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, 2021

☐ 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.)
1101 N. Argonne Road, Suite A-211, Spokane Valley, WA	**99212**
(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 website, 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 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 ☑
			Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262 (b)) by the registered public accounting firm that prepared or issued its audit report. ☐

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 $0.01 on August 31, 2020, as reported by the OTC Pink® Open Market was $514,624.

At May, 26 2021, the registrant had 60,491,122 outstanding shares of $0.001 par value common stock.

DOCUMENTS INCORPORATED BY REFERENCE:

None.

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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. Forward-looking statements include statements relating to future events or our future financial or operating performance, including statements regarding guidance, industry prospects or future results of operations or financial position, made in this Annual Report on Form 10-K. 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 future financing;
- Our expansion and growth of operations; and
- Our future investments in and acquisitions of crude 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;
- National and international pandemic such as the novel coronavirus COVID-19 outbreak;
- Exposure to market risks in our financial instruments;
- Fluctuations in worldwide prices and demand for crude oil and natural gas;
- Our ability to find, acquire and develop crude oil and natural gas properties;
- Fluctuations in the levels of our crude oil and natural gas exploration and development activities;
- Changes to our reserve estimates or the recovery of crude oil and natural gas quantities that is less than our reserve estimates;
- Risks associated with crude oil and natural gas exploration and development activities;
- Competition for raw materials and customers in the crude oil and natural gas industry;
- Technological changes and developments in the crude oil and natural gas industry;
- Legislative and regulatory uncertainties, including proposed changes to federal tax law and climate change legislation, regulation of hydraulic fracturing, and potential environmental liabilities;
- Our ability to continue as a going concern;
- Our ability to secure financing under any commitments as well as additional capital to fund operations; and
- Other factors discussed elsewhere in this Form 10-K; in our other public filings and 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 any underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. These risks and uncertainties, as well as other risks and uncertainties that could cause our actual results to differ significantly from management's expectations, are described in greater detail in Item 1A of Part 1, "Risk Factors". 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," "us," "Daybreak" or the "Company") was originally incorporated in the State of Washington on March 11, 1955 as Daybreak Uranium, Inc. The Company was organized to explore for, acquire and develop mineral properties throughout the Western United States. In August 1955, we acquired the assets of Morning Sun Uranium, Inc. By the late 1950's, we 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, development and production company in the crude oil and natural 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 Pink® Open Market under the symbol DBRM.

Our corporate office is located at 1101 N. Argonne Road, Suite A-211, Spokane Valley, Washington 99212-2699. Our telephone number is (509) 232-7674. Additionally, we have a regional operations office located at 1414 S. Friendswood Dr., Suite 212, Friendswood, Texas 77546. The telephone number of our office in Friendswood is (281) 996-4176.

Crude Oil and Natural Gas Overview

We are an independent crude oil and natural gas exploration, development and production company. Our basic business model is to increase shareholder value by finding and developing crude oil and natural 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 crude oil and natural 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. A secondary means of generating returns can include the sale of either producing or non-producing lease properties.

Our long-term success depends on, among many other factors, the acquisition and drilling of commercial grade crude oil and natural gas properties and on the prevailing sales price for crude oil and natural gas along with associated operating expenses. The volatile nature of the energy markets makes it difficult to estimate future prices of crude oil and natural gas; however, any prolonged period of depressed prices or market volatility, such as we have experienced since June of 2014, will and does have a material adverse effect on our results of operations and financial condition.

The Company's focus is to pursue crude oil and natural 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 crude oil and natural gas companies or individuals. We identify and evaluate prospective crude oil and natural 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.

Modern technology including 3-D seismic helps us identify potential crude oil and natural gas reservoirs and to mitigate our risk. The Company conducts all of our drilling, exploration and production activities in the United States, and all of our revenues are derived from sales to customers within the United States. We seek to maximize the value of our asset base by exploring and developing properties that have both production and reserve growth potential. Currently, our core areas of activity are located in Kern County, California and Michigan, although new opportunities may ultimately be secured in other areas.

In some instances, such as with our California crude oil operations, we strive to be the operator of our crude oil and natural gas properties. As the operator, we are more directly in control of the timing; costs of drilling and completion; and production operations on our projects. We are compensated by our other working interest partners for the additional duties performed by Daybreak as operator. In other instances, we may not serve as operator where we have concluded that the existing operator has existing operational knowledge, equipment and personnel in place, and operates competently and prudently and with the same operational goals that we would have if we served as operator. However, we have our own personnel onsite during critical operations such as drilling, fracturing and completion operations.

In January 2017, we acquired a 30% working interest in 1,400 acres in the Michigan Basin. The leases have been secured and multiple targets were identified through a 2-D seismic interpretation. A 3-D seismic survey was obtained in January and February of 2017 on the first prospect. An analysis of the 3-D seismic survey confirmed the first prospect originally identified on the 2-D seismic, as well as several additional drilling locations. We have plans to obtain an additional 3-D survey on the second prospect. However; the two prospects are independent of each other and the success or failure of either one does not effect the other. The wells will be drilled vertically with conventional completions and no hydraulic fracturing is anticipated. With the settlement of our debt obligations in December 2018 with Maximilian Resources LLC, a Delaware limited liability company and successor by assignment from Maximilian Investors LLC (either party, as appropriate, is referred to as "Maximilian"), we acquired an additional 40% working interest, bringing our aggregate working interest in Michigan to 70%.

Known Trends and Uncertainties

As we continue to pursue our development and exploratory drilling programs in our California and Michigan properties, respectively, the timing of these activities continues to be determined by current crude oil and natural gas prices; the availability of drilling funds; and in California, the length and timing of the drilling permit approval process. Additionally, our drilling programs are also very sensitive to drilling costs. We attempt to control these costs through drilling efficiencies by working with service providers to receive acceptable unit costs.

In order to continue our drilling program in California and undertake a new drilling program in Michigan, we must be able to realize an acceptable margin between our expected cash flows from new production and the cost to drill and complete new wells. If any combination of a decrease in crude oil and natural gas prices; the availability of drilling funds; and/or, the rising costs of drilling, completion and other field services occurs in future periods, we may be forced to modify or discontinue a planned drilling program.

All of the Company's crude oil production in California is sold under contracts which are market-sensitive. Accordingly, the Company's financial condition, results of operations, and capital resources are highly dependent upon prevailing market prices of hydrocarbon prices and demand for crude 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. Some of these factors include the level of global demand for and price of petroleum products, foreign supply of crude oil and natural 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. Because of the size of our Company, we are highly susceptible to downward changes in the price we receive for our hydrocarbon sales especially crude oil.

A severe industry downturn and commodity price collapse caused by the global Coronavirus Disease 2019 (COVID-19) pandemic and the over-supply resulting from a price war between members of the Organization of the Petroleum Exporting Countries (OPEC) and Russia and other allied producing countries negatively impacted our revenues during the twelve months ended February 28, 2021 in comparison to the twelve months ended February 29, 2020.

California Crude Oil Prices

The price we receive for crude oil sales in California is based on prices posted for Midway-Sunset crude oil delivery contracts, less deductions that vary by grade of crude oil sold and transportation costs. The posted Midway-Sunset price generally moves in correlation to, and at a discount to, prices quoted on the New York Mercantile Exchange ("NYMEX") for spot West Texas Intermediate ("WTI") Cushing, Oklahoma delivery contracts. We do not currently have any natural gas revenues.

There continues to be a significant amount of volatility in hydrocarbon prices and a dramatic decline in our realized sale price of crude oil since June of 2014 when the monthly average price of WTI oil was $105.79 per barrel and our realized price per barrel of crude oil was $98.78. As an example, for the month of April 2020, the monthly average price of WTI crude oil was $16.55 and our monthly realized price was $16.96 per barrel. This volatility in crude oil prices continued throughout most of the 2020-2021 fiscal year. The volatility and decline in the price of crude oil has had a substantial negative impact on our profitability and cash flow from our producing California properties.

It is beyond our ability to accurately predict how long crude oil prices will continue to remain at these lower price levels; when or at what level they may begin to stabilize; or if they may start to rebound as there are many factors beyond our control such as the current COVID-19 restrictions that influences the price we receive on our crude oil sales.

A comparison of the average WTI price and average realized crude oil sales price at our East Slope Project in California for the twelve months ended February 28, 2021 and February 29, 2020 is shown in the table below:

	Twelve Months Ended		
	February 28, 2021	February 29, 2020	Percentage Change
Average twelve month WTI crude oil price	$ 39.48	$ 57.13	(30.9%)
Average twelve month realized crude oil sales price (Bbl)	$ 36.91	$ 60.25	(38.7%)

For the twelve months ended February 28, 2021, the average WTI price was $39.48 and our average realized crude oil sale price was $36.91, representing a discount of $2.57 per barrel or 6.5% lower than the average WTI price. In comparison, for the twelve months ended February 29, 2020, the average WTI price was $57.13 and our average realized sale price was $60.25 representing a premium of $3.12 per barrel or 5.5% higher than the average WTI price. Historically, the sale price we receive for California heavy crude oil has been less than the quoted NYMEX WTI price because of the lower API gravity of our California crude oil in comparison to WTI crude oil API gravity.

California Crude Oil Revenue and Production

Crude oil revenue in California for the twelve months ended February 28, 2021 decreased $258,611 or 39.0% to $404,901 in comparison to revenue of $663,512 for the twelve months ended February 29, 2020. The average sale price of a barrel of crude oil for the twelve months ended February 28, 2021 was $36.91 in comparison to $60.25 for the twelve months ended February 29, 2020. The decrease of $23.34 or 38.7% per barrel in the average realized price of a barrel of crude oil accounted for 99.4% of the decrease in crude oil revenue for the twelve months ended February 28, 2021.

Our net sales volume for the twelve months ended February 28, 2021 was 10,970 barrels of crude oil in comparison to 11,013 barrels sold for the twelve months ended February 29, 2020. This decrease in crude oil sales volume of 43 barrels or 0.4% accounted for 0.6% of the decrease in crude oil revenue for the twelve months ended February 28, 2021 and was primarily due to the natural decline in reservoir pressure during the twelve months ended February 28, 2021.

The gravity of our produced crude oil in California ranges between 14° API and 16° API. Production for the twelve months ended February 28, 2021 was from 20 wells resulting in 7,288 well days of production in comparison to 7,167 well days of production from 20 wells for the twelve months ended February 29, 2020.

Competition

We compete with other independent crude oil and natural 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 crude oil assets are located in the United States and all of our revenues are from sales to customers within the United States.

Marketing Arrangements – Principal Customer

At our East Slopes Project, located in Kern County, California, we sell all of our crude oil production to one buyer. At February 28, 2021 and February 29, 2020, this one individual customer represented 100% of crude oil sales receivable. If this local purchaser is unable to resell their products or if they lose a significant sales contract then we may incur difficulties in selling our crude oil production.

The Company’s accounts receivable for California crude oil sales at February 28, 2021 and February 29, 2020 are set forth in the table below.

		February 28, 2021		February 29, 2020	
Project	Customer	Accounts Receivable Crude Oil Sales	Percentage	Accounts Receivable Crude Oil Sales	Percentage
California – East Slopes Project (Crude oil)	Plains Marketing	$ 108,993	100.0%	$ 56,910	100.0%

Title to Properties

As is customary in the crude oil and natural gas industry, we make only a cursory review of title to undeveloped crude 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. Except for encumbrances we have granted as described below under "Encumbrances," we believe that we have good title to our crude oil and natural gas properties, some of which are subject to immaterial easements, and restrictions.

Regulation

The exploration and development of crude oil and natural 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, hydraulic fracturing operations, 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.

All of the states in which we operate generally require permits for drilling operations, require drilling bonds and reports concerning operations and impose other requirements relating to the exploration and production of crude oil and natural gas. Such states also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of crude oil and natural gas properties, the establishment of maximum rates of production from crude oil and natural gas wells, the spacing, plugging and abandonment of such wells, restrictions on venting or flaring of natural gas and requirements regarding the ratability of production.

These laws and regulations may limit the amount of crude oil and natural gas we can produce from our wells and may limit the number of wells or the locations at which we can drill. Moreover, many states impose a production or severance tax with respect to the production and sale of crude oil and natural gas within their jurisdiction. States do not generally regulate wellhead prices or engage in other, similar direct economic regulation of production, but there can be no assurance they will not do so in the future.

In California, where we currently operate a 20 well oilfield project, there is substantial federal and state regulation and oversight of produced water and its disposal. Water regulations in California are currently under review and are subject to change. We produce a substantial amount of water while lifting oil from our reservoirs. While the water we produce is considered to be "fresh water" under current testing standards and is suitable for use for livestock and agricultural purposes, its handling and use are currently under review by regional authorities. As rules change, we may be required to invest in additional water management infrastructure. There is no guarantee that we will not have to incur additional costs in the future in regards to the disposal and use of our produced water.

CalGEM is California's primary regulator of the oil and natural gas industry on private and state lands, with additional oversight from the State Lands Commission's administration of state surface and mineral interests. Government actions, including the issuance of certain permits or approvals, by state and local agencies or by federal agencies may be subject to environmental reviews, respectively, under the California Environmental Quality Act (CEQA) or the National Environmental Policy Act (NEPA), which may result in delays, imposition of mitigation measures or litigation. CalGEM currently requires an operator to identify the manner in which CEQA has been satisfied prior to issuing various state permits, typically through either an environmental review or an exemption by a state or local agency.

In Kern County this requirement has typically been satisfied by complying with the local oil and gas ordinance, which was supported by an Environmental Impact Report (EIR) certified by the Kern County Board of Supervisors in 2015. A group of plaintiffs challenged the EIR and on February 25, 2020, a California Court of Appeal issued a ruling that invalidates a portion of the EIR until the County makes certain revisions to the EIR and recertifies it. On February 12, 2021, the Kern County Planning Commission voted to recommend approval of the revisions in a supplementary EIR in order to reestablish the county's oil and gas permitting system, though it must be approved by the county Board of Supervisors before becoming effective. This certification is expected to be completed in the first half of 2021; however, the supplemental EIR and certification may also be subject to litigation. After the supplementary EIR is certified, it is expected that CalGEM will rely on Kern County to serve as lead agent for CEQA purposes, reducing unnecessary delays at the state level.

The California Legislature has significantly increased the jurisdiction, duties and enforcement authority of CalGEM, the State Lands Commission and other state agencies with respect to oil and natural gas activities in recent years. For example, 2019 state legislation expanded CalGEM's duties effective on January 1, 2020 to include public health and safety and reducing or mitigating greenhouse gas emissions while meeting the state's energy needs, and will require CalGEM to study and prioritize idle wells with emissions, evaluate costs of abandonment, decommissioning and restoration, and review and update associated indemnity bond amounts from operators if warranted, up to a specified cap which may be shared among operators. Other 2019 legislation specifically addressed oil and natural gas leasing by the State Lands Commission, including imposing conditions on assignment of state leases, requiring lessees to complete abandonment and decommissioning upon the termination of state leases, and prohibiting leasing or conveyance of state lands for new oil and natural gas infrastructure that would advance production on certain federal lands such as national monuments, parks, wilderness areas and wildlife refuges.

In the event we conduct operations on federal, state or American Indian crude oil and natural gas leases, our operations may be required to comply with additional regulatory restrictions, including various nondiscrimination statutes, royalty and related valuation requirements and on-site security regulations, and other appropriate permits issued by the Bureau of Land Management or other relevant federal or state agencies.

The sales price of crude oil and natural gas are not presently regulated but rather are set by the market. We cannot predict, however, whether new legislation to regulate the price of energy commodities might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, the proposals might have on the operations of the underlying properties.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. Hydraulic fracturing typically is regulated by state crude oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act over certain hydraulic fracturing activities involving the use of diesel fuel. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, chemical disclosure and well construction requirements on hydraulic fracturing activities. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities, and perhaps even be precluded from drilling wells. We do not presently use hydraulic fracturing methods in our crude oil exploration and production in California.

Operational Hazards and Insurance

Our operations are subject to the usual hazards incident to the drilling and production of crude oil and natural gas, such as blowouts, cratering, explosions, uncontrollable flows of crude oil, natural 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.

Human Capital

At February 28, 2021, we had three full-time employees and one part-time employee. Two other employees had been temporarily furloughed in an effort to preserve our cash flow. We anticipate they will return to full employment in the near future. Additionally, we regularly use the services of four consultants on an as-needed basis for accounting, technical, oil field, geological, investor relations 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 future as needed. All other services are currently contracted for with independent contractors. We have not obtained "key person" life insurance on any of our officers or directors. As we continue to manage the business ongoing, we are focused on retaining and developing our existing employees who are critical to the business.

Long-Term Success

Our long-term success depends on the successful acquisition, exploration and development of commercial grade crude oil and natural gas properties as well as the prevailing prices for crude oil and natural gas to generate future revenues and operating cash flow. Crude oil and natural gas prices are extremely volatile and have decreased significantly since June of 2014 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 crude oil and natural gas; however, any prolonged period of price instability, such as we have experienced since June 2014, has had and will likely continue to have a material adverse effect on our results of operations and financial condition. Such pricing factors are beyond our control, and have resulted and will result in negative fluctuations of our earnings. We believe; however, that even in this volatile pricing environment there are significant opportunities available to us in the crude oil and natural 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 website at www.daybreakoilandgas.com under the "Shareholder/Financial" section of our website 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. Copies of our Ethical Business Conduct Policy Statement and Code of Ethics for Senior Financial Officers are available under the "Shareholder/Financial" section of our website 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 website, information on any amendment to or waiver of these codes with respect to our executive officers and directors. Waiver information disclosed via the website will remain on the website 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 website 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.
1101 N. Argonne Road, Suite A-211
Spokane Valley, WA 99212-2699
Attention: Corporate Secretary
Telephone: (509) 232-7674

Information contained on or connected to our website 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. There are many factors that affect our business, a number of which are beyond our control. Our business, financial condition and results of operations could be materially adversely affected by any of these factors. The nature of our business activities further subjects us to certain hazards and risks. The risks described below are a summary of the known material risks relating to our business. Additional risks and uncertainties not presently known to us or that we currently deem to be immaterial individually or in aggregate may also impair our business operations. If any of these risks actually occur, it could harm our business, financial condition or results of operations and impair our ability to implement our business plan or complete development projects as scheduled. In any such case, the trading price of our Common Stock could decline, and you could lose all, or a part, of your investment.

Risks Related to Volatile Energy Prices

Crude oil and natural gas prices are volatile. Since the second half of 2014 when the price of WTI oil was $105.79 per barrel, there has been substantial volatility and uncertainty in commodity prices, which has significantly adversely affected, and in the future may continue to 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 crude oil and natural gas. Product prices affect our cash flow available for capital expenditures and our ability to access funds through the capital markets. Declines in commodity prices have historically adversely affected the estimated value of our proved reserves and our cash flows. The volatility in hydrocarbon prices from June of 2014, which we are currently experiencing has had a material adverse effect on our cash flows, reserves valuation and availability of funds in the financial markets. Specifically, our average realized price of crude oil sales for the twelve months ended February 28, 2021 was $36.91 in comparison to the average realized price of $60.25 for the twelve months ended February 29, 2020.

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

- changes in the supply of and demand for crude 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 crude oil and natural gas;
- the price of crude oil and natural gas imports
- national and international pandemics like the COVID-19; and
- overall domestic and foreign economic conditions.

These factors make it very difficult to predict future hydrocarbon commodity price movements with any certainty. It is beyond our control and ability to accurately predict when there will be a sustained improvement in hydrocarbon prices. All of our crude oil and natural gas sales are made pursuant to contracts based on spot market prices and are not based on long-term fixed price contracts. Crude oil and natural gas prices do not necessarily fluctuate in direct relation to each other.

The COVID-19 pandemic caused crude oil prices to decline significantly in 2020, which has materially and adversely affected our business, results of operations and financial condition.

The COVID-19 pandemic has adversely affected the global economy, and has resulted in, among other things, travel restrictions, business closures and the institution of quarantining and other mandated and self-imposed restrictions on movement. As a result, there has been an unprecedented reduction in demand for crude oil. The severity, magnitude and duration of current or future COVID-19 outbreaks, the extent of actions that have been or may be taken to contain or treat their impact, and the impacts on the economy generally and oil prices in particular, are uncertain, rapidly changing and hard to predict. Lower future commodity prices caused by the COVID-19 pandemic could force us to reduce costs, including by decreasing operating expenses and lowering capital expenditures, and such actions could negatively affect future production and our reserves. Our operations also may be adversely affected if portions of our workforce are unable to work effectively, including because of illness, quarantines, government actions or other restrictions in connection with the pandemic. In addition, we are exposed to changes in commodity prices which have been and will likely remain volatile.

Additionally, to the extent the COVID-19 pandemic or any resulting worsening of the global business and economic environment adversely affects our business and financial results, it may also have the effect of heightening or exacerbating many of the other risks described in the “Risk Factors” herein.

***The Company is unable to predict the full impact of COVID-19 on its business*.**

The occurrence of an uncontrollable event such as the COVID-19 pandemic has negatively affected our operations. A pandemic typically results in social distancing, travel bans and quarantine, and this may limit access to our facilities, customers, management, support staff and professional advisors. These factors, in turn, have not only impacted our operations, financial condition and demand for our crude oil but also our overall ability to react timely to mitigate the impact of this event. Also, it may hamper our efforts to comply with our filing obligations with the Securities and Exchange Commission.

Hydrocarbon price declines may result in impairments of our asset carrying values.

Commodity prices have a significant impact on the present value of our proved reserves. Accounting rules require us to impair, as a non-cash charge to earnings, the carrying value of our crude oil and natural gas properties in certain situations. We are required to perform impairment tests on our assets periodically and whenever events or changes in circumstances warrant a review of our assets. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our assets, the carrying value may not be recoverable, and an impairment may be required. Any impairment charges we record in the future could have a material adverse effect on our results of operations in the period incurred. For the twelve months ended February 28, 2021, we determined that a non-cash impairment will not be recognized on our California crude oil properties due to the prevailing increase in the current hydrocarbon prices.

Risks Related to Our Business

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.

Our business plan contemplates the execution of our current exploration and development projects and the expansion of our business by identifying, acquiring, and developing additional crude oil and natural gas properties. We plan to rely on external sources of financing to meet the capital requirements associated with these activities. We will have to obtain any additional funding we need through debt and equity markets or the sale of producing or non-producing assets. 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.

Low hydrocarbon price environments and the volatility in prices that we are currently experiencing, as well as operating difficulties and other factors, many of which are beyond our control, are causing our revenues and cash flows from operating activities to decrease and may limit our ability to internally fund our exploration and development activities.

We may make offers to acquire crude oil and natural 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 crude oil and natural 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 crude oil and natural gas property interests.

The crude oil and natural gas business is highly competitive, placing us at an operating disadvantage.

We expect to be at a competitive disadvantage in (a) seeking to acquire suitable crude oil and or natural gas drilling prospects; (b) undertaking exploration and development; and (c) seeking additional financing. We base our preliminary decisions regarding the acquisition of crude oil and or natural 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 larger crude oil and natural 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 crude oil and natural gas;
- acquire and evaluate larger volumes of critical information; and
- compete for industry-offered business ventures.

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

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

Our future performance depends upon our ability to find, acquire, and develop crude oil and natural 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 crude oil and natural gas deposits will be discovered that are sufficient to enable us to recover our exploration and development costs.

Our limited capital expenditures and drilling program, when coupled with a sustained depression in crude oil and natural gas prices, will significantly reduce our cash flow and constrain any future drilling, which would have a material adverse effect on our business, financial condition and results of operations.

Historically, we have made substantial capital expenditures for the exploration and development of crude oil and natural gas reserves. The combination of lower hydrocarbon prices and the reduction of our drilling operations has resulted in reduced production and operating cash flows since June of 2014. A continued sustained volatility in these hydrocarbon prices combined with reduced production and accompanying lower cash flows will continue to adversely affect our business financial condition and results of operations.

Our proved reserves are estimates and depend on many assumptions. Any material inaccuracies in these assumptions could cause the quantity and value of our crude oil reserves, and our revenues, profitability and cash flows to be materially different from our estimates.

The accuracy of estimated proved reserves and estimated future net cash flows from such reserves is a function of the quality of available geological, geophysical, engineering and economic data and is subject to various assumptions, including assumptions required by the SEC relating to crude oil prices, drilling and operating expenses and other matters. Although we believe that our estimated proved reserves represent reserves that we are reasonably certain to recover, actual future production, crude oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable crude oil reserves will most likely vary from the assumptions and estimates used to determine proved reserves. Any significant variance could materially affect the estimated quantities and value of our crude oil reserves, which in turn could adversely affect our cash flows, results of operations, financial condition and the availability of capital resources. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing crude oil prices and other factors, many of which are beyond our control. Downward adjustments to our estimated proved reserves could require us to impair the carrying value of our crude oil properties, which would reduce our earnings and increase our stockholders' deficit.

The present value of proved reserves will not necessarily equal the current fair market value of our estimated crude oil reserves. In accordance with reserve reporting requirements of the SEC, we are required to establish economic production for reserves on an average historical price. Actual future prices and costs may be materially higher or lower than those required by the SEC. The timing of both the production and expenses with respect to the development and production of crude oil properties will affect the timing of future net cash flows from proved reserves and their present value.

The estimated proved reserve information is based upon reserve reports prepared by an independent engineer. From time to time, estimates of our reserves are also made by our company engineer for use in developing business plans and making various decisions. Such estimates may vary significantly from those of the independent engineers and may have a material effect upon our business decisions and available capital resources.

We may not be able to replace current production with new crude oil and natural gas reserves.

In general, the volume of production from a crude oil and natural gas property declines as reserves related to that property are depleted. The decline rates depend upon reservoir characteristics. In past years other than our East Slopes project in California, our crude oil and natural gas properties have had steep rates of decline and relatively short estimated productive lives.

Our identified drilling locations are scheduled out over multiple years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management team has specifically identified and scheduled certain drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including hydrocarbon prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory and zoning approvals and other factors.

Because of these uncertain factors, we do not know if the numerous drilling locations we have identified will ever be drilled. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the drilling locations are obtained, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified. In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our business and results of operations.

Due to the volatility in crude oil prices and the lack of available drilling capital, we have not drilled any prospective development locations in California since November of 2013.

We may reclassify proved undeveloped reserves to unproved reserves due to our inability to commit sufficient capital within the required five-year development window, which could adversely affect the value of our properties.

The SEC generally requires that any undrilled location can be classified as a proved undeveloped reserve only if a development plan has been adopted indicating that the location is scheduled to be drilled within five years. The reduction of our drilling program in response to depressed crude oil and natural gas prices and a lack of drilling capital has impacted our ability to develop proved undeveloped reserves within such five-year period. If our reduced drilling plans continue over a significant period of time our future access to capital resources will be limited, and we will also likely further delay the development of our proved undeveloped reserves or ultimately suspend such development which could result in the reclassification of a significant amount of our proved undeveloped reserves as probable or possible reserves. A significant reclassification of proved undeveloped reserves could adversely affect the value of our properties.

