Oasis Petroleum Inc.
Form 10-K
March 10, 2011

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

Form 10-K

þ	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
	For the fiscal year ended December 31, 2010
	OR
o	**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number: 1-34776

Oasis Petroleum Inc.
(Exact name of registrant as specified in its charter)

Delaware	**80-0554627**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
1001 Fannin Street, Suite 1500 Houston, Texas	**77002**
(Address of principal executive offices)	*(Zip Code)*

(281) 404-9500
(Registrant s telephone number, including area code)
Securities Registered Pursuant to Section 12(b) of the Act:

(Title of Class)	(Name of Exchange)
Common Stock, par value $0.01 per share	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act:
None

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

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

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

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

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

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

Large accelerated filer o	Accelerated filer o	Non-accelerated filer þ (Do not check if a smaller reporting company)	Smaller Reporting company o

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant s most recently completed second fiscal quarter: $1,337,121,778

Number of shares of registrant s common stock outstanding as of March 9, 2011: 92,310,145

Documents Incorporated By Reference:

Portions of the registrant s definitive proxy statement for its 2011 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2010, are incorporated by reference into Part III of this report for the year ended December 31, 2010.

OASIS PETROLEUM INC.
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2010

TABLE OF CONTENTS

Table of Contents

CAUTIONARY NOTE REGARDING 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, as amended, and Section 21E of the Securities and Exchange Act of 1934, as amended. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this Annual Report on Form 10-K, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report on Form 10-K, the words could, believe, anticipate, intend, estimate, expect, may, continue, predict, potential, project ar are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements about our:

business strategy;

reserves;

technology;

cash flows and liquidity;

financial strategy, budget, projections and operating results;

oil and natural gas realized prices;

timing and amount of future production of oil and natural gas;

availability of drilling and production equipment;

availability of qualified personnel;

the amount, nature and timing of capital expenditures, including future development costs;

availability and terms of capital;

drilling of wells;

transportation and marketing of oil and natural gas;

exploitation or property acquisitions;

costs of exploiting and developing our properties and conducting other operations;

general economic conditions;

competition in the oil and natural gas industry;

effectiveness of our risk management activities;

environmental liabilities;

counterparty credit risk;

governmental regulation and taxation of the oil and natural gas industry;

developments in oil-producing and natural gas-producing countries;

uncertainty regarding our future operating results;

estimated future net reserves and present value thereof; and

plans, objectives, expectations and intentions contained in this report that are not historical.

All forward-looking statements speak only as of the date of this Annual Report on Form 10-K. We disclaim any obligation to update or revise these statements unless required by Securities law, and you should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Annual Report on Form 10-K are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under Item 1A. Risk Factors and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and elsewhere in this Annual Report on Form 10-K. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

PART I

Item 1. *Business*

Overview

Oasis Petroleum Inc. (together with our consolidated subsidiaries, the Company, we, us, or our) is an independent exploration and production company focused on the development and acquisition of unconventional oil and natural gas resources. As of December 31, 2010, we accumulated 303,231 net leasehold acres in the Williston Basin. We are currently focused on exploiting what we have identified as significant resource potential from the Bakken and Three Forks formations, which are present across a substantial majority of our acreage. A report issued by the United States Geological Survey (USGS) in April 2008 classified these formations as the largest continuous oil accumulation ever assessed by it in the contiguous United States of America. We believe the location, size and concentration of our acreage in our core project areas create an opportunity for us to achieve cost, recovery and production efficiencies through the large-scale development of our project inventory. Our management team has a proven track record in identifying, acquiring and executing large, repeatable development drilling programs, which we refer to as resource conversion opportunities, and has substantial experience in the Williston Basin. In 2010, we drilled and completed 26 gross operated wells in the Williston Basin and achieved 100% success in the finding of hydrocarbons (25 of which are economic based on current prices as of December 31, 2010). This success has been achieved through the application of the latest drilling and completion techniques. We have built our leasehold acreage position in the Williston Basin primarily through acquisitions in our three primary project areas: West Williston, East Nesson and Sanish. For a description of our acquisition activity, please see Our history below.

DeGolyer and MacNaughton, our independent reserve engineers, estimated our net proved reserves to be 39.8 MMBoe (39.7 MMBoe in the Williston Basin) as of December 31, 2010, 43% of which were classified as proved developed and 92% of which were comprised of oil. The following table presents summary data for each of our primary project areas as of December 31, 2010:

		Identified Drilling Locations		2011 Budget			Estimated Net Proved Reserves as of December 31, 2010		2010 Average Daily Production (Boe/d)
	Net Acreage	Gross	Net	Gross Wells	Net Wells	Drilling Capital (In millions)	MMBoe	% Developed	
Williston Basin									
West Williston(1)	191,716	859	393.1	77	43.6	$ 366	22.9	39	2,070
East Nesson(1)	102,786	255	127.6	16	5.6	51	9.6	42	1,643
Sanish(2)	8,729	189	16.6	60	3.9	24	7.2	55	1,419
Total Williston Basin	303,231	1,303	537.3	153	53.1	441	39.7	43	5,132

Other	879						0.1	100	74
Total	304,110	1,303	537.3	153	53.1	$	441	39.8	43	5,206

(1) Identified gross and net drilling locations in our West Williston and East Nesson project areas are based on mostly 1,280 acre spacing units with three wells targeting the Bakken formation in each identified spacing unit (excluding previously drilled wells). With the exception of one proved undeveloped drilling location, the drilling locations do not include wells targeting the Three Forks formation.

(2) Identified gross and net drilling locations in our Sanish project area include up to three wells targeting the Bakken formation and two wells targeting the Three Forks formation per identified spacing unit (excluding previously drilled wells). In the Sanish project area, we have identified 57 gross (5.1 net) drilling locations remaining in the Bakken formation and 132 gross (11.5 net) drilling locations remaining in the Three Forks formation.

