of crude oil and natural gas. Under this method, revenues are recognized based on actual volumes of oil and gas sold to purchasers. The volumes sold may differ from the volumes to which the Company is entitled based on its interests in the properties. These differences create imbalances that are recognized as a liability only when the imbalance exceeds the estimate of remaining reserves. The Company had no significant imbalances as of February 28, 2011 and 2010.

Reclamation Bonds

Included in other assets as of February 28, 2011, are funds which have been pledged as collateral in connection with asset retirement obligations for future plugging, abandonment and site remediation. The amount pledged for an operator bond in California is approximately $100,000 plus accrued interest. The pledging of these funds is required by any state in which the Company operates.

Asset Retirement Obligation

The Company follows the provisions of FASB ASC Topic 410, *"Asset Retirement and Environmental Obligations"* ("ASC 410"), which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. This standard requires that the Company recognize the fair value of a liability for an asset retirement obligation ("ARO") in the period in which it is incurred. The ARO is capitalized as part of the carrying value of the assets to which it is associated, and depreciated over the useful life of the asset. The ARO and the related asset retirement cost are recorded when an asset is first drilled, constructed or purchased. The asset retirement cost is determined and discounted to present value using a credit-adjusted risk-free rate. After initial recording, the liability is increased for the passage of time, with the increase being reflected as accretion expense in the statements of operations. Subsequent adjustments in the cost estimate are reflected in the ARO liability and the amounts continue to be amortized over the useful life of the related long-lived assets.

Suspended Well Costs

The Company accounts for any suspended well costs in accordance with FASB ASC Topic 932, *"Extractive Activities – Oil and Gas"* ("ASC 932"). ASC 932 states that exploratory well costs should continue to be capitalized if: (1) a sufficient quantity of reserves are discovered in the well to justify its completion as a producing well and (2) sufficient progress is made in assessing the reserves and the economic and operating feasibility of the well. If the exploratory well costs do not meet both of these criteria, these costs should be expensed, net of any salvage value. Additional annual disclosures are required to provide information about management's evaluation of capitalized exploratory well costs.

In addition, ASC 932 requires annual disclosure of: (1) net changes from period to period of capitalized exploratory well costs for wells that are pending the determination of proved reserves, (2) the amount of exploratory well costs that have been capitalized for a period greater than one year after the completion of drilling and (3) an aging of exploratory well costs suspended for greater than one year, designating the number of wells the aging is related to. Further, the disclosures should describe the activities undertaken to evaluate the reserves and the projects, the information still required to classify the associated reserves as proved and the estimated timing for completing the evaluation.

Income Taxes

On March 1, 2007, the Company adopted the provisions of FASB ASC Topic 740, *"Income Taxes"* ("ASC 740"). As required under ASC 740, the Company accounts for income taxes using an asset and liability approach, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the financial statements and tax bases of assets and liabilities at the applicable tax rates. A valuation allowance is utilized when it is more likely than not, that some portion of, or all of the deferred tax assets will not be realized. Deferred tax assets and liabilities are adjusted for the effects of changes in tax laws and rates on the date of enactment.

ASC 740 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. Under ASC 740, the Company recognizes 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.

Use of Estimates and Assumptions

In preparing financial statements in conformity with accounting principles generally accepted in the United States of America, management is required to make estimates and assumptions. These estimates and assumptions may affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and reported amounts of revenues and expenses during the reporting periods. Actual results could differ materially from those estimates. The accounting policies most affected by management's estimates and assumptions are as follows:

- The reliance on estimates of proved reserves to compute the provision for depreciation, depletion and amortization and to determine the amount of any impairment of proved properties;
- The valuation of unproved acreage and proved oil and gas properties to determine the amount of any impairment of oil and gas properties;
- Judgment regarding the productive status of in-progress exploratory wells to determine the amount of any provision for abandonment; and
- Estimates regarding the timing and cost of future abandonment obligations.

Recent Accounting Pronouncements

In January 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2010-06, Improving Disclosures about Fair Value Measurements (ASU 2010-06). This update provides amendments to Subtopic 820-10 and requires new disclosures for 1) significant transfers in and out of Level 1 and Level 2 and the reasons for such transfers and 2) activity in Level 3 fair value measurements to show separate information about purchases, sales, issuances and settlements. In addition, this update amends Subtopic 820-10 to clarify existing disclosures around the disaggregation level of fair value measurements and disclosures for the valuation techniques and inputs utilized (for Level 2 and Level 3 fair value measurements). The provisions in ASU 2010-06 are applicable to interim and annual reporting periods beginning subsequent to December 15, 2009, with the exception of Level 3 disclosures of purchases, sales, issuances and settlements, which will be required in reporting periods beginning after December 15, 2010. The adoption of ASU 2010-06 did not impact the Company's operating results, financial position or cash flows and related disclosures.

In February 2010, FASB issued ASU No. 2010-09, Amendments to Certain Recognition and Disclosure Requirements (ASU 2010-09). This update amends Subtopic 855-10 and gives a definition to the Securities and Exchange Commission (the "SEC") filer, and requires SEC filers to assess for subsequent events through the issuance date of the financial statements. This amendment states that an SEC filer is not required to disclose the date through which subsequent events have been evaluated for a reporting period. ASU 2010-09 becomes effective upon issuance of the final update. The Company has adopted the provisions of ASU 2010-09.

Reclassifications

Certain reclassifications have been made to conform the prior period's financial information to the current period's presentation. These reclassifications had no effect on previously reported net loss or accumulated deficit.

NOTE 4 — ACCOUNTS RECEIVABLE:

Accounts receivable consists primarily of receivables from the sale of oil and gas production by the Company and receivables from the Company's working interest partners in oil and gas projects in which the Company acts as Operator of the project.

Oil and gas sales receivables balances at February 28, 2011 and 2010 represent oil sales that occurred during the months of February 2011 and 2010, respectively.

Joint interest participant receivables balances at February 28, 2011 and 2010 represent amounts due from working interest partners net of an allowance for doubtful accounts of $33,346 and $ 16,237, respectively. The allowance for doubtful accounts balance at February 28, 2011 includes $32,035 related to partner receivables from projects in which the Company no longer participates. The Company is still in the process of trying to collect from these working interest partners.

Production revenue receivable balances, both current and long-term, of $350,000 represent amounts due the Company from a portion of the sale price of a 25% working interest in East Slopes Project in Kern County, California that was acquired through the default of certain original working interest partners in the project.

Refund receivables balance is comprised of refunds for franchise tax and legal expenses that the Company is due at February 28, 2011.

NOTE 5 — OIL AND GAS PROPERTIES:

On March 19, 2010, the Company closed on the sale of its interest in the East Gilbertown Field in Choctaw County, Alabama to a third party with an effective date of March 1, 2010. There was no effect on net oil and gas property balances from the sale of this property since the Company had previously fully impaired its capitalized cost of approximately $257,000 in this property due to low oil prices in prior periods. In connection with the sale, the Company recognized a gain from sale of oil and gas properties for the year ended February 28, 2011 of $10,285 which is presented under “Discontinued Operations” in the Statement of Operations and discussed in Note 8 below. The gain resulted mainly from the extinguishment of certain liabilities associated with the Gilbertown interest.

On September 17, 2010, the Company exercised a preferential right to acquire an additional 16.67% working interest from another working interest owner in the East Slopes Project. This purchase resulted in an increase to the gross balances of proved oil and gas properties of approximately $61,869 and unproved oil and gas properties of approximately $421,464.