Our producing reserves are located in one major geographic area. Concentration of reserves in limited geographic areas may disproportionately expose us to operational, regulatory and geological risks.

Our one core producing property is located in Kern County, California. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, or interruption of the processing or transportation of crude oil.

When we make the determination to invest in crude oil or natural 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 crude oil or natural gas exists at a particular location. This data is also used to determine whether crude 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, an increase in the 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 crude 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.

Shortages of oilfield equipment, services and qualified personnel could delay our drilling program and increase the prices we pay to obtain such equipment, services and personnel.

The demand for qualified and experienced field personnel to drill wells and conduct field operations in the crude oil and natural gas industry can fluctuate significantly, often in correlation with crude oil and natural gas prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other oilfield equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher crude oil and natural gas prices generally stimulate demand and result in increased prices for drilling and workover rigs, crews, and associated supplies, equipment and services. It is beyond our control and ability to predict whether these conditions will exist in the future and, if so, what their timing and duration will be.

Drilling is a high risk activity and, as a result, we may not be able to adhere to our proposed drilling schedule, or our drilling program may not result in commercially productive reserves.

Our future success will partly depend on the success of our drilling programs. The future cost or timing of drilling, completing, and producing wells is inherently uncertain. Our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors including:

- unexpected drilling conditions;
- well integrity issues and surface expressions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- compliance with landowner requirements;
- current crude oil and natural gas prices and estimates of future crude oil and natural gas prices;
- availability, costs and terms of contractual arrangements with respect to pipelines and related facilities to gather, process, transport and market crude oil and natural gas; and
- shortages or delays in the availability of drilling rigs and the delivery of equipment and/or services, including experienced labor.

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

All of our properties are held under interests in crude oil and natural 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 a crude oil or natural 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 crude oil and natural gas produced by our leases. We may not be able to obtain any such additional funds on acceptable terms.

Title deficiencies could render our crude oil and natural 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 crude oil and natural gas lease brokers who perform the fieldwork 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 crude oil and natural gas industry.

We anticipate that we, or the person or company acting as operator 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 operator of our crude oil project fail to maintain adequate insurance, our business could be exposed to significant losses.

Our crude oil projects are subject to risks inherent in the crude oil and natural gas industry. These risks involve explosions, uncontrollable flows of crude oil, natural 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 any project in which we are not the operator, we will 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.

New technologies may cause our current exploration and drilling methods to become obsolete.

There have been rapid and significant advancements in technology in the natural gas and crude oil industry, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial increase in cost. Further, competitors may obtain patents which might prevent us from implementing new technologies. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. One or more of the technologies that we currently use or that we may implement in the future may become obsolete. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are unable to maintain technological advancements consistent with industry standards, our operations and financial condition may be adversely affected.

Risks related to Environmental Regulation

Recent and future actions by the state of California could result in restrictions to our operations and result in decreased demand for oil and gas within the state.

In September 2020, Governor Gavin Newsom of California issued an executive order (Order) that seeks to reduce both the demand for and supply of petroleum fuels in the state. The Order establishes several goals and directs several state agencies to take certain actions with respect to reducing emissions of GHGs, including, but not limited to: phasing out the sale of new emissions-producing passenger vehicles, drayage trucks and off-road vehicles by 2035 and, to the extent feasible, medium and heavy duty trucks by 2045; developing strategies for the closure and repurposing of oil and gas facilities in California; and proposing legislation to end the issuance of new hydraulic fracturing permits in the state by 2024. The Order also directs the California Department of Conservation, Geologic Energy Management Division (CalGEM) to strictly enforce bonding requirements for oil and gas operations and to complete its ongoing public health and safety review of oil production and propose additional regulations, which are expected to include expanded land use setbacks or buffer zones.

In October 2020, the Governor issued an executive order that establishes a state goal to conserve at least 30% of California’s land and coastal waters by 2030 and directs state agencies to implement other measures to mitigate climate change and strengthen biodiversity. In February 2021, SB 467 was introduced in the state senate. If passed, the bill would ban new permits for hydraulic fracturing, acid well stimulation treatments, cyclic steaming, water flooding and steam flooding – beginning in 2022 and would ban these activities in total beginning in 2027. The bill would also allow local governments to prohibit such practices prior to 2027. After the bill was introduced one of the authors announced that it would also be amended to also add a 2,500 feet setback for new wells from sensitive receptors. We cannot predict the outcome of this most recent legislative effort. Previous high profile efforts to pass mandatory setbacks have failed; however, any of the foregoing developments and other future actions taken by the state may materially and adversely affect our operations and properties and the demand for our products.

We face various risks associated with the trend toward increased anti-crude oil and natural gas development activity.

In recent years, we have seen significant growth in opposition to crude oil and natural gas development in the United States. Companies in our industry can be the target of opposition to hydrocarbon development from stakeholder groups, including national, state and local governments, regulatory agencies, non-government organizations and public citizens. This opposition is focused on attempting to limit or stop hydrocarbon development. Examples of such opposition include: efforts to reduce access to public and private lands; delaying or canceling permits for drilling or pipeline construction; limiting ore banning industry techniques such as hydraulic fracturing, and/or adding restrictions on or the use of water and associated disposal; imposition of set-backs on crude oil and natural gas sites; delaying or denying air-quality permits; advocating for increased punitive taxation or citizen ballot initiatives or moratoriums on industry activity; and the use of social media channels to cause reputational harm. Recent efforts by the US Administration to modify federal crude oil and natural gas regulations could intensify the risk of anti-development efforts from grass roots opposition.

Our need to incur costs associated with responding to these anti-development efforts, including legal challenges, or complying with any new legal or regulatory requirements from these efforts, could have a material adverse effect on our business.

Restricted land access could reduce our ability to explore for and develop crude oil and natural gas reserves.

Our ability to adequately explore for and develop crude oil and natural gas resources is affected by a number of factors related to access to land. Examples of factors which reduce our access to land include, among others:

- new municipal, state or federal land use regulations, which may restrict drilling locations or certain activities such as hydraulic fracturing;
- local and municipal government control of land or zoning requirements, which can conflict with state law and deprive land owners of property development rights;
- landowner, community and/or governmental opposition to infrastructure development;
- regulation of federal and Indian land by the Bureau of Land Management;
- anti-development activities, which can reduce our access to leases through legal challenges or lawsuits, disruption of drilling, or damage to equipment;
- the presence of threatened or endangered species or of their habitat;
- Disputes regarding leases; and
- Disputes with landowners, royalty owners, or other operators over such matters as title transfer, joint interest billing arrangements, revenue distribution, or production or cost sharing arrangements.

Reduced ability to obtain new leases could constrain our future growth and opportunity resulting in a material adverse effect on our business, financial condition, results of operations and our cash flows.

Our crude oil and natural 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 crude oil and natural 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.

Climate change legislation or regulations restricting emissions of greenhouse gases ("GHG") could result in increased operating costs and reduced demand for the crude oil we produce.

Climate change continues to attract considerable public and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHGs. These efforts have included consideration by states or groupings of states of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources.

At the federal level, no comprehensive climate change legislation has been implemented to date. However, the EPA has determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment and has adopted regulations under existing provisions of the Clean Air Act. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States on an annual basis, including, among others, onshore and offshore crude oil and natural gas production facilities and onshore processing, transmission, storage and distribution facilities. In October 2015, the EPA amended and expanded the GHG reporting requirements to all segments of the crude oil and natural gas industry, including gathering and boosting facilities and blowdowns of natural gas transmission pipelines, and in January 2016, the EPA proposed additional revisions to leak detection methodology.

The adoption and implementation of any international, federal or state legislation, regulations or other regulatory initiatives that require reporting of GHGs or otherwise restricts emissions of GHGs from our equipment and operations could cause us to incur increased costs that could have an adverse effect on our business, financial condition and results of operations. Moreover, such new legislation or regulatory programs could also increase the cost to the consumer, and thereby reduce demand for crude oil and natural gas, which could reduce the demand for the crude oil or natural gas we produce and lower the value of our reserves.

Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornados and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially hotter or colder than their historical averages. Extreme weather conditions can interfere with our production and increase our operating expenses. Such damage or increased expenses from extreme weather may not be fully insured. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations. At this time, we have not developed a comprehensive plan to address the legal, economic, social or physical impacts of climate change on our operations.

Risks Related to Our Indebtedness

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 net loss of approximately $512,265 for the year ended February 28, 2021, and we have an accumulated deficit through February 28, 2021 of approximately $29.4 million. Without successful exploration and development of our properties and a significant sustained increase in hydrocarbon prices any investment in Daybreak could become devalued or worthless.

We have substantial indebtedness. The amount of our outstanding indebtedness and our current inability to meet our debt obligations will have adverse consequences on our business, financial condition and results of operations.

At February 28, 2021, we had approximately $6.0 million of consolidated indebtedness comprised of a variety of short-term and long-term borrowings; related party notes and payables; a line of credit; trade payables; and 12% Subordinated Notes. The 12% Notes had a maturity date of January 29, 2019 and the principal balance of $565,000 has not been paid. The level of indebtedness we have affects our operations in a number of ways. We will need to use a portion of our cash flow to meet principal, interest and payables commitments; which reduces the amount of funds we will have available to finance our operations. This lack of funds limits planning for or reacting to changes in our business and the industry in which we operate and could limit our ability to make funds 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 the level of hydrocarbon prices and 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.

General Risk Factors

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

Legislation previously 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 crude 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 crude 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 U.S. 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 type of 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 crude oil and natural 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.

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

Our President and Chief Executive Officer, who is also acting as our interim principal finance and accounting officer, our Director of Field Operations, and two of our directors each have substantial experience in the crude oil and natural 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.

A terrorist attack, anti-terrorist efforts or other armed conflict could adversely affect our business by decreasing our revenues and increasing our costs.

A terrorist attack, anti-terrorist efforts or other armed conflict involving the United States may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur or escalate, the resulting political instability and societal disruption could reduce overall demand for crude oil and natural gas, potentially putting downward pressure on demand for our services and causing a decrease in our revenues. Crude oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if significant infrastructure or facilities used for the production, transportation, processing or marketing of crude oil and natural gas production are destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Risks Related to Our Common Stock

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, 2021 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 not held an annual meeting of our shareholders since 2010; as such, our shareholders have not had the opportunity to elect directors since 2010.

Our bylaws and the Washington Business Corporation Act state that we must hold an annual meeting of our shareholders for the election of directors and other business as may be properly brought before the meeting. However, because we have had limited financial resources, we have not held an annual meeting of our shareholders since 2010. As such, our shareholders have not had the opportunity to vote in an election of our directors since 2010. When we hold an annual shareholders' meeting in the future, our shareholders will then have the opportunity to vote on the election of our directors.

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

Daybreak's Common Stock (OTC Pink: DBRM) trades on the OTC Pink® Open Market under the OTC Markets Group segment, Pink Current Information. Prior to May 1, 2016, our stock had traded on the OTCQB Venture Marketplace. Our transition to the OTC Pink® Open Market was the result of a cost-savings move for the company related to listing fees on the Venture Marketplace.

Because of the limited liquidity of our stock, 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 crude oil and natural gas exploration and development industry including volatility in crude oil and natural gas prices, and other events or factors. The decline, instability and volatility in hydrocarbon prices, that we have been experiencing since June 2014, has had a corresponding material adverse impact on our revenues and a similar direct material adverse impact on the trading price of our Common Stock.

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 do 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.

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

To date, while we generally have had positive cash flow from our 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 profitably especially in the current low-priced hydrocarbon environment. 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 resale of shares offered in private placements could depress the value of the shares.

In the past, 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, 2021, there were 60,491,122 shares of Common Stock and 709,568 shares of Series A Convertible Preferred stock outstanding.

Historically we have issued, and likely will continue to issue, additional shares of our Common Stock in connection with the compensation of personnel, future acquisitions, private placements, possible equity swaps for debt 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 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 our Series A Convertible Preferred Shares. The rights and preferences of these 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; and
- a preference upon any actual or “deemed” liquidation, dissolution or winding up of the Company.

The issuance of these preferred shares could make it less likely that shareholders would 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.

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

We will need to 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 crude oil and natural gas reserves. In the past, we have obtained debt financing through commercial loans and credit facilities. Subsequent 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.

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 the Company’s inception in 1955. 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 that 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. Investors must rely on sales of their Common Stock after price appreciation, which may never occur, as the only way to realize a return on their investment. Investors seeking cash dividends should not purchase 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

We conduct all of our drilling, exploration and production activities in the United States. All of our crude oil assets are located in the United States, and all of our revenues are derived from sales to customers within the United States. During the year ended February 28, 2021, we were involved in the operation of a 20 well oilfield project in Kern County, California.

We have not filed any estimates of total, proved net crude oil or natural gas reserves with any federal agency other than this report to the SEC for the fiscal year ended February 28, 2021. Throughout this Annual Report on Form 10-K, crude oil is shown in barrels ("Bbls"); natural gas is shown in thousands of cubic feet ("Mcf") or British Thermal Units ("BTU") unless otherwise specified, and hydrocarbon totals are expressed in barrels of oil equivalent ("BOE").

Kern County, California (East Slopes Project)

The East Slopes Project is located in the southeastern part of the San Joaquin Basin near Bakersfield, California. Drilling targets are porous and permeable sandstone reservoirs that exist at depths of 1,200 feet to 4,500 feet. Since January 2009, we have participated in the drilling of 25 wells in this project. We have been the Operator at the East Slopes Project since March 2009.

Our 20 producing crude oil wells in the East Slopes Project produce from five reservoirs at our Sunday, Bear, Black, Ball and Dyer Creek locations. The Sunday property has six producing wells, while the Bear property has nine producing wells. The Black property is the smallest of all currently producing reservoirs, and currently has two producing wells at this property. The Ball property also has two producing wells while the Dyer Creek property has one producing well. Our average working interest and NRI in these 20 producing crude oil wells is 36.6% and 28.4%, respectively.

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 Central Processing and Storage Facility

The crude oil produced from our acreage in California is considered heavy crude oil. The crude oil ranges from 14° to 16° API gravity. All of the crude oil from our five producing properties is processed, stored and sold from the Sunday central processing and storage facility. The crude 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. In 2013, we completed an upgrade to this facility including the addition of a second crude oil storage tank to handle the additional crude oil production from the wells drilled in 2013.

By utilizing the Sunday centralized production facility our average production expenses have been reduced from over $40 per barrel in 2009 to around $17 per barrel of crude oil for the year ended February 28, 2021. With this centralized facility and having permanent electrical power available, we are ensuring that our operating expenses are kept to a minimum.

California Producing Properties

Sunday Property

In November 2008, we made our initial crude 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 #2, Sunday #3 and Sunday #4H wells, respectively. During May and June 2013, we drilled two additional development wells: the Sunday #5 and Sunday #6. We have a 37.5% working interest with a 26.1% net revenue interest ("NRI") in the Sunday #1 well. For the Sunday #2 and Sunday #3 wells, we have a 33.8% working interest with a 24.3% NRI. In the Sunday #4H well, we have a 33.8% working interest with a 27.1% NRI. In both the Sunday #5 and Sunday #6 wells we have a 37.5% working interest and a NRI of 30.1%. Our average working interest and NRI for the Sunday property six producing wells in aggregate is 35.6% and 27.0%, respectively. The Sunday reservoir is estimated to be approximately 35 acres in size with the potential for at least five more development wells to be drilled in the future.

Bear Property

In February 2009, we made our second crude 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 on this property by drilling and completing the Bear #2 well. In April 2010, we successfully drilled and completed the Bear #3 and the Bear #4 wells. In May and June 2013, we drilled three additional development wells, the Bear #5, Bear #6 and Bear #7, on this property. In November 2013, we drilled and put on production two additional development wells: Bear #8 and Bear #9. We have a 37.5% working interest in all wells on the Bear property. Our NRI in the Bear #1, Bear #2, Bear #3 and Bear #4 wells is 26.1%. For the Bear #5, Bear #6 and Bear #7 wells our NRI is 30.1%. Our NRI in the Bear #8 and Bear #9 wells is 31.7%. The average working interest and NRI for the Bear property for the ten producing wells in aggregate is 37.5% and 28.7%, respectively. The Bear reservoir is estimated to be approximately 62 acres in size with the potential for at least eleven more development wells to be drilled in the future.

Black Property

The Black property was acquired through a farm-in arrangement with a local operator. The Black property is just south of the Bear property 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 approximately 2,200 feet. In May 2013, we drilled a development well, the Black #2, on this property. We have a 33.8% working interest with a 26.8% NRI in the two producing wells on this property. The Black reservoir is estimated to be approximately 13 acres in size with the potential for at least three more development wells to be drilled in the future.

Ball Property

The Ball #1-11 well was put on production in late October 2010. In June 2013 we drilled a development well, the Ball #2-11, on this property. Production on this property is from the Vedder Sand at approximately 2,500 feet. We have a 37.5% working interest with a 31.7% NRI in the two producing wells on this property. Our 3-D seismic data indicates a reservoir of approximately 38 acres in size with the potential for at least three more development wells to be drilled in the future.

Dyer Creek Property

The Dyer Creek #67X-11 (“DC67X”) well was also put on production in late October 2010. This well produces from the Vedder Sand and is located to the north of the Bear property on the same trapping fault. We have a 37.5% working interest with a 31.7% NRI in all wells on this property. The Dyer Creek property has the potential for at least one development well in the future.

California Drilling Plans

Planned drilling activity and implementation of our oilfield development plan will not begin until there is a sustained improvement in crude oil prices and additional financing is put in place. We do not plan to make any capital investments within the East Slopes Project area in the 2021 - 2022 fiscal year if no new financing is in place. If new financing is secured, we plan to drill four development wells for a total of $525,000.

Michigan Acreage Acquisition

In January 2017, we acquired a 30% working interest in 1,400 acres in the Michigan Basin. The leases have been secured and multiple targets were identified through a 2-D seismic interpretation. A 3-D seismic survey was obtained in January and February of 2017 on the first prospect. An analysis of the 3-D seismic survey confirmed the first prospect originally identified on the 2-D seismic, as well as identified several additional drilling locations. We have plans to obtain an additional 3-D survey on the second prospect after drilling a well on the first prospect. However the two prospects are independent of each other and the success or failure of either one does not affect the other. The wells will be drilled vertically with conventional completions and no hydraulic fracturing is anticipated. With the settlement of our debt obligations in December 2018 with Maximilian, a former lender, we acquired an additional 40% working interest, bringing our aggregate working interest in Michigan to 70%.

Encumbrances

On October 17, 2018, a working interest partner in California filed a UCC financing statement in regards to payables owed to the partner by the Company. As of February 28, 2021, we had no encumbrances on our crude oil project in Michigan.

Reserves

Crude oil is shown in barrels ("Bbls"); natural gas is shown in thousands of cubic feet ("Mcf") or British Thermal Units ("BTU") unless otherwise specified, and hydrocarbon totals are expressed in barrels of oil equivalent ("BOE"). The following table sets forth our estimated net quantities of proved reserves as of February 28, 2021.

As of February 28, 2021, our total reserves were comprised of our working interest in East Slopes Project located in Kern County, California.

	Proved Reserves			
Reserve Category	**Crude Oil (Barrels)**	**Natural Gas (Mcf)**	**Total Crude Oil Equivalents (BOE)**	**Percent of Oil Equivalents (BOE)**
Developed	95,120	—	95,120	21.9%
Undeveloped	339,103	—	339,103	78.1%
Total Proved	434,223	—	434,223	100.0%

Changes in our estimated net proved reserves for the twelve months ended February 28, 2021 are set forth in the table below.

	Proved Reserves (BOE)
Balance as of February 29, 2020	495,977
Revisions	(50,784)
Discoveries and extensions	—
Production	(10,970)
Balance as of February 28, 2021	434,223

Revisions. Net downward revisions of 50,784 BOE in aggregate were due to lower crude oil prices in California during the twelve months ended February 28, 2021 decreasing the economic life of our proved reserves.

Discoveries and extensions. For the twelve months ended February 28, 2021, there were no discovery or extension reserves added in California.

Production. Production in California was 10,970 BOE in aggregate of proved reserves for the twelve months ended February 28, 2021.

As of February 28, 2021, our total proved undeveloped reserves were comprised of our interests in Kern County, California.

Changes in our estimated net proved undeveloped reserves for the twelve months ended February 28, 2021 are set forth in the table below.

	Proved Undeveloped Reserves (BOE)
Balance as of February 29, 2020	382,198
Revisions	(43,095)
Discoveries and extensions	—
Balance as of February 28, 2021	339,103

Revisions. There were net downward revisions of 43,095 BOE in aggregate due to lower crude oil prices during the twelve months ended February 28, 2021 decreasing the economic life of our proved undeveloped reserves.

Discoveries and extensions. For the twelve months ended February 28, 2021, there were there were no discoveries or extensions in California.

Our estimated net proved developed producing reserves in California at February 28, 2021 are set forth in the table below.

	Proved Developed Reserves			
Location	**Oil (Barrels)**	**Natural Gas (Mcf)**	**Total Oil Equivalents (BOE)**	**Percent of Oil Equivalents (BOE)**
California	95,120	—	95,120	100.0%

Our estimated net proved undeveloped reserves in California at February 28, 2021 are set forth in the table below.

	Proved Undeveloped Reserves			
Location	Oil (Barrels)	Natural Gas (Mcf)	Total Oil Equivalents (BOE)	Percent of Oil Equivalents (BOE)
California	339,103	—	339,103	100.0%

The Company has 321,130 Bbls of proved undeveloped reserves that have remained undeveloped for a period greater than five years. These proved undeveloped reserves have remained undeveloped due to depressed crude oil and natural gas prices and a lack of capital available for drilling. Under our current drilling plans, we intend to convert all 321,130 BOE or 100.0% of the proved undeveloped reserves disclosed as of February 28, 2021 to proved developed reserves within the next five years.

Our estimated proved reserves (BOE) and PV-10 valuation in California at February 28, 2021 are set forth in the table below.

	Proved Reserves		
Location	Total Oil Equivalents (BOE)	PV-10 of Proved Reserves	PV-10 as a Percentage of Proved Reserves
California	434,223	1,648,418	100.0%

The present value of future net cash flows from proved reserves, before deductions for estimated future income taxes and asset retirement obligations, discounted at 10% ("PV-10"), was approximately $1.6 million at February 28, 2021 a decrease of approximately $3.0 million or 64.6% from the PV-10 reserve valuation at February 29, 2020. This decrease is primarily due to the decrease in the base price of crude oil in the current report in comparison to the base price of crude oil in the February 29, 2020 report. The commodity prices used to estimate proved reserves and their related PV-10 at February 28, 2021 were based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the twelve month period from March 2020 through February 2021. The WTI benchmark average price for the twelve months ended February 28, 2021 was $38.64 per barrel of crude oil in comparison to $56.87 in the prior year reserve report.

These benchmark average prices were further adjusted for crude oil quality and gravity, transportation fees and other price differentials resulting in an average realized price in California for the February 28, 2021 reserve report of $36.14 in comparison to $59.65 in the February 29, 2020 reserve report. Adverse changes in any price differential would reduce our cash flow from operations and the PV-10 of our proved reserves. Operating costs were not escalated.

PV-10 is not a generally accepted accounting principal ("GAAP") financial measure, but we believe it is useful as a supplemental disclosure to the standardized measure of discounted future net cash flows presented in our financial statements. The PV-10 of proved reserves is based on prices and discount factors that are consistent for all companies and can be used within the industry and by securities analysts to evaluate proved reserves on a comparable basis.

Reserve Estimation

All of our estimated proved reserves of 434,223 BOE for the twelve months ended February 28, 2021 were derived from engineering reports prepared by PGH Petroleum and Environmental Engineers, LLC ("PGH") of Austin, Texas in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC.

PGH is an independent petroleum engineering consulting firm registered in the State of Texas, and Frank J. Muser, a Petroleum Engineer, is the technical person at PGH primarily responsible for evaluating the proved reserves covered by their report. Mr. Muser graduated from the University of Texas at Austin with a Bachelor of Science degree in Chemical Engineering. He is a licensed Professional Engineer in the states of Texas, Alabama, Kansas, North Dakota and West Virginia and has been employed by PGH as a staff engineer since 2012. Mr. Muser has over 20 years of extensive crude oil and natural gas experience working in both private industry and for the State of Texas. The services provided by PGH 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 PGH, 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 is performed by Bobby Ray Greer, Director of Field Operations. Mr. Greer is a 1984 graduate of University of Southern Mississippi in Hattiesburg, Mississippi with a Bachelor of Science Degree in Geology and is a certified Petroleum Geologist and a member, in good standing, of the American Association of Petroleum Geologists and is a registered professional geologist in Mississippi. Mr. Greer has over 35 years of experience in petroleum exploration, reservoir analysis, drilling rig construction, oilfield operations and management.

Although we believe that the estimates of reserves prepared by Mr. Greer 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 PGH for their analysis all pertinent data needed to properly evaluate our reserves. We consult regularly with PGH 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 crude 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 crude 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, crude oil and natural 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 crude oil 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 crude oil 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 crude oil and natural gas industry in general are subject.

Delivery Commitments

As of February 28, 2021, we had no commitments to provide any fixed or determinable quantities of crude oil or natural gas in the near future under contracts or agreements.

Summary Operating Data

The following table sets forth our net share of annual production in each project for the periods shown. One barrel of crude oil equivalent ("BOE") is roughly equivalent to 6,000 cubic feet or 6 Mcf of gas.

As of February 28, 2021, our total reserves were comprised of our working interest in East Slopes Project located in Kern County, California.

	For the Twelve Months Ended February 28/29,		
	2021	2020	2019
Crude Oil and Natural Gas Production Data:			
California crude oil	10,970	11,013	11,492
Total (BOE)	10,970	11,013	11,492

The following table sets forth our net share of crude oil and natural gas revenue by project area for the periods shown.

	For the Twelve Months Ended February 28/29,		
	2021	2020	2019
Crude Oil and Gas Revenue:			
California crude oil	404,901	663,512	742,857
Total	$ 404,901	$ 663,512	$ 742,857

The following table sets forth the average realized sales price from each project area for the periods shown.

	For the Twelve Months Ended February 28/29,		
	2021	2020	2019
Average Realized Price:			
Crude oil – California (Bbl)	$ 36.91	$ 60.25	$ 64.64

The following table sets forth the average production expense (BOE) for the periods shown.