Based on the delineation of the Bakken formation throughout much of our acreage, we had 1,303 gross drilling locations as of December 31, 2010. This drilling inventory is based on 472 substantially delineated and economically viable spacing units. In our West Williston and East Nesson project areas, our drilling inventory includes three wells per spacing unit (excluding previously drilled wells). In the more mature Sanish project area, our drilling inventory includes up to three Bakken wells and two Three Forks wells per spacing unit (excluding previously drilled wells). Assuming three Three Forks wells per spacing unit, this would add an additional 1,155 potential gross (544.1 net) Three Forks locations in our West Williston and East Nesson project areas. Throughout the Williston Basin, we believe we have an aggregate of 2,458 gross (1,081.4 net) potential drilling locations targeting the Bakken and Three Forks formations.

Our history

Oasis Petroleum Inc. was incorporated in February 2010 pursuant to the laws of the State of Delaware to become a holding company for Oasis Petroleum LLC, which was formed as a Delaware limited liability company in February 2007 by certain members of our senior management team and certain private equity funds managed by EnCap Investments L.P. (EnCap). We completed our initial public offering in June 2010 (IPO). In connection with our IPO and related corporate reorganization, we acquired all of the outstanding membership interests in Oasis Petroleum LLC, our predecessor, in exchange for shares of our common stock. Our business continues to be conducted through Oasis Petroleum LLC, a wholly owned subsidiary of the Company.

We built our leasehold position in our West Williston, East Nesson and Sanish project areas through the following acquisitions and development activities:

In June 2007, we acquired approximately 175,000 net leasehold acres in the Williston Basin with then-current net production of approximately 1,000 Boe/d. This acreage is the core of our West Williston project area.

In May 2008, we entered into a farm-in and purchase arrangement, under which we earned or acquired approximately 48,000 net leasehold acres, establishing our initial position in the East Nesson project area.

In June 2009, we acquired approximately 37,000 net leasehold acres with then-current net production of approximately 800 Boe/d, approximately 92% of which was from the Williston Basin. This acquisition consolidated our acreage in the East Nesson project area and established our Sanish project area.

In September 2009, we acquired an additional 46,000 net leasehold acres with then-current net production of approximately 300 Boe/d. This acquisition further consolidated our acreage in the East Nesson project area.

In the fourth quarter of 2010, we acquired approximately 16,700 net leasehold acres located in Roosevelt County, Montana with then-current net production of approximately 300 Boe/d and approximately 10,000 net leasehold acres primarily located in Richland County, Montana with then-current net production of approximately 200 Boe/d. This acreage is part of our West Williston project area.

Our business strategy

Our goal is to enhance value by building reserves, production and cash flows at attractive rates of return. We seek to achieve our goals through the following strategies:

Develop our Williston Basin leasehold position. We intend to drill and develop our acreage position to maximize the value of our resource potential. The aggregate 771 gross (485.6 net) operated drilling locations that we have specifically identified in the Bakken formation in our West Williston and East Nesson project areas will be our primary targets in the near term. Our 2011 drilling plan contemplates drilling approximately 69 gross (46.8 net) operated wells in these project areas by using seven operated drilling rigs throughout the year. We believe we have the ability to add additional rigs during 2011 if market conditions and program results warrant.

Focus on operational and cost efficiencies. Our management team is focused on continuous improvement of our operating measures and has significant experience in successfully converting early-stage resource conversion opportunities into cost-efficient development projects. We believe the magnitude and concentration of our acreage within our project areas provides us with the opportunity to capture economies of scale, including the ability to drill multiple wells from a single drilling pad, utilizing centralized production and fluid handling facilities and reducing the time and cost of rig mobilization.

Adopt and employ leading drilling and completion techniques. Our team is focused on enhancing our drilling and completion techniques to maximize recovery. We believe these techniques have significantly evolved over the last several years, resulting in increased initial production rates and recoverable hydrocarbons per well through the implementation of techniques such as using longer laterals and more tightly spaced fracturing stimulation stages. We continuously evaluate our internal drilling results and monitor the results of other operators to improve our operating practices, and we expect our drilling and completion techniques will continue to evolve. This continued evolution may significantly enhance our initial production rates, ultimate recovery factors and rate of return on invested capital.

Pursue strategic acquisitions with significant resource potential. As opportunities arise, we intend to identify and acquire additional acreage and producing assets in the Williston Basin to supplement our existing operations. Going forward, we may selectively target additional basins that would allow us to employ our resource conversion strategy on large undeveloped acreage positions similar to what we have accumulated in the Williston Basin.

Maintain financial flexibility and conservative financial position. We are committed to maintaining a conservative financial strategy by managing our liquidity position and leverage levels. As of December 31, 2010, we had no outstanding borrowings under our revolving credit facility. After the closing of our private placement of $400 million of 7.25% senior unsecured notes due 2019 on February 2, 2011, we had $671.0 million of liquidity available, including approximately $533.5 million in cash and $137.5 million available under our revolving credit facility. This liquidity position, along with internally generated cash flows, will provide additional financial flexibility as we continue to develop our acreage position in the Williston Basin. Furthermore, as a result of our IPO and our private placement of senior unsecured notes in February 2011, we now have access to the public equity and debt markets and we intend to maintain a conservative, balanced capital structure by prudently raising proceeds from future offerings as additional capital needs arise.

Our competitive strengths

We have a number of competitive strengths that we believe will help us to successfully execute our business strategies:

Substantial leasehold position in one of North America s leading unconventional oil-resource plays. Our current leasehold position of 303,231 net leasehold acres in the Williston Basin is highly prospective in the Bakken formation and 92% of our 39.7 MMBoe net proved reserves in this area were comprised of oil as of December 31, 2010. We believe our acreage is one of the largest concentrated leasehold positions that is prospective in the Bakken formation, and much of our acreage is in areas of significant drilling activity by other exploration and production companies. While we are initially targeting the Bakken formation, we are also evaluating what we believe to be significant prospectivity in the Three Forks formation that underlies a large portion of our acreage. We expect that the scale and concentration of our acreage will enable us to continue to improve our drilling and completion costs and operational efficiency.

Large, multi-year project inventory. We have an inventory of approximately 1,303 gross drilling locations, primarily targeting the Bakken formation. We plan to drill 69 gross (46.8 net) operated wells across our West Williston and East Nesson project areas in 2011, the completion of which would represent 9% of our 771 gross (485.6 net) operated drilling locations in the Bakken formation in these two project areas.