Oil and gas properties, at cost:

	February 28, 2011	February 28. 2010
Proved leasehold costs	$ 8,975	$ 6,720
Unproved leasehold costs	452,570	17,350
Costs of wells and development	422,694	285,896
Capitalized exploratory well costs	2,229,511	1,439,126
Capitalized asset retirement costs	47,909	33,349
Total cost of oil and gas properties	3,161,659	1,782,441
Accumulated depletion, depreciation amortization and impairment	(871,658)	(571,642)
Oil and gas properties, net	$ 2,290,001	$ 1,210,799

Asset Retirement Obligation

The Company’s financial statements reflect the provisions of ASC 410. The ARO primarily represents the estimated present value of the amount the Company will incur to plug, abandon and remediate its producing properties at the end of their productive lives, in accordance with applicable state laws. The Company determines the ARO on its oil and gas properties by calculating the present value of estimated cash flows related to the liability. As of February 28, 2011 and 2010, ARO obligations were considered to be long term based on the estimated timing of the anticipated cash flows. For the years ended February 28, 2011 and 2010, the Company recognized accretion expense of $5,519 and $3,325, respectively, which is included in DD&A in the statement of operations.

Changes in the asset retirement obligations for the year ended February 28, 2011are set forth in the table below.

Asset retirement obligation, beginning of period	$ 53,318
Accretion expense	5,519
Asset retirement additions	35,305
Change in asset retirement estimates	(20,744)
Asset retirement obligation, due to sale of assets	(18,276)
Asset retirement obligation, end of period	$ 55,122

NOTE 6 — ACCOUNTS PAYABLE:

On March 1, 2009, the Company became the operator for its East Slopes Project located in Kern County, California. Additionally, the Company then assumed certain original defaulting partners' approximate $1.5 million liability representing a 25% working interest in the drilling and completion costs associated with the East Slopes Project four earning wells program. The Company subsequently sold the 25% working interest on June 11, 2009. Approximately $329,834 of the $1.5 million default remains unpaid and is included in the February 28, 2011 accounts payable balance.

NOTE 7 — NOTES PAYABLE:

Short-Term

On September 17, 2010, the Company exercised a preferential right to acquire an additional 16.67% working interest in its East Slopes Project from another working interest owner. The Company financed the additional working interest purchase by issuing, to a third party, a one-year convertible secured promissory note for the principal amount of $750,000 (the "Loan"), subject to an annual interest rate of 10% per annum, which was prepaid at closing. Interest expense related to the Loan for the year ended February 28, 2011 was $37,500. Unamortized interest expense amounted to $37,500 as of February 28, 2011.

The third party may convert up to 50% of the unpaid principal balance into the Company's Common Stock at a conversion price of $0.16 per share at any time prior to the Loan being paid in full.

The Company also issued 250,000 shares of the Company's Common Stock to the third party as a loan origination fee. The fair value of these shares amounted to $23,750 which was deferred and amortized over the term of the Loan. Amortization expense for the year ended February 28, 2011 was $11,875. Unamortized loan origination fee expense amounted to $11,875 as of February 28, 2011.

The Loan is secured by a Mortgage, Deed of Trust, Assignment of Production, Security Agreement and Financing Statement on the Sunday and Bear leases in the Company's East Slopes Project. Furthermore, as a condition precedent to the Loan, the Company entered into a Technical and Consulting Services Agreement with the third party, whereby the Company will provide operating, engineering and technical consulting to the third party for a one-year period for the purpose of evaluating 22 wells in Hutchinson County, Texas for the third party.

As additional consideration for the Loan the Company executed an Assignment of Net Profits Interest in favor of the third party, whereby the Company assigned two percent of the net profits realized by the Company on its leases in the East Slopes Project. The fair value of the two percent net profits interest was determined to be $60,210 and has been recognized as a discount to the debt to be amortized over the term of the Loan. Amortization expense for the year ended February 28, 2011 amounted to $30,105. Unamortized debt discount amounted to $30,105 as of February 28, 2011.

The Company analyzed the Loan for derivative accounting consideration and determined that derivative accounting does not apply to this instrument.

Long-Term

12% Subordinated Notes

On January 13, 2010 the Company commenced a private placement of 12% Subordinated Notes ("Notes"). On March 16, 2010, the Company closed its private placement of Notes to 13 accredited investors resulting in total gross proceeds of $595,000. The note principal is payable in full at the expiration of the term of the Notes, which is January 29, 2015. The Notes are subject to an annual interest rate of 12%, payable semi-annually, and mature on January 29, 2015. On the maturity date, the Company may elect a mandatory conversion of the unpaid principal and interest into the Company's Common Stock at a conversion rate equal to 75% of the average closing price of the Company's Common Stock over the 20 consecutive trading days preceding December 31, 2014. A total of $250,000 in Notes was sold to a related party, the Company's President and Chief Executive Officer. The terms and conditions of the related party Note were identical to the terms and conditions of the other participants' Notes.

Two Common Stock purchase warrants were issued for every dollar raised through the private placement resulting in 1,190,000 warrants being issued through the year ended February 28, 2011. The warrants have an exercise price of $0.14 and expire on January 29, 2015. The fair value of the warrants, as determined by the Black-Scholes option pricing model, was $116,557 using the following weighted-average assumptions: a risk free interest rate of 2.33%; volatility of 147.6%; and dividend yield of 0.0%. The fair value of the warrants was recognized as a discount to debt and is being amortized over the term of the Notes using the effective interest method. Amortization expense related to the Notes debt discount for the year ended February 28, 2011 amounted to $16,234. Unamortized debt discount amounted to $99,106 as of February 28, 2011.

The Company analyzed the Notes and warrants for derivative accounting consideration and determined that derivative accounting does not apply to these instruments.

NOTE 8 — DISCONTINUED OPERATIONS:

On March 15, 2010, the Company finalized the sale of its 12.5% working interest in the East Gilbertown Field located in Choctaw County, Alabama by assigning its interest to a third party.

The table below set forth the revenues and expenses related to the East Gilbertown Field for the years ended February 28, 2011 and 2010. The cost and expense information for the years ended February 28, 2011 and 2010 reflects certain credits that result in this information being additions to revenue rather than deductions from revenue.

	2011	2010
Oil sales revenue – East Gilbertown Field	$ —	$ 84,353
Cost and expenses	731	23,246
Income from discontinued operations	$ 731	$ 107,599

NOTE 9 — STOCKHOLDERS' EQUITY:

Series A Convertible Preferred Stock

The Company is authorized to issue up to 10,000,000 shares of $0.001 par value preferred stock. The Company has designated 2,400,000 shares of the 10,000,000 total preferred shares as "Series A Convertible Preferred Stock" ("Series A Preferred"), with a $0.001 par value. The Series A Preferred can be converted by the shareholder at any time into three shares of the Company's Common Stock.

At February 28, 2011, there were 906,565 shares issued and outstanding, held by accredited investors that had not been converted into the Company's Common Stock. During the year ended February 28, 2011, there were a total of 102,000 shares of Series A Preferred that were converted to 306,000 shares of Common Stock. As of February 28, 2011, there have been 30 accredited investors convert 493,200 Series A Preferred shares into 1,479,600 shares of Daybreak Common Stock. The conversions of Series A Preferred that have occurred since the Series A Preferred was first issued in July 2006 is set forth in the table below.