	For the Twelve Months Ended February 28/29,		
	2021	2020	2019
Average Production Expense (BOE):			
California	$ 17.12	$ 16.43	$ 12.96

Gross and Net Acreage

The following table sets forth our interests in developed and undeveloped crude oil lease acreage in California and our undeveloped crude oil lease acreage in Michigan held by us as of February 28, 2021. As of December 2018, our interest in undeveloped lease acreage in Michigan increased to 70%. These ownership interests generally take the form of working interests in crude oil leases that have varying terms. Developed acreage includes leased acreage that is allocated or assignable to producing wells. Undeveloped acreage includes leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil, regardless of whether or not the acreage contains proved reserves. Gross acres represents the total number of acres in which we have an interest. Net acres represents the sum of our fractional working interests owned in the gross acres.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
California	800	292	2,694	1,010	3,494	1,302
Michigan	—	—	700	490	700	490
Total Acreage	800	292	3,394	1,500	4,194	1,792
Average working interest		36.5%		44.2%		42.7%

Undeveloped Acreage Expirations

The following table sets forth expiration dates of our gross and net undeveloped acres in California for the years shown.

	Twelve Months Ended February 28, 2022		Twelve Months Ended February 28, 2023		Twelve Months Ended February 29, 2024	
	Gross	Net	Gross	Net	Gross	Net
California	—	—	—	—	—	—
Michigan	248	174	—	—	—	—
Total Acreage	248	174	—	—	—	—
Average working interest		70.2%		—		—

In all cases the drilling of a commercial crude oil or natural gas well will hold acreage beyond the lease expiration date. In the past we have been able to, and expect in the future to be able to extend the lease terms of some of these leases. The expirations included in the table above do not take into account the fact that we may be able to extend the lease terms. However, based on our evaluation of prospective economics, we have allowed acreage to expire from time to time and we expect to allow additional acreage to expire in the future. In California, we have previously determined that there is no likely benefit to pursuing any drilling opportunities on the majority of the expiring leases, so the expiration of these leases is expected to be immaterial to our operations. Further, none of our proved undeveloped reserves have been assigned to locations that are scheduled to be drilled after the expiration of the current leases. In California, all of our proved undeveloped reserves are assigned to leases that are currently held by production ("HBP").

Producing Wells

The following table sets forth our gross and net productive crude oil wells in California as of February 28, 2021. Productive wells are producing wells and wells capable of production. Gross wells represent the total number of wells in which we have an interest. Net wells represent the sum of our fractional working interests owned in the gross wells.

Property Location	Gross	Net
California	20	7.3
Average working interest		36.5%

Drilling Activity

The following table sets forth our exploratory and development well drilling activity in California for the periods shown. We have had no drilling activity in the past three years due to the volatility of crude oil prices and the lack of available drilling capital.

	Twelve Months Ended February 28, 2021		Twelve Months Ended February 29, 2020		Twelve Months Ended February 28, 2019	
Property Location	Productive	Dry	Productive	Dry	Productive	Dry
California						
Exploratory	—	—	—	—	—	—
Developmental	—	—	—	—	—	—
Total	—	—	—	—	—	—

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. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Our Common Stock is quoted on the OTC Pink Marketplace under the symbol "DBRM". Prior to May 1, 2016, our stock had traded on the OTCQB Venture Marketplace. Our transition to the OTC Pink Marketplace resulted from a cost-savings program for the company and related to listing fees on the Venture Marketplace.

The following table sets forth the high and low closing sales prices for our Common Stock for the two most recent twelve month periods shown. 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.

	Twelve Months Ended February 28, 2021		Twelve Months Ended February 29, 2020	
	High	Low	High	Low
First Quarter	0.013	0.006	0.029	0.014
Second Quarter	0.012	0.007	0.027	0.008
Third Quarter	0.015	0.006	0.010	0.006
Fourth Quarter	0.029	0.006	0.013	0.005

We feel the decline in the trading price of our stock can be directly linked to the similar dramatic decline in crude oil and natural gas prices and lack of capital to pursue drilling opportunities since June of 2014.

As of May 25, 2021, the Company had 1,611 shareholders of record of its Common Stock. This number does not include an indeterminate number of shareholders whose shares are held by brokers in street name.

Transfer Agent

Effective December 22, 2020, the Company appointed Sedona Equity Registrar & Transfer, Incorporated ("Sedona") as its transfer agent and shareholder support provider. On December 28, 2020, all of the Company's directly held shares of common stock, files and information have been transferred from Computershare to Sedona. In this capacity, Sedona will manage all stock registry requests for shareholders, including change of address, certificate replacement and transfer of shares. All stock and investment information will automatically transfer to Sedona from our former Transfer Agent and Registrar, Computershare, and no action is required on the part of the shareholder.

The transfer agent for our Common Stock is Sedona Equity Registrar & Transfer, 143 W. Helena Drive Phoenix, AZ 85023. Their website address is: www.sedonaequity.com.

Dividend Policy

The Company has not declared or paid cash dividends or made any distributions since its inception in 1955. Furthermore, the Company does not anticipate that it will pay cash dividends or make any cash distributions in the foreseeable future.

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.

Series A Convertible Preferred Stock

The Company has designated 2,400,000 shares of the 10,000,000 preferred shares as Series A Convertible Preferred Stock ("Series A Preferred"), with a $0.001 par value. In July 2006, we completed a private placement of the Series A Preferred that resulted in the issuance of 1,399,765 Series A Preferred shares to 100 accredited investors.

The terms of the Series A Preferred are disclosed in the Company's Amended and Restated Articles of Incorporation. Conversion of Series A Preferred to the Company's Common Stock by the accredited investors relies upon an exemption from registration provided by Section 3(a)(9) of the Securities Act of 1933 relating to securities exchanged by the issuer with its existing security holders exclusively where no commission or other remuneration is paid or given directly or indirectly for soliciting such exchange.

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

Voluntary Conversion:

The Series A Preferred that is currently issued and outstanding is eligible to be converted by the shareholder at any time into three shares of the Company's Common Stock. During the twelve months ended February 28, 2021 and February 29, 2020, there were no conversions of Series A Preferred.

At February 28, 2021, there were 709,568 shares issued and outstanding that had not been converted into our Common Stock. As of February 28, 2021, there were 44 accredited investors who had converted 690,197 Series A Preferred shares into 2,070,591 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 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
Year Ended February 29, 2012	—	—	—
Year Ended February 28, 2013	18,000	54,000	2
Year Ended February 28, 2014	151,000	453,000	9
Year Ended February 28, 2015	3,000	9,000	1
Year Ended February 29, 2016	10,000	30,000	1
Year Ended February 28, 2017	—	—	—
Year Ended February 28, 2018	14,997	44,991	1
Year Ended February 28, 2019	—	—	—
Year Ended February 29, 2020	—	—	—
Year Ended February 28, 2021	—	—	—
Totals	690,197	2,070,591	44

Automatic Conversion:

The Series A Preferred shall be automatically converted into Common Stock, if the Common Stock into which the Series A Preferred is convertible, any time the Company's Common Stock closes at or above $3.00 per share for 20 out of 30 trading days.

Dividends:

Holders of Series A Preferred 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 Preferred do not bear interest. Dividends are payable upon declaration by the Board of Directors. There have been no cash or common stock dividends declared by the Board of Directors to date.

Cumulative dividends earned for each twelve month period since issuance are set forth in the table below:

Fiscal Year Ended	Shareholders at Period End		Accumulated Dividends
February 28, 2007	100	$	155,311
February 29, 2008	90		242,126
February 28, 2009	78		209,973
February 28, 2010	74		189,973
February 28, 2011	70		173,707
February 29, 2012	70		163,624
February 28, 2013	68		161,906
February 28, 2014	59		151,323
February 28, 2015	58		132,634
February 29, 2016	57		130,925
February 28, 2017	57		130,415
February 28, 2018	56		128,231
February 28, 2019	56		127,714
February 29, 2020	56		128,063
February 28, 2021	56		127,714
		$	2,353,639

Liquidation Preference:

In the event of any liquidation, dissolution or winding up of the Company, either voluntary or involuntary, the holders of the Series A Preferred shall be entitled to receive, prior and in preference to any distribution of any of the assets or surplus funds of the Company to the holders of Common Stock by reason of their ownership thereof, and subject to the rights of any series of preferred stock that may rank on liquidation prior to the Series A Preferred, an amount equal to all accrued or declared but unpaid dividends on such shares, for each share of Series A Preferred then held by them. The remaining assets shall be distributed ratably to the holders of Common Stock and Series A Preferred on a common equivalent basis. Certain other events, as described in our Amended and Restated Articles of Incorporation, including a consolidation or merger of the Company or the disposition of the Company's assets, may trigger the payment of the liquidation preference to the holders of Series A Preferred.

Voting Rights:

The holders of the Series A Preferred 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 Preferred 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 Preferred.

Common Stock

The Company is authorized to issue up to 200,000,000 shares of $0.001 par value Common Stock of which 60,491,122 and 53,532,364 shares were issued and outstanding as of February 28, 2021 and February 29, 2020, respectively.

	Common Stock Balance		Par Value
Common stock, Issued and Outstanding, February 28, 2019	51,532,364		
Share issuances during the twelve months ended February 29, 2020	2,000,000	$	2,000
Common stock, Issued and Outstanding, February 29, 2020	53,532,364		
Share issuances during the twelve months ended February 28, 2021	6,958,758	$	6,959
Common stock, Issued and Outstanding, February 28, 2021	60,491,122		

During the twelve months ended February 28, 2021, there were 6,958,758 common stock shares issued to settle a related party note payable debt. The value of the common stock transaction was determined to be $27,835. During the twelve months ended February 29, 2020, there were 2,000,000 common stock shares issued to a third-party vendor as part of a settlement agreement for outstanding accounts payable. Based on the closing price of the Company's common stock on the settlement agreement date, the value of the common stock transaction was determined to be $6,000. During the twelve months ended February 28, 2021 and February 29, 2020, there were no conversions of the Company's Series A Preferred Convertible Stock to our common stock.

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.

Warrants

During the twelve months ended February 29, 2020 there were 2.1 million warrants issued to a third party for investor relations services. The fair value of the warrants was determined by the Black-Scholes pricing model, was $17,689, and is being amortized over the three year vesting period of the warrants. The Black-Scholes valuation encompassed the following assumptions: a risk-free interest rate of 1.68%; volatility rate of 260.23%; and a dividend yield of 0.0%. The warrant contains a vesting blocking provision that prevents the vesting of any warrants that such vesting would cause the warrant holder's beneficial ownership (as such term is defined in Section 13d-3 of the Securities Exchange Act of 1934, as amended) to exceed more than four and ninety-nine one-hundredths percent (4.99%) of the Company's outstanding Common Stock. The foregoing restriction may not be waived by either party. The warrants vest in equal parts over a three year period beginning on January 2, 2020 and all warrants expire on January 2, 2024. As of February 28, 2021 and February 29, 2020, there were 528,507 and 190,000 exercisable warrants. At February 28, 2021, the outstanding warrants have a weighted average exercise price of $0.01; a weighted average remaining life of 2.83 years, and an intrinsic value of $6,300. At February 29, 2020, both the outstanding warrants and the exercisable warrants had a weighted average exercise price of $0.01; a weighted average remaining life of 3.83 years, and an intrinsic value of -$0-. The recorded amount of warrant expense for the twelve months ended February 28, 2021 and February 29, 2020 was $5,897 and $6,879, respectively.

Warrant activity for the twelve months ended February 28, 2021 and February 29, 2020 is set forth in the table below:

	Warrants	Weighted Average Exercise Price
Warrants outstanding, February 28, 2019	—	$ —
Changes during the twelve months ended February 29, 2020:		
Issued	2,100,000	0.01
Expired / Cancelled / Forfeited	—	
Warrants outstanding, February 29, 2020	2,100,000	$ 0.01
Warrants exercisable, February 29, 2020	190,000	
Changes during the twelve months ended February 28, 2021:		
Issued	—	$ 0.01
Expired / Cancelled / Forfeited	—	
Warrants outstanding, February 28, 2021	2,100,000	$ 0.01
Warrants exercisable, February 28, 2021	528,507	$ 0.01

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 financial condition, changes in our financial condition and our results of operations and cash flows for the twelve months ended February 28, 2021 and February 29, 2020. 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 crude oil and natural gas exploration, development and production company. Our basic business model is to increase shareholder value by finding and developing crude oil and natural 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 crude oil and natural 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. A secondary means of generating returns can include the sale of either producing or non-producing lease properties.

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

Our operations are focused on identifying and evaluating prospective crude oil and natural gas properties and funding projects that we believe have the potential to produce crude oil or natural gas in commercial quantities. We conduct all of our drilling, exploration and production activities in the United States, and all of our revenues are derived from sales to customers within the United States. We are currently in the process of developing a multi-well oilfield projects in Kern County, California and an exploratory project in Michigan.

Our management cannot provide any assurances that Daybreak will ever operate profitably. While we have positive cash flow from our crude oil operations in California, we have not yet generated sustainable positive cash flow or earnings on a company-wide basis. As a small company, we are more susceptible to the numerous business, investment and industry risks that have been more fully described in Item 1A. Risk Factors of this Annual Report on Form 10-K for the fiscal year ended February 28, 2021.

Throughout this Annual Report on Form 10-K, crude oil is shown in barrels ("Bbls"); natural gas is shown in thousands of cubic feet ("Mcf") or British Thermal Units ("BTU") unless otherwise specified, and hydrocarbon totals are expressed in barrels of oil equivalent ("BOE").

Year-to-Date Results

Below is brief summary of our crude oil and natural gas projects in California and Michigan. Refer to our discussion in Item 2. Properties, in this Annual Report on Form 10-K for more information on our East Slopes Project in Kern County, California.

Kern County, California (East Slopes Project)

The East Slopes Project is located in the southeastern part of the San Joaquin Basin near Bakersfield, California. Drilling targets are porous and permeable sandstone reservoirs that exist at depths of 1,200 feet to 4,500 feet. Since January 2009, we have participated in the drilling of 25 wells in this project. The crude oil produced from our acreage in the Vedder Sand is considered heavy crude oil. The produced crude oil ranges from 14° to 16° API gravity and must be heated to separate and remove water prior to sale. During the twelve months ended February 28, 2021 we had production from 20 vertical crude oil wells. Our average working interest and NRI in these 20 wells is 36.6% and 28.4%, respectively. We have been the Operator at the East Slopes Project since March 2009.

Michigan Acreage Acquisition

In January 2017, we acquired a 30% working interest in 1,400 acres in the Michigan Basin. The leases have been secured and multiple targets were identified through a 2-D seismic interpretation. A 3-D seismic survey was obtained in January and February of 2017 on the first prospect. An analysis of the 3-D seismic survey confirmed the first prospect originally identified on the 2-D seismic, as well as several additional drilling locations. We have plans to obtain an additional 3-D survey on the second prospect after drilling a well on the first prospect, however; the two prospects are independent of each other and the success or failure of either one does not effect the other. The wells will be drilled vertically with conventional completions and no hydraulic fracturing is anticipated. With the settlement of our debt obligations in December 2018 with Maximilian, our former lender, the Company acquired an additional 40% working interest, bringing our aggregate working interest in Michigan to 70%.

Results of Operations – For the years ended February 28, 2021 and February 29, 2020

California Crude Oil Prices

The price we receive for crude oil sales in California is based on prices posted for Midway-Sunset crude oil delivery contracts, contracts, less deductions that vary by grade of crude oil sold and transportation costs. The posted Midway-Sunset price generally moves in correlation to, and at a discount to, prices quoted on the New York Mercantile Exchange ("NYMEX") for spot West Texas Intermediate ("WTI") Cushing, Oklahoma delivery contracts. We do not have any natural gas revenues in California.

There continues to be a significant amount of volatility in hydrocarbon prices and a dramatic decline in our realized sale price of crude oil since June of 2014, when the monthly average price of WTI oil was $105.79 per barrel and our realized price per barrel of crude oil was $98.78. As an example, for the month of April 2020, the monthly average price of WTI crude oil was $16.55 and our monthly realized price was $16.96 per barrel. This volatility in crude oil prices continued throughout most of the 2020-2021 fiscal year. The volatility and decline in the price of crude oil has had a substantial negative impact on our profitability and cash flow from our producing California properties.

It is beyond our ability to accurately predict how long crude oil prices will continue to remain at these lower price levels; when or at what level they may begin to stabilize; or if they may start to rebound as there are many factors beyond our control such as the current COVID-19 restrictions that influence the price we receive on our crude oil sales.

A comparison of the average WTI price and average realized crude oil sales price at our East Slopes Project in California for the twelve months ended February 28, 2021 and February 29, 2020 is shown in the table below:

	Twelve Months Ended		
	February 28, 2021	February 29, 2020	Percentage Change
Average twelve month WTI crude oil price	$ 39.48	$ 57.13	(30.9%)
Average twelve month realized crude oil sales price (Bbl)	$ 36.91	$ 60.25	(38.7%)

For the twelve months ended February 28, 2021, the average WTI price was $39.48 and our average realized crude oil sale price was $36.91, representing a discount of $2.57 per barrel or 6.5% lower than the average WTI price. In comparison, for the twelve months ended February 29, 2020, the average WTI price was $57.13 and our average realized sale price was $60.25 representing a premium of $3.12 per barrel or 5.5% higher than the average WTI price.

Historically, the sale price we receive for California heavy crude oil has been less than the quoted WTI price because of the lower API gravity of our California crude oil in comparison to the API gravity of WTI crude oil. It is beyond our control and ability to accurately predict how long hydrocarbon prices will continue to decline; when or at what level they may begin to stabilize; or when they may start to rebound as there are many factors beyond our control that dictate the price we receive on our hydrocarbon sales.

California Crude Oil Revenue and Production

Crude oil sales revenue in California for the twelve months ended February 28, 2021 decreased $258,611 or 39.0% to $404,901 in comparison to revenue of $663,512 for the twelve months ended February 29, 2020. The average sale price of a barrel of crude oil for the twelve months ended February 28, 2021 was $36.91 in comparison to $60.25 for the twelve months ended February 29, 2020. The decrease of $23.34 or 38.7% in the average realized price of a barrel of crude oil accounted for 99.4% of the decrease in crude oil revenue for the twelve months ended February 28, 2021.

Our net sales volume for the twelve months ended February 28, 2021 was 10,970 barrels of crude oil in comparison to 11,013 barrels sold for the twelve months ended February 29, 2020. This decrease in crude oil sales volume of 43 barrels or 0.4% accounted for 0.6% of the decrease in crude oil revenue for the twelve months ended February 28, 2021 and was primarily due to the natural decline in reservoir pressure during the twelve months ended February 28, 2021.

The gravity of our produced oil in California ranges between 14° API and 16° API. Production for the twelve months ended February 28, 2021 was from 20 wells resulting in 7,288 well days of production in comparison to 7,167 well days of production for the twelve months ended February 29, 2020.

Our crude oil sales revenue from California is set forth in the table below:

	Twelve Months Ended February 28, 2021		Twelve Months Ended February 29, 2020	
Project	Revenue	Percentage	Revenue	Percentage
California – East Slopes Project	$ 404,901	100.0%	$ 663,512	100.0%
Total crude oil revenues*	$ 404,901	100.0%	$ 663,512	100.0%

*Our average realized sale price on a BOE basis for the twelve months ended February 28, 2021 was $36.91 in comparison to $60.25 for the twelve months ended February 29, 2020, representing a decrease of $23.34 or 38.7% per barrel.

Of the $258,611 or 39.0% decrease in revenue for twelve months ended February 28, 2021, approximately $257,007 or 99.4% can be attributed to the decrease in the realized price of crude oil and $1,604 or 0.6% can be attributed to the decline in production volume.

Operating Expenses

Total operating expenses decreased $185,872 or 19.8% to $753,708 for the twelve months ended February 28, 2021 in comparison to $939,580 for the twelve months ended February 29, 2020. Our operating expenses are set forth in the table below:

	Twelve Months Ended February 28, 2021			Twelve Months Ended February 29, 2020		
	Expenses	Percentage	BOE Basis	Expenses	Percentage	BOE Basis
Production expenses	$ 187,858	24.9%		$ 180,982	19.3%	
Exploration and drilling expenses	83	0.0%		123	0.0%	
Depreciation, Depletion, Amortization (“DD&A”)	60,063	8.0%		55,443	5.9%	
General and Administrative (“G&A”) expenses	505,704	67.1%		703,032	74.8%	
Total operating expenses	$ 753,708	100.0%	$ 68.71	$ 939,580	100.0%	$ 85.32

Production expenses include expenses associated with the production of crude oil and natural gas. These expenses include pumper salaries, electricity, road maintenance, control of well insurance, property taxes and well maintenance and workover expenses; and, relate directly to the number of wells that are on production. For the twelve months ended February 28, 2021, these expenses increased $6,876, or 3.8% to $187,858 in comparison to $180,982 for the twelve months ended February 29, 2020. We had 20 wells on production in California for the twelve months ended February 28, 2021 and February 29, 2020. Production expenses on a BOE basis in California for the twelve months ended February 28, 2021 and February 29, 2020 were $17.12 and $16.43, respectively. Production expenses represented 24.9% and 19.3% of total operating expenses for the twelve months ended February 28, 2021 and February 29, 2020, respectively.

Exploration and drilling expenses include geological and geophysical (“G&G”) expenses as well as leasehold maintenance, plugging and abandonment (“P&A”) expenses and dry hole expenses. These expenses decreased $40 to $83 for the twelve months ended February 28, 2021 in comparison to $123 for the twelve months ended February 29, 2020. Exploration and drilling expenses represented 0.0% and 0.0% of total operating expenses for the twelve months ended February 28, 2021 and February 29, 2020, respectively.

Depreciation, Depletion, Amortization (“DD&A”) expense relates to equipment, proven reserves and property costs, and is another component of operating expenses. These expenses increased $4,620 or 8.3% to $60,063 for the twelve months ended February 28, 2021 in comparison to $55,443 for the twelve months ended February 29, 2020. The primary reason for the increase in DD&A expense was due to lower realized crude oil prices thus decreasing the estimated economic life of our reserves in comparison to our reserve report from the prior year. On a BOE basis, DD&A expense in California for the twelve months ended February 28, 2021 and February 29, 2020 was $5.48 and $5.03, respectively. DD&A expenses represented 8.0% and 5.9% of total operating expenses for the twelve months ended February 28, 2021 and February 29, 2020, respectively.

General and administrative ("G&A") expenses decreased $197,328 or 28.1% to $505,704 for the twelve months ended February 28, 2021 in comparison to $703,032 for the twelve months ended February 29, 2020. The decline in G&A expenses was primary due to a decrease in the salary expense of management and employees. Due to a decline in cash flow because of lower realized crude oil prices during the twelve months ended February 28, 2021, certain employees of the Company were laid-off, while other employees had their salaries partially reduced or temporarily suspended. Other items included in our G&A expenses are legal and accounting expenses, investor relations fees, travel expenses, insurance, Sarbanes-Oxley ("SOX") compliance expenses and other administrative expenses necessary for an operator of oil and gas properties as well as for the management a public company. For the year ended February 28, 2021, we received, as Operator of the East Slopes project in California, administrative overhead reimbursement of $53,287, which was used to directly offset certain employee salaries. We are continuing a program of reducing all of our G&A costs wherever possible. G&A expenses represented 67.1% and 74.8% of total operating expenses for the twelve months ended February 28, 2021 and February 29, 2020, respectively.

Other expense, net decreased 315,118 or 65.8% to $163,458 for the twelve months ended February 28, 2020 in comparison to $478,576 for the twelve months ended February 29, 2020. The primary reason for the decrease was lower interest expense as well as the recognition of loan forgiveness in relation to the Small Business Administration (SBA) paycheck protection program (PPP) loan that we received during the twelve months ended February 28, 2021 in the amount of $74,355.

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. Our revenues are dependent upon both hydrocarbon production levels and the price we receive for hydrocarbon sales. This revenue is subject to the volatility of hydrocarbon prices and the material adverse impact of lower crude oil prices on our revenues cannot be overstated. For the twelve months ended February 28, 2021 our sales volume of crude oil declined 43 barrels or 0.4% while our crude oil revenues decreased $258,611 or 39.0%. 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, plus the size of our proven reserve base and the market price of energy products. G&A expenses will also fluctuate based on our current requirements, but will generally tend to increase as we expand the business operations of the Company. An on-going goal of the Company is to improve cash flow to cover the current level of G&A expenses; to fund our development drilling in California; and, future drilling programs in Michigan and other geographic locations.

Capital Resources and Liquidity

Our primary financial resource is our base of crude oil reserves. Our ability to fund our capital expenditure program is dependent upon the prices we receive from our crude oil and natural gas sales; the success of our exploration program in Michigan; and the availability of capital resource financing. We do not plan to invest any new capital investments within the East Slopes Project area in the 2021-2022 fiscal year if no new financing is in place. If new financing is secured, we plan to drill four development wells for a total of $525,000.

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.

Changes in our capital resources at February 28, 2021 are set forth in the table below:

	February 28, 2021	February 29, 2020	Increase (Decrease)	Percentage Change
Cash	$ 33,528	$ 94,043	$ (60,515)	(64.3%)
Current Assets	$ 283,239	$ 240,434	$ 42,805	17.8%
Total Assets	$ 912,125	$ 917,456	$ (5,331)	(0.6%)
Current Liabilities	$ (4,469,074)	$ (4,063,712)	$ 405,362	10.0%
Total Liabilities	$ (6,029,265)	$ (5,556,063)	$ 473,202	8.5%
Working Capital Deficit	$ (4,185,835)	$ (3,823,278)	$ 362,557	9.5%

Our working capital deficit increased $362,557 or 9.5% from a deficit of approximately $3.8 million at February 29, 2020 to a deficit of approximately $4.2 million at February 28, 2021. The increase in the working capital deficit was due to a decrease in cash offset by an increase in our accounts receivable combined with an increase in accounts payable and accrued interest. While for most of the twelve months ended February 28, 2021, we continued to have ongoing positive cash flow from our crude oil operations in California, we were unable to generate sufficient cash flow to cover all of our general and administrative ("G&A") and interest expense requirements.

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. We will have to rely on the 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 crude oil and natural gas producing properties, which will 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, as well as the instability and volatility in crude oil prices since June of 2014 has restricted our ability to obtain needed capital. No assurance can be given that we will be able to obtain funding under any loan commitments or any additional financing on favorable terms, if at all.

The Company's financial statements for the twelve months ended February 28, 2021 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. We have incurred a cumulative net loss since entering the crude oil and natural gas exploration industry in 2005. As of February 28, 2021, we have an accumulated deficit of approximately $29.4 million and a working capital deficit of approximately $4.2 million which raises substantial doubt about our ability to continue as a going concern.