Management team with proven operating and acquisition skills. Our senior management team has extensive expertise in the oil and gas industry as previous members of management at Burlington Resources. The senior technical team has an average of more than 25 years of industry experience, including experience in multiple North American resource plays as well as experience in other North American and international basins. We believe our management and technical team is one of our principal competitive strengths relative to our industry peers due to our team s proven track record in identification, acquisition and execution of resource conversion opportunities. In addition, this team possesses substantial expertise in horizontal drilling techniques and managing and acquiring large development programs, and also has prior experience in the Williston Basin. Please see Our operations Management experience with resource conversion plays and horizontal drilling techniques.

Incentivized management team. As of December 31, 2010, our executive officers owned approximately 11% of our common stock. We believe our executive officers ownership interest in us provides them with significant incentives to grow the value of our business for the benefit of all stakeholders.

Operating control over the majority of our portfolio. In order to maintain better control over our asset portfolio, we have established a leasehold position comprised primarily of properties that we expect to operate. We expect to operate approximately 59% of our 1,303 identified gross drilling locations, or 90% of our 537.3 identified net drilling locations. As of December 31, 2010, approximately 79% of our total proved reserves were attributable to properties that we expect to operate. Approximately 91% of our estimated 2011 drilling and completion capital expenditure budget is related to operated wells, which we anticipate will result in an increase in 2011 of the percentage of our proved reserves attributable to properties we expect to operate. As of December 31, 2010, our average working interest in our operated and non-operated identified drilling locations was 63% and 10%, respectively. Controlling operations will allow us to dictate the pace of development as well as the costs, type and timing of exploration and development activities. We believe that maintaining operational control over the majority of our acreage will allow us to better pursue our strategies of enhancing returns through operational and cost efficiencies and maximizing hydrocarbon recovery through continuous improvement of drilling and completion techniques.

Marketing and transportation

The Williston Basin crude oil transportation and refining infrastructure has grown substantially in recent years, largely in response to drilling activity in the Bakken formation. Based on a December 30, 2010 report from the North Dakota Pipeline Authority, oil production in North Dakota, Eastern Montana and South Dakota was approximately 415,000 barrels per day during December 2010. As of December 31, 2010, there were approximately 480,000 barrels per day of crude oil transportation and refining capacity in the Williston Basin, comprised of approximately 280,000 barrels per day of pipeline transportation capacity and approximately 58,000 barrels per day of refining capacity at the Tesoro Corporation Mandan refinery. In addition, approximately 65,000 barrels per day of specifically dedicated railcar transportation capacity has been placed into service and there are approximately 80,000 barrels per day being transported by truck to Canada and by other smaller rail sites in the Williston Basin. Based on publicly announced expansion projects, pipeline transportation capacity for Williston Basin oil production could increase by approximately 170,000 barrels per day by 2013 and additional pipeline projects totaling approximately 230,000 barrels per day are under consideration. An additional 107,000 barrels per day of rail transportation has also been announced and is expected to be in place by 2013. Additional rail projects have been announced since December 31, 2010. We sell a substantial majority of our oil production directly at the wellhead and are not responsible for its transportation. However, the price we receive at the wellhead is impacted by transportation and refining infrastructure constraints. For a discussion of the potential risks to our business that could result from transportation and refining infrastructure constraints in the Williston Basin, please see Item 1A. Risk

Table of Contents

Factors Risks related to the oil and natural gas industry and our business Insufficient transportation or refining capacity in the Williston Basin could cause significant fluctuations in our realized oil and natural gas prices.

Our operations

Estimated proved reserves

Unless otherwise specifically identified, the summary data with respect to our estimated proved reserves presented below has been prepared by our independent reserve engineering firms in accordance with rules and regulations of the Securities and Exchange Commission (SEC) applicable to companies involved in oil and natural gas producing activities. As discussed below, the SEC adopted new rules relating to disclosures of estimated reserves that were effective for fiscal years ending on or after December 31, 2009. Our proved reserve estimates do not include probable or possible reserves which may exist, categories which the new SEC rules now permit us to disclose in public reports. Our estimated proved reserves under the SEC rules in effect for the year ended December 31, 2008 were determined using constant prices and unescalated costs based on the prices received and costs incurred on a field-by-field basis as of the year end. For the years ended December 31, 2009 and 2010 and for future periods, our estimated proved reserves were and will be determined using the preceding twelve months unweighted arithmetic average of the first-day-of-the-month prices, rather than year-end prices. For a definition of proved reserves under the SEC rules for both the fiscal years ending on or after December 31, 2009 and the fiscal year ending December 31, 2008, please see the Glossary of oil and natural gas terms included at the end of this report.

The table below summarizes our estimated proved reserves and related PV-10 at December 31, 2010 and 2009 for each of our project areas. All of the reserve estimates at December 31, 2010 and 2009 presented in the table below are based on reports prepared by DeGolyer and MacNaughton, our independent reserve engineers. In preparing its reports, DeGolyer and MacNaughton evaluated properties representing all of our PV-10 at December 31, 2010 and 2009 under the new SEC rules. For more information regarding our independent reserve engineers, please see Independent petroleum engineers below. The information in the following table does not give any effect to or reflect our commodity derivatives.

	At December 31, 2010		At December 31, 2009	
Project Area	**Proved Reserves (MMBoe)**	**PV-10(2) (In millions)**	**Proved Reserves (MMBoe)**	**PV-10(2) (In millions)**
Williston Basin:				
West Williston	22.9	$ 380.0	5.0	$ 50.7
East Nesson	9.6	160.7	3.9	31.6
Sanish	7.2	156.4	4.3	50.6
Total Williston Basin	39.7	$ 697.1	13.2	$ 132.9
Other(1):	0.1	0.7	0.1	0.6
Total	39.8	$ 697.8	13.3	$ 133.5

(1) Represents data relating to our properties in the Barnett shale.