Fiscal Period	Shares of Series A Preferred Converted to Common Stock	Shares of Common Stock Issued from Conversion	Number of Accredited Investors
Year Ended February 29, 2008	102,300	306,900	10
Year Ended February 28, 2009	237,000	711,000	12
Year Ended February 28, 2010	51,900	155,700	4
Year Ended February 28, 2011	102,000	306,000	4
Totals	493,200	1,479,600	30

Holders of Series A Preferred earn a dividend, in the amount of 6% of the original purchase price per year. Accumulated dividends do not bear interest; and as of February 28, 2011 dividends amounted to $971,825. Dividends can be paid in cash or stock at the discretion of the Company and are payable upon declaration by the Board of Directors. Dividends are earned until the Series A Preferred is converted to Common Stock. No dividends have been declared as of February 28, 2011.

Cumulative dividends earned for each fiscal year since issuance is set forth in the table below.

Fiscal Year Ended	Shareholders at Period End	Accumulated Dividends
February 28, 2007	100	$ 155,333
February 29, 2008	90	242,165
February 28, 2009	78	209,974
February 28, 2010	74	190,460
February 28, 2011	70	173,893
		$ 971,825

Common Stock

The Company is authorized to issue up to 200,000,000 shares of $0.001 par value Common Stock of which 48,791,599 shares were issued and outstanding as of February 28, 2011. For the year ended February 28, 2011 a total of 1,006,000 shares were issued.

Share issuances of the Company's Common Stock for the year ended February 28, 2011, are set forth in the table below.

Reason for Issuances	Shares Issued
Conversion of Series A Preferred	306,000
Loan origination fees	250,000
2009 Stock Plan	450,000
	1,006,000

The 250,000 shares of the Company's Common Stock issued for loan origination fees relates to the purchase of an additional 16.67% working interest in the Company's East Slopes Project in Kern County, California as discussed in Note 5 and Note 7 above.

Common Stock Issued through Restricted Stock and Restricted Stock Unit Plan

On April 6, 2009, the Board approved the 2009 Restricted Stock and Restricted Stock Unit Plan (the "2009 Plan") allowing the executive officers, directors, consultants and employees of the Company and its affiliates to be eligible to receive restricted stock and restricted stock unit awards. Refer to the discussion in Note 11 for the issuances made under the 2009 Plan.

NOTE 10 – WARRANTS:

Warrants outstanding and exercisable as of February 28, 2011 are set forth in the table below:

Description	Warrants		Exercise Price	Remaining Life (Years)	Exercisable Warrants Remaining
Spring 2006 Common Stock Private Placement	4,013,602	$	2.00	0.25	4,013,602
Placement Agent Warrants - Spring 2006 PP	802,721	$	0.75	2.25	802,721
Placement Agent Warrants - Spring 2006 PP	401,361	$	2.00	2.25	401,361
July 2006 Preferred Stock Private Placement	2,799,530	$	2.00	0.50	2,799,530
Placement Agent Warrants - July 2006 PP	419,930	$	1.00	2.50	419,930
Convertible Debenture Term Extension	150,001	$	2.00	0.75	150,001
12% Subordinated Notes	1,190,000	$	0.14	3.75	1,190,000
Warrants Issued for Services	150,000	$	0.14	4.25	150,000
	9,927,145				9,927,145

For the year ended February 28, 2011, a total of 39,550 warrants expired. These warrants were issued to a placement agent from a private placement of Common Stock that occurred in the year ended February 28, 2008.

During the year ended February 28, 2011, a total of 210,000 warrants were issued by the Company. A total of 60,000 warrants were issued as a part of the private placement of the Subordinated Notes discussed in Note 7 above. The remaining 150,000 warrants were issued to a consultant for services rendered and expire on April 16, 2015 with an exercise price of $0.14. The fair value of the warrants, as determined by the Black-Scholes option pricing model, was $14,600 using the following assumptions: a risk free interest rate of 2.49%; volatility of 143.5%; and dividend yield of 0.0%.

There were no warrants exercised during the year ended February 28, 2011. As of February 28, 2011 and February 28, 2010, there were 9,927,145 and 9,756,695 warrants issued and outstanding, respectively.

The outstanding warrants as of February 28, 2011, have a weighted average exercise price of $1.61; a weighted average remaining life of 1.14 years; and an intrinsic value of $-0-.

NOTE 11 — RESTRICTED STOCK and RESTRICTED STOCK UNIT PLAN:

On April 6, 2009, the Board approved the 2009 Plan allowing the executive officers, directors, consultants and employees of the Company and its affiliates to be eligible to receive restricted stock and restricted stock unit awards. Subject to adjustment, the total number of shares of the Company's Common Stock that will be available for the grant of awards under the 2009 Plan may not exceed 4,000,000 shares; provided, that, for purposes of this limitation, any stock subject to an award that is forfeited in accordance with the provisions of the 2009 Plan will again become available for issuance under the 2009 Plan.

The Company believes that awards of this type further align the interests of its employees and its shareholders by providing significant incentives for these employees to achieve and maintain high levels of performance. Restricted stock and restricted stock units also enhance the Company's ability to attract and retain the services of qualified individuals.

On April 7, 2009, the Compensation Committee of the Board awarded 1,000,000 restricted shares of the Company's Common Stock to a current and a former executive officer of the Company. These shares were granted pursuant to the 2009 Plan and fully vest equally over a period of three years.

On April 7, 2009, the Compensation Committee of the Board awarded 900,000 restricted shares of the Company's Common Stock, to the five non-employee members of the Board of Directors. These shares were granted pursuant to the 2009 Plan and fully vest equally over a period of three years.

On July 16, 2009, the Compensation Committee of the Board awarded 25,000 restricted shares of the Company's Common Stock to the five non-employee directors, as part of the director compensation plan. These shares were granted pursuant to the 2009 Plan and fully vest equally over a period of three years.

On July 16, 2009, the Compensation Committee of the Board awarded 625,000 restricted shares of the Company's Common Stock, to four employees of the Company. These shares were granted pursuant to the 2009 Plan and fully vest equally over a period of four years.

On July 22, 2010, the Compensation Committee of the Board awarded 25,000 restricted shares of its Common Stock to the five non-employee Directors as a part of the director compensation plan. These shares were granted pursuant to the 2009 Plan and fully vest equally over a period of three years.

On July 22, 2010, the Compensation Committee of the Board awarded 425,000 restricted shares of its Common Stock to five employees of Daybreak. These shares were granted pursuant to the 2009 Plan and fully vest equally over a period of four years.

At February 28, 2011, a total of 1,000,000 shares remained available for issuance pursuant to the 2009 Plan. A summary of the 2009 Plan issuances is set forth in the table below:

Grant Date	Shares Awarded	Vesting Period	Shares Vested	Shares Outstanding (Unvested)
4/7/2009	1,900,000	3 Years	633,331	1,266,669
7/16/2009	25,000	3 Years	8,330	16,670
7/16/2009	625,000	4 Years	156,250	468,750
7/22/2010	25,000	3 Years	—	25,000
7/22/2010	425,000	4 Years	—	425,000
	3,000,000		797,911	2,202,089

For the year ended February 28, 2011, the Company recognized compensation expense related to the above restricted stock grants of $88,508. Unamortized compensation expense amounted to $133,272 as of February 28, 2011.