In this current fiscal year, we will continue to seek additional financing for our planned exploration and development activities in California and Michigan. We could obtain financing through one or more 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. No assurance can be given that we will be able to obtain funding under any loan commitments or any additional financing on favorable terms, if at all. Sales of interests in our assets may be another source of cash flow.

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:

	Twelve Months Ended February 28, 2020	Twelve Months Ended February 29, 2021	Increase (Decrease)	Percentage Change
Net cash provided by (used in) operating activities	$ (143,526)	$ 41,291	$ (184,817)	(447.6%)
Net cash provided by (used in) investing activities	$ —	$ —	$ —	—
Net cash provided by financing activities	$ 83,011	$ 22,674	$ 60,337	266.1%)

Cash Flow Provided by (Used in) Operating Activities

Cash flow from operating activities is derived from the production of our crude oil reserves and changes in the balances of non-cash accounts, receivables, payables or other non-energy property asset account balances. Cash flow used in our operating activities for the twelve months ended February 28, 2021 was $143,526 in comparison to cash flow provided by our operating activities of $41,291 for the twelve months ended February 29, 2020. Changes in our cash flow operating activities for the twelve months ended February 28, 2021 in comparison to the twelve months ended February 29, 2020 were $184,817 and consisted of decreases in our non-cash expenses of $319,101, primarily from amortization of debt discount and the forgiveness of our PPP loan; increases in our accounts receivable balances of $128,145; increases of $43,335 in our prepaid expenses; decreases in our account payable and accrued interest balances of $23,285 and the decrease in our net loss for the year of $242,379. Variations in cash flow from operating activities may impact our level of exploration and development expenditures.

Our expenditures in operating activities consist primarily of exploration and drilling expenses, production expenses, geological, geophysical and engineering services and maintenance of existing mineral leases. Our expenses also consist of consulting and professional services, employee compensation, legal, accounting, travel and other G&A expenses that we have incurred in order to address normal and necessary business activities of a public company in the crude oil exploration and production industry.

Cash Flow Provided by (Used in) Investing Activities

Cash flow from investing activities is derived from changes in oil and gas property balances and any lending activities. We had no cash flow from investing activities for the twelve months ended February 28, 2021 and February 29, 2020, respectively.

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 our financing activities was $83,011 for the twelve months ended February 28, 2021 in comparison to $22,674 for the twelve months ended February 29, 2020. For the twelve months ended February 28, 2021, we received $74,355 under the paycheck protection program (PPP). For the twelve months ended February 28, 2021 and February 29, 2020, we made payments of $60,000, respectively, on the UBS Bank line of credit balances. We received advances of $74,000 from our line of credit with UBS Bank during the twelve months ended February 29, 2020. Additionally during the twelve months ended February 28, 2021, we received $144,619 from a related party note payable. During the twelve months ended February 29, 2020, we received $27,835 from a related party in the form of a convertible note payable. Finally, we made insurance premium financing payments of $74,553 and $19,161 during the twelve months ended February 28, 2021 and February 29, 2020, respectively. The following is a summary of the Company's financing activities for the twelve months ended February 28, 2021.

Current debt (short-term borrowings)

Related Party

The Company's Chairman, President and Chief Executive Officer had loaned to the Company in previous fiscal years an aggregate $250,100 that was used for a variety of corporate purposes. During the twelve months ended February 29, 2020, in connection with its debt reduction efforts, the Company entered into a Note Payoff Agreement with this related party. Pursuant to the Note Payoff Agreement, the Company issued as payment in full of the Notes, a production payment interest in certain of the Company's production revenue from the drilling of future wells in California and Michigan. The production payment interest was granted for a deemed consideration amount of the balance of the Notes and made pursuant to a Production Payment Interest Purchase Agreement dated as of August 22, 2019. The grant was made on the same terms as the Company has sold production payment interests to other third parties in the 2018-2019 fiscal year pursuant to its previously disclosed program. For further information on the production revenue program refer to the "Production Revenue Payable" section below.

Convertible Promissory Note

During the twelve months ended February 29, 2020, the Company's Chairman, President and Chief Executive Officer loaned the Company $27,835 for general operating expenses under a Convertible Note Purchase Agreement. The Note had a maturity date of 180 days, or July 12, 2020 and carried no interest, fees or penalties. On July 13, 2020, the note payable was converted to 6,958,758 shares of the Company's common stock. The note payable had a conversion price of $0.004 per share.

12% Subordinated Notes

The Company's 12% Subordinated Notes ("the Notes") issued pursuant to a January 2010 private placement offering to accredited investors, resulted in $595,000 in gross proceeds (of which $250,000 was from a related party) to the Company and accrue interest at 12% per annum, payable semi-annually on January 29th and July 29th. On January 29, 2015, the Company and 12 of the 13 holders of the Notes agreed to extend the maturity date of the Notes for an additional two years to January 29, 2017. Effective January 29, 2017, the maturity date of the Notes was extended for an additional two years to January 29, 2019. The 980,000 warrants held by ten noteholders expired on January 29, 2019.

The Company has informed the Note holders that the payment of principal and final interest will be late and is subject to future financing being completed. The Notes principal of $565,000 was payable in full at the amended maturity date of the Notes, and has not been paid. Interest continues to accrue on the unpaid $565,000 principal balance. The terms of the Notes, state that should the Board of Directors, on any future maturity date, 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, 2018. The accrued interest on the 12% Notes at February 28, 2021 and February 29, 2020 was $340,042 and $272,428, respectively.

12% Note balances at February 28, 2021 and February 29, 2020 are set forth in the table below:

	February 28, 2021	February 29, 2020
12% Subordinated notes – third party	$ 315,000	$ 315,000
12% subordinated notes – related party	250,000	250,000
12% Subordinated notes balance	$ 565,000	$ 565,000

The accrued interest owed on the 12% Subordinated Note to the related party is presented on the Company's Balance Sheets under the caption *Accounts payable – related party* rather than under the caption *Accrued interest*.

Line of Credit

The Company has an existing $890,000 line of credit for working capital purposes with UBS Bank USA ("UBS"), established pursuant to a Credit Line Agreement dated October 24, 2011 that is secured by the personal guarantee of our President and Chief Executive Officer. On July 10, 2017, a $700,000 portion of the outstanding credit line balance was converted to a 24-month fixed term annual interest rate of 3.244% with interest payable monthly. On July 10, 2019, the 24-month fixed term loan amount of $700,000 was renewed at the same annual percentage interest rate of 3.244% for an additional 24 months. The remaining balance of the credit line has a stated reference rate of 0.249% + 337.5 basis points with interest payable monthly. The reference rate is based on the 30-day LIBOR ("London Interbank Offered Rate") and is subject to change from UBS.

During the twelve months ended February 28, 2021 and February 29, 2020, we received advances on the line of credit of $-0- and $74,000, respectively. During the twelve months ended February 28, 2021 and February 29, 2020, the Company made payments to the line of credit of $60,000 and $60,000, respectively. Interest converted to principal for the twelve months ended February 28, 2021 and February 29, 2020 was $28,503 and $31,548, respectively. At February 28, 2021 and February 29, 2020, the line of credit had an outstanding balance of $840,904 and $872,401, respectively.

Note Payable

In December 2018, the Company was able to settle an outstanding balance owed to one of its third-party vendors. This settlement resulted in a $120,000 note payable being issued to the vendor. Additionally, the Company agreed to issue 2,000,000 shares of the Company's common stock as a part of the settlement agreement. Based on the closing price of the Company's common stock on the date of the settlement agreement, the value of the common stock transaction was determined to be $6,000. The common stock shares were issued during the twelve months ended February 29, 2020. The note has a maturity date of January 1, 2022 and bears an interest rate of 10% rate per annum. Monthly interest is accrued and payable on January 1st of each anniversary date until maturity of the note. At February 28, 2021, the accrued interest had not been paid and was outstanding. The accrued interest on the Note was $26,000 and $14,000 at February 28, 2021 and February 29, 2020, respectively.

Production Revenue Payable

Since December 2018, the Company has been conducting a fundraising program to fund the drilling of future wells in California and Michigan and to settle some of its existing historical debt. The purchasers of production payment interests receive a production revenue payment on future wells to be drilled in California and Michigan in exchange for their purchase. On August 22, 2019, the Company entered into a Note Payoff Agreement with the Company's Chairman, President and Chief Executive Officer as payment in full of the $250,100 that had been loaned to the Company during the years ended February 29, 2012 and February 28, 2013. Pursuant to the Note Payoff Agreement, the Company issued a production payment interest in certain of the Company's production revenue from the drilling of future wells in California and Michigan. The production payment interest was granted for a deemed consideration amount of the balance of the Notes. The grant was made on the same terms as the Company has sold production payment interests to other third parties in the 2018-2019 fiscal year pursuant to its previously disclosed program. As of February 28, 2021 and February 29, 2020, the production revenue payment program balance was $950,100, respectively, of which $550,100, respectively, was owed to a related party - the Company's Chairman, President and Chief Executive Officer.

The production payment interest entitles the purchasers to receive production payments equal to twice their original amount paid, payable from a percentage of the Company's future net production payments from wells drilled after the date of the purchase and until the Production Payment Target (as described below) is met. The Company shall pay fifty percent (50%) of its net production payments from the relevant wells to the purchasers until each purchaser has received two times the purchase price (the "Production Payment Target"). Once the Company pays the purchasers amounts equal to the Production Payment Target, it shall thereafter pay a pro-rated eight percent (8%) of $1.3 million on its net production payments from the relevant wells to each of the purchasers. However, if the total raised is less than the target $1.3 million, then the payment will be a proportionate amount of the eight percent (8%). Additionally, if the Production Payment Target is not met within the first three years, the Company shall pay seventy-five percent (75%) of its production payments from the relevant wells to the purchasers until the Production Payment Target is met. At February 28, 2021, the Production Payment Target has not been met within the original three years and all future payments will be at the seventy-five percent (75%) rate.

The Company accounted for the amounts received from these sales in accordance with ASC 470-10-25 and 470-10-35 which require amounts recorded as debt to be amortized under the interest method as described in ASC 835-30, Interest Method. Consequently, the program balance of $950,100 has been recognized as a production revenue payable. The Company determined an effective interest rate based on future expected cash flows to be paid to the holders of the production payment interests. This rate represents the discount rate that equates estimated cash flows with the initial proceeds received from the sales and is used to compute the amount of interest to be recognized each period. Estimating the future cash outflows under this agreement requires the Company to make certain estimates and assumptions about future revenues and payments and such estimates are subject to significant variability. Therefore, the estimates are likely to change which may result in future adjustments to the accretion of the interest expense and the amortized cost based carrying value of the related payables.

Accordingly, the Company has estimated the cash flows associated with the production revenue payments and determined a discount of $1,050,158 as of February 28, 2021, which is being accounted as interest expense over the estimated period over which payments will be made based on expected future revenue streams. For the twelve months ended February 28, 2020 and February 29, 2020, amortization of the debt discount on these payables amounted to $115,151 and $361,583, respectively, which has been included in interest expense in the statements of operations.

Production revenue payable balances at February 28, 2020 and February 29, 2020 are set forth in the table below:

	February 28, 2021		February 29, 2020	
Estimated payments of production revenue payable	$	2,000,258	$	2,054,766
Less: unamortized discount		(496,836)		(666,495)
		1,503,422		1,388,271
Less: current portion		(111,753)		(43,069)
Net production revenue payable – long term	$	1,391,669	$	1,345,202

Paycheck Protection Program (PPP) Loan

On March 27, 2020, President Trump signed into law the Coronavirus Aid, Relief, and Economic Security Act commonly referred to as the CARES Act. One component of the CARES Act was the first draw paycheck protection program ("PPP") which provides small business with the resources needed to maintain their payroll and cover applicable overhead. The PPP is implemented by the Small Business Administration ("SBA") with support from the Department of the Treasury. The PPP provides funds to pay up to eight weeks of payroll costs including benefits. Funds can also be used to pay interest on mortgages, rent, and utilities. We applied for, and were accepted to participate in this program. On May 11, 2020, we received funding for $74,355. We used all the loan proceeds to partially subsidize direct payroll expenses.

The loan is a two-year loan with a maturity date of May 5, 2022. The loan bears an annual interest rate of 1%. The loan shall be payable monthly with the first six monthly payments deferred. On February 12, 2021, we applied for loan forgiveness under the provisions of Section 1106 of the CARES Act. Loan forgiveness is subject to the sole approval of the SBA. On February 23, 2021, the SBA notified our lender that the loan was forgiven.

On March 4, 2021, we applied for, and were accepted to participate in the SBA Second Draw PPP program. On March 15, 2021, we received funding for $72,800. It is the Company's intent to apply for loan forgiveness for the Second Draw PPP loan. Loan forgiveness is subject to the sole approval of the SBA. The Company is eligible for loan forgiveness in an amount equal to payments made during the 24-week period beginning on the loan date, with the exception that no more than 25.0% of the amount of loan forgiveness may be for certain expenses other than payroll expenses. We intend to use all the loan proceeds to partially subsidize direct payroll expenses.

Note Payable – Related Party

On December 22, 2020, the Company entered into a Secured Promissory Note (the "*Note*"), as borrower, with James Forrest Westmoreland and Angela Marie Westmoreland, Co-Trustees of the James and Angela Westmoreland Revocable Trust, or its assigns (the "*Noteholder*"), as the lender. James F. Westmoreland is the Company's Chairman, President and Chief Executive Officer. Pursuant to the Note, the Noteholder loaned the Company an aggregate principal amount of $155,548. After the deduction of loan fees of $10,929 the net proceeds from the loan were $144,619. The loan fees are being amortized as original issue discount (OID) over the term of the loan. The interest rate of the loan is 2.25%. The Note requires monthly payments on the Note balance until repaid in full. The maturity date of the Note is December 21, 2035. For the twelve months ended February 28, 2021, the Company made principal payments of $1,410 and amortized debt discount of $121. The obligations under the Note are secured by a lien on and security interest in the Company's oil and gas assets located in Kern County, California, as described in a Deed of Trust entered into by the Company in favor of the Noteholder to secure the obligations under the Note. Such lien shall be a first priority lien, subject only to a pre-existing lien filed by a working interest partner of the Company.

The proceeds of the Note are to be used for general working capital of the Company. The Company may prepay the Note at any time. Upon the occurrence of any Event of Default and expiration of any applicable cure period, and at any time thereafter during the continuance of such Event of Default, the Noteholder may at its option, by written notice to the Company: (a) declare the entire principal amount of the Note, together with all accrued interest thereon and all other amounts payable hereunder, immediately due and payable; (b) exercise any of its remedies with respect to the collateral set forth in the Deed of Trust; and/or (c) exercise any or all of its other rights, powers or remedies under applicable law.

Note payable –related party short-term balances at February 28, 2021 and February 29, 2020 are set forth in the table below:

	February 28, 2021	February 29, 2020
Note payable –related party, short-term	$ 8,598	$ —
Unamortized debt issuance expenses, short-term	(728)	—
Note payable – related party, short-term net	$ 7,870	$ —

Note payable –related party long-term balances at February 28, 2021 and February 29, 2020 are set forth in the table below:

	February 28, 2021	February 29, 2020
Note payable – related party, long-term	$ 145,539	$ —
Unamortized debt issuance expenses, long-term	(10,079)	—
Note payable– related party, long-term, net	$ 135,460	$ —

Future estimated payments on the outstanding note payable – related party are set forth in the table below:

Twelve month periods ending February 28/29	
2022	$ 7,870
2023	8,100
2024	8,337
2025	8,580
2026	8,830
Thereafter	101,613
Total	$ 143,330

Encumbrances

On October 17, 2018, a working interest partner in California filed a UCC financing statement in regards to payable amounts owed to the partner by the Company. As of February 28, 2021, we had no encumbrances on our crude oil project in Michigan.

Capital Commitments

Daybreak has ongoing capital commitments to develop certain oil and gas 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.

Leases

The Company leases approximately 988 rentable square feet of office space from an unaffiliated third party for our corporate office located in Spokane Valley, Washington. Additionally, we lease approximately 416 and 695 rentable square feet from unaffiliated third parties for our regional operations office in Friendswood, Texas and storage and auxiliary office space in Wallace, Idaho, respectively. The lease in Friendswood is a 12-month lease that expires in October 2021 and as such is considered a short-term lease. The Company has elected to not apply the recognition requirements of ASC 842 to this short-term lease. The Spokane Valley and Wallace leases are currently on a month-to-month basis. The Company's lease agreements do not contain any residual value guarantees, restrictive covenants or variable lease payments. The Company has not entered into any financing leases.

The Balance Sheet classification of lease assets and liabilities was as follows:

	February 28, 2021	February 29, 2020
Assets		
Operating lease right-of use assets, beginning balance	$ 5,857	$ 13,787
Current period amortization	(5,857)	(7,930)
Total operating lease right-of-use asset	—	5,857
Liabilities		
Operating lease liability – current	—	5,857
Operating lease liability – long-term	—	—
Total lease liabilities	$ —	$ 5,857

Rent expense for the twelve months ended February 28, 2021 and February 29, 2020 was $23,589 and $23,489, respectively.

Crude Oil and Natural Gas Reserves

Daybreak's total net proved developed and undeveloped crude oil reserves on a per barrel of oil equivalent ("BOE") basis decreased by 61,754 BOE, or 12.5%, to 434,223 BOE at February 28, 2021 compared to 495,977 BOE at February 29, 2020. These reserves are all located in our California East Slopes project. The primary reason for the overall decrease in our total proven reserves was primarily due to lower hydrocarbon prices from the past year lowering the economic life our wells. The year-to-year reserve decrease consisted of a 18,659 barrel or 16.4% decrease in our PDP reserves and a 43,095 barrel or 11.3% decrease in our PUD reserves. Our production of PDP reserves for the year ended February 28, 2021 was 10,970 BOE and was a part of the overall decline in PDP reserves. The 43,095 decrease in the PUD reserves was all due to downward revisions again because of lower crude oil prices in the past year. Our reserves were fully engineered by PGH Petroleum and Environmental Engineers, LLC of Austin, Texas in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. For further information on our reserve report, refer to exhibit 99.1 of this Annual Report on Form 10-K.

Changes in Financial Condition

During the year ended February 28, 2021, we received crude oil sales revenue from 20 wells in our East Slopes Project in Kern County, California. Our commitment to improving corporate profitability remains unchanged. Since June 2014, there has been significant volatility and uncertainty in the WTI price of crude oil and correspondently in the realized price we receive from oil sales. This volatility in the price of crude oil has created a substantial negative impact on the cash flow of our producing crude oil properties in California. During the twelve months ended February 28, 2021 and February 29, 2020, crude oil revenue from California was $404,901 and $663,512, respectively. Of the $258,611 decrease in revenue during the twelve months ended February 28, 2021, $257,007 or 99.4% can be attributed to the decline in our realized crude oil sales price and $1,604 or 0.6% can be attributed to the decline in our sales volume. For the twelve months ended February 28, 2021 and February 29, 2020, we had an operating loss of $348,807 and $276,068, respectively.

Our balance sheet at February 28, 2021 reflects total assets of approximately $0.91 million, a decrease of approximately $5,000 in comparison to approximately $0.92 million at February 29, 2020. This decrease of approximately $5,000 in total assets was due increases in accounts receivable offset by a decrease in cash and lower crude oil property balances in California.

At February 28, 2021, total liabilities were approximately $6.0 million, an increase of approximately $0.4 million in comparison to approximately $5.6 million at February 28, 2019. This increase was primarily due to increases in payables and in debt with related parties.

Common Stock shares issued and outstanding at February 28, 2021 and February 29, 2020 were 60,491,122 and 53,532,364. The 6,958,758 share increase in common stock was due to a conversion of debt to common stock from a related party. There was no change in the amount of Series A Preferred Stock shares issued and outstanding of 709,568 for the twelve months ended February 28, 2021 and February 29, 2020.

Accumulated Deficit

Our financial statements for the twelve months ended February 28, 2021 and February 29, 2020 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 show 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 approximately $28.9 million at February 29, 2020 to $29.4 million at February 28, 2021 was primarily due to the net loss for the year of $0.5 million.

Cash Balance

We maintain our cash balance by increasing or decreasing our exploration and drilling expenditures as limited by availability of cash from operations, investments and capital resource funding. Our cash balances were $33,528 and $94,043 at February 28, 2021 and February 29, 2020, respectively.

Crude oil and natural gas revenues

Crude oil revenues decreased $258,611 or 39.0% to $404,901 for the twelve months ended February 28, 2021 in comparison to $663,512 for the twelve months ended February 29, 20209. Of the $258,611 decrease in revenue during the twelve months ended February 28, 2021, $257,007 or 99.4% can be attributed to the decline in our realized crude oil sales price and $1,604 or 0.6% can be attributed to the decline in sales volume.

Operating Expenses

Operating expenses for the twelve months ended February 28, 2021 decreased by $185,872 or 19.8% to approximately $754,000 in comparison to approximately $940,000 for the year ended February 29, 2020.

Operating Loss

For the twelve months ended February 28, 2021 and February 29, 2020, we reported an operating loss of $348,807 and $276,068, respectively. The increase in the operating loss for the twelve months ended February 28, 2021 of $72,739 was primary due to lower realized sale prices of our crude oil.

Net Loss

Since entering the crude oil and natural gas exploration industry, we have incurred net losses with periodic negative cash flow and have depended on external financing and the sale of crude oil and natural gas assets to sustain our operations. For the twelve months ended February 28, 2021 we reported a net loss of $512,265 in comparison to net loss of $754,644 for the twelve months ended February 29, 2020.

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 20 producing crude oil 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. Our average working interest in these wells is 36.6% and the average net revenue interest is 28.4%.

We anticipate revenues will continue to increase as the Company participates in the drilling of more wells in the East Slopes Project in California and our project in Michigan. However given the current decline and instability in hydrocarbon prices, the timing of any drilling activity in California will be dependent on a sustained improvement in hydrocarbon prices and a successful refinancing or restructuring of our current credit facility.

We believe that our liquidity will improve when there is a sustained improvement in hydrocarbon prices. Our sources of funds in the past have included the debt or equity markets and the sale of assets. While the Company does have positive cash flow from its crude oil and natural gas properties, it has not yet established a positive cash flow on a company-wide basis. It will be necessary for the Company to obtain 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.

Summary of Critical Accounting Policies and Estimates

Critical accounting policies are policies that are both most important to the portrayal of the Company's financial condition and results, and that require management's most difficult, subjective or complex judgments, often as a result of the need to make estimates about the effect of matters that are inherently uncertain. 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. These judgments and uncertainties do affect the application of these critical accounting policies. There is a strong likelihood that materially different amounts could be reported under different conditions or using different assumptions. 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.

Proved Crude Oil and Natural Gas Reserves

Proved reserves are defined by the SEC as those quantities of crude 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 regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether the estimate is a deterministic estimate or probabilistic estimate. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or through installed extraction equipment and infrastructure operational at the time of the reserve estimates if the extraction is by means not involving a well. Although our external engineers are knowledgeable of and follow the guidelines for reserves as established by the SEC, the estimation of reserves requires the engineers to make a significant number of assumptions based on professional judgment. Estimated reserves are often subject to future revision, certain of which could be substantial, based on the availability of additional information, including reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Changes in crude oil and natural gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions inherently lead to adjustments of depreciation rates used by us. We cannot predict the types of reserve revisions that will be required in future periods.

While the estimates of our proved reserves at February 28, 2021 included in this report have been prepared based on what we and our independent reserve engineers believe to be reasonable interpretations of the SEC rules, those estimates could differ materially from our actual results.

Successful Efforts Accounting Method

We use the successful efforts method of accounting for crude oil and natural gas property acquisition, exploration, development, and production activities. Costs to acquire mineral interests in crude oil and natural 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 crude oil and natural gas properties that are individually significant are also periodically assessed for impairment of value. An impairment loss for unproved crude oil and natural 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 crude oil and natural gas properties are classified as long-term other assets.

Revenue Recognition

Our customer sales contracts include only crude oil sales in California. Each unit (crude oil barrel) of commodity product represents a separate performance obligation which is sold at variable prices, determinable on a monthly basis. The pricing provisions of our crude oil contracts are primarily tied to a market index with certain adjustments based on factors such as delivery, product quality and prevailing supply and demand conditions in the geographic areas in which we operate. We will allocate the transaction price to each performance obligation and recognize revenue upon delivery of the commodity product when the customer obtains control. Control of our produced crude oil volumes passes to our customers when the oil is measured by a trucking oil ticket. The Company has no control over the crude oil after this point and the measurement at this point dictates the amount on which the customer's payment is based. Our crude oil revenue stream includes volumes burdened by royalty and other joint owner working interests. Our revenues are recorded and presented on our financial statements net of the royalty and other joint owner working interests. Our revenue stream does not include any payments for services or ancillary items other than sale of crude oil. We record revenue in the month our crude oil production is delivered to the purchaser.

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.

Off-Balance Sheet Arrangements

As of February 28, 2021, 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.

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 Shareholders and Board of Directors of
Daybreak Oil and Gas, Inc.

Opinion on the Financial Statements

We have audited the accompanying balance sheets of Daybreak Oil and Gas, Inc. (the "Company") as of February 28, 2021 and February 29, 2020, and the related statements of operations, changes in stockholders' deficit, and cash flows for the years then ended, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of February 28, 2021 and February 29, 2020, 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.

Going Concern Matter

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 2 to the financial statements, the Company has suffered recurring losses from operations and has a net capital deficiency that raises substantial doubt about its ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 2. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting 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.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

Critical audit matters, are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. We determined that there are no critical audit matters.