(2) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effect of income taxes on discounted future net cash flows. However, our PV-10 and our Standardized Measure are equivalent at December 31, 2009 because as of December 31, 2009, we were a limited liability company not subject to entity level taxation. Neither PV-10 nor Standardized Measure represent an estimate of the fair market value of our oil and natural gas properties. The oil and gas industry uses PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities. See Reconciliation of PV-10 to Standardized Measure below.

Table of Contents

The following table sets forth more information regarding our estimated proved reserves at December 31, 2010, 2009 and 2008:

	At December 31,		
	2010	**2009**	**2008**
Reserve Data(1):			
Estimated proved reserves:			
Oil (MMBbls)	36.6	12.4	2.2
Natural gas (Bcf)	19.4	5.3	0.7
Total estimated proved reserves (MMBoe)	39.8	13.3	2.3
Percent oil	92%	93%	95%
Estimated proved developed reserves:			
Oil (MMBbls)	15.7	5.2	2.2
Natural gas (Bcf)	8.2	2.3	0.7
Total estimated proved developed reserves (MMBoe)	17.0	5.6	2.3
Percent proved developed	43%	42%	100%
Estimated proved undeveloped reserves:			
Oil (MMBbls)	20.9	7.2	
Natural gas (Bcf)	11.2	3.0	
Total estimated proved undeveloped reserves (MMBoe)	22.8	7.7	
PV-10 (in millions)(2)	$ 697.8	$ 133.5	$ 17.7
Standardized Measure (in millions)(3)	$ 485.7	$ 133.5	$ 17.7

(1) Our estimated proved reserves and related future net revenues, PV-10 and Standardized Measure were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $79.40/Bbl for oil and $4.38/MMBtu for natural gas for the year ended December 31, 2010 and $61.04/Bbl for oil and $3.87/MMBtu for natural gas for the year ended December 31, 2009. The index prices were $44.60/Bbl for oil and $5.63/MMBtu for natural gas at December 31, 2008. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

(2) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effect of income taxes on discounted future net cash flows. However, our PV-10 and our Standardized Measure are equivalent at December 31, 2008 and 2009 because as of December 31, 2009, we were a limited liability company not subject to entity level taxation. Accordingly, no provision for federal or state corporate income taxes was provided prior to our IPO and corporate reorganization because taxable income passed through to our equity holders. However, in connection with the closing of our IPO, we merged into a corporation that became a holding company for Oasis Petroleum LLC. As a result, we are treated as a taxable entity for federal income tax purposes and our income taxes are dependent upon our taxable income. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas properties. The oil and gas industry uses PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities. The PV-10 amount included in the report of W.D. Von Gonten & Co. at December 31, 2008 was $19.2 million because the PV-10 amount included in such report did not give effect to additional estimated

plugging and abandonment costs.

(3) Standardized Measure represents the present value of estimated future net cash flows from proved oil and natural gas reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses (if applicable), discounted at 10% per annum to reflect timing of future cash flows. In connection with the closing of our IPO, we merged into a corporation that is treated as a taxable entity for federal income tax purposes. For further discussion of income taxes, see Note 11 to our audited consolidated financial statements.

Reconciliation of PV-10 to Standardized Measure

PV-10 is derived from the Standardized Measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the Standardized Measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure of discounted future net cash flows. Our PV-10 measure and the Standardized Measure of discounted future net cash flows do not purport to present the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of PV-10 to the Standardized Measure of discounted future net cash flows at December 31, 2010, 2009 and 2008:

	December 31,		
	2010	**2009**	**2008**
		(In millions)	
PV-10	$ 697.8	$ 133.5	$ 17.7
Present value of future income taxes discounted at 10%(1)	212.1		
Standardized Measure of discounted future net cash flows	$ 485.7	$ 133.5	$ 17.7

(1) Our PV-10 and our Standardized Measure are equivalent at December 31, 2009 and 2008 because prior to our corporate reorganization in June 2010, we were a limited liability company not subject to entity-level income tax. Accordingly, no provision for federal or state corporate income taxes was recorded for the years ended December 31, 2009 and 2008 as the taxable income was allocated directly to our equity holders. In connection with the closing of our IPO, we merged into a corporation and became subject to federal and state entity-level taxation. See Note 11 to our audited consolidated financial statements.

Estimated proved reserves at December 31, 2010 were 39.8 MMBoe, a 199% increase from reserves of 13.3 MMBoe at December 31, 2009. Our 2010 estimated proved reserves increased 26.5 MMBoe over our 2009 estimated reserves due to acquisitions, our drilling program and higher oil price assumptions at December 31, 2010. Our commodity price assumption for oil increased $18.36/Bbl to $79.40/Bbl for the year ended December 31, 2010 from $61.04/Bbl for the year ended December 31, 2009. Our proved developed producing reserves increased 11.4 MMBoe, or 204%, to 17.0 MMBoe for the year ended December 31, 2010 from 5.6 MMBoe for the year ended December 31, 2009 due to acquisitions and our drilling program. Our proved undeveloped reserves increased to 22.8 MMBoe for the year ended

December 31, 2010 from 7.7 MMBoe for the year ended December 31, 2009 due to significant regional drilling activity, higher commodity price assumptions and higher overall estimated ultimate recoveries using recent drilling and completion techniques.

Estimated proved reserves at December 31, 2009 were 13.3 MMBoe, a 477% increase from reserves of 2.3 MMBoe at December 31, 2008. Our 2009 estimated proved reserves increased 11.0 MMBoe over our 2008 estimated reserves due to acquisitions, our drilling program and higher oil price assumptions at December 31, 2009. Our commodity price assumption for oil increased $16.44/Bbl to $61.04/Bbl for the year ended December 31, 2009 from $44.60/Bbl for the year ended December 31, 2008. Our proved developed producing

Table of Contents

reserves increased 3.3 MMBoe, or 144%, to 5.6 MMBoe for the year ended December 31, 2009 from 2.3 MMBoe for the year ended December 31, 2008 due to acquisitions and our drilling program. Our proved undeveloped reserves increased to 7.7 MMBoe for the year ended December 31, 2009 from 0.0 MMBoe for the year ended December 31, 2008 due to significant regional drilling activity, higher commodity price assumptions and higher overall estimated ultimate recoveries using recent drilling and completion techniques.