NOTE 12 — INCOME TAXES:

Reconciliation between actual tax expense (benefit) and income taxes computed by applying the U.S. federal income tax rate and state income tax rate to income from continuing operations before income taxes is as follows:

		February 28, 2011
Computed at U.S. and State statutory rates (40%)	$	(486,300)
Permanent Differences		14,731
Changes in valuation allowance		471,569
Total	$	-0-

Tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred liabilities are presented below:

	February 28, 2011	February 28, 2010
Deferred tax assets:		
Net operating loss carryforwards	$ 5,900,491	$ 5,114,269
Oil and gas properties	(226,994)	123,062
Stock based compensation	35,403	—
Less valuation allowance	(5,708,900)	(5,237,331)
Total	$ -0-	$ -0-

At February 28, 2011, the Company had a net operating loss (“NOL”) carryforwards for federal and state income tax purposes of approximately $14,751,228, which will begin to expire, if unused, beginning in 2024. The valuation allowance increased by approximately $471,569 and $891,046 for the years ended February 28, 2011 and February 28, 2010, respectively. Section 382 Rule of the Internal Revenue Code will place annual limitations on the Company’s NOL carryforward.

The above estimates are based upon management’s decisions concerning certain elections which could change the relationship between net income and taxable income. Management decisions are made annually and could cause the estimates to vary significantly.

NOTE 13 — COMMITMENTS AND CONTINGENCIES:

Various lawsuits, claims and other contingencies arise in the ordinary course of the Company’s business activities. While the ultimate outcome of the aforementioned contingencies are not determinable at this time, management believes that any liability or loss resulting therefrom will not materially affect the financial position, results of operations or cash flows of the Company.

The Company, as an owner or lessee and operator of oil and gas properties, is subject to various federal, state and local laws and regulations relating to discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liability on the lessee under an oil and gas lease for the cost of pollution clean-up resulting from operations and subject the lessee to liability for pollution damages. In some instances, the Company may be directed to suspend or cease operations in the affected area. The Company maintains insurance coverage that is customary in the industry, although the Company is not fully insured against all environmental risks.

The Company is not aware of any environmental claims existing as of February 28, 2011. There can be no assurance, however, that current regulatory requirements will not change, or past non-compliance with environmental issues will not be discovered on the Company’s oil and gas properties.

NOTE 14 — SUPPLEMENTARY INFORMATION FOR OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

All of the Company's continuing operations are directly related to oil and natural gas producing activities located in California.

Capitalized Costs Relating to Oil and Gas Producing Activities

	As of February 28, 2011	As of February 28, 2010
Proved leasehold costs		
Mineral Interests	$ 7,848	$ 6,720
Wells, equipment and facilities	2,701,241	1,754,488
Total Proved Properties	2,709,089	1,761,208
Unproved properties		
Mineral Interests	431,895	17,350
Uncompleted wells, equipment and facilities	20,675	3,883
Total unproved properties	452,570	21,233
Less accumulated depreciation, depletion amortization and impairment	(871,658)	(571,642)
Net capitalized costs	$ 2,290,001	$ 1,210,799

Costs Incurred in Oil and Gas Producing Activities

	12 Months Ended February 28, 2011	12 Months Ended February 28, 2010
Acquisition of proved properties	$ 1,128	$ 6,720
Acquisition of unproved properties	431,337	21,233
Development costs	946,753	948,271
Exploration costs	184,255	301,912
Total costs incurred	$ 1,563,473	$ 1,278,136

Results of Operations from Oil and Gas Producing Activities

	12 Months Ended February 28, 2011	12 Months Ended February 28, 2010
Oil and gas revenues	$ 1,079,496	$ 471,442
Production costs	(172,250)	(269,820)
Exploration expenses	(184,255)	(301,912)
Depletion, depreciation, amortization and impairment	(307,023)	(550,755)
Result of oil and gas producing operations before income taxes	415,968	(651,045)
Provision for income taxes		
Results of oil and gas producing activities	$ 415,968	$ (651,045)

Proved Reserves

The Company's proved oil and natural gas reserves have been estimated by the certified independent engineering firm, Lonquist & CO. LLC. Proved reserves are the estimated quantities that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods when the estimates were made. Due to the inherent uncertainties and the limited nature of reservoir data, such estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of these reserves may be substantially different from the original estimate. Revisions result primarily from new information obtained from development drilling and production history; acquisitions of oil and natural gas properties; and changes in economic factors. Our proved reserves are summarized in the table below:

	Oil (Barrels)	BOE (Barrels)
Proved reserves:		
February 28, 2009	17,250	17,250
Revisions[1]	(10,414)	(10,414)
Extensions and discoveries	45,184	45,184
Production	(3,142)	(3,142)
Purchases (sales) of minerals-in-place	13,277	13,277
February 28, 2010	62,155	62,155
Revisions[2]	24,880	24,880
Extensions and discoveries	145,648	145,648
Production	(13,009)	(13,009)
Purchases (sales) of minerals-in-place	18,146	18,146
February 28, 2011	237,820	237,820

(1) The revisions of previous estimates for the year ended February 28, 2010, resulted from a revised lower estimate of reserve value after continued reservoir production.

(2) The revisions of previous estimates for the year ended February 28, 2011, resulted from a revised increased estimate of reserve value after continued reservoir production and increased hydrocarbon prices in the energy markets.

The Company's proved reserves are set forth in the table below.

	Developed		Undeveloped		Total Reserves	
	Oil (Bbls)	BOE (Bbls)	Oil (Bbls)	BOE (Bbls)	Oil (Bbls)	BOE (Bbls)
February 28, 2009	8,625	8,625	8,625	8,625	17,250	17,250
February 28, 2010	38,648	38,648	23,507	23,507	62,155	62,155
February 28, 2011	88,840	88,840	148,980	148,980	237,820	237,820

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following information is based on the Company's best estimate of the required data for the Standardized Measure of Discounted Future Net Cash Flows as of February 28, 2011 and 2010 in accordance with ASC 932, *"Extractive Activities – Oil and Gas"* which requires the use of a 10% discount rate. This information is not the fair market value, nor does it represent the expected present value of future cash flows of the Company's proved oil and gas reserves.

Future cash inflows for the years ended February 28, 2010 and 2011 were estimated as specified by the SEC through calculation of an average price based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period from March through February during each respective fiscal year. The resulting net cash flows are reduced to present value by applying a 10% discount factor.

	12 Months Ended	
	February 28, 2011	February 28, 2010
Future cash inflows	$ 18,138,730	$ 3,657,798
Future production costs [1]	(6,896,130)	(809,091)
Future development costs	(1,667,310)	(345,567)
Future income tax expenses [2]		
Future net cash flows	9,575,290	2,503,140
10% annual discount for estimated timing of cash flows	(4,215,510)	(527,212)
Standardized measure of discounted future net cash flows at the end of the fiscal year	$ 5,359,780	$ 1,975,928

(1) Production costs include oil and gas operations expense, production ad valorem taxes, transportation costs and G&A expense supporting the Company's oil and gas operations.

(2) The Company has sufficient tax deductions and allowances related to proved oil and gas reserves to offset future net revenues.

Average oil prices are set forth in the table below.

	Average Price Oil (Barrel)
February 28, 2011 [1]	$ 76.27
February 28, 2010 [1]	$ 58.86
February 28, 2009	$ 35.40

(1) Average prices for February 28, 2011 and 2010 were based on 12-month unweighted arithmetic average of the first-day-of-the-month prices for the period from March through February during each respective fiscal year.

Future production and development costs, which include dismantlement and restoration expense, are computed by estimating the expenditures to be incurred in developing and producing the Company's proved crude oil and natural gas reserves at the end of the year, based on year-end costs, and assuming continuation of existing economic conditions.