/s/ MaloneBailey, LLP
www.malonebailey.com
We have served as the Company's auditor since 2006.
Houston, Texas
May 27, 2021

DAYBREAK OIL AND GAS, INC.
Balance Sheets
As of February 28, 2021 and February 29, 2020

	As of February 28, 2021	As of February 29, 2020
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 33,528	$ 94,043
Accounts receivable:		
Crude oil sales	108,993	56,910
Joint interest participants	79,411	38,366
Prepaid expenses and other current assets	61,307	51,115
Total current assets	283,239	240,434
OIL AND GAS PROPERTIES, successful efforts method, net		
Proved properties	556,456	598,735
Unproved properties	55,978	55,978
PREPAID DRILLING COSTS	16,452	16,452
OPERATING LEASE, right-of-use asset	—	5,857
Total long-term assets	628,886	677,022
Total assets	$ 912,125	$ 917,456
LIABILITIES AND STOCKHOLDERS' DEFICIT		
CURRENT LIABILITIES:		
Accounts payable and other accrued liabilities	$ 1,710,922	$ 1,555,700
Accounts payable - related parties	988,966	919,888
Accrued interest	123,659	73,962
Note payable	120,000	—
Note payable - related party, current, net of unamortized discount of $728 and $-0-, respectively	7,870	—
Convertible Note payable, related party	—	27,835
12% Notes payable	315,000	315,000
12% Note payable - related party	250,000	250,000
Operating lease liability	—	5,857
Line of credit	840,904	872,401
Production revenue payable, current, net of unamortized discount	111,753	43,069
Total current liabilities	4,469,074	4,063,712
LONG TERM LIABILITIES:		
Note payable	—	120,000
Note payable - related party, net of current portion and net of unamortized discount of $10,080 and $-0-, respectively	135,460	—
Production revenue payable, net of current portion and net of unamortized discount	1,391,669	1,345,202
Asset retirement obligation	33,062	27,149
Total long-term liabilities	1,560,191	1,492,351
Total liabilities	6,029,265	5,556,063
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' DEFICIT:		
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; 709,568 shares issued and outstanding	710	710
Common stock- 200,000,000 shares authorized; $0.001 par value, 60,491,122 and 53,532,364 shares issued and outstanding, respectively	60,491	53,532
Additional paid-in capital	24,250,556	24,223,783
Accumulated deficit	(29,428,897)	(28,916,632)
Total stockholders' deficit	(5,117,140)	(4,638,607)
Total liabilities and stockholders' deficit	$ 912,125	$ 917,456

The accompanying notes are an integral part of these financial statements

DAYBREAK OIL AND GAS, INC.
Statements of Operations
For the Twelve Months Ended February 28, 2021 and February 29, 2020

	Twelve Months Ended February 28, 2021	Twelve Months Ended February 29, 2020
REVENUE:		
Crude oil sales	$ 404,901	$ 663,512
OPERATING EXPENSES:		
Production	187,858	180,982
Exploration and drilling	83	123
Depreciation, depletion and amortization	60,063	55,443
General and administrative	505,704	703,032
Total operating expenses	753,708	939,580
OPERATING LOSS	(348,807)	(276,068)
OTHER INCOME (EXPENSE):		
Interest expense, net	(237,813)	(478,576)
Gain on debt forgiveness – SBA paycheck protection program (PPP)	74,355	—
Total other expenses	(163,458)	(478,576)
NET LOSS	(512,265)	(754,644)
Cumulative convertible preferred stock dividend requirement	(127,714)	(128,063)
NET LOSS AVAILABLE TO COMMON SHAREHOLDERS	$ (639,979)	$ (882,707)
NET LOSS PER COMMON SHARE		
Basic and diluted	$ (0.01)	$ (0.02)
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING		
Basic and diluted	57,916,382	53,192,364

The accompanying notes are an integral part of these financial statements

DAYBREAK OIL AND GAS, INC.
Statements of Changes in Stockholders' Deficit
For the Twelve Months Ended February 28, 2021 and February 29, 2020

	Series A Convertible Preferred Stock		Common Stock		Additional Paid-In Capital	Accumulated Deficit	Total
	Shares	Amount	Shares	Amount			
BALANCE, FEBRUARY 28, 2019	709,568	$ 710	51,532,364	$ 51,532	$ 22,997,759	$ (28,161,988)	$ (5,111,987)
Issuance of common stock for:							
Accounts payable settlement	—	$ —	2,000,000	$ 2,000	$ 4,000	$ —	$ 6,000
Forgiveness of liabilities to related parties	—	$ —	—	$ —	$ 1,215,145	$ —	$ 1,215,145
Recognition of warrants for:							
Investor relations services	—	$ —	—	$ —	$ 6,879	$ —	$ 6,879
Net Loss	—	$ —	—	$ —	$ —	$ (754,644)	$ (754,644)
BALANCE, FEBRUARY 29, 2020	709,568	$ 710	53,532,364	$ 53,532	$ 24,223,783	$ (28,916,632)	$ (4,638,607)
Issuance of common stock for:							
Convertible note payable – related party	—	$ —	6,958,758	$ 6,959	$ 20,876	$ —	$ 27,835
Recognition of warrants for:							
Investor relations services	—	$ —	—	$ —	$ 5,897	$ —	$ 5,897
Net Loss	—	$ —	—	$ —	$ —	$ (512,265)	$ (512,265)
BALANCE, FEBRUARY 28, 2021	709,568	$ 710	60,491,122	$ 60,491	$ 24,250,556	$ (29,428,897)	$ (5,117,140)

The accompanying notes are an integral part of these financial statements

DAYBREAK OIL AND GAS, INC.
Statements of Cash Flows
For the Twelve Months Ended February 28, 2021 and February 29, 2020

	Twelve Months Ended	
	February 28, 2021	**February 29, 2020**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (512,265)	$ (754,644)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Gain on forgiveness of PPP loan	(74,355)	—
Depreciation, depletion and amortization	60,063	55,443
Amortization of debt discount	115,272	361,583
Operating lease expense in conjunction with right of use asset	5,857	7,930
Warrants issued for investor relations services	5,897	6,879
Changes in assets and liabilities:		
Accounts receivable – crude oil and natural gas sales	(52,083)	18,500
Accounts receivable – joint interest participants	(41,045)	16,517
Prepaid expenses and other current assets	54,896	11,561
Accounts payable and other accrued liabilities	152,816	153,279
Accounts payable - related parties	69,078	90,722
Operating lease liability change in conjunction with right of use asset	(5,857)	(7,930)
Accrued interest	78,200	81,451
Net cash provided by (used in) operating activities	(143,526)	41,291
CASH FLOWS FROM INVESTING ACTIVITIES:		
Additions to crude oil and natural gas properties	—	—
Net cash used in investing activities	—	—
CASH FLOWS FROM FINANCING ACTIVITIES:		
Additions to line of credit	—	74,000
Payments to line of credit	(60,000)	(60,000)
Proceeds from convertible note payable, related party	—	27,835
Insurance financing repayments	(74,553)	(19,161)
Proceeds from note payable – related party	144,619	—
Payments to note payable – related party	(1,410)	—
Proceeds from SBA PPP loan	74,355	—
Net cash provided by financing activities	83,011	22,674
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(60,515)	63,965
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	94,043	30,078
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 33,528	$ 94,043
CASH PAID FOR:		
Interest	$ 15,106	$ 5,225
Income taxes	$ —	$ —

The accompanying notes are an integral part of these financial statements

DAYBREAK OIL AND GAS, INC.
Statements of Cash Flows (continued)
For the Twelve Months Ended February 28, 2021 and February 29, 2020

	Twelve Months Ended	
	February 28, 2021	February 29, 2020
SUPPLEMENTAL CASH FLOW INFORMATION:		
ARO asset and liability decrease due to changes in estimates	$ 1,863	$ 6,864
Unpaid additions to crude oil and natural gas properties	$ 11,871	$ 210
Operating lease – right of use asset and associated liabilities	$ —	$ 13,787
Non-cash addition to line of credit due to monthly interest	$ 28,503	$ 31,548
Financing of insurance premiums	$ 65,088	$ 39,500
Forgiveness of liabilities to related parties credited to additional paid in capital	$ —	$ 1,215,145
Settlement of related party debt with production revenue interest	$ —	$ 250,100
Common stock issued for settlement of accounts payable	$ —	$ 6,000
Common stock issued on conversion of related party debt	$ 27,835	$ —

The accompanying notes are an integral part of these financial statements

NOTE 1 — ORGANIZATION AND BASIS OF PRESENTATION:

Originally incorporated as Daybreak Uranium, Inc., ("Daybreak Uranium") on March 11, 1955, under the laws of the State of Washington, Daybreak Uranium was organized to explore for, acquire, and develop mineral properties in the Western United States. In August 1955, the assets of Morning Sun Uranium, Inc. were acquired by Daybreak Uranium. In May 1964, Daybreak Uranium changed its name to Daybreak Mines, Inc. During 2005, management of the Company decided to enter the crude oil and natural gas exploration and production industry. On October 25, 2005, the Company's 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 crude oil 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, crude oil. 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 crude oil and natural gas, the establishment of and compliance with production quotas by crude 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, crude oil disputes between OPEC members; and national and international pandemics like the coronavirus outbreak.

NOTE 2 — GOING CONCERN:

Financial Condition

Daybreak's financial statements for the twelve months ended February 28, 2021 and February 29, 2020 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 approximately $29.4 million and a working capital deficit of approximately $4.2 million, 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 20 producing crude oil 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. The Company's average working interest in these wells is 36.6% and the average net revenue interest is 28.4% for these same wells.

In December 2019, the 2019 novel coronavirus ("COVID-19") surfaced in Wuhan, China. The World Health Organization declared a global emergency on January 30, 2020, with respect to the outbreak and several countries, including the United States, Japan, parts of Europe and Australia have initiated travel restrictions to and from China. The impacts of the outbreak are unknown and rapidly evolving. This widespread health crisis and the governmental restrictions associated with it, have adversely affected demand for crude oil, depressed crude oil prices, and affected our ability to access capital. These factors, in turn, have had a negative impact on our operations, and financial condition as evidenced by the unprecedented decline in crude oil prices and our revenues during this same time period.

On March 27, 2020, President Trump signed into law the Coronavirus Aid, Relief, and Economic Security Act commonly referred to as the CARES Act. One component of the CARES Act was the paycheck protection program ("PPP") which provides small business with the resources needed to maintain their payroll and cover applicable overhead. The PPP is implemented by the Small Business Administration ("SBA") with support from the Department of the Treasury. The PPP provides funds to pay up to eight weeks of payroll costs including benefits. Funds can also be used to pay interest on mortgages, rent, and utilities. The Company applied for, and was accepted to participate in this program. The Company received funding for approximately $74,355. On February 23, 2021, the SBA notified our lender that the loan was forgiven in full.

The Company anticipates revenue will continue to increase as the Company participates in the drilling of more wells in the East Slopes Project in California and our project in Michigan. However given the current decline and instability in hydrocarbon prices, the timing of any drilling activity in California will be dependent on a sustained improvement in hydrocarbon prices and success in securing financing for the Company's drilling program.

The Company believes that our liquidity will improve when there is a sustained improvement in hydrocarbon prices. Daybreak's sources of funds in the past have included the debt or equity markets and the sale of assets. While the Company has experienced periodic revenue growth, which has resulted in positive cash flow from its crude oil and natural gas properties, it has not yet established a positive cash flow on a company-wide basis. It will be necessary for the Company to obtain 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, 2021 and February 29, 2020 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 has in the past maintained balances in financial institutions where deposits may exceed the federally insured deposit limit of $250,000. The Company has not experienced any losses from such accounts and does not believe it is exposed to any significant credit risk on cash.

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. Substantially all of the Company's trade accounts receivable result from crude oil in California or joint interest billings to its working interest partners in California. 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. Trade accounts receivable are generally not collateralized. There were no allowances for doubtful accounts for the Company's trade accounts receivable at February 28, 2021 and February 29, 2020.

Crude Oil and Natural Gas Properties

The Company uses the successful efforts method of accounting for crude oil and natural gas property acquisition, exploration, development, and production activities. Costs to acquire mineral interests in crude oil and natural 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 Codification ("ASC") Topic 360, *"Property, Plant and Equipment"* the Company reviews proved crude 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 crude oil and natural gas. Any downward revisions to management's estimates of future production or product prices could result in an impairment of the Company's crude oil and natural gas properties in subsequent periods. Unproved crude oil and natural gas properties that are individually significant are also periodically assessed for impairment of value. An impairment loss for unproved crude oil and natural gas properties is recognized at the time of impairment by providing an impairment allowance.

The Company did not recognize any asset impairment for the twelve months ended February 28, 2021 and February 29, 2020.

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 and natural gas pipelines are 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, short-term liabilities and the line of credit approximated their fair values due to the relatively short period to maturity for these instruments. The long-term notes payable approximates 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 on the grant date using 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.

Earnings (Loss) per Share of Common Stock

Basic earnings (loss) per share of Common Stock is calculated by dividing net earnings (loss) available to common stockholders by the weighted average number of common shares issued and outstanding during the year. Diluted earnings per share is computed based on the weighted average number of common shares outstanding, increased by dilutive Common Stock equivalents. For the years ended February 28, 2021 and February 29, 2020, Common Stock equivalents are excluded from the calculations since their effect is anti-dilutive due to the Company's net loss.

Concentration of Credit Risk

Substantially all of the Company's accounts receivable result from crude oil sales in California or joint interest billings to its working interest partners in California. 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.

At the Company's East Slopes project in California we deal with only one buyer for the purchase of all crude oil production. The Company has no natural gas production in California. At February 28, 2021 and February 29, 2020, this one individual customer represented 100.0% of crude oil sales receivable from operations. If this buyer is unable to resell its products or if they lose a significant sales contract then the Company may incur difficulties in selling its crude oil production.

The Company's accounts receivable in California for crude oil sales at February 28, 2021 and February 29, 2020, respectively are set forth in the table below.

		February 28, 2021		February 29, 2020	
Project	Customer	Accounts Receivable Crude Oil Sales	Percentage	Accounts Receivable Crude Oil Sales	Percentage
California – East Slopes Project (Crude oil)	Plains Marketing	$ 108,993	100.0%	$ 56,910	100.0%

Revenue Recognition

The Company recognizes revenue under ASC 606, *Revenue from Contracts with Customers* ("Topic 606"). Under Topic 606, revenue will generally be recognized upon delivery of our produced crude oil and natural gas volumes to our customers. Our customer sales contracts include only crude oil sales in California. Under Topic 606, each unit (crude oil barrel) of commodity product represents a separate performance obligation which is sold at variable prices, determinable on a monthly basis. The pricing provisions of our crude oil contracts are primarily tied to a market index with certain adjustments based on factors such as delivery, product quality and prevailing supply and demand conditions in the geographic areas in which we operate. We will allocate the transaction price to each performance obligation and recognize revenue upon delivery of the commodity product when the customer obtains control. Control of our produced crude oil volumes passes to our customers when the oil is measured by a trucking oil ticket. The Company has no control over the crude oil after this point and the measurement at this point dictates the amount on which the customer's payment is based. Our crude oil revenue stream includes volumes burdened by royalty and other joint owner working interests. Our revenues are recorded and presented on our financial statements net of the royalty and other joint owner working interests. Our revenue stream does not include any payments for services or ancillary items other than sale of crude oil. We record revenue in the month our crude oil production is delivered to the purchaser.

Asset Retirement Obligation ("ARO")

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

The Company follows 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 crude oil and natural gas properties to determine the amount of any impairment of crude oil and natural 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; and,
- Estimates regarding projected cash flows used in determining the production payable discount.

Recent Accounting Pronouncements

Accounting Standards Issued and Adopted

The Company does not believe that any recently issued effective pronouncements, or pronouncements issued but not yet effective, if adopted, would have a material effect on the Company's financial statements.

NOTE 4 — ACCOUNTS RECEIVABLE:

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

Crude oil sales receivables balances of $108,993 and $56,910 at February 28, 2021 and February 29, 2020, represent crude oil sales that occurred in February 2021 and 2020, respectively.

Joint interest participant receivables balances of $79,411 and $38,366 at February 28, 2021 and February 29, 2020, respectively, represent amounts due from working interest partners in California, where the Company is the Operator.

There were no allowances for doubtful accounts for the Company's trade accounts receivable at February 28, 2021 and February 29, 2020.

NOTE 5 — CRUDE OIL PROPERTIES:

Crude oil property balances at February 28, 2021 and February 29, 2020 are set forth in the table below:

	February 28, 2021	February 29, 2020
Proved leasehold costs	$ 115,119	$ 115,119
Unproved leasehold costs	55,978	55,978
Costs of wells and development	2,291,924	2,278,190
Capitalized exploratory well costs	1,341,494	1,341,494
Total cost of oil and gas properties	3,804,515	3,790,781
Accumulated depletion, depreciation amortization and impairment	(3,192,081)	(3,136,068)
Oil and gas properties, net	$ 612,434	$ 654,713

For the twelve months ended February 28, 2021 and February 29, 2020, the Company recognized depletion expense of $56,013 and $51,025, respectively which is included in DD&A in the statement of operations.

NOTE 6 — ASSET RETIREMENT OBLIGATION ("ARO")

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 crude oil and natural gas properties by calculating the present value of estimated cash flows related to the liability. As of February 28, 2021 and February 29, 2020, ARO obligations were considered to be long-term based on the estimated timing of the anticipated cash flows. For the twelve months ended February 28, 2021 and February 29, 2020, the Company recognized accretion expense of $4,050 and $4,418, respectively which is included in DD&A in the statements of operations.

Changes in the asset retirement obligations for the twelve months ended February 28, 2021 and February 29, 2020 are set forth in the table below.

	February 28, 2021	February 29, 2020
Asset retirement obligation, beginning of period	$ 27,149	$ 29,595
Accretion expense	4,050	4,418
Revisions to asset retirement obligation	1,863	(6,864)
Asset retirement obligation, end of period	$ 33,062	$ 27,149

NOTE 7 — ACCOUNTS PAYABLE:

On March 1, 2009, the Company became the operator for the 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 $244,849 of the $1.5 million default remains unpaid and is included in the February 28, 2021 and February 29, 2020 accounts payable balance. Payment of this liability has been delayed until the Company's cash flow situation improves. On October 17, 2018, a working interest partner in California filed a UCC financing statement in regards to payables owed to the partner by the Company. At February 28, 2021 and February 29, 2020, the balance owed this working interest partner was $88,905 and $101,544, respectively and is included in the accounts payable balances.

NOTE 8 — ACCOUNTS PAYABLE- RELATED PARTIES:

The February 28, 2021 and February 29, 2020 accounts payable – related parties balances of $988,966 and $919,888, respectively, were comprised primarily of deferred salaries of one of the Company's Executive Officers and certain employees; directors' fees; expense reimbursements; and deferred interest payments on a 12% Subordinated Notes owed to the Company's Chairman, President and Chief Executive Officer. On August 22, 2019, an agreement was reached between the Company and the Company's Chairman, President and Chief Executive Officer whereby all deferred salary owed by the Company to this related party was forgiven. The agreement has an effective date of June 1, 2019. This agreement resulted in a decrease of approximately $882,043 in net salary payable from the prior related party payables balance. This agreement also resulted in a decrease of $123,414 in estimated payroll taxes from accounts payable balances. Additionally, on August 22, 2019 the three non-employee directors of the Company to whom director fees were owed agreed to forgive 50% (fifty percent) of the amounts owed to each individual director. These agreements had an effective date of June 1, 2019 and resulted in a reduction of $209,688 in the related party payables balance. The total amount of liability forgiveness was approximately $1.2 million and was recorded as an addition to additional paid in capital (APIC) for the twelve months ended February 29, 2020. Payment of any other deferred items has been delayed until the Company's cash flow situation improves.

NOTE 9 — SHORT-TERM AND LONG-TERM BORROWINGS:

Note Payable – Related Party

On December 22, 2020, the Company entered into a Secured Promissory Note (the "*Note*"), as borrower, with James Forrest Westmoreland and Angela Marie Westmoreland, Co-Trustees of the James and Angela Westmoreland Revocable Trust, or its assigns (the "*Noteholder*"), as the lender. James F. Westmoreland is the Company's Chairman, President and Chief Executive Officer. Pursuant to the Note, the Noteholder loaned the Company an aggregate principal amount of $155,548. After the deduction of loan fees of $10,929 the net proceeds from the loan were $144,619. The loan fees are being amortized as original issue discount (OID) over the term of the loan. The interest rate of the loan is 2.25%. The Note requires monthly payments on the Note balance until repaid in full. The maturity date of the Note is December 21, 2035. For the twelve months ended February 28, 2020, the Company made principal payments of $1,410 and amortized debt discount of $121. The obligations under the Note are secured by a lien on and security interest in the Company's oil and gas assets located in Kern County, California, as described in a Deed of Trust entered into by the Company in favor of the Noteholder to secure the obligations under the Note. Such lien shall be a first priority lien, subject only to a pre-existing lien filed by a working interest partner of the Company.

The Company may prepay the Note at any time. Upon the occurrence of any Event of Default and expiration of any applicable cure period, and at any time thereafter during the continuance of such Event of Default, the Noteholder may at its option, by written notice to the Company: (a) declare the entire principal amount of the Note, together with all accrued interest thereon and all other amounts payable hereunder, immediately due and payable; (b) exercise any of its remedies with respect to the collateral set forth in the Deed of Trust; and/or (c) exercise any or all of its other rights, powers or remedies under applicable law.

Current portion of note payable – related party balances at February 28, 2021 and February 29, 2020 are set forth in the table below:

	February 28, 2021	February 29, 2020
Note payable – related party, current portion	$ 8,598	$ —
Unamortized debt issuance expenses	(728)	—
Note payable – related party, current portion, net	$ 7,870	$ —

Note payable –related party long-term balances at February 28, 2021 and February 29, 2020 are set forth in the table below:

	February 28, 2021	February 29, 2020
Note payable – related party, non-current	$ 145,540	$ —
Unamortized debt issuance expenses	(10,080)	—
Note payable– related party, non-current, net	$ 135,460	$ —

Future estimated payments on the outstanding note payable – related party are set forth in the table below:

Twelve month periods ending February 28/29	
2022	$ 8,598
2023	8,829
2024	9,065
2025	9,309
2026	9,558
Thereafter	108,779
Total	$ 154,138

Convertible Note Payable – Related Party

During the twelve months ended February 29, 2020, the Company's Chairman, President and Chief Executive Officer loaned the Company $27,835 for general operating expenses under a Convertible Note Purchase Agreement. The Note had a maturity date of 180 days, or July 12, 2020 and carried no interest, fees or penalties. On July 13, 2020, the note payable was converted to 6,958,758 shares of the Company's common stock. The note payable had a conversion price of $0.004 per share.

12% Subordinated Notes

The Company's 12% Subordinated Notes ("the Notes") issued pursuant to a January 2010 private placement offering to accredited investors, resulted in $595,000 in gross proceeds (of which $250,000 was from a related party) to the Company and accrue interest at 12% per annum, payable semi-annually on January 29th and July 29th. On January 29, 2015, the Company and 12 of the 13 holders of the Notes agreed to extend the maturity date of the Notes for an additional two years to January 29, 2017. Effective January 29, 2017, the maturity date of the Notes was extended for an additional two years to January 29, 2019. The 980,000 warrants held by ten noteholders expired on January 29, 2019.

The Company has informed the Note holders that the payment of principal and final interest will be late and is subject to future financing being completed. The Notes principal of $565,000 was payable in full at the amended maturity date of the Notes, and has not been paid. Interest continues to accrue on the unpaid $565,000 principal balance. The terms of the Notes, state that should the Board of Directors, on any future maturity date, 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, 2018. The accrued interest on the 12% Notes at February 28, 2021 and February 29, 2020 was $340,042 and $272,428, respectively.

12% Note balances at February 28, 2021 and February 29, 2020 are set forth in the table below:

	February 28, 2021	February 29, 2020
12% Subordinated notes - third party	$ 315,000	$ 315,000
12% Subordinated notes - related party	250,000	250,000
Net 12% Subordinated Note balance	$ 565,000	$ 565,000

The accrued interest owed on the 12% Subordinated Note to the related party is presented on the Company's Balance Sheets under the caption *Accounts payable – related party* rather than under the caption *Accrued interest*.

Line of Credit

The Company has an existing $890,000 line of credit for working capital purposes with UBS Bank USA ("UBS"), established pursuant to a Credit Line Agreement dated October 24, 2011 that is secured by the personal guarantee of our President and Chief Executive Officer. On July 10, 2017, a $700,000 portion of the outstanding credit line balance was converted to a 24-month fixed term annual interest rate of 3.244% with interest payable monthly. On July 10, 2019, the 24-month fixed term loan amount of $700,000 was renewed at the same annual percentage interest rate of 3.244% for an additional 24 months. The remaining balance of the credit line has a stated reference rate of 0.249% + 337.5 basis points with interest payable monthly. The reference rate is based on the 30-day LIBOR ("London Interbank Offered Rate") and is subject to change from UBS.

During the twelve months ended February 28, 2021 and February 29, 2020, we received advances on the line of credit of $-0- and $74,000, respectively. During the twelve months ended February 28, 2021 and February 29, 2020, the Company made payments to the line of credit of $60,000 and $60,000, respectively. Interest converted to principal for the twelve months ended February 28, 2021 and February 29, 2020 was $28,503 and $31,548, respectively. At February 28, 2021 and February 29, 2020, the line of credit had an outstanding balance of $840,904 and $872,401, respectively.

Note Payable

In December 2018, the Company was able to settle an outstanding balance owed to one of its third-party vendors. This settlement resulted in a $120,000 note payable being issued to the vendor. Additionally, the Company agreed to issue 2,000,000 shares of the Company's common stock as a part of the settlement agreement. Based on the closing price of the Company's common stock on the date of the settlement agreement, the value of the common stock transaction was determined to be $6,000. The common stock shares were issued during the twelve months ended February 29, 2020. The note has a maturity date of January 1, 2022 and bears an interest rate of 10% rate per annum. Monthly interest is accrued and payable on January 1st of each anniversary date until maturity of the note. At February 28, 2021, the accrued interest had not been paid and was outstanding. The accrued interest on the Note was $26,000 and $14,000 at February 28, 2021 and February 29, 2020, respectively.

Production Revenue Payable

Since December 2018, the Company has been conducting a fundraising program to fund the drilling of future wells in California and Michigan and to settle some of its existing historical debt. The purchasers of production payment interests receive a production revenue payment on future wells to be drilled in California and Michigan in exchange for their purchase. On August 22, 2019, the Company entered into a Note Payoff Agreement with the Company's Chairman, President and Chief Executive Officer as payment in full of the $250,100 that had been loaned to the Company during the fiscal years ended February 29, 2012 and February 28, 2013. Pursuant to the Note Payoff Agreement, the Company issued a production payment interest in certain of the Company's production revenue from the drilling of future wells in California and Michigan. The production payment interest was granted for a deemed consideration amount of the balance of the Notes. The grant was made on the same terms as the Company has sold production payment interests to other third parties in the 2018-2019 fiscal year pursuant to its previously disclosed program. As of February 28, 2021 and February 29, 2020, the production revenue payment program balance was $950,100, respectively, of which $550,100, respectively, was owed to a related party - the Company's Chairman, President and Chief Executive Officer.

The production payment interest entitles the purchasers to receive production payments equal to twice their original amount paid, payable from a percentage of the Company's future net production payments from wells drilled after the date of the purchase and until the Production Payment Target (as described below) is met. The Company shall pay fifty percent (50%) of its net production payments from the relevant wells to the purchasers until each purchaser has received two times the purchase price (the "Production Payment Target"). Once the Company pays the purchasers amounts equal to the Production Payment Target, it shall thereafter pay a pro-rated eight percent (8%) of $1.3 million on its net production payments from the relevant wells to each of the purchasers. However, if the total raised is less than the target $1.3 million, then the payment will be a proportionate amount of the eight percent (8%). Additionally, if the Production Payment Target is not met within the first three years, the Company shall pay seventy-five percent (75%) of its production payments from the relevant wells to the purchasers until the Production Payment Target is met. At February 28, 2021, the Production Payment Target has not been met within the original three years and all future payments will be at the seventy-five percent (75%) rate.