The PV-10 of our estimated proved reserves at December 31, 2010 was $697.8 million, a 423% increase from PV-10 of $133.5 million at December 31, 2009. Our PV-10 of estimated proved reserves increased $564.3 million over the 2009 PV-10 due to an increase in reserves and higher oil price assumptions.

The following table sets forth the estimated future net revenues, excluding derivative contracts, from proved reserves, the present value of those net revenues (PV-10) and the expected benchmark prices used in projecting net revenues at December 31, 2010, 2009 and 2008:

	At December 31,		
	2010	2009	2008
		(In millions)	
Future net revenues	$ 1,561.3	$ 286.1	$ 27.1
Present value of future net revenues:			
Before income tax (PV-10)	697.8	133.5	17.7
After income tax (Standardized Measure)(1)	485.7	133.5	17.7
Benchmark oil price($/Bbl)(2)	$ 79.40	$ 61.04	$ 44.60

(1) Standardized Measure represents the present value of estimated future net cash inflows from proved oil and natural gas reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses (if applicable), discounted at 10% per annum to reflect timing of future cash flows. In connection with the closing of our IPO, we merged into a corporation that is treated as a taxable entity for federal income tax purposes. For further discussion of income taxes, see Note 11 to our audited consolidated financial statements.

(2) Our estimated proved reserves and related future net revenues, PV-10 and Standardized Measure were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $79.40/Bbl for oil and $4.38/MMBtu for natural gas for the year ended December 31, 2010 and $61.04/Bbl for oil and $3.87/MMBtu for natural gas for the year ended December 31, 2009. The index prices were $44.60/Bbl for oil and $5.63/MMBtu for natural gas at December 31, 2008. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. The PV-10 amount included in the report of W.D. Von Gonten & Co. at December 31, 2008 was $19.2 million because the PV-10 amount included in such report did not give effect to additional estimated plugging and abandonment costs.

Future net revenues represent projected revenues from the sale of proved reserves net of production and development costs (including operating expenses and production taxes). Such calculations at December 31, 2010 and 2009 are based on costs in effect at December 31 of each year and the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period January through December of such year, without giving effect to derivative transactions, and are held constant throughout the life of the properties. Such calculations at December 31, 2008 are based on costs and prices in effect at December 31, 2008, without giving effect to derivative transactions, and are held constant throughout the life of the properties. There can be no assurance that the proved reserves will be produced within the periods indicated or that prices and costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties.

Table of Contents

Proved undeveloped reserves

At December 31, 2010, we had approximately 22.8 MMBoe of proved undeveloped reserves as compared to 7.7 MMBoe at December 31, 2009.

The following table summarizes the changes in our proved undeveloped reserves during 2010 (in MBoe):

At December 31, 2009	7,686
Extensions, discoveries and other additions	16,351
Purchases of minerals in place	443
Sales of minerals in place	
Revisions of previous estimates	1,763
Conversion to proved developed reserves	(3,481)
At December 31, 2010	22,762

During 2010, we spent $41.5 million converting 3,481MBoe of proved undeveloped reserves to proved developed reserves. As we did not have any proved undeveloped reserves for the year ended December 31, 2008, no investment in conversion of proved undeveloped reserves to proved developed reserves was made in 2009.

All of our proved undeveloped reserves at December 31, 2010 are expected to be developed within the next five years.

Independent petroleum engineers

Our estimated reserves, Standardized Measure and related future net revenues and PV-10 at December 31, 2009 and 2010 are based on reports prepared by DeGolyer and MacNaughton, our independent reserve engineers, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and current guidelines established by the SEC. DeGolyer and MacNaughton is a Delaware corporation with offices in Dallas, Houston, Calgary and Moscow. The firm s more than 100 professionals include engineers, geologists, geophysicists, petrophysicists and economists engaged in the appraisal of oil and gas properties, evaluation of hydrocarbon and other mineral prospects, basin evaluations, comprehensive field studies and equity studies related to the domestic and international energy industry. DeGolyer and MacNaughton has provided such services for over 70 years. The Senior Vice President at DeGolyer and MacNaughton primarily responsible for overseeing the preparation of the reserve estimates is a Registered Petroleum Engineer in the State of Texas with more than 35 years of experience in oil and gas reservoir studies and reserve evaluations. He graduated with a Bachelor of Science degree in Petroleum Engineering from Texas A&M University in 1974 and he is a member of the International Society of Petroleum Engineers and the American Association of Petroleum Geologists. DeGolyer and MacNaughton restricts its activities exclusively to consultation; it does not accept contingency fees, nor does it own operating interests in any oil, gas or mineral properties, or securities or notes of clients. The firm subscribes to a code of professional conduct, and its employees actively support their related technical and professional societies. The firm is a Texas Registered Engineering Firm.

Our estimated reserves and related future net revenues and PV-10 at December 31, 2008 are based on a report prepared by W.D. Von Gonten & Co., our independent reserve engineers at such date, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC in effect at such time. W.D. Von Gonten & Co. was formed in 1995 and is located in Houston, Texas. The firm has a professional staff consisting of over nineteen petroleum engineers, geologists and other technical staff. W.D. Von

Gonten & Co. provides a variety of services to the oil and gas industry, including field studies, oil and gas reserve estimations, appraisals of oil and gas properties and reserve reports for both public and private companies. W.D. Von Gonten & Co. is a Texas Registered Engineering Firm.

Table of Contents

Technology used to establish proved reserves

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

In order to establish reasonable certainty with respect to our estimated proved reserves, DeGolyer and MacNaughton employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic 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. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated using performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity. These wells were considered to be analogous based on production performance from the same formation and completion using similar techniques. For wells and locations targeting the Bakken formation, the evaluation included an assessment of the beneficial impact of the use of multi-stage hydraulic fracture stimulation treatments on estimated recoverable reserves. In addition to assessing reservoir continuity, geologic data from well logs, core analyses and seismic data related to the Bakken formation were used to estimate original oil in place. In portions of our Sanish project area where estimated proved reserves were attributed to more than one well per spacing unit, the estimated original oil in place was used to calculate reasonable estimated recovery factors based on experience with similar reservoirs where similar drilling and completion techniques have been employed.