Sources of Changes in Discounted Future Net Cash Flows

Principal changes in the aggregate standardized measure of discounted future net cash flows attributable to the Company's proved crude oil and natural gas reserves, as required by ASC 932, at fiscal year-end are set forth in the table below.

	12 Months Ended	
	February 28, 2011	February 28, 2010
Standardized measure of discounted future net cash flows at the beginning of the year	$ 1,975,928	$ 356,279
Extensions, discoveries and improved recovery, less related costs	3,053,440	1,849,004
Revisions of previous quantity estimates	560,714	(333,444)
Purchase of minerals in place	513,643	—
Net changes in prices and production costs	(491,475)	270,243
Accretion of discount	197,593	35,628
Sales of oil produced, net of production costs	(802,245)	(207,641)
Development costs incurred during the period	597,796	112,343
Changes in future development costs	(256,408)	(142,978)
Changes in timing of future production	10,794	36,494
Net changes in income taxes	—	—
Standardized measure of discounted future net cash flows at the end of the year	$ 5,359,780	$ 1,975,928

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Management's Evaluation of Disclosure Controls and Procedures

As of the end of the reporting period, February 28, 2011, an evaluation was conducted by Daybreak management, including our President and Chief Executive Officer, also serving as our interim principal finance and accounting officer, as to the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(e) of the Exchange Act. Such disclosure controls and procedures are designed to ensure that information required to be disclosed by a company in the reports that it files under the Exchange Act is recorded, processed, summarized and reported within required time periods specified by the SEC rules and forms. Additionally, it is vital that such information is accumulated and communicated to our management including our President and Chief Executive Officer, in a manner to allow timely decisions regarding required disclosures. Based on that evaluation, our management concluded that our disclosure controls were effective as of February 28, 2011.

Internal Control Over Financial Reporting

The Company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Our internal controls over financial reporting include those policies and procedures that:

1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;

2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made in accordance with authorizations of management and our Board of Directors; and

3) provide reasonable assurance regarding prevention or timely detection of any unauthorized acquisition, use or disposition of assets that could have a material effect on the financial statements.

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

Management's Report on Internal Control Over Financial Reporting

Daybreak management including our President and Chief Executive Officer, also serving as our interim principal finance and accounting officer 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. Our management assessed the effectiveness of our internal control over financial reporting as of February 28, 2011. In making this assessment, management used certain criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework.* Based on such assessment and those criteria, management believes that the Company maintained effective internal control over financial reporting as of February 28, 2011.

This annual report does not include an attestation report of the Company's registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by the Company's registered public accounting firm pursuant to SEC rules that permit the company to provide only management's report in this annual report.

Changes in Internal Control over Financial Reporting

There have not been any changes in the Company's internal control over financial reporting during the quarter ended February 28, 2011 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Limitations

Our management does not expect that our disclosure controls or internal controls over financial reporting will prevent all errors or all instances of fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the control system's objectives will be met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs.

Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Controls can also be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls is based in part upon certain assumptions about the likelihood of future events, and any design may not succeed in achieving its stated goals under all potential future conditions.

Over time, controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with policies or procedures. Because of the inherent limitation of a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

ITEM 9B. OTHER INFORMATION

None.

PART III

Certain information required by Part III is omitted from this Annual Report on Form 10-K because we will file a definitive proxy statement pursuant to Regulation 14A (the “Proxy Statement”), not later than 120 days after the end of the fiscal year covered by this Form 10-K, and certain information to be included therein is incorporated herein by reference, or if the Registrant’s Schedule 14A is not filed within such period, will be included in an amendment to this Report on Form 10-K which will be filed within such 120 day period.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

This Item is incorporated by reference to our definitive proxy statement on Schedule 14A, which will be filed with the Commission not later than 120 days after the close of the fiscal year covered by this report on Form 10-K, or if the Registrant’s Schedule 14A is not filed within such period, will be included in an amendment to this Report on Form 10-K which will be filed within such 120 day period.

ITEM 11. EXECUTIVE COMPENSATION

This Item is incorporated by reference to our definitive proxy statement on Schedule 14A, which will be filed with the Commission not later than 120 days after the close of the fiscal year covered by this report on Form 10-K, or if the Registrant’s Schedule 14A is not filed within such period, will be included in an amendment to this Report on Form 10-K which will be filed within such 120 day period.

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

This Item is incorporated by reference to our definitive proxy statement on Schedule 14A, which will be filed with the Commission not later than 120 days after the close of the fiscal year covered by this report on Form 10-K, or if the Registrant’s Schedule 14A is not filed within such period, will be included in an amendment to this Report on Form 10-K which will be filed within such 120 day period.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

This Item is incorporated by reference to our definitive proxy statement on Schedule 14A, which will be filed with the Commission not later than 120 days after the close of the fiscal year covered by this report on Form 10-K, or if the Registrant’s Schedule 14A is not filed within such period, will be included in an amendment to this Report on Form 10-K which will be filed within such 120 day period.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

This Item is incorporated by reference to our definitive proxy statement on Schedule 14A, which will be filed with the Commission not later than 120 days after the close of the fiscal year covered by this report on Form 10-K, or if the Registrant’s Schedule 14A is not filed within such period, will be included in an amendment to this Report on Form 10-K which will be filed within such 120 day period.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

The following Exhibits are filed as part of the report:

3.01	Amended and Restated Articles of Incorporation of Daybreak Oil and Gas, Inc. dated July 17, 2009 (18)
3.02	Amended and Restated Bylaws (1)
4.01	Specimen Stock Certificate (2)
4.02	Designations of Series A Convertible Preferred Stock (3)
4.03	Warrant for the purchase shares of Common Stock, March 2006 private placement (4)
4.04	Registration rights agreement, March 2006 private placement (4)
4.05	Warrant for the purchase shares of Common Stock, July 2006 private placement (5)
4.06	Registration rights agreement, July 2006 private placement (5)
4.07	Additional warrant to purchase shares of Common Stock associated with the Spring 2006 and the July 2006 private placement offerings (2)
4.08	2009 Restricted Stock and Restricted Stock Unit Plan (6)*
4.09	Form of Restricted Stock Award Agreement (6)*
4.10	Form of Restricted Stock Unit Award Agreement (6)*
4.11	Form of 12% Subordinated Note due 2015 (17)
4.12	Form of Warrant in connection with 12% Subordinated Notes (17)
10.01	Development agreement with Chicago Mill Joint Venture for Louisiana project (7)
10.02	Prospect review and non-competition agreement for California project (7)
10.03	Joint Venture Agreement with Nomad Hydrocarbons, Ltd. for California project (7)
10.04	Prospect review agreement for California project (7)
10.05	Development agreement with Vision Exploration for Krotz Springs 3D Prospect (7)
10.06	Subscription agreement and letter of investment intent, March 2006 private placement (4)
10.07	Pipeline license agreement for Tuscaloosa project in Louisiana (7)
10.08	Subscription agreement and letter of investment intent, July 2006 private placement (5)
10.09	Purchase of additional mineral interest in Tuscaloosa project in Louisiana (8)
10.10	Farmout agreement with Monarch Gulf Exploration, Inc. (9)
10.11	Oil and gas lease with Anadarko E&P Company, L.P. (10)
10.12	Drilling contract with Energy Drilling for two wells in Louisiana (11)
10.13	Seismic Option Farmin Agreement with Chevron U.S.A. (12)
10.14	Joint Development Participation Agreement for Tuscaloosa project in Louisiana (13)
10.15	Purchase and Sale Agreement with Lasso Partners, LLC (14)
10.16	Letter of Agreement to amend the Purchase and Sale Agreement with Lasso Partners, LLC (15)
10.17	Purchase of Tuscaloosa interest from Kirby Cochran (14)
10.18	Purchase of Tuscaloosa interest from 413294 Alberta Ltd. (Robert N. Martin) (14)
10.19	Purchase of Tuscaloosa interest from Tempest Energy, Inc (Eric L. Moe) (14)
10.20	Letter of Agreement on North Shuteston Assignment of Interest (14)
10.21	Exchange Option Agreement with O&G Energy Partners and San Joaquin Investments, Inc. (16)
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10.26	Assignment of Oil and Gas Leases and Agreements Among Chevron U.S.A. Inc., San Joaquin Investments, Inc. and Daybreak Oil & Gas, Inc. (19)
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23.1 Consent of Lonquist & Co. LLC. [21]