The Company accounted for the amounts received from these sales in accordance with ASC 470-10-25 and 470-10-35 which require amounts recorded as debt to be amortized under the interest method as described in ASC 835-30, Interest Method. Consequently, the program balance of $950,100 has been recognized as a production revenue payable. The Company determined an effective interest rate based on future expected cash flows to be paid to the holders of the production payment interests. This rate represents the discount rate that equates estimated cash flows with the initial proceeds received from the sales and is used to compute the amount of interest to be recognized each period. Estimating the future cash outflows under this agreement requires the Company to make certain estimates and assumptions about future revenues and payments and such estimates are subject to significant variability. Therefore, the estimates are likely to change which may result in future adjustments to the accretion of the interest expense and the amortized cost based carrying value of the related payables.

Accordingly, the Company has estimated the cash flows associated with the production revenue payments and determined a discount of $1,050,158 as of February 28, 2021, which is being accounted as interest expense over the estimated period over which payments will be made based on expected future revenue streams. For the twelve months ended February 28, 2020 and February 29, 2020, amortization of the debt discount on these payables amounted to $115,151 and $361,583, respectively, which has been included in interest expense in the statements of operations.

Production revenue payable balances at February 28, 2020 and February 29, 2020 are set forth in the table below:

		February 28, 2021		February 29, 2020
Estimated payments of production revenue payable	$	2,000,258	$	2,054,766
Less: unamortized discount		(496,836)		(666,495)
		1,503,422		1,388,271
Less: current portion		(111,753)		(43,069)
Net production revenue payable – long term	$	1,391,669	$	1,345,202

Paycheck Protection Program (PPP) Loan

On March 27, 2020, President Trump signed into law the Coronavirus Aid, Relief, and Economic Security Act commonly referred to as the CARES Act. One component of the CARES Act was the first draw paycheck protection program (“PPP”) which provides small business with the resources needed to maintain their payroll and cover applicable overhead. The PPP is implemented by the Small Business Administration (“SBA”) with support from the Department of the Treasury. The PPP provides funds to pay up to eight weeks of payroll costs including benefits. Funds can also be used to pay interest on mortgages, rent, and utilities. We applied for, and were accepted to participate in this program. On May 11, 2020, we received funding for $74,355. We used all the loan proceeds to partially subsidize direct payroll expenses.

The loan is a two-year loan with a maturity date of May 5, 2022. The loan bears an annual interest rate of 1%. The loan shall be payable monthly with the first six monthly payments deferred. On February 12, 2021, we applied for loan forgiveness under the provisions of Section 1106 of the CARES Act. Loan forgiveness is subject to the sole approval of the SBA. On February 23, 2021, the SBA notified our lender that the loan was forgiven in full.

On March 4, 2021, we applied for, and were accepted to participate in the SBA Second Draw PPP program. On March 15, 2021, we received funding for $72,800. It is the Company’s intent to apply for loan forgiveness for the Second Draw PPP loan. Loan forgiveness is subject to the sole approval of the SBA. The Company is eligible for loan forgiveness in an amount equal to payments made during the 24-week period beginning on the loan date, with the exception that no more than 25.0% of the amount of loan forgiveness may be for certain expenses other than payroll expenses. We intend to use all the loan proceeds to partially subsidize direct payroll expenses.

Encumbrances

On October 17, 2018, a working interest partner in California filed a UCC financing statement in regards to payable amounts owed to the partner by the Company. As of February 28, 2021, we had no encumbrances on our crude oil project in Michigan.

NOTE 10 — LEASES:

The Company leases approximately 988 rentable square feet of office space from an unaffiliated third party for our corporate office located in Spokane Valley, Washington. Additionally, we lease approximately 416 and 695 rentable square feet from unaffiliated third parties for our regional operations office in Friendswood, Texas and storage and auxiliary office space in Wallace, Idaho, respectively. The lease in Friendswood is a 12-month lease that expires in October 2021 and as such is considered a short-term lease. The Company has elected to not apply the recognition requirements of ASC 842 to this short-term lease. The Spokane Valley and Wallace leases are currently on a month-to-month basis. The Company's lease agreements do not contain any residual value guarantees, restrictive covenants or variable lease payments. The Company has not entered into any financing leases.

The Balance Sheet classification of lease assets and liabilities was as follows:

	February 28, 2021	February 29, 2020
Assets		
Operating lease right-of use assets, beginning balance	$ 5,857	$ 13,787
Current period amortization	(5,857)	(7,930)
Total operating lease right-of-use asset	—	5,857
Liabilities		
Operating lease liability – current	—	5,857
Operating lease liability – long-term	—	—
Total lease liabilities	$ —	$ 5,857

Rent expense for the twelve months ended February 28, 2021 and February 29, 2020 was $23,589 and $23,489, respectively.

NOTE 11 — RELATED PARTY TRANSACTIONS:

The Company's Chief Operating Officer, Bennett Anderson is fifty percent (50%) owner in Great Earth Power, a company that provides a portion of the electrical service to Daybreak for its production operations at the East Slopes Project in Bakersfield, California. Great Earth Power began providing solar powered electricity for the production operations in California in September 2020. Mr. Anderson received approximately $9,000 from Great Earth Power during the twelve months ended February 28, 2021.

Mr. Anderson is also a fifty percent (50%) owner in ABPlus Net Holdings, a company that provides tank rentals to Daybreak for its production operations in Kern County, California. The Company began renting tanks from ABPlus Net Holdings in November 2020. Mr. Anderson received approximately $2,440 from ABPlus Net Holdings during the twelve months ended February 28, 2021.

NOTE 12 — STOCKHOLDERS' DEFICIT:

Preferred Stock

The Company is authorized to issue up to 10,000,000 shares of preferred stock with a par value of $0.001. The Company's 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.

Series A Convertible Preferred Stock

The Company has designated 2,400,000 shares of the 10,000,000 preferred shares as Series A Convertible Preferred Stock ("Series A Preferred"), with a $0.001 par value. In July 2006, we completed a private placement of the Series A Preferred that resulted in the issuance of 1,399,765 shares to 100 accredited investors.

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

Voluntary Conversion:

The Series A Preferred that is currently issued and outstanding is eligible to be converted by the shareholder at any time into three shares of the Company's Common Stock. During the twelve months ended February 28, 2021 and February 29, 2020, there were no conversions of Series A Preferred.

At February 28, 2021, there were 709,568 shares issued and outstanding that had not been converted into our Common Stock. As of February 28, 2021, there were 44 accredited investors who had converted 690,197 Series A Preferred shares into 2,070,591 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 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
Year Ended February 29, 2012	—	—	—
Year Ended February 28, 2013	18,000	54,000	2
Year Ended February 28, 2014	151,000	453,000	9
Year Ended February 28, 2015	3,000	9,000	1
Year Ended February 29, 2016	10,000	30,000	1
Year Ended February 28, 2017	—	—	—
Year Ended February 28, 2018	14,997	44,991	1
Year Ended February 28, 2019	—	—	—
Year Ended February 29, 2020	—	—	—
Year Ended February 28, 2021	—	—	—
Totals	690,197	2,070,591	44

Automatic Conversion:

The Series A Preferred shall be automatically converted into Common Stock, if the Common Stock into which the Series A Preferred is convertible, any time 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 Preferred 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 Preferred do not bear interest. Dividends are payable upon declaration by the Board of Directors. There have been no cash or common stock dividends declared by the Board of Directors to date.

Cumulative dividends earned for each twelve month period since issuance are set forth in the table below:

Fiscal Year Ended	Shareholders at Period End	Accumulated Dividends
February 28, 2007	100	$ 155,311
February 29, 2008	90	242,126
February 28, 2009	78	209,973
February 28, 2010	74	189,973
February 28, 2011	70	173,707
February 29, 2012	70	163,624
February 28, 2013	68	161,906
February 28, 2014	59	151,323
February 28, 2015	58	132,634
February 29, 2016	57	130,925
February 28, 2017	57	130,415
February 28, 2018	56	128,231
February 28, 2019	56	127,714
February 29, 2020	56	128,063
February 28, 2021	56	127,714
		$ 2,353,639

Liquidation Preference:

In the event of any liquidation, dissolution or winding up of the Company, either voluntary or involuntary, the holders of the Series A Preferred shall be entitled to receive, prior and in preference to any distribution of any of the assets or surplus funds of the Company to the holders of Common Stock by reason of their ownership thereof, and subject to the rights of any series of preferred stock that may rank on liquidation prior to the Series A Preferred, an amount equal to all accrued or declared but unpaid dividends on such shares, for each share of Series A Preferred then held by them. The remaining assets shall be distributed ratably to the holders of Common Stock and Series A Preferred on a common equivalent basis. Certain other events, as described in our Amended and Restated Articles of Incorporation, including a consolidation or merger of the Company or the disposition of the Company's assets, may trigger the payment of the liquidation preference to the holders of Series A Preferred.

Voting Rights:

The holders of the Series A Preferred 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 Preferred 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 Preferred.

Common Stock

The Company is authorized to issue up to 200,000,000 shares of $0.001 par value Common Stock of which 60,491,122 and 53,532,364 shares were issued and outstanding as of February 28, 2021 and February 29, 2020, respectively.

	Common Stock Balance	Par Value
Common stock, Issued and Outstanding, February 28, 2019	51,532,364	
Share issuances during the twelve months ended February 29, 2020	2,000,000	$ 2,000
Common stock, Issued and Outstanding, February 29, 2020	53,532,364	
Share issuances during the twelve months ended February 28, 2021	6,958,758	$ 6,959
Common stock, Issued and Outstanding, February 28, 2021	60,491,122	

During the twelve months ended February 28, 2021, there were 6,958,758 common stock shares issued to settle a related party note payable debt. The value of the common stock transaction was determined to be $27,835. During the twelve months ended February 29, 2020, there were 2,000,000 common stock shares issued to a third-party vendor as part of a settlement agreement for outstanding accounts payable. Based on the closing price of the Company's common stock on the settlement agreement date, the value of the common stock transaction was determined to be $6,000.

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.

NOTE 13 — WARRANTS:

During the twelve months ended February 29, 2020 there were 2.1 million warrants issued to a third party for investor relations services. The fair value of the warrants was determined by the Black-Scholes pricing model, was $17,689, and is being amortized over the three year vesting period of the warrants. The Black-Scholes valuation encompassed the following assumptions: a risk-free interest rate of 1.68%; volatility rate of 260.23%; and a dividend yield of 0.0%. The warrant contains a vesting blocking provision that prevents the vesting of any warrants that such vesting would cause the warrant holder's beneficial ownership (as such term is defined in Section 13d-3 of the Securities Exchange Act of 1934, as amended) to exceed more than four and ninety-nine one-hundredths percent (4.99%) of the Company's outstanding Common Stock. The foregoing restriction may not be waived by either party. The warrants vest in equal parts over a three year period beginning on January 2, 2020 and all warrants expire on January 2, 2024. As of February 28, 2021 and February 29, 2020, there were 528,507 and 190,000 exercisable warrants. At February 28, 2021, the outstanding warrants have a weighted average exercise price of $0.01; a weighted average remaining life of 2.83 years, and an intrinsic value of $6,300. At February 29, 2020, both the outstanding warrants and the exercisable warrants had a weighted average exercise price of $0.01; a weighted average remaining life of 3.83 years, and an intrinsic value of -$0-. The recorded amount of warrant expense for the twelve months ended February 28, 2021 and February 29, 2020 was $5,897 and $6,879, respectively.

Warrant activity for the twelve months ended February 28, 2021 and February 29, 2020 is set forth in the table below:

	Warrants		Weighted Average Exercise Price
Warrants outstanding, February 28, 2019	—	$	—
Changes during the twelve months ended February 29, 2020:			
Issued	2,100,000		0.01
Expired / Cancelled / Forfeited	—		
Warrants outstanding, February 29, 2020	2,100,000	$	0.01
Warrants exercisable, February 29, 2020	190,000		
Changes during the twelve months ended February 28, 2021:			
Issued	—	$	0.01
Expired / Cancelled / Forfeited	—		
Warrants outstanding, February 28, 2021	2,100,000	$	0.01
Warrants exercisable, February 28, 2021	528,507	$	0.01

NOTE 14 — INCOME TAXES:

On December 22, 2017, the federal government enacted a tax bill H.R.1, an act to provide for reconciliation pursuant to Titles II and V of the concurrent resolution on the budget for fiscal year 2018, commonly referred to as the Tax Cuts and Jobs Act. The Tax Cuts and Jobs Act contains significant changes to corporate taxation, including, but not limited to, reducing the U.S. federal corporate income tax rate from 35% to 21% and modifying or limiting many business deductions. The Company has re-measured its deferred tax liabilities based on rates at which they are expected to be utilized in the future, which is generally 21%.

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, 2021		February 29, 2020
Computed at U.S. and state statutory rates (29.84%)	$	(152,860)	$	(225,186)
Permanent differences		15,342		111,854
Changes in valuation allowance		137,518		113,332
Total	$	—	$	—

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

		February 28, 2021		February 29, 2020
Deferred tax assets:				
Net operating loss carryforwards	$	5,587,416	$	5,463,014
Oil and gas properties		63,438		50,322
Stock based compensation		66,187		66,187
Other		27,838		27,838
Less valuation allowance		(5,744,879)		(5,607,361)
Total	$	—	$	—

At February 28, 2021, the Company had a net operating loss ("NOL") carryforwards for federal and state income tax purposes of approximately $18,724,586, which will begin to expire, if unused, beginning in 2024. Under the Tax Cuts and Jobs Act, the NOL portion of the loss incurred in the 2018 and 2020 period of $340,749 and $339,299, respectively, and the loss incurred for the year ended February 28, 2021 in the amount of $416,918 will not expire and will carry over indefinitely. The valuation allowance increased approximately $137,518 for the year ended February 28, 2021 and increased approximately $113,332 for the year ended February 29, 2020. 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 that could change the relationship between net income and taxable income. Management decisions are made annually and could cause the estimates to vary significantly. The Company's files federal income tax returns with the United States Internal Revenue Service and state income tax returns in various state tax jurisdictions. As a general rule, the Company's tax returns for the fiscal years after 2016 currently remain subject to examinations by appropriate tax authorities. None of our tax returns are under examination at this time.

NOTE 15 — 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 cleanup 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, 2021. 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 16 — SUBSEQUENT EVENTS:

On March 15, 2021, the Company received $72,800 in funding through the second draw paycheck protection program ("PPP") pursuant to The Economic Aid Act. The PPP is implemented by the Small Business Administration ("SBA") with support from the Department of the Treasury. The loan is a five-year loan with a maturity date of March 6, 2026. The loan bears an annual interest rate of 1%. The monthly payment is $1,670 with the first payment due on July 6, 2022. It is the Company's intent to apply for loan forgiveness under the provisions of the second draw PPP program. Loan forgiveness is subject to the sole approval of the SBA. The receipt of these funds will be reflected in the Company's first quarter financial statements covering the three-month period ended May 31, 2021

NOTE 17 — SUPPLEMENTARY INFORMATION FOR CRUDE OIL PRODUCING ACTIVITIES (UNAUDITED)

Capitalized Costs Relating to Crude Oil and Natural Gas Producing Activities

	As of February 28, 2021	As of February 29, 2020
Proved leasehold costs		
Mineral Interests	$ 115,119	$ 115,119
Wells, equipment and facilities	3,633,418	3,619,684
Total Proved Properties	3,748,537	3,734,803
Unproved properties		
Mineral Interests	55,978	55,978
Uncompleted wells, equipment and facilities	—	—
Total unproved properties	55,978	55,978
Less accumulated depreciation, depletion amortization and impairment	(3,192,081)	(3,136,068)
Net capitalized costs	$ 612,434	$ 654,713

Costs Incurred in Oil and Gas Producing Activities

	12 Months Ended February 28, 2021	12 Months Ended February 29, 2020
Acquisition of proved properties	$ —	$ —
Acquisition of unproved properties	—	210
Development costs	11,871	—
Exploration costs	—	—
Total costs incurred	$ 11,871	$ 210

Results of Operations from Oil and Gas Producing Activities

	12 Months Ended February 28, 2021	12 Months Ended February 29, 2020
Oil and gas revenues	$ 404,901	$ 663,512
Production costs	(187,858)	(180,982)
Exploration expenses	(83)	(123)
Depletion, depreciation and amortization	(60,063)	(55,443)
Impairment of oil properties	—	—
Result of oil and gas producing operations before income taxes	156,897	426,964
Provision for income taxes	—	—
Results of oil and gas producing activities	$ 156,897	$ 426,964

Proved Reserves

The Company's proved oil and natural gas reserves have been estimated by the certified independent engineering firm, PGH Petroleum and Environmental Engineers, 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.

As of February 28, 2021, our total reserves were comprised of our working interest in East Slopes Project located in Kern County, California.

Our proved reserves are summarized in the table below:

	Oil (Barrels)	Natural Gas (Mcf)	BOE (Barrels)
Proved reserves:			
February 28, 2019	454,261	—	454,261
Revisions[1]	40,003	—	40,003
Discoveries and extensions	12,726	—	12,726
Production	(11,013)	—	(11,013)
February 29, 2020	495,977	—	495,977
Revisions[2]	(50,784)	—	(50,784)
Discoveries and extensions	—	—	—
Production	(10,970)	—	(10,970)
February 28, 2021	434,223	—	434,223

(1) The revisions of previous estimates resulted from an improvement of reservoir performance offset by lower realized crude oil prices in the energy markets.
(2) The revisions of previous estimates resulted from a decrease in the estimated economic life of the reservoirs due to lower realized crude oil 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, 2019	118,114	118,114	336,147	336,147	454,261	454,261
February 29, 2020	113,779	113,779	382,198	382,198	495,977	495,977
February 28, 2021	95,120	95,120	339,103	339,103	434,223	434,223

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, 2021 and February 29, 2020 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, 2021 and February 29, 2020 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 flow are reduced to present value by applying a 10% discount factor.

	12 Months Ended	
	February 28, 2021	February 29, 2020
Future cash inflows	$ 15,692,834	$ 29,585,007
Future production costs[(1)]	(8,076,769)	(13,481,167)
Future development costs	(2,510,625)	(3,063,750)
Future income tax expenses[(2)]	—	—
Future net cash flows	5,105,440	13,040,090
10% annual discount for estimated timing of cash flows	(3,457,022)	(8,387,948)
Standardized measure of discounted future net cash flows at the end of the fiscal year	$ 1,648,418	$ 4,652,142

(1) Production costs include crude oil and natural gas operations expense, production ad valorem taxes, transportation costs and G&A expense supporting the Company’s crude oil and natural gas operations.
(2) The Company has sufficient tax deductions and allowances related to proved crude oil and natural gas reserves to offset future net revenues.

Average hydrocarbon prices are set forth in the table below.

	Average Price Crude Oil (Bbl)	Natural Gas (Mcf)
Year ended February 28, 2021[(1)]	$ 36.91	$ —
Year ended February 29, 2020[(1)]	$ 60.25	$ —
Year ended February 28, 2019[(1)]	$ 63.58	$ —

(1) Average prices 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, 2021	February 29, 2020
Standardized measure of discounted future net cash flows at the beginning of the year	$ 4,652,142	$ 4,916,671
Extensions, discoveries and improved recovery, less related costs	—	48,310
Revisions of previous quantity estimates	(287,596)	463,375
Net changes in prices and production costs	(1,899,026)	57,891
Accretion of discount	465,214	491,667
Sales of oil produced, net of production costs	(217,043)	(482,530)
Development costs incurred during the period	—	—
Changes in future development costs	9,077	(9,152)
Changes in timing of future production	(1,074,350)	(834,090)
Net changes in income taxes	—	—
Standardized measure of discounted future net cash flows at the end of the year	$ 1,648,418	$ 4,652,142

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, 2021, an evaluation was conducted by Daybreak's 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, 2021.

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's 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, 2021. 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 (2013).* Based on such assessment and those criteria, management believes that the Company maintained effective internal control over financial reporting as of February 28, 2021.

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, 2021 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

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

Directors of Daybreak Oil and Gas, Inc.

The following information reflects the business experience of each individual serving on the Board of Directors (the "Board") of Daybreak Oil and Gas, Inc.

Name	Age	Director Since
Timothy R. Lindsey	69	2007
James F. Meara	68	2008
James F. Westmoreland	65	2008

Timothy R. Lindsey has served as a member of the Board of Directors since January 2007. He served as the Company's Interim President and Chief Executive Officer from December 2007 until his resignation in October 2008. Mr. Lindsey has over 40 years of energy and mineral exploration, technical and executive leadership in global exploration, production, technology, and business development. From March 2005 to the present, Mr. Lindsey has been the Principal of Lindsey Energy and Natural Resources, an independent consulting firm specializing in energy and mining industry issues. From September 2003 to March 2005, Mr. Lindsey held executive positions including Senior Vice-President, Exploration with The Houston Exploration Company, a Houston-based independent natural gas and oil company formerly engaged in the exploration, development, exploitation and acquisition of domestic natural gas and oil properties. From October 1975 to February 2003, Mr. Lindsey was employed with Marathon Oil Corporation, a Houston-based company engaged in the worldwide exploration and production of crude oil and natural gas, as well as the domestic refining, marketing and transportation of petroleum products. During his 27-year tenure with Marathon, Mr. Lindsey held a number of positions including senior management roles in both domestic and international exploration and business development. Mr. Lindsey served as a director and Chairman of the Board of Directors of Revett Mining Company., a publicly-listed company with mining activities in Montana from April 2009 until the merger of Revett Mining Company into Helca Mining in June 2015. Mr. Lindsey obtained his Bachelor of Science degree in geology at Eastern Washington University in 1973, and completed graduate studies in economic geology from the University of Montana in 1975. In addition, he completed the Advanced Executive Program from the Kellogg School of Management, Northwestern University, in 1990. Mr. Lindsey is a member of the American Association of Petroleum Geologists, the Rocky Mountain Association of Geologists, the Montana Mining Association, and, the American Exploration and Mining Association.

James F. Meara has served as a member of the Board of Directors since March 2008. From 1980 through December 2007, Mr. Meara was employed with Marathon Oil Corporation, a Houston-based company engaged in the worldwide exploration and production of crude oil and natural gas, as well as the domestic refining, marketing and transportation of petroleum products. During his 27-year tenure with Marathon, Mr. Meara moved through a series of posts in the tax department, becoming manager of Tax Audit Systems and Planning in 1988, and in 1995 he was named Commercial Director of Sakhalin Energy in Moscow, Russia. In 2000, Mr. Meara served as Controller and was appointed to Vice President of Tax in January 2002, serving until his retirement in December 2007. He also serves as a director of Canadian Sahara Energy Inc., a private company incorporated in Canada. Mr. Meara holds a bachelor's degree in accounting from the University of Kentucky and a master's degree in business administration from Bowling Green State University, and is a member of the American Institute of Certified Public Accountants.

James F. Westmoreland was elected Chairman of the Board of Directors in 2014, and appointed President and Chief Executive Officer and director in October 2008. He also serves as interim principal finance and accounting officer. Prior to that, he had been our Executive Vice President and Chief Financial Officer since April 2008. He also served as the Company's interim Chief Financial Officer from December 2007 to April 2008. From August 2007 to December 2007, he consulted with the Company on various accounting and finance matters. Prior to that time, Mr. Westmoreland was employed in various financial and accounting capacities for The Houston Exploration Company for 21 years, including Vice President, Controller and Corporate Secretary, serving as its Vice President and Chief Accounting Officer from October 1995 until its acquisition by Forest Oil Corporation in June 2007. Mr. Westmoreland has almost 40 years of experience in oil and gas accounting, finance, corporate compliance and governance, both in the public and private sector. He earned his Bachelor of Business Administration in accounting from the University of Houston.

When analyzing whether directors and nominees have the experience, qualifications, attributes and skills, taken as a whole, to enable the Board of Directors to satisfy its oversight responsibilities effectively in light of the Company's business and structure, the Governance Committee and the Board focus on the information as summarized in each of the Directors' individual biographies set forth above.

In particular, the Governance Committee and the Board considered:

- Mr. Lindsey's over 40 year career as a successful senior executive in the energy industry, his extensive knowledge of the industry and his active participation in energy related professional organizations are also valuable assets to the Board. His knowledge and expertise in the energy business and management leadership regarding the issues affecting our business have been invaluable to the Board of Directors in overseeing the business affairs of our Company. Further, the Committee believes that his extensive background and service with other public companies in the energy and mining sectors and his technical expertise provide the Board with superior leadership and decision-making skills.
- Mr. Meara's education, executive leadership roles and 27 year work experience in finance, tax and accounting in the crude oil and natural gas industry provide the knowledge and financial expertise needed to serve on the Board and the Company's audit committee.
- Mr. Westmoreland's over 40 year career in various operational financial and accounting capacities, including Vice President, Chief Accounting Officer, Controller and Corporate Secretary at a public crude oil and natural gas company along with his recent experience as President, Chief Executive Officer, Executive Vice President and Chief Financial Officer of the Company. The Board also considered his role in reorganizing the Company and his day-to-day management of the Company.

Information About Our Executive Officers

Executive officers are elected annually by our Board and serve at the discretion of the Board. There are no arrangements or understandings between any of the directors, officers, and other persons pursuant to which such person was selected as an executive officer.

The following information concerns our executive officers, including the business experience of each during the past five years:

Name	Age	Executive Since	Office
James F. Westmoreland	65	2007	Chairman of the Board, President and Chief Executive Officer
Bennett W. Anderson	60	2006	Chief Operating Officer

James F. Westmoreland was elected Chairman of the Board of Directors in 2014, and appointed President and Chief Executive Officer and director in October 2008. He also serves as interim principal finance and accounting officer. Prior to that, he had been our Executive Vice President and Chief Financial Officer since April 2008. He also served as the Company's interim Chief Financial Officer from December 2007 to April 2008. From August 2007 to December 2007, he consulted with the Company on various accounting and finance matters. Prior to that time, Mr. Westmoreland was employed in various financial and accounting capacities for The Houston Exploration Company for 21 years, including Vice President, Controller and Corporate Secretary, serving as its Vice President and Chief Accounting Officer from October 1995 until its acquisition by Forest Oil Corporation in June 2007. Mr. Westmoreland has over 40 years of experience in oil and gas operations, accounting, finance, corporate compliance and governance, both in the public and private sector. He earned his Bachelor of Business Administration in accounting from the University of Houston.