Internal controls over reserves estimation process

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to our independent reserve engineers in their reserves estimation process. Our Senior Vice President Asset Management is the technical person primarily responsible for overseeing the preparation of our reserves estimates. Our Senior Vice President Asset Management has over 20 years of industry experience with positions of increasing responsibility in engineering and evaluations and holds both a Bachelor of Science degree and Master of Science degree in petroleum engineering. Our Senior Vice President Asset Management reports directly to our Chief Operating Officer.

Throughout each fiscal year, our technical team meets with representatives of our independent reserve engineers to review properties and discuss methods and assumptions used in preparation of the proved reserves estimates. While we have no formal committee specifically designated to review reserves reporting and the reserves estimation process, a preliminary copy of the reserve report is reviewed by our Chief Operating Officer with representatives of our independent reserve engineers and internal technical staff. Our Audit Committee also conducts a review on an annual basis.

Production, revenues and price history

Oil and natural gas are commodities. The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Demand for oil and natural gas in the United States has increased dramatically over the last ten years. However, the economic slowdown during the second half of 2008 and through 2009 reduced this demand. In 2010, demand for oil and gas increased as the economy recovered. Demand is impacted by general economic conditions, weather and other seasonal conditions, including hurricanes and tropical storms. Over or under supply of oil or natural gas can result in substantial price volatility. Historically, commodity prices have been volatile and we expect that volatility to continue in the future. A substantial or extended decline in oil or natural gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and natural gas reserves that may be economically produced and our ability to access capital markets.

The following table sets forth information regarding oil and natural gas production, revenues and realized prices and production costs for the periods indicated. For additional information on price calculations, please see information set forth in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation.

	Year Ended December 31,		
	2010	**2009**	**2008**
Operating data:			
Net production volumes:			
Oil (MBbls)	1,792	658	379
Natural gas (MMcf)	651	326	123
Oil equivalents (MBoe)	1,900	712	400
Average daily production (Boe/d)	5,206	1,950	1,092
Average sales prices:			
Oil, without realized derivatives (per Bbl)	$ 69.60	$ 55.32	$ 88.07
Oil, with realized derivatives (per Bbl)(1)	69.53	58.82	69.79
Natural gas (per Mcf)	6.52	4.24	10.91
Costs and expenses (per Boe):			
Lease operating expenses	$ 7.67	$ 12.21	$ 17.70
Production taxes	7.25	5.35	7.51
Depreciation, depletion and amortization	19.91	23.42	21.73
General and administrative expenses	10.39	13.12	13.64
Stock-based compensation expenses(2)	4.60		

(1) Realized prices include realized gains or losses on cash settlements for our commodity derivatives, which do not qualify for and were not designated as hedging instruments for accounting purposes.

(2) In March 2010, we recorded a $5.2 million stock-based compensation charge associated with Oasis Petroleum Management LLC (OPM) granting 1.0 million C Units to certain of our employees. During the fourth quarter of 2010, we recorded an additional $3.5 million in stock-based compensation expense primarily associated with OPM granting discretionary shares of our common stock to certain of our employees who were not C Unit holders and certain contractors. See Note 10 to our audited consolidated financial statements.

Net production volumes for the year ended December 31, 2010 were 1,900 MBoe, a 167% increase from net production of 712 MBoe for the year ended December 31, 2009. Our net production volumes increased 1,188 MBoe over 2009 due to a successful operated and non-operated drilling and completion program and acquisitions. Average oil sales prices, without realized derivatives, increased by $14.28/Bbl, or 26%, to an average of $69.60/Bbl for the year ended December 31, 2010 as compared to the year ended December 31, 2009. Giving effect to our derivative transactions in both periods, our oil sales prices increased $10.71/Bbl to $69.53/Bbl for the year ended December 31, 2010 from $58.82/Bbl for the year ended December 31, 2009. Lease operating expenses increased $5.9 million to

$14.6 million for the year ended December 31, 2010 compared to the year ended December 31, 2009. This increase was primarily due to the higher number of productive wells from our well completions during the twelve months of 2010. The 167% increase in production volumes from the year ended December 31, 2009 to the year ended December 31, 2010 resulted in a 37% decrease in unit operating costs to $7.67/Boe.

Net production volumes for the year ended December 31, 2009 were 712 MBoe, a 78% increase from net production of 400 MBoe for 2008. Our net production volumes increased 312 MBoe over 2008 net production volumes due to acquisitions and a successful operated and non-operated drilling and completion program. Our average oil sales prices, without the effect of realized derivatives, decreased $32.75/Bbl to $55.32/Bbl for the year ended December 31, 2009 from $88.07/Bbl for the year ended December 31, 2008. Giving effect to our derivative transactions in both periods, our oil sales prices decreased $10.97/Bbl to $58.82/Bbl for the year ended December 31, 2009 from $69.79/Bbl for the year ended December 31, 2008. Our lease operating expenses decreased $5.49/Boe, or 31%, to $12.21/Boe for the year ended December 31, 2009 from $17.70/Boe for the year ended December 31, 2008 due to acquisitions and our drilling program. The Bakken formation generally has a lower per unit lease operating cost than conventional producing horizons.

The following table sets forth information regarding our average daily production for the years ended December 31, 2010 and 2009:

	Average Daily Production for the Years Ended December 31,					
		2010			2009	
	Bbls	Mcf	Boe	Bbls	Mcf	Boe
Williston Basin:						
West Williston	1,976	564	2,070	936	378	999
East Nesson	1,607	215	1,643	505	18	508
Sanish	1,325	561	1,419	349	101	366
Total Williston Basin	4,908	1,340	5,132	1,790	497	1,873
Other		444	74	11	395	77
Total	4,908	1,784	5,206	1,801	892	1,950

Productive wells

The following table presents the total gross and net productive wells by project area and by oil or gas completion as of December 31, 2010:

	Oil Wells		Natural Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Williston Basin:						
West Williston	160	67.6			160	67.6
East Nesson	66	29.3			66	29.3
Sanish	123	9.6			123	9.6
Total Williston Basin	349	106.5			349	106.5
Other			27	3.3	27	3.3

Total	349	106.5	27	3.3	376	109.8

Gross wells are the number of wells in which a working interest is owned and net wells are the total of our fractional working interests owned in gross wells.