23.2 Consent of MaloneBailey, LLP [21]

31.1 Certification of principal executive and principal financial officer as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 [21]

32.1 Certification of principal executive and principal financial officer as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 [21]

99.1 Reserves Report of Lonquist & Co. LLC, independent petroleum engineering consulting firm, as of March 1, 2011. [21]

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(1) Previously filed as exhibit to Form 8-K on April 9, 2008, and incorporated by reference herein.

(2) Previously filed as exhibits to Form 10-K on May 28, 2009, and incorporated by reference herein.

(3) Previously filed as exhibit to Form SB-2 on July 18, 2006, and incorporated by reference herein. (filed as part of the Articles of Amendment to the Articles of Incorporation of Daybreak Oil & Gas, Inc. dated June 30, 2006.)

(4) Previously filed as exhibits to Form SB-2 on July 18, 2006, and incorporated by reference herein.

(5) Previously filed as exhibits to Form 10-KSB on September 21, 2007, and incorporated by reference herein.

(6) Previously filed as exhibits to Form S-8 filed on April 7, 2009 and incorporated by reference herein.

(7) Previously filed as exhibits to Form SB-2/A on December 28, 2006, and incorporated by reference herein.

(8) Previously filed as exhibit to Form 8-K on September 28, 2006, and incorporated by reference herein.

(9) Previously filed as exhibit to Form 8-K on October 26, 2006, and incorporated by reference herein.

(10) Previously filed as exhibit to Form 8-K on November 7, 2006, and incorporated by reference herein.

(11) Previously filed as exhibit to Form 8-K on November 17, 2006, and incorporated by reference herein.

(12) Previously filed as exhibit to Form 8-K on July 16, 2007, and incorporated by reference herein.

(13) Previously filed as exhibit to Form 8-K on July 20, 2007, and incorporated by reference herein.

(14) Previously filed as exhibits to Form 10-KSB filed on May 27, 2008, and incorporated by reference herein.

(15) Previously filed as exhibit to Form 8-K on May 2, 2008, and incorporated by reference herein.

(16) Previously filed as exhibit to Form 8-K on June 16, 2009, and incorporated by reference herein.

(17) Previously filed as exhibits to Form 8-K on February 3, 2010, and incorporated by reference herein.

(18) Previously filed as exhibit to Form 10-K on May 28, 2010, and incorporated by reference herein.

(19) Previously filed as exhibit to Form 10-Q on October 15, 2010, and incorporated by reference herein.

(20) Previously filed as exhibit to Form 8-K on September 23, 2010, and incorporated by reference herein.

(21) Filed herewith.

[*] Contract or compensatory plan or arrangement in which directors and/or officers may participate.

GLOSSARY OF TERMS

The following are abbreviations and definitions of terms commonly used in the oil and gas industry and this Form 10-K.

3-D seismic. An advanced technology method of detecting accumulations of hydrocarbons identified by the collection and measurement of the intensity and timing of sound waves transmitted into the earth as they reflect back to the surface.

BOE. A barrel of oil equivalent (BOE) is the standard convention used to express oil and gas volumes on a comparable oil equivalent basis. Gas equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of gas to 1.0 Bbl of oil or natural gas liquid.

Bbl. One barrel, or 42 U.S. gallons of liquid volume.

Completion. The installation of permanent equipment for the production of oil or gas.

DD&A. Refers to depreciation, depletion and amortization of the Company’s property and equipment.

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

Dry hole. A well found to be incapable of producing hydrocarbons 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 oil or natural gas in another reservoir.

Gross acres or wells. Refers to the total acres or wells in which the Company has a working interest.

Horizontal drilling. A drilling technique that permits the operator to contact and intersect a larger portion of the producing horizon than conventional vertical drilling techniques and may, depending on the horizon, result in increased production rates and greater ultimate recoveries of hydrocarbons.

Net acres or wells. Refers to the gross sum of fractional working interest ownership in gross acres or wells.

Net production. Oil and gas production that is owned by the Company, less royalties and production due others.

NYMEX. New York Mercantile Exchange, the exchange on which commodities, including crude oil and natural gas futures contracts, are traded.

Oil. Crude oil or condensate.

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

Productive wells. Producing wells and wells mechanically capable of production.

Proved Developed Reserves. 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 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 government entities.

Proved undeveloped reserves (PUD). 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, or by other evidence using reliable technology establishing reasonable certainty.

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

SEC. The United States Securities and Exchange Commission.

Standardized measure of discounted future net cash flows. Present value of proved reserves, as adjusted to give effect to (i) estimated future abandonment costs, net of the estimated salvage value of related equipment, and (ii) estimated future income taxes.

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 gas, regardless of whether such acreage contains proved reserves.

Working interest. An interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations. The share of production to which a working interest is entitled will be smaller than the share of costs that the working interest owner is required to bear to the extent of any royalty burden.

Workover. Operations on a producing well to restore or increase production.

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.

DAYBREAK OIL AND GAS, INC.

By: /s/ JAMES F. WESTMORELAND

James F. Westmoreland, its
President, Chief Executive Officer and
interim principal finance and
accounting officer
Date: May 26, 2011

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

By: /s/ JAMES F. WESTMORELAND

James F. Westmoreland
Director / President and Chief Executive Officer
Date: May 26, 2011

By: /s/ DALE B. LAVIGNE

Dale B. Lavigne
Director / Chairman
Date: May 26, 2011

By: /s/ TIMOTHY R. LINDSEY

Timothy R. Lindsey
Director
Date: May 26, 2011

By: /s/ WAYNE G. DOTSON

Wayne G. Dotson
Director
Date: May 26, 2011

By: /s/ RONALD D. LAVIGNE

Ronald D. Lavigne
Director
Date: May 26, 2011

By: /s/ JAMES F. MEARA

James F. Meara
Director
Date: May 26, 2011

Exhibit 23.1

AUSTIN
3345 Bee Cave Road
Suite 201
Austin, Texas 78746 USA
Tel 512.732.9812
Fax 512.732.9816

LONQUIST & CO. LLC
PETROLEUM ENGINEERS
ENERGY ADVISORS
www.lonquist.com

HOUSTON
1001 McKinney
Suite 420
Houston, Texas 77002 USA
Tel 713.559.9950
Fax 713.559.9959

May 26, 2011

Daybreak Oil and Gas, Inc.
601 W. Main Ave.
Suite 1012
Spokane, WA 99201

Re: Securities and Exchange Commission Annual Report on Form 10-K; Consent of Independent Petroleum Engineer

Dear Sirs:

We hereby consent to the use of the name Lonquist & Co. LLC, and to references to Lonquist & Co. LLC an independent petroleum engineering firm, and to the inclusion of information contained in our reports as of March 1, 2011, in your Annual Report on Form 10-K for the year ended February 28, 2011 to be filed on or around May 26, 2011.