Bennett W. Anderson was appointed Chief Operating Officer in 2006. Prior to that time, he was a private investor from 2002 - 2006. He served as a Senior Vice President with Novell, Inc. from 1998-2002. Mr. Anderson's duties included product direction, strategy and market direction, and training and support for the field sales staff. From 1978 to 1982, Mr. Anderson worked as a rig hand and was involved in drilling over a dozen wells in North Dakota. He holds a Bachelor of Science from Brigham Young University in Computer Science and graduated with University Honors of Distinction.

Legal Proceedings

As of the date hereof, it is the opinion of management that there is no material proceeding to which any other director, officer or affiliate of the registrant, any owner of record or beneficially of more than five percent of any class of voting securities of the registrant, or any associate of any such director, officer, affiliate of the registrant, or security holder is a party adverse to the registrant or any of its subsidiaries or has a material interest adverse to the registrant or any of its subsidiaries.

None of Daybreak's other current directors or Executive Officers has, during the past ten years:

a) Had any bankruptcy petition filed by or against any business of which such person was a general partner or executive officer either at the time of the bankruptcy or within two years prior to that time;

b) Been convicted in a criminal proceeding or been subject to a pending criminal proceeding;

c) Been the subject of any order, judgment, or decree, not subsequently reversed, suspended or vacated, of any court of competent jurisdiction, permanently or temporarily enjoining, barring, suspending or otherwise limiting his involvement in any type of business, securities or banking activities; or

d) Been found by a court of competent jurisdiction (in a civil action), the Securities and Exchange Commission or the Commodity Futures Trading Commission to have violated a federal or state securities or commodities law, and the judgment has not been reversed, suspended, or vacated.

Code of Ethics

Ethical Business Conduct Policy Statement and Code of Ethics for Senior Financial Officers

All of our employees, officers and directors are required to comply with our Ethical Business Conduct Policy Statement to help ensure that our business is conducted in accordance with the highest standards of moral and ethical behavior. Our Ethical Business Conduct Policy covers all areas of professional conduct including:

- Conflicts of interest;
- Customer relationships;
- Insider trading of our securities;
- Financial disclosure;
- Protection of confidential information; and
- Strict legal and regulatory compliance.

Our employees, officers and directors are required to certify their compliance with our Ethical Business Conduct Policy Statement once each year.

In addition to the Ethical Business Conduct Policy Statement, all members of our senior financial management, including our President and Chief Executive Officer, have agreed in writing to our Code of Ethics for Senior Financial Officers, which prescribes additional ethical obligations pertinent to the integrity of our internal controls and financial reporting process, as well as the overall fairness of all financial disclosures.

The full text of our Ethical Business Conduct Policy Statement and the Code of Ethics for Senior Financial Officers are available under the "Shareholder/Financial - Corporate Governance" section of our website at www.daybreakoilandgas.com and are also available upon request, without charge, by contacting the Corporate Secretary at Daybreak Oil and Gas, Inc., 1101 N. Argonne Rd., Suite A-211, Spokane Valley, Washington 99212.

We intend to promptly disclose via a Current Report on Form 8-K or an update to our website information any amendment to, or waiver of, these codes with respect to our executive officers and directors.

Consideration of Nominees and Qualifications for Nominations to the Board of Directors

Our Corporate Governance Guidelines, which can be found under the "Shareholder/Financial - Corporate Governance" section of our website at www.daybreakoilandgas.com, contain Board membership criteria that apply to nominees recommended by the Nominating and Corporate Governance Committee (the "Governance Committee") for a position on the Board. The Corporate Governance Guidelines state that the Board's Governance Committee is responsible for making recommendations to the Board concerning the appropriate size and composition of the Board, as well as for recommending to the Board nominees for election or re-election to the Board. In formulating its recommendations for Board nominees, the Governance Committee will assess each proffered candidate's independence and weigh his or her qualifications in accordance with the Governance Committee's stated Qualifications for Nominations to the Board of Directors, which can be found under the "Shareholder/Financial - Corporate Governance" section of our website at www.daybreakoilandgas.com.

Audit Committee

The Audit Committee is responsible for monitoring the integrity of the Company's financial reporting standards and practices and its financial statements, overseeing the Company's compliance with ethics and legal and regulatory requirements, and selecting, compensating, overseeing and evaluating the Company's independent registered public accountants.

During the fiscal year ended February 28, 2021, the Audit Committee met seven times. The Audit Committee operates under a charter that is available under the "Shareholder/Financial - Corporate Governance" section of our website at www.daybreakoilandgas.com and also upon request, without charge, by contacting the Corporate Secretary at Daybreak Oil and Gas, Inc., 1101 N. Argonne Road, Suite A 211, Spokane Valley, Washington 99212.

The Audit Committee's purpose is to assist the Board in fulfilling its responsibility to oversee management activities related to accounting and financial reporting policies, internal controls, auditing practices and related legal and regulatory compliance. In that connection, the Audit Committee is directly responsible for the appointment, compensation, retention and oversight of the work of our independent registered public accountants for the purposes of preparing or issuing an audit report or performing other audit, review or attest services. The Audit Committee determines the independence of our independent registered public accountants, and our independent registered public accountants report directly to the Audit Committee, which also must review and pre-approve the current year's audit and non-audit fees. The Audit Committee has the authority to select, retain and/or replace consultants to provide independent advice to the Committee. The Audit Committee discusses quarterly with the independent auditor the applicable requirements of the Public Company Accounting Oversight Board ("PCAOB") and the Commission.

The Audit Committee charter prescribes the Committee's functions, which include the following:

- Maintaining our compliance with legal and regulatory requirements relating to financial reporting accounting and controls;
- Overseeing our whistleblower procedures;
- Overseeing the pre-approval of audit fees;
- Appointing and overseeing our independent registered public accountants;
- Overseeing our internal audit function;
- Overseeing the integrity of our financial reporting processes, including the Company's internal controls;
- Assessing the effect of regulatory and accounting initiatives, as well as any off-balance sheet structures, on our financial statements;
- Reviewing our earnings press releases, guidance and SEC filings;
- Overseeing our risk analysis and risk management procedures;
- Resolving any disagreements between management and the independent registered public accountants regarding financial reporting;
- Overseeing our business practices and ethical standards;
- Preparing an audit committee report to be included in our public filings pursuant to applicable rules and regulations of the SEC.

Timothy R. Lindsey and James F. Meara serve on the Audit Committee. All members of the Audit Committee satisfy all SEC criteria for independence and meet all financial literacy and other SEC and NYSE American (formerly NYSE MKT LLC) requirements for Audit Committee service. The Board has determined that James F. Meara is an "audit committee financial expert" as defined by the rules of the SEC.

ITEM 11. EXECUTIVE COMPENSATION

Executive Officers

Named Executive Officers

Named executive officers consist of any individual who served as our Chief Executive Officer during the fiscal year ended February 28, 2021, and up to two of our most highly compensated executive officers other than the Chief Executive Officer during the fiscal year ended February 28, 2021. For the fiscal year ended February 28, 2021, under the smaller reporting company rules, our named executive officers are: James F. Westmoreland, President and Chief Executive Officer; and Bennett W. Anderson, our Chief Operating Officer (collectively, the "Named Executive Officers"). Executive officers are elected annually by our Board and serve at the discretion of the Board. There are no arrangements or understandings between any of the directors, officers, and other persons pursuant to which any such person was selected as an executive officer.

The following information concerns our Named Executive Officers for the fiscal year ended February 28, 2021.

Name	Age	Executive Since	Office
James F. Westmoreland	65	2007	President and Chief Executive Officer
Bennett W. Anderson	60	2006	Chief Operating Officer

EXECUTIVE COMPENSATION

We currently qualify as a "smaller reporting company" as such term is defined in Rule 405 of the Securities Act and Item 10 of Regulation S-K. Accordingly, and in accordance with relevant SEC rules and guidance, we have elected, with respect to the disclosures required by Item 402 (Executive Compensation) of Regulation S-K, to comply with the disclosure requirements applicable to smaller reporting companies. The following Compensation Overview is not comparable to the "Compensation Discussion and Analysis" that is required of SEC reporting companies that are not smaller reporting companies.

Compensation Overview

This Compensation Overview discusses the material elements of the compensation awarded to, earned by or paid to our executive officers, and the Compensation Committee's role in the design and administration of these programs and policies in making specific compensation decisions for our executive officers, including officers who are considered to be "Named Executive Officers" during the fiscal year ended February 28, 2021.

General Discussion of Executive Compensation

The Compensation Committee is responsible for establishing, implementing and continually monitoring adherence to our compensation philosophy. In doing so, the Compensation Committee reviews and approves on, at least, an annual basis the evaluation process and compensation structure for the Company's Named Executive Officers. The Committee reviews and recommends to the Board the annual compensation, including salary, and any incentive and/or equity-based compensation for such officers. The Committee also provides oversight of management's decisions concerning the performance and compensation of other employees.

The current and future objectives of Daybreak's compensation program are to keep compensation aligned with Daybreak's cost structure, financial position, and strategic business and financial objectives. Daybreak's financial position and its plans going forward are integral to the design and implementation of officer and employee compensation. Therefore, the Compensation Committee reviews the Company's cash flow with the Chief Executive Officer at a minimum, on an annual basis, in order to evaluate the current compensation program and its effects on the financial position of the Company. In deciding on the type and amount of compensation for each Named Executive Officer, the Compensation Committee focuses on the market value of the role and pay of the individual, along with the Company's cost structure and financial position.

Larger companies such as NYSE or NASDAQ listed companies in the crude oil and natural gas industry have well pronounced trends in compensation, including cash and equity components. Daybreak competes with larger crude oil and natural gas companies that have substantially greater resources.

For the fiscal years ended February 28, 2021 and February 29, 2020, compensation to our Named Executive Officers consisted solely of base salaries. The Board, with the assistance of the Compensation Committee, has reviewed the compensation structure of the Company's Named Executive Officers. After taking into consideration the Company's current cost structure, financial position, and current compensation structure (discussed under the heading "Narrative Disclosure to Summary Compensation Table, Base Salaries"), the Board approved continuation of the current compensation structure. In addition, the full Board reviewed and discussed the performance and compensation of all of Daybreak's employees.

The elements of compensation are described in more detail under "Narrative Disclosure to Summary Compensation Table", below, beginning on page 80 of this Form 10-K.

Summary Compensation Table

The following table sets forth summary information concerning the compensation paid to or earned by our Named Executive Officers during the fiscal years ended February 28, 2021 and February 29, 2020.

Name and Principal Position	Fiscal Year Ended	Salary ($)	Bonus ($)	All Other Compensation ($)	Total ($)
James F. Westmoreland[1]	February 28, 2021	65,625[2]	—	—	65,625[2]
President and Chief Executive Officer	February 29, 2020	93,750[3]	—	—	93,750[3]
Bennett W. Anderson	February 28, 2021	39,113[4]	—	—	39,113[4]
Chief Operating Officer	February 29, 2020	55,875[5]	—	—	55,875[5]

(1) Mr. Westmoreland commenced his employment on December 14, 2007 as the Company's interim Chief Financial Officer and was appointed Executive Vice President and Chief Financial Officer in April 2008. He was appointed to the position of President and Chief Executive Officer of the Company in October 2008 and also continues to serve as the interim principal finance and accounting officer of the Company.

(2) As a result of the effect of low oil prices on the Company's cash flow; and the lack of outside financing, Mr. Westmoreland deferred partial salary payments during the fiscal year ended February 28, 2021. During the fiscal year ended February 28, 2021, Mr. Westmoreland was paid $37,500; and $28,125 was accrued, but not paid. The accrued liability was recorded on our balance sheet under accrued liabilities.

(3) As a result of the effect of declining oil prices on the Company's cash flow; and the lack of outside financing, Mr. Westmoreland deferred partial salary payments during the fiscal year ended February 29, 2020. During the fiscal year ended February 29, 2020, Mr. Westmoreland was paid $75,000; and $18,750 was accrued, but not paid. The accrued liability was recorded on our balance sheet under accrued liabilities. Effective June 1, 2019, Mr. Westmoreland agreed to forgive all deferred salary owed him by the Company, totaling $943,750, (*which includes the previously accrued, but not paid $18,750 for the FYE2/29/20*) and reduce his annual base salary by 50%, to $75,000.

(4) As a result of the effect of low oil prices on the Company's cash flow; and the lack of outside financing, Mr. Anderson deferred partial salary payments during the fiscal year ended February 28, 2021. During the fiscal year ended February 28, 2021, Mr. Anderson was paid $22,350; and $16,763 was accrued, but not paid.

(5) As a result of the effect of declining oil prices on the Company's cash flow; and the lack of outside financing, Mr. Anderson deferred partial salary payments during the fiscal year ended February 29, 2020. During the fiscal year ended February 29, 2020, Mr. Anderson was paid $44,700; and $11,175 was accrued, but not paid. Effective June 1, 2019, the Company ended its policy of deferring base salary amounts of its Named Executive Officers and key employees, and reduced base salaries by 50%, but will continue to owe previously deferred amounts to these individuals.

Narrative Disclosure to Summary Compensation Table

Base Salaries

The Board, with the assistance of the Compensation Committee, has reviewed the compensation structure of the Company's Named Executive Officers. After taking into consideration the Company's current cost structure and financial position, on August 22, 2019, the Compensation Committee, along with the Board of Directors entered into a series of arrangements with its Named Executive Officers, as well as its board of directors and other key employees. As part of these efforts, Mr. Westmoreland agreed to forgive deferred salary owed him by the Company, totaling $943,750, and to reduce his annual base salary by 50%, to $75,000. The Company also ended its policy of deferring base salary amounts of its other Named Executive Officer and key employees, and temporarily reduced such executive and employee's base salaries by 50%, but will continue to owe previously deferred amounts to these individuals. These changes were agreed to by each affected person and were deemed to take effect as of June 1, 2019. This structure is expected to remain in place, and at least annually, the Committee will re-evaluate these actions, at which time the board of directors will re-evaluate the policy in light of the Company's financial status.

Outstanding Equity Awards at Fiscal Year-End

The Company has no unvested outstanding restricted stock awards held by our Named Executive Officers for the fiscal year ended February 28, 2021. The Company has no qualified or nonqualified stock option plans and has no outstanding stock options.

Other: Securities Trading

We have a policy that executive officers and directors may not purchase or sell exchange traded options to sell or buy Daybreak stock ("puts" and "calls"), engage in short sales with respect to Daybreak stock or otherwise hedge equity positions in Daybreak (e.g., by buying or selling straddles, swaps or other derivatives).

Executive Employment Agreements

Our employees, including our named executive officers, are employed at will and do not have employment agreements. Our Compensation Committee believes that employment agreements encourage a short-term rather than long-term focus, provide inappropriate security to the executives and employees and undermine the team spirit of the organization.

Payments Upon Termination or Change in Control

We do not have any agreements with any of our named executive officers that affect the amount paid or benefits provided following termination or a change in control.

Pension Plan Benefits

The Company does not have any pension plans that oblige the Company to make payments or provide benefits at, following or in connection with retirement of its Directors, Officers or employees.

Deductibility of Compensation

Section 162(m) of the Internal Revenue Code (the "Code") places a $1 million per executive cap on the compensation paid to executives that can be deducted for tax purposes by publicly traded corporations each year. Amounts that qualify as "performance based" compensation under Section 162(m)(4)(c) of the Code are exempt from the cap and do not count toward the $1 million limit if certain requirements are satisfied. At our current named executive officer compensation levels, we do not presently anticipate that Section 162(m) of the Code will be applicable, and accordingly, our Compensation Committee did not consider its impact in determining compensation levels for our Named Executive Officers for the fiscal year ended February 28, 2021.

Stock Compensation Expense

Stock awards are accounted for under FASB ASC 718, "Stock Compensation." 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.

DIRECTOR COMPENSATION

The Board adopted a Non-Employee Director Compensation Policy (the "Director Compensation Policy") under which it compensates directors who are not employees of the Company.

Under the Director Compensation Policy, each director who is not an employee or officer of the Company ("non-employee director") receives an annual cash retainer of $9,000. Each non-employee director also receives $500 per Board meeting attended and $500 per committee meeting attended. Additionally, the chairman of the Audit Committee receives an additional annual retainer of $1,500 and all other committee chairmen receive an additional $750 annual retainer. Director fees are paid in cash on a quarterly basis. Additionally, directors are reimbursed for any out-of-pocket expenses incurred in attending board meetings.

The Compensation Committee periodically reviews our director compensation practices. The Compensation Committee believes that our director compensation is fair and appropriate in light of the responsibilities and obligations of our directors.

On August 22, 2019 The Compensation Committee, along with the Board of Directors agreed to forgive 50% of all accrued, deferred board fees owed to them, and to temporarily discontinue future board fees. These changes deemed to take effect as of June 1, 2019, and at least annually, the Compensation Committee will re-evaluate the policy taking into consideration the Company's financial status. All details can be seen in the Director Summary Compensation Table below on page 82.

On August 27, 2020 the Compensation Committee, along with the Board of Directors agreed to revise the Director Compensation Policy to remove awards of all shares mentioned from the Board of Directors' Compensation under the Non-Employee Director Compensation Policy. The Compensation Committee will re-evaluate the policy at least annually, taking into consideration the Company's financial status.

Director Summary Compensation Table

Members of our board of directors are reimbursed for actual expenses incurred in attending Board meetings. The table below provides information concerning compensation paid to, or earned by, directors for the fiscal year ended February 28, 2021[1].

Name	Fees Earned Or Paid in Cash[2] ($)	All other compensation ($)	Total[2] ($)
Timothy R. Lindsey	—	—	—
James F. Meara	—	—	—

(1) As an employee director, Mr. James F. Westmoreland did not receive any compensation for serving on the Board of Directors during the fiscal year ended February 28, 2021. Only non-employee directors receive compensation for serving on the Board of Directors.

(2) As a result of the Company's limited available cash, the Board of Directors, beginning in June 2010 postponed receiving payments of meeting fees and quarterly retainer fees until cash flow would allow. On August 22, 2019, the board of directors agreed to forgive 50% of accrued, deferred board fees owed to them, and to temporarily discontinue future board fees, deemed to take effect as of June 1, 2019. The Compensation Committee will re-evaluate the policy at least annually, taking into consideration the Company's financial status.

(3) Payment of any accrued fees will not be made until cash flow would allow. This liability is recorded on our balance sheet under accrued liabilities.

REPORT OF THE COMPENSATION COMMITTEE

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

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

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

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

Security Ownership of Certain Beneficial Owners and Management

Our four directors and officers of the Company, together own and control about 14.9% percent of our outstanding common stock.

Our shareholders do not have the right to cumulative voting in the election of our directors. Cumulative voting could allow a minority group to elect at least one director to our Board. Because there is no provision for cumulative voting, a minority group will not be able to elect any directors. Conversely, if our principal beneficial shareholders and directors wish to act in concert, they would be able to vote to appoint directors of their choice, and otherwise directly or indirectly control the direction and operation of the Company.

As of May 25, 2021, based on information available to the Company, the following table shows the beneficial ownership of the Company's voting securities (Common Stock and Series A Convertible Preferred stock) by: (i) any persons or entities known by management to beneficially own more than 5% of the outstanding shares of the Company's Common Stock; (ii) each current director of the Company; (iii) each current executive officer of the Company named in the Summary Compensation Table appearing on page 80; and (iv) all of the current directors and executive officers of Daybreak as a group. The address of each of the beneficial owners, except where otherwise indicated, is the Company's address. Unless otherwise indicated, each person shown below has the sole power to vote and the sole power to dispose of the shares of voting stock listed as beneficially owned.

Class of Stock	Name of Beneficial Owner	Amount and Nature of Beneficial Ownership(1,2)	Warrants Currently Exercisable or Exercisable Within 60 Days(3)	Total Beneficial Holdings	Percent of Class(4)(5) (Less than 1% not shown)
Common Stock	**Timothy R. Lindsey,** *Director*	910,000	-	910,000	1.5
	James F. Meara, *Director*	160,000	-	160,000	*
	James F. Westmoreland, *President and Chief Executive Officer and Director*	7,558,758(6)	-	7,558,758(6)	12.5
	Bennett W. Anderson, *Chief Operating Officer*	400,000	-	400,000	*
	All (4) directors and executive officers as a group	9,028,758	-	9,028,758	14.9
Series A Convertible Preferred Stock(7)	**Tensas River Farms I,II,III** 551 Lawrence 5470 Alicia, AR 72410	66,667	-	66,667	9.4
	Summittcrest Capital Partners 50 California St., Suite 450 San Francisco, CA 94111	58,333	-	58,333	8.2

(1) Includes shares believed to be held directly or indirectly by 5% or higher shareholders, directors and executive officers that have voting power and/or the power to dispose of such shares. Unless otherwise noted, each individual or member of the group has the sole power to vote and the sole power to dispose of the shares listed as beneficially owned.

(2) To reflect "beneficial ownership" as defined in Rule 13d-3 promulgated under the Securities Exchange Act of 1934, this column includes shares as to which each individual has (A) sole voting power, (B) shared voting power, (C) sole investment power, or (D) shared investment power and the right to acquire within sixty days (from May 25, 2021).

(3) To reflect "beneficial ownership" as defined in Rule 13d-3 promulgated under the Securities Exchange Act of 1934, this column includes shares as to which each individual has the right to acquire within sixty days (from May 25, 2021).

(4) Based upon 60,491,122 shares of common stock outstanding as of May 25, 2021 entitled to one vote per share within 60 days of May 25, 2021.

(5) Ed Capko (Bear to Bull Investor Relations, LLC) is the holder of a warrant, and beneficial ownership, which includes the 528,507 shares underlying the warrant held by him that are exercisable within 60 days of May 25, 2021. Mr. Capko's total holdings consist of 2,490,000 shares of common stock and 2,100,000 shares underlying the warrant provided, however, that this warrant shall not vest as to any Shares (and instead vesting will continue with respect to such Shares until the restriction no longer applies) to the extent such vesting would cause the Subscriber's beneficial ownership (as such term is defined in Section 13d-3 of the Securities Exchange Act of 1934, as amended) of more than four and ninety-nine one-hundredths percent (4.99%) of the Company's outstanding Common Stock. The foregoing restriction may not be waived by either party. The Warrant would become vested and exercisable as follows; as to 1/3 of the Shares on January 2, 2020; as to 1/3 of the Shares on January 2, 2021; and as to 1/3 of the Shares on January 2, 2022. The Warrant will expire at the close of business on the Expiration Date set forth, as January 2, 2024, or earlier as provided in the Warrant. Notwithstanding the foregoing, this Warrant will terminate on any earlier date when the Warrant has been exercised as to all Shares. Under the terms of the restriction limiting the vesting of no more than four and ninety-nine one-hundredths percent (4.99%) of the Company's outstanding Common Stock, on January 2, 2020; 190,000 shares underlying the warrant became vested and exercisable; and on July 13, 2020, 338,507 shares underlying the warrant became vested and exercisable. The total number of shares vested and exercisable are 528,507; with 1,571,493 un-exercisable shares underlying the warrant remaining. Mr. Capko's total beneficial holdings, include 490,000 shares held in "street name" in a broker account; 2,000,000 wholly-owned shares and 528,507 shares underlying the warrant held by him that are exercisable within 60 days of May 25, 2021.

(6) This includes 6,958,758 shares converted under the terms of a Convertible Note Purchase Agreement with Mr. Westmoreland, the Company's Chairman, President and Chief Executive Officer. He loaned the Company $27,835 for general operating expenses under a Convertible Note Purchase Agreement. The Note had a maturity date of 180 days, or July 12, 2020 and carried no interest, fees or penalties. On July 13, 2020, the note payable was converted to 6,958,758 shares of the Company's common stock. The note payable had a conversion formula of $0.004 per share.

(7) The Series A Convertible Preferred ("Preferred") stock has 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 shares. Each share of Series A Convertible Preferred stock can be converted to three common stock shares at any time. As of May 25, 2021, 709,568 shares of Daybreak Series A Convertible Preferred stock were outstanding.

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

Transactions with Related Persons, Promoters and Certain Control Persons

The Board adopted a policy prescribing procedures for review, approval and monitoring of transactions involving Daybreak and "related persons" (directors and executive officers or their immediate family members, or shareholders owning 5% [five percent] or greater of our outstanding stock). The Policy Statement Regarding Related Party Transactions of Daybreak Oil and Gas, Inc. ("Related Party Transactions Policy") supplements the conflict of interest provisions in our Ethical Business Policy Conduct Statement and Corporate Governance Guidelines. The Board has determined that the Governance Committee is best suited to review and consider for approval related party transactions, although the Board may instead determine that a particular related party transaction be reviewed and considered for approval by a majority of disinterested directors.

The Related Party Transactions Policy covers any related person transaction that involves amounts exceeding $50,000 in which a related person has a direct or indirect material interest. In addition, the Related Party Transactions Policy applies specifically to transactions involving Daybreak and any of the following:

(1) all officers;

(2) directors and director nominees;

(3) 5% shareholders;

(4) immediate family members of the foregoing individuals (broadly defined to include any child, stepchild, parent, stepparent, spouse, sibling, mother-in-law, father-in-law, son-in-law, daughter-in-law, brother-in-law, or sister-in-law);

(5) any entity controlled by any of the individuals in (1), (2), (3) or (4) above (whether through ownership, management authority or otherwise); and

(6) certain entities at which any of the individuals in (1), (2), (3) or (4) above is employed (generally, if the individual employed is directly involved in the negotiation of the transaction, has or shares responsibility at such entity for such transaction, or might receive compensation tied to such transaction).

The Company's Chairman, President and Chief Executive Officer had loaned to the Company in previous fiscal years ended February 29, 2012 and February 28, 2013 an aggregate $250,100 that was used for a variety of corporate purposes. During the fiscal year ended February 29, 2020, in connection with its debt reduction efforts, the Company entered into a Note Payoff Agreement with this related party. Pursuant to the Note Payoff Agreement, the Company issued as payment in full of the Notes, a production payment interest in certain of the Company's production revenue from the drilling of future wells in California and Michigan. The production payment interest was granted for a deemed consideration amount of the balance of the Notes and made pursuant to a Production Payment Interest Purchase Agreement dated as of August 22, 2019. The grant was made on the same terms as the Company has sold production payment interests to other third parties in the 2018-2019 fiscal year pursuant to its previously disclosed program. For further information on the production revenue program refer to the "Production Revenue Payable" beginning on page 41. During the twelve months ended February 29, 2020, this same officer loaned the Company $27,835 for general operating expenses under a Convertible Note Purchase Agreement. The Note had a maturity date of 180 days, or July 12, 2020 and carried no interest, fees or penalties. If the Note was not repaid in full on or before the Maturity Date then, on the day following the Maturity Date, the Note automatically converted into that number of Conversion Shares equal to the quotient obtained by dividing (x) the outstanding principal balance of the Note on the date of such conversion by (y) a Conversion Price of $0.004. During the twelve months ended February 28, 2021, there were 6,958,758 common stock shares issued to settle that related party note payable debt.