Table of Contents

Acreage

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own a working interest as of December 31, 2010 for each of our project areas. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Williston Basin:						
West Williston	80,322	49,490	221,764	142,226	302,086	191,716
East Nesson	45,858	31,234	116,020	71,552	161,878	102,786
Sanish	42,082	8,633	878	96	42,960	8,729
Total Williston Basin	168,262	89,357	338,662	213,874	506,924	303,231
Other	5,917	879			5,917	879
Total	174,179	90,236	338,662	213,874	512,841	304,110

Undeveloped acreage

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2010 that will expire over the next three years by project area unless production is established within the spacing units covering the acreage prior to the expiration dates:

	Expiring 2011		Expiring 2012		Expiring 2013	
	Gross	Net	Gross	Net	Gross	Net
Williston Basin:						
West Williston	67,874	39,884	30,269	15,248	37,652	15,044
East Nesson	36,532	14,025	22,104	8,734	52,728	27,103
Sanish	160	28	320	12		
Total Williston Basin	104,566	53,937	52,693	23,994	90,380	42,147
Other						
Total	104,566	53,937	52,693	23,994	90,380	42,147

Drilling activity

The following table summarizes our drilling activity for the years ended December 31, 2010, 2009 and 2008. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells.

	Year Ended December 31,					
	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Oil	100	22.7	31	2.3	7	1.3
Gas	2	0.1				
Dry(1)					1	1.0
Total development wells	102	22.8	31	2.3	8	2.3
Exploratory wells:						
Oil	14	5.7	12	5.0	26	3.8
Gas						
Dry(1)					1	0.3
Total exploratory wells	14	5.7	12	5.0	27	4.1
Total wells	116	28.5	43	7.3	35	6.4

(1) Dry wells were drilled in conventional formations other than the Bakken.

As of December 31, 2010, there were 35 gross (14.7 net) wells awaiting completion or in the process of drilling.

Our drilling activity has increased each year since our inception. Exploration wells in 2008, 2009 and 2010 primarily focused on delineation and appraisal of the Bakken formation in our West Williston and East Nesson areas. Following our June 2009 acquisition, many operators increased the pace of development drilling in the Sanish project area, and as a result, we participated in a number of wells on a non-operated basis.

In 2008, we had a total of 2 gross (1.3 net) wells that were deemed dry wells, which were focused on conventional formations. In 2009 and 2010, we did not drill any dry wells. In our 2011 capital plan, we have and expect to continue to be focused on drilling in the Bakken and Three Forks formations.

Capital expenditure budget

In 2010, we spent $345.6 million on capital expenditures, which represented an approximate 287% increase over the $89.3 million spent during 2009. This increase was a result of (i) improved industry conditions and technology in the Bakken formation as well as increased economics in the area, (ii) an increase in total net wells drilled in 2010 and (iii) additional lease acquisitions. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and capital resources Cash flows used in investing activities.

Our total 2011 capital expenditure budget is $490 million, which consists of:

- $402 million for drilling and completing operated wells;
- $39 million for drilling and completing non-operated wells;
- $19 million for maintaining and expanding our leasehold position;
- $21 million for constructing infrastructure to support production in our core project areas; and
- $9 million for micro-seismic work, purchasing seismic data and other test work.

While we have budgeted $490 million for these purposes, the ultimate amount of capital we will expend may fluctuate materially based on market conditions and the success of our drilling results as the year progresses. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and capital resources.

Our core project areas

Williston Basin

Our operations are focused in the Williston Basin in North Dakota and Montana. While we have interests in a substantial number of wells in the Williston Basin that target several different zones, our exploration and development activities currently are concentrated in the Bakken formation. Our management team originally targeted the Williston Basin because of its oil prone nature, multiple, stacked producing horizons, substantial resource potential and management s previous professional history in the basin. The Williston Basin also has established infrastructure and access to materials and services. Regulatory delays are minimal in the Williston Basin due to fee ownership of properties, efficient state and local regulatory bodies and reasonable permitting requirements.

The entire Williston Basin is spread across North Dakota, South Dakota, Montana and parts of southern Canada. The basin produces oil and natural gas from numerous producing horizons including, but not limited to, the Bakken, Three Forks, Madison and Red River formations. Commercial oil production activities began in the Williston Basin in the 1950 s with the first well drilled in 1953. Since then, an estimated 3.8 billion barrels have been produced from the basin, primarily from conventional oil accumulations, which can be found at depths ranging from 5,000 feet to 15,000 feet. The Williston Basin is now one of the most actively drilled unconventional oil resource plays in the United States with approximately 167 rigs drilling in the basin, including 159 in North Dakota and 8 in Montana based on Anderson Reports weekly rig count dated

January 4, 2011. A report issued by the USGS in April 2008 classified these formations as the largest continuous oil accumulation ever assessed by it in the contiguous United States.

The Devonian-age Bakken formation is found within the Williston Basin underlying portions of North Dakota and Montana and is comprised of three lithologic members including the upper shale, middle Bakken and lower shale. The formation ranges up to 150 feet thick. The upper and lower shales are highly organic, thermally mature and over pressured and can act as both a source and reservoir for the oil. The middle Bakken, which varies in composition from a silty dolomite to shalely limestone or sand, also serves as a reservoir and is a critical component for commercial production. Generally, the Bakken formation is found at vertical depths of 8,500 to 11,500 feet.

Following the drilling of the first well in 1953, vertical well development of the Bakken formation occurred intermittently until 1987, when development of the upper shale using horizontal wells began to occur in the Bicentennial and Elkhorn Ranch areas. Development in the middle Bakken using horizontal wells began in 2001 with the discovery of the Elm Coulee Field. The use of horizontal drilling and improvements in completion technology has since expanded the development of the middle Bakken across a larger portion of the Williston Basin.