LONQUIST & CO. LLC
Texas Firm Registration No. F-8952
May 26, 2011

/s/ RICHARD R. LONQUIST

Richard R. Lonquist, P.E.
President

Exhibit 23.2

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the registration statement on Form S-8 (File No. 333-158448) of Daybreak Oil and Gas, Inc. of our report dated May 26, 2011 related to the financial statements of Daybreak Oil and Gas, Inc. as of and for the years ended February 28, 2011 and 2010.

/s/ MaloneBailey, LLP

www.malonebailey.com
Houston, Texas
May 26, 2011

Exhibit 31.1

Certification

I, James F. Westmoreland, certify that:

(1) I have reviewed this annual report on Form 10-K of Daybreak Oil and Gas, 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 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 15(d)-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 my supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to me 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 and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

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

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

Date: May 26, 2011

By /s/ JAMES F. WESTMORELAND

James F. Westmoreland, President, Chief Executive Officer
and interim principal finance and accounting officer
(Principal Executive Officer, Principal Financial Officer and Principal Accounting Officer)

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Daybreak Oil and Gas, Inc. on Form 10-K for the period ending February 28, 2011, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, the undersigned, in the capacity and on the date indicated below, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: May 26, 2011

By /s/ JAMES F. WESTMORELAND

James F. Westmoreland, President, Chief Executive Officer
and interim principal finance and accounting officer
(Principal Executive Officer, Principal Financial Officer and Principal Accounting Officer)

DAYBREAK OIL AND GAS, INC.

Southern San Joaquin Basin, East Slopes Project
Kern County, California

Estimated Future Reserves and Revenues
As of March 1, 2011

SEC Guideline Case

LONQUIST & CO. LLC

PETROLEUM ENGINEERS | ENERGY ADVISORS

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WWW.lonquist.com

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Tel 713.559.9950
Fax 713.559.9959

April 19, 2011

Mr. James F. Westmoreland
President & CEO
Daybreak Oil and Gas, Inc.
601 West Main Ave., Suite 1012
Spokane, WA 99201

Re: Daybreak Oil and Gas, Inc.
1P Reserve Report
As of March 1, 2011
SEC Guideline Case

Dear Mr. Westmoreland:

Pursuant to your request, Lonquist & Co. LLC, ("L&Co") has estimated the future oil and gas Reserves and projected the associated future revenues for certain properties owned by Daybreak Oil and Gas, Inc. ("Daybreak"). The properties evaluated herein are located in Kern County, California. At the request of Daybreak, we have evaluated Proved Developed Producing ("PDP"), Proved Developed Non-Producing ("PDNP"), and Proved Undeveloped ("PUD") Reserves.

Effective March 1, 2011, our conclusions are as follows:

	Net to Daybreak Oil and Gas, Inc.						
	Proved Developed						
SEC Pricing as of March 1, 2011	**Producing**	**Non-Producing[a]**	**Proved Undeveloped**	**Total Proved[b]**	**Total Probable[b]**	**Total Possible[b]**	**Grand Total[b]**
Estimated Future Net Oil/Condensate, bbl	80,500	8,340	148,990	237,820	0	0	237,820
Estimated Future Net Gas, MMcf	0	0	0	0	0	0	0
Total Future Gross Revenue, $	6,139,410	635,990	11,363,320	18,138,730	0	0	18,138,730
Estimated Future Production Taxes, $	75,030	7,780	138,860	221,650	0	0	221,650
Estimated Future Operating Expenses, $	2,732,540	221,120	3,720,810	6,674,480	0	0	6,674,480
Estimated Future Capital Costs, $	0	36,060	1,631,250	1,667,310	0	0	1,667,310
Estimated Future Net Revenue ("FNR"), $	3,331,840	371,040	5,872,400	9,575,290	0	0	9,575,290
Discounted FNR at 10%, $	2,020,050	258,910	3,080,820	5,359,780	0	0	5,359,780
Discounted FNR at 15%, $	1,721,910	223,360	2,395,140	4,340,420	0	0	4,340,420
Estimated Net Revenues by Year, $							
2011	556,280	50,930	-666,280	-59,070	0	0	-59,070
2012	451,910	75,780	1,312,890	1,840,590	0	0	1,840,590
2013	331,220	51,220	827,100	1,209,550	0	0	1,209,550
Subtotal	1,339,410	177,930	1,473,710	2,991,070	0	0	2,991,070
Thereafter	1,992,430	193,110	4,398,690	6,584,220	0	0	6,584,220
Total	3,331,840	371,040	5,872,400	9,575,290	0	0	9,575,290
Estimated Average Net Production Rate - 2011							
Oil/Condensate, bbl/D	30.0	3.6	42.7	76 .3	0	0	76.3
Gas, Mcf/D	0	0	0	0	0	0	0

[a]Column includes the Proved Developed Non-Producing, behind pipe, and shut-in cash flows and volumes.

[b]Totals might not match due to computer rounding.

Purpose of Report and Standards of Practice

This report was prepared to provide the management of Daybreak Oil and Gas, Inc. with a projection of estimated remaining hydrocarbon Reserves and projected future net revenues, effective March 1, 2011. These estimates have not been adjusted for risk.

This report has been prepared in accordance with our understanding of the Securities and Exchange Commission, S-X Reg. §210.4-10a, dated December 30, 2008 (*Modernization of Oil and Gas Reporting; Final Rule*; January 14, 2009); we have evaluated the 1P Reserves. The applicable SEC oil and gas Reserve definitions are attached hereto.

Liquid hydrocarbon volumes are expressed in standard 42-gallon barrels. All natural gas volumes are sales gas expressed at the official pressure and temperature bases of the areas in which the gas Reserves are located.

All currencies in this report are expressed in U.S. dollars.

Reserve Estimates

Well-by-well production data in this report were updated through February 28, 2011. Extrapolation of historical production data was utilized for those producing properties where sufficient data were available to suggest decline trends. Reserves assigned to the remaining producing properties and the volumes associated with non-producing assets were determined by analogy to offset wells producing from similar formations or by volumetric analyses. Hydrocarbon volumes assigned by analogy and volumetric analyses are subject to greater revision than those projected using established performance trends.

As of March 1, 2011, the 1P net remaining Reserves were estimated to be 237,820 barrels of oil. The net present value, discounted at 10%, of the total Proved Reserves was $5,359,780. Of the total net revenue, discounted at 10%, 37.7% was derived from the PDP Reserves. The Reserve life index (“R/P”) of the PDP Reserves was estimated to be 7.4 years.

Property Overview

The San Joaquin East Slope Region, located in Kern County California, is operated by Daybreak Oil and Gas. On this leasehold, 3D seismic survey data have been shot on 22,000 acres. Using these data, twelve prospective areas have been identified, of which five have been drilled. The areas evaluated in this report, Sunday, Bear, Black, Dyer Creek and Ball have been classified as Proved, and are in the development phase. All production is from the Vedder formation, which is typically an unconsolidated reservoir requiring gravel packed completions.

Sunday Prospect

To date, the Sunday #1, #2, #3 and #4 have produced 50,920 barrels of oil from the Vedder formation. The Sunday #4 was drilled as a horizontal well but is producing as a vertical well after a workover. The Vedder net pay map over the Sunday Prospect contains 34.6 acres and three PUD locations were assigned.