On December 22, 2020, the Company entered into a Secured Promissory Note (the "*Note*"), as borrower, with the Company's President and Chief Executive Officer for an aggregate principal amount of $155,548.34. The Note requires monthly payments on the Note balance until repaid in full. The maturity date of the Note is December 21, 2035. The obligations under the Note are secured by a lien on and security interest in the Company's oil and gas assets located in Kern County, California, as described in a Deed of Trust entered into by the Company in favor of the Noteholder to secure the obligations under the Note. Such lien shall be a first priority lien, subject only to a pre-existing lien filed by a working interest partner of the Company.

The Note and Deed of Trust were each reviewed and approved by the Company's board of directors, including all disinterested directors, all the members of the Nominating and Corporate Governance Committee, and were approved pursuant to the Company's Related Party Transactions policy. The terms of the Note are more favorable to the Company than the financing available to the Company from a third party. For further information on the production revenue program refer to the "Production Revenue Payable" beginning on page 41.

The Company's Chief Operating Officer, Bennett Anderson is 50% owner in Great Earth Power a Company that provides a portion of the electrical service for Daybreak's production operations at its East Slopes Project in Bakersfield, California. Great Earth Power began providing solar powered electricity for the Company's production operations in California in September 2020. Mr. Anderson received approximately $9,000 from Great Earth Power in our fiscal year ended February 28, 2021.

Mr. Anderson is also a 50% owner in ABPlus Net Holdings a Company that provides tank rentals to the Company for its production operations in Kern County California. The Company began renting tanks from ABPlus Net Holdings in November 2020. Mr. Anderson received approximately $2,440 from ABPlus Net Holdings in our fiscal year ended February 28, 2021.

Great Earth Power provides solar electricity and ABPlus Net Holdings provides tank rentals to Daybreak at very reasonable rates, saving the Company significant money.

All transactions were reviewed and approved by the Company's board of directors, including all disinterested directors, all the members of the Compensation Committee and all the members of the Nominating and Corporate Governance Committee, and were approved pursuant to the Company's Related Party Transactions policy.

Director Independence

Independence of Board Members

We seek individuals who are able to guide our operations based on their business experience, both past and present, or their education. Our business model is not complex and our accounting issues are straightforward.

The Governance Committee is delegated with the responsibility to review the independence and qualifications of each member of the Board and its various Committees. Directors are deemed independent only if the Board affirmatively determines that they have no material relationship with Daybreak, directly, or as an officer, shareowner or partner of an organization that has a relationship with us.

The Company has adopted the standards of NYSE American (formerly NYSE MKT LLC) for determining the independence of its directors. The Company is not listed on NYSE American and is not subject to the rules of NYSE American but applies the rules established by NYSE American to establish director independence.

These independence standards specify the relationships deemed sufficiently material to create the presumption that a director is not independent. No director qualifies as independent unless the Company's Board affirmatively determines that the director does not have a relationship that would interfere with the exercise of independent judgment in carrying out the responsibilities of a director. In addition, Section 803A of the NYSE American Company Guide (and related commentary) sets forth the following non-exclusive list of persons who shall not be considered independent:

(a) a director who is, or during the past three years was, employed by the Company, other than prior employment as an interim executive officer (provided the interim employment did not last longer than one year);

(b) a director who accepted or has an immediate family member who accepted any compensation from the Company in excess of $120,000 during any period of twelve consecutive months within the three years preceding the determination of independence, other than the following:

  (i) compensation for Board or Board committee service,

  (ii) compensation paid to an immediate family member who is an employee (other than an executive officer) of the Company,

  (iii) compensation received for former service as an interim executive officer (provided the interim employment did not last longer than one year), or

  (iv) benefits under a tax-qualified retirement plan, or non-discretionary compensation;

(c) a director who is an immediate family member of an individual who is, or at any time during the past three years was, employed by the Company as an executive officer;

(d) a director who is, or has an immediate family member who is, a partner in, or a controlling shareholder or an executive officer of, any organization to which the Company made, or from which the Company received, payments (other than those arising solely from investments in the Company's securities or payments under non-discretionary charitable contribution matching programs) that exceed 5% of the organization's consolidated gross revenues for that year, or $200,000, whichever is more, in any of the most recent three fiscal years;

(e) a director who is, or has an immediate family member who is, employed as an executive officer of another entity where at any time during the most recent three fiscal years any of the issuer's executive officers serve on the compensation committee of such other entity; or

(f) a director who is, or has an immediate family member who is, a current partner of the Company's outside auditor, or was a partner or employee of the Company's outside auditor who worked on the Company's audit at any time during any of the past three years.

Directors serving on the Company's audit committee must also comply with the additional, more stringent requirements set forth in Section 803B of the NYSE American (formerly NYSE MKT LLC) Company Guide and Rule 10A-3 of the Securities Exchange Act of 1934, as amended.

Consistent with these considerations, after review of all relevant transactions and/or relationships between each director and any of his family members and Daybreak, its senior management and its independent registered public accountants, the Board affirmatively determined that two of the current directors, Messrs. Timothy R. Lindsey, and James F. Meara are independent. Mr. James F. Westmoreland, our President and Chief Executive Officer, is not independent. Beginning July 1, 2013, directors serving on the Company's compensation committee must also comply with the additional, more stringent requirements as set forth in Section 805(c) of the NYSE American (formerly NYSE MKT LLC) Company Guide.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Fees Billed by Independent Registered Public Accountants

A summary of fees for professional services performed by MaloneBailey, LLP ("MaloneBailey") for the audit of our financial statements for the fiscal years ended February 28, 2021 and February 29, 2020 is set forth in the table below:

Services Rendered	Fees Billed for the Fiscal Year Ended February 28 2021	Fees Billed for the Fiscal Year Ended February 29, 2020
Audit fees	$ 70,000	$ 70,000
Audit-related fees	—	—
Tax fees	—	—
All other fees	—	—
Total	$ 70,000	$ 70,000

The Audit Committee has reviewed the nature and scope of the services provided by MaloneBailey and considers the services provided to have been compatible with the maintenance of MaloneBailey's independence.

Pre-Approval Policies and Procedures

The Audit Committee has adopted guidelines for the pre-approval of audit and permitted non-audit services by our independent registered public accountants. The Audit Committee considers annually and approves the provision of audit services by our independent registered public accountants and considers and pre-approves the provision of certain defined audit and non-audit services. The Audit Committee also considers on a case-by-case basis and approves specific engagements that are not otherwise pre-approved. Any proposed engagement that does not fit within the definition of a pre-approved service may be presented to the Chairman of the Audit Committee. The Chairman of the Audit Committee reports any specific approval of services at the next regular Audit Committee meeting. The Audit Committee reviews a summary report detailing all services being provided to Daybreak by its independent registered public accountants. All of the fees and services described above under "audit fees," "audit-related fees," "tax fees" and "all other fees" were pre-approved in accordance with the Audit Fee Pre-Approval Policy and pursuant to Section 202 of the Sarbanes-Oxley Act of 2002.

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 (incorporated by reference to Exhibit 3.01 of the Company's Annual Report on Form 10-K for year ended February 28, 2010).

3.02 Amended and Restated Bylaws (incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K filed on April 9, 2008).

4.01+ Specimen Stock Certificate

4.02 Description of Securities (incorporated by reference to Exhibit 4.02 of the Company's Annual Report on Form 10-K for year ended February 28, 2019).

4.03 Designations of Series A Convertible Preferred Stock (incorporated by reference to Exhibit 3.1 of the Company's 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 and Gas, Inc. dated June 30, 2006.))

4.04 Form of 12% Subordinated Note due 2015 (incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed on February 3, 2010).

4.05 Form of Warrant in connection with 12% Subordinated Notes (incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K, filed on February 3, 2010).

4.06 Form of Amendment to 12% Subordinated Note due 2015 and Warrant to Purchase Shares of Common Stock (incorporated by reference to Exhibit 4.13 of the Company's Annual Report on Form 10-K for year ended February 28, 2015).

4.07 Form of Second Amendment to 12% Subordinated Note due 2017 and Warrant to Purchase Shares of Common Stock (incorporated by reference to Exhibit 4.14 of the Company's Annual Report on Form 10-K for the year ended February 28, 2017).

4.08 Warrant Agreement by and between Daybreak Oil and Gas, Inc., and Bear to Bull Investor Relations, LLC, dated November 27, 2019. (incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the period ended November 30, 2019).

10.01 Prospect review and non-competition agreement for California project (incorporated by reference to Exhibit 10vi of the Company's SB-2/A filed on December 28, 2006).

10.02 Prospect review agreement for California project (incorporated by reference to Exhibit 10x of the Company's SB-2/A filed on December 28, 2006).

10.03 Form of Subscription Agreement for 12% Subordinated Note due 2015 (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed on February 3, 2010).

10.04 Promissory Note, dated June 20, 2011, by and between Daybreak Oil and Gas, Inc. and James F. Westmoreland (incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the period ended August 31, 2011).

10.05 Promissory Note, dated January 31, 2012, by and between Daybreak Oil and Gas, Inc. and James F. Westmoreland (incorporated by reference to Exhibit 10.6 of the Company's Quarterly Report on Form 10-Q for the period ended November 30, 2012).

10.06 Credit Line Agreement, dated October 24, 2011, by and between Daybreak Oil and Gas, Inc. and UBS Bank USA (incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the period ended November 30, 2011).

10.07 Mortgage, Deed of Trust, Assignment of Production, Security Agreement and Financing Statement (incorporated by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q for the period ended November 30, 2020).

10.11	Promissory Note, dated August 21, 2012, by and between Daybreak Oil and Gas, Inc. and James F. Westmoreland (incorporated by reference to Exhibit 10.7 of the Company's Quarterly Report on Form 10-Q for the period ended November 30, 2012).
10.12	Promissory Note, dated December 22, 2020, by and between Daybreak Oil and Gas, Inc. and James Forrest Westmoreland and Angela Marie Westmoreland, Co-Trustees of the James and Angela Westmoreland Revocable Trust (incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the period ended November 30, 2020).
10.30	Securities Purchase Agreement dated December 27, 2018 by and between Daybreak Oil and Gas, Inc. and Maximilian Resources, LLC. (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K filed on January 3, 2019).
10.31	Production Payment Interest Purchase Agreement dated December 27, 2018 by and among Daybreak Oil and Gas, Inc. and the purchasers named therein. (incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed on January 3, 2019).
10.32	Consulting Agreement by and between Daybreak Oil and Gas, Inc., and Bear to Bull Investor Relations, LLC, dated October 8, 2019. (incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the period ended August 31, 2019).
10.33	Form of Convertible Note Purchase Agreement and Note, issued by the Company by and between Daybreak Oil and Gas, Inc. and James F. Westmoreland dated as of January 14, 2020. (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed on January 17, 2020).
23.1+	Consent of PGH Petroleum and Environmental Engineers, LLC
31.1+	Certification of principal executive and principal financial officer as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1+	Certification of principal executive and principal financial officer as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1+	Reserve Report of PGH Petroleum and Environmental Engineers, LLC, independent petroleum engineering consulting firm, as of February 28, 2021
101.INS	XBRL Instance Document *
101.SCH	XBRL Taxonomy Schema *
101.CAL	XBRL Taxonomy Calculation Linkbase *
101.DEF	XBRL Taxonomy Definition Linkbase *
101.LAB	XBRL Taxonomy Label Linkbase *
101.PRE	XBRL Taxonomy Presentation Linkbase *

+ Filed herewith.

* Furnished herewith.

ITEM 16. FORM 10–K SUMMARY

The Company has elected not to include the optional summary information hyperlink.

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 27, 2021

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 27, 2021

By: /s/ TIMOTHY R. LINDSEY
Timothy R. Lindsey
Director
Date: May 27, 2021

By: /s/ JAMES F. MEARA
James F. Meara
Director
Date: May 27, 2021

GLOSSARY OF TERMS

The following are abbreviations and definitions of terms commonly used in the crude oil and natural 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.

API. American Petroleum Institute, a petroleum induction association that sets standards for oil field equipment and operations. Also see Oil Gravity.

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

Fracturing. A procedure undertaken to attempt to increase the flow of crude oil or natural gas from a well. A fluid (usually crude oil, diesel oil or water) is pumped into the reservoir with such great force that the reservoir rock is physically broken and split open. Usually the "frac fluid" carries small pellets or beads mixed in with it; the idea is for them to get caught in the fractures and prop them open (the beads or pellets are called the propping agent or proppant). As the pumping pressures are gradually released at the surface, the natural reservoir pressures will force the "frac fluid" out of the reservoir, and back into the well as the well begins to flow. The proppant remains behind, holding the fractures open, thereby increasing the flow of crude oil or natural gas from the reservoir into the well. This procedure is also called hydraulic fracturing. To "frac a well" means to hydraulically fracture a reservoir in a 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 crude oil or natural gas in another reservoir.

Gas. Refers to natural gas. A mixture of gaseous hydrocarbons formed naturally in the earth.

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.

Hydrocarbons. A large class of organic compounds composed of hydrogen and carbon. Crude oil, natural gas and natural gas condensate are all mixtures of various hydrocarbons, among which methane is the simplest.

Hydraulic fracturing. Refer to the definition of fracturing.

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

Net production. Crude oil and natural 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. Refers to crude oil or condensate. A naturally occurring mixture of liquid hydrocarbons as it comes out of the ground.

Oil Gravity. The density of liquid hydrocarbons generally measured in degrees API. The lighter the crude oil, the higher the API gravity. Heavy oil has an API gravity of 20° API or less. For example, motor lubricating oil is around 26° API; while gasoline is approximately 55° API.

Operator. The individual or company responsible for the exploration, development and production of a crude oil or natural 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 crude oil and natural gas reserves are those quantities of crude 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 – 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 crude oil or natural 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 crude 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 crude oil and natural 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 a crude oil and natural 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 crude oil or natural gas, regardless of whether such acreage contains proved reserves.

Working interest. An interest in a crude oil and natural gas lease that gives the owner of the interest the right to drill for and produce crude oil and natural 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.

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 27, 2021

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, 2021, 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 27, 2021

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 4.01

• NOT VALID UNLESS COUNTERSIGNED BY TRANSFER AGENT
• INCORPORATED UNDER THE LAWS OF THE STATE OF WASHINGTON

NUMBER

SHARES

AUTHORIZED COMMON STOCK:
200,000,000 SHARES
PAR VALUE: $0.001

DBRM

CUSIP NO. 239559 107

This Certifies that

Is The Record Holder Of

Fully paid and non-assessable shares of **Daybreak Oil & Gas, Inc.** Common Stock
transferable on the books of the Corporation in person or by attorney upon surrender of this certificate duly endorsed or assigned.
This certificate and the shares represented hereby are subject to the laws of the State of Nevada.
and to the Articles of Incorporation and Bylaws of the Corporation. as now or hereafter amended.
This certificate is not valid until countersigned by the Transfer Agent.

Witness the facsimile seal of the Corporation and the facsimile signatures of its duly authorized officers.

Dated:

SECRETARY

DAYBREAK OIL & GAS, INC.
CORPORATE
Seal
WASHINGTON

PRESIDENT

NOT VALID UNLESS COUNTERSIGNED BY TRANSFER AGENT

Countersigned by SEDONA EQUITY REGISTRAR & TRANSFER, INC.
Phoenix, Arizona 85022

Authorized Signature

The following abbreviations, when used in the inscription on the face of this certificate, shall be construed as though they were written out in full according to applicable laws or regulations.

TEN COM	- as tenants in common	UNIF GIFT MIN ACT.........................Custodian......................
		(Cust) (Minor)
TEN ENT	- as tenants by the entireties	
JT TEN	- as joint tenants with the right of survivorship and not as tenants in common	Act..
		(State)

Additional abbreviations may also be used though not in the above list.

For value received, ________________________________ *hereby sell, assign and transfer unto*

PLEASE INSERT SOCIAL SECURITY OR OTHER IDENTIFYING NUMBER OF ASSIGNEE

____

(PLEASE PRINT OR TYPEWRITE NAME AND ADDRESS, INCLUDING ZIP CODE, OF ASSIGNEE)

____

____

____

____ *shares*

of the capital stock represented by the within Certificate, and do hereby irrevocably constitute and appoint

____, *Attorney*

to transfer the said stock on the books of the within named Corporation with full power of substitution in the premises.

Dated ________________________

X ____

THE SIGNATURE TO THIS ASSIGNMENT MUST CORRESPOND WITH THE NAME AS WRITTEN UPON THE FACE OF THIS CERTIFICATE. THE SIGNATURE(S) MUST BE GUARANTEED BY AN ELIGIBLE GUARANTOR INSTITUTION (Banks, Stockbrokers, Savings and Loan Associations and Credit Unions).

SIGNATURE GUARANTEED:

TRANSFER FEE WILL APPLY

ENGINEERS · CONSULTANTS

May 26, 2021

Daybreak Oil and Gas, Inc.
1101 N. Argonne Road
Suite A-211
Spokane Valley, WA 99212

Re: Securities and Exchange Commission Annual Report on Form 10-K

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

We hereby consent to the use of the name PGH Petroleum and Environmental Engineers, LLC; and to references to PGH Petroleum and Environmental Engineers LLC an independent petroleum engineering firm; and to the inclusion of information contained in our reports as of March 1, 2021, in your Annual Report on Form 10-K for the year ended February 28, 2021 to be filed on or around May 26, 2021

PGH Petroleum and Environmental Engineers, LLC
Texas Firm Registration No. F-9137
Austin, Texas
May 26, 2021

ENGINEERS · CONSULTANTS

May 26, 2021

Daybreak Oil and Gas, Inc.
1101 N. Argonne Road
Suite A-211
Spokane Valley, WA 99212

Re: Securities and Exchange Commission Annual Report on Form 10-K

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

We hereby consent to the use of the name PGH Petroleum and Environmental Engineers, LLC; and to references to PGH Petroleum and Environmental Engineers LLC an independent petroleum engineering firm; and to the inclusion of information contained in our reports as of March 1, 2021, in your Annual Report on Form 10-K for the year ended February 28, 2021 to be filed on or around May 26, 2021

PGH Petroleum and Environmental Engineers, LLC
Texas Firm Registration No. F-9137
Austin, Texas
May 26, 2021

April 22, 2021

Mr. James F. Westmoreland
President and CEO
Daybreak Oil and Gas, Inc.
1101 N. Argonne Road
Suite A-211
Spokane Valley, WA 99212

Ref: Daybreak Oil and Gas, Inc.
Proved ("1P") Reserve Report – SEC Case
As of February 28, 2021

Dear Mr. Westmoreland

In accordance with your request, PGH Petroleum & Environmental Engineers, LLC ("PGH", "we", "our") has performed an engineering evaluation to estimate proved oil and gas reserves and projected the associated future revenues for certain properties owned by Daybreak Oil and Gas, Inc. ("Daybreak") interests in select oil and gas properties located in Kern County, California as of February 28, 2021. This evaluation was prepared for public disclosure by Daybreak in filings made with the United States Securities and Exchange Commission ("SEC") in accordance with the disclosure requirements set forth in the SEC regulations and is an annual update of evaluated properties. The assumptions, data and procedures used in the preparation of this report are appropriate for this purpose. This report was completed on April 22, 2021 and is effective as of February 28, 2021.

As presented in this report, we estimate the net reserves and future net revenue to Daybreak's interests as follows:

Daybreak Oil and Gas, Inc.
Total Proved Reserves

As of February 28, 2021

	Net Oil, MBbl	Net Gas, MMcf	Future Net Revenue, M$	Present Worth 10%, M$
Proved Producing	95.120	-	970.481	646.855
Proved Undeveloped	339.103	-	4,134.960	1,001.562
Grand Total	**434.223**	**-**	**5,105.440**	**1,648.418**

Note: Columns may not add due to rounding.

Projections of the reserves and future net revenue were estimated in accordance with our understanding of the definitions and disclosure guidelines of the SEC contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). A copy of the applicable SEC oil and gas reserve definitions for "Proved" reserves are attached hereto. Additionally, this report has also been prepared in accordance with the Society of Petroleum

Engineers ("SPE") - Petroleum Resources Management System ("SPE-PRMS"). Risk factors have not been applied to these estimates. This report also conforms to our understanding of the *Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information* promulgated by SPE and the *Guidelines for Application of Definitions for Oil and Gas Reserves* prepared by the Society of Petroleum Evaluation Engineers ("SPEE").

California Prospects (Kern County):

Ball Prospect

The Ball prospect is the northern most pool and contains two producing wells in the Vedder formation. The pool area encompasses approximately 40 Acres and the cumulative production from the producing wells is 37,378 barrels of oil.

Bear Prospect

Nine wells have been completed in the Bear pool and one well the Bear No. 10 was an unsuccessful completion. All of these wells are producing from the Vedder formation. In addition to these wells, there are eleven more locations categorized as proved undeveloped. The pool area conservatively encompasses approximately 62.5 Acres. The cumulative production for the producing wells is 232,323 barrels of oil.

Black Prospect

The Black pool is located to the South of the Bear pool and contains two producing wells in the Vedder formation. In addition to the producing wells, there are three more locations which are categorized as proved undeveloped. The pool area encompasses approximately 13.4 Acres. The cumulative production for the producing wells is 48,553 barrels of oil.

Dyer Creek Prospect

The Dyer Creek structure lies between the Bear and the Ball pools and is open to the South. The Dyer Creek Pool has approximately 23 acres and the cumulative production for the producing well is 16,853 barrels of oil.

Sunday Prospect

The Sunday pool area encompasses approximately 34.6 acres and contains six producing wells along with five proved undeveloped locations. The cumulative production for the producing wells out of the Vedder formation is 201,148 barrels of oil.

Reserves

The oil reserves shown are expressed in barrels where one barrel equals 42 US gallons. The California properties evaluated by PGH in this report represent 100 percent of Daybreak's total net proved reserves as of February 28, 2021. The California properties represent 100 percent of the total proved developed net liquid hydrocarbon reserves and 100 percent of the total proved undeveloped net liquid hydrocarbon reserves of Daybreak as of February 28, 2021.

Future reserves in this report are based on volumetric calculations (oil in place) and conventional decline curve analysis. The volumetric calculations were based off of well log analysis (reservoir thickness, porosity and water saturation).

The reserves projections in this evaluation are based on the use of available data and accepted industry engineering methods. Future changes in any operational or economic parameters or production characteristics of the evaluated properties could increase or decrease the reserves. Unforeseen changes in market demand or allowables set by various regulatory agencies could also cause actual production rates to vary from those projected.

Values for reserves are expressed in terms of future net revenue and present worth of future net revenue. Future net revenue is defined as revenue that will accrue to the appraised interests from the production and sale of the estimated net reserves after deducting production taxes, ad valorem taxes, direct lease operating expenses and capital costs. Neither plug and abandonment costs nor salvage was considered in this evaluation. No estimate of Federal Income Tax has been made in this report. Present worth is defined as the future net revenue discounted at the rate shown per year, compounded monthly.

As of February 28, 2021, the net remaining 1P reserves were estimated to be 434,223 barrels of oil. This volume represents 100 percent of the total proved reserves of Daybreak. The net present value, discounted at 10%, of the total proved reserves was $1,648,418.

Price Assumptions

Oil

The reserve estimates use oil prices based on the Cushing, OK West Texas Intermediate ("WTI") Spot Price, for the twelve month period (unweighted arithmetic average of the first day of the month) prior to the ending date of the report (March 2020 – February 2021) resulting in a base price of $38.64 per barrel.

A differential of (-$2.50) has been applied to reflect actual commodity sale prices from March 2020 through February 2021 resulting in an average realized price of $36.14 per barrel for the California properties.

It should be emphasized that with current economic uncertainties, fluctuations in market conditions could significantly change the economics of the properties included in this report.

Expenses & Capital Costs

Lease operating expenses are used to establish the economic limit of each property in this report and were not escalated. Lease operating expenses as well as state and local tax rates were provided by Daybreak. Future proved undeveloped wells were assigned expenses based on actual lease operating costs for each of the prospect areas.

Capital costs for each well to be drilled and completed in the future were based on a summary provided by Daybreak. This report assumes that a typical well will cost approximately $350,000 ($375,000 for the Ball Lease and the Bear 23 and Bear XY) on a gross basis for the remaining proved locations. The drilling schedule for this report was based on a proposed drilling schedule provided by Daybreak.

Report Qualifications

All reserve estimates herein have been performed in accordance with sound engineering principles and generally accepted industry practice. As in all aspects of oil and gas evaluations, there are uncertainties inherent in the interpretation of engineering and geologic data and all conclusions and projections contained herein represent the informed, professional judgment of the undersigned. The reserves may or may not be recovered, and the revenues there from and the cost related thereto could be more or less than the estimated amounts. Estimates of reserves may increase or decrease as a result of future operations, governmental policies, product supply and demand, and also are subject to revision as additional operating history becomes available and as economic conditions change.

The evaluation of potential environmental liability costs from the operation and abandonment of the properties evaluated was beyond the scope of this report. In addition, no evaluation was made to determine the degree of operator compliance with current environmental rules, regulations and reporting requirements. Therefore, no estimate of the potential economic liability, if any, from environmental concerns is included in the projections presented herein.

The operations of Daybreak may be subject to various levels of government controls and regulations. These controls and regulations may include matters relating to land tenure, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income taxes all of which may be subject to change from time to time. Such changes in government regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

Data Sources

Daybreak provided basic well information, production data, capital expenses, operating costs, initial test rates and ownership interests which we have accepted as correct. This data has not been independently verified. Historical production data was also obtained from public sources such as state regulatory agencies and IHS Energy production data base. Basic geologic and field performance data together with our engineering work sheets along with digital, hard copy and other pertinent data relating to the properties evaluated will be retained in our files and will be available for review upon request. We have not inspected or performed well tests on the individual properties in this report.

Independent Evaluation

We do not own an interest in the subject properties. The employment to make this study and the compensation is not contingent on our estimates of reserves and future income for the subject properties. We appreciate the opportunity to prepare this report. If you have any questions regarding this report, please contact the undersigned.

Sincerely,

4-22-2021

Frank J. Muser, P.E.
PGH Petroleum & Environmental Engineers, L.L.C.
Texas Engineering License No. 93590
Texas Firm Registration No. F-9137

STATE OF TEXAS
FRANK J. MUSER
93590
LICENSED
PROFESSIONAL ENGINEER

PGH PETROLEUM &
ENVIRONMENTAL
ENGINEERS, LLC
F-9137