Bear Prospect

To date, four wells have been drilled in the Bear Prospect. The Bear #1, #2, #3 and #4 are all producing from the Vedder formation. The Bear #3, the southernmost well in the pool, is believed to have mechanical problems and has never performed up to expectations. As a result of the mechanical issues, the Bear #3 has an estimated ultimate recovery of 2,818 barrels of oil. An offset location was not assigned in this area. At the time of this report, the identified pool covers 62 acres, of which 34 acres contain Proved Reserves. In addition, three PUD locations were identified.

Black Prospect

The Black Prospect is located south of the Bear Prospect, and contains 13.4 acres in the Vedder formation. The Black #1 is the only producing property in this area. After looking at core data and low productivity, a workover has been scheduled at the end of the current economic life to recover additional Reserves. At the time of this report, two PUD locations were identified.

Ball Prospect

The Ball Prospect is the northernmost pool in the Dyer Creek Field Trend and has 37.5 acres of mapped closure in the Vedder formation. The Ball #1-11 was drilled and completed in October 2010. A workover has been scheduled for May 2011 to repair a suspected leaking plug below the Upper Vedder. At the time of this report, two PUD locations were identified.

Dyer Creek Prospect

The Dyer Creek structure, which lies between the Bear and the Ball, is not closed to the south and therefore may be in communication with the Bear structure. The Dyer Creek #67X-11 was drilled and completed in October 2010. Due to completion problems, this well has an estimated ultimate recovery of 7,613 barrels of oil. At the time of this report, one PUD was identified.

Product Prices

The base oil price of $82.01 per barrel utilized herein is the average closing oil price of the first trading day of each month for the prior twelve months as of February 28, 2011, as reported by the Energy Information Administration. As stipulated by SEC regulations, no price escalations were included in this report. Product price differentials were calculated by comparing the realized prices, as calculated from revenue statements, to the average NYMEX futures price for the same calendar month. This average differential is expressed as a percentage multiplier on price in the economic model.

Operating Expenses

Direct operating expense data, input as dollars per month in the economic models, were supplied by Daybreak. These direct operating costs were based on actual expenses from March 2010 through February 2011, and were adjusted for non-recurring costs, where applicable.

Severance and ad valorem taxes were deducted as a percentage of gross revenues or as a charge per unit of production. The individual well projections of oil and gas cease when the operating expenses exceed the gross revenues.

Operating expenses were not escalated in this report.

Capital Expenses

Estimated capital costs were input as approximate costs for the operations that would be performed on wells in the PDNP and PUD Reserve categories. A more accurate cost estimate for these individual investments will be generated at the time they are carried out. These operations were modeled to start at a specific point in the future. Any deviation from these dates will result in a change in the projected future net revenues for those properties evaluated herein.

Capital expenditures were not escalated in this report.

Values Not Considered

In all cases we have attempted to account for all deductions from gross revenues except for the following:

- Federal Income Tax
- Depreciation, depletion, and/or amortization, if any
- Costs in excess of revenues from uneconomic leases
- Plugging and abandonment costs in excess of salvage value
- Environmental restoration costs, if any
- Product price hedges, if any

No value has been assigned to non-producing acreage or to acreage held by production.

Report Qualifications

The future net revenues were based on projections of recoverable hydrocarbons, rates of production, timing of recompletions and drilling, proration by state and federal agencies, direct taxes, and product prices. All estimated future net revenues presented in this report are after the deduction of royalties, production costs, and development costs. This evaluation does not include indirect costs such as administrative, overhead, and other miscellaneous expenses. Any unusual combination of the many factors, including weather, political risk or acts of terrorism could result in future receipts being considerably less or more than those estimated herein.

THE REVENUES AND PRESENT WORTH OF FUTURE NET REVENUES PRESENTED HEREIN ARE NOT REPRESENTED TO BE MARKET VALUES EITHER FOR THE INDIVIDUAL PROPERTIES OR ON A TOTAL PROPERTY BASIS.

Data Sources

Data including basic well information, geological interpretations, realized product prices, operating costs, initial test rates, and ownership interests were supplied by Daybreak. L&Co has accepted these data as correct.

Historical production data were obtained from Daybreak as well as public sources, such as Lasser Production Data Services, DrillingInfo.com, and HPDI Production Data Applications. Production data was updated though February 2011. We retain in our files digital databases for all properties and certain other hard copy information that we believe pertinent.

We have not inspected the properties evaluated in this report, nor have we conducted independent well tests.

Independent Evaluation

Neither Lonquist & Co. LLC nor any of its employees have any interest or ownership in the subject properties, and neither our employment nor compensation is contingent on our findings herein.

Sincerely,

Lonquist & Co., LLC
Texas Registration No. F-8952

/s/ RICHARD R. LONQUIST

Richard R. Lonquist, P.E.
Petroleum Engineer
Texas License No. 73008

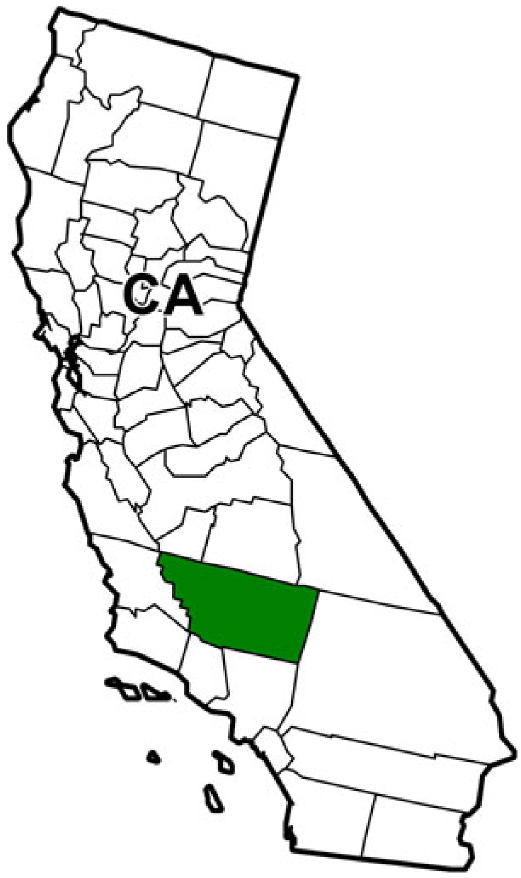
Date Signed: April 19, 2011
Austin, Texas

/s/ TEREASA S. MONTEMAYOR

Tereasa S. Montemayor
Sr. Petroleum Engineer

AREA OF INTEREST

Daybreak Oil and Gas, Inc.



LONQUIST & CO. LLC
PETROLEUM ENGINEERS
ENERGY ADVISORS

OIL AND GAS RESERVE DEFINITIONS

The Securities and Exchange Commission, SX Reg. § 210.4-10 dated November 18, 1981 as amended September 19, 1989 requires adherence to the following definitions of "Proved" oil and gas reserves:

Definitions:

(2) ***Proved oil and gas reserves.*** Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

(3) ***Proved developed oil and gas reserves.*** Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

(4) ***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. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates, for proved undeveloped reserves be attributable to any acreage or which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Amended SEC guidelines Reg. § 210.4-10 definitions (*Modernization of Oil and Gas Reporting; Final Rule*; January 14, 2009):

(17) ***Possible reserves*.** Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10 percent probability that the total quantities ultimately recovered will equal or exceed the estimated 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 defined project.

(18) ***Probable reserves***. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves, but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus reserves. When probabilistic methods are used, there should be at least a 50 percent probability that the quantities actually 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.