Generally, the reservoir rocks in the Bakken formation exhibit low porosity and permeability and require horizontal drilling and fracture stimulation technology in order to produce economically. The fracture stimulation techniques vary but most commonly utilize multi-stage mechanically diverted stimulations using un-cemented liners and packers. Completion techniques have evolved as the Bakken formation has developed, with operators generally increasing lateral length and fracture stimulation stages. Improvements in completion techniques during 2009 and 2010 increased costs by 20% to 40% on a normalized basis, but we believe they also increased estimated ultimate recoveries of hydrocarbons by over 100% across a large portion of the Williston Basin based on our results to date as well as publicly available information for other operators in the basin. Based on our geologic interpretation of the Bakken formation, the evolution of completion techniques, our own drilling results as well as the publicly available drilling results for other operators in the basin, we believe that a substantial portion of our Williston Basin acreage is prospective in the Bakken formation and that the formation is the primary target for all of the well locations in our current drilling inventory.

The Three Forks formation generally found immediately under the Bakken formation has also proven to contain productive reservoir rock that may add incremental reserves to our existing leasehold positions. The Three Forks formation typically consists of interbedded dolomites and shale with local development of a discontinuous sandy member at the top, known as the Sanish sand. The Three Forks formation is an unconventional carbonate play. Similar to the Bakken formation, the Three Forks formation has recently been exploited primarily using horizontal drilling and advanced completion techniques. Drilling in the Three Forks formation began in mid-2008 and a number of operators are currently drilling wells targeting this formation. Based on our geologic interpretation of the Three Forks formation and the evolution of completion techniques, we believe that much of our Williston Basin acreage is prospective in the Three Forks formation. However, there have been limited Three Forks tests on and around our acreage to date other than in our Sanish project area. As a result, we have not assigned drilling inventory to the Three Forks formation except for 132 gross (11.5 net) wells in our Sanish project area and one proved undeveloped well in our East Nesson project area.

Our total leasehold position in the Williston Basin as of December 31, 2010 consisted of 303,231 net acres. Our estimated net proved reserves in the Williston Basin were 39.7 MMBoe at December 31, 2010. Of our proved reserves in the Williston Basin, approximately 16.9 MMBoe were proved developed reserves, which are comprised of a combination of wells drilled to conventional reservoirs, Bakken wells drilled with older completion techniques and Bakken and Three Forks wells drilled with more recent completion techniques. Based on our results to date, we estimate that the Bakken and Three Forks wells drilled with more recent completion techniques will achieve estimated ultimate recovery rates that will in many cases more than double the ultimate recovery rates we expect from the

Bakken wells with older completion techniques. Based on publicly available information for other operators in the basin, we believe this trend towards higher recovery rates is generally consistent across the basin. Of our proved reserves, 22.8 MMBoe were proved undeveloped reserves, all of which consisted of Bakken and Three Fork wells to be drilled with recent completion techniques. We expect that all of our identified drilling locations in each of our project areas will be drilled and completed using recent completion techniques.

As of December 31, 2010, we had a total of 106.5 net operated and non-operated producing wells and 84.5 net operated producing wells in the Williston Basin. We had average daily production of 5,132 net Boe/d for the year ended December 31, 2010 in the Williston Basin. During 2010, our Bakken and Three Forks wells produced a daily average of 4,417 net Boe/d with 58.8 net producing wells on December 31, 2010. Accordingly, our 58.8 net Bakken and Three Forks wells were responsible for 85% of our average daily production during 2010. Our working interest for all producing wells averages 30% and in the wells we operate is approximately 84%. As of January 1, 2011, we were drilling or completing 35 gross (14.7 net) wells in the Williston Basin. We participated in the drilling and completion of 114 gross wells for the year ended 2010.

Currently, we estimate our capital expenditures for 2011 will be $490 million, which includes drilling 69 gross (46.8 net) horizontal operated wells, numerous non-operated wells, construction of infrastructure to support production and leasehold acquisitions. Since most of this capital is expected to be spent on horizontal drilling in the Bakken and Three Forks formations, we expect that the proportion of our production from these formations will grow in the future. Accordingly, we expect our average net production per net producing well to similarly increase in the future. By using advanced completion techniques and longer laterals, the wells in the Bakken formation in our West Williston and East Nesson project areas, which we have recently participated in, have produced at average gross oil rates of between or exceeding 350 to 700 barrels per day for the first 30 days of steady production and are expected to decline to between or exceeding 100 and 200 barrels per day after 12 months of production. We believe that this production profile is comparable to that realized in other areas of the Williston Basin with similar geological characteristics and completion techniques.

Our Williston Basin activities are evaluated in three primary areas of operations: the West Williston area, the East Nesson area and the Sanish area.

West Williston

The West Williston project area was our first area of operations and was established through an asset acquisition from Bill Barrett Corporation in June 2007. We control 191,716 net acres in the area, primarily in Williams and McKenzie counties in North Dakota and Roosevelt and Richland counties in Montana.

We had average daily production of 2,070 net Boe/d for the year ended December 31, 2010, 66% of which was produced from the Bakken formation and the remainder from other conventional formations. As of December 31, 2010, we had an average working interest of 42% and operated 87% of our 67.6 net producing wells in the West Williston project area. Additionally, as of December 31, 2010, we had 859 gross (393.1 net) identified drilling locations based on mostly 1280-acre spacing units, of which 66% gross (93% net) are estimated to be operated by us, targeting the Bakken formation in the West Williston project area.

During the year ended December 31, 2010, we participated in the drilling and completion of 28 gross (13.7 net) horizontal Bakken wells in the West Williston project area. As of January 1, 2011, we were participating in drilling or completion of 18 gross (12.2 net) wells in the West Williston project area. We have budgeted $365.6 million in capital expenditures in the West Williston project area in 2011 for the drilling and completion of 77 gross (43.6 net) wells.

East Nesson

We expanded into the East Nesson project area through a farm-in transaction in May 2008 with Fidelity Exploration and Production Company and Kerogen Resources, Inc. We subsequently increased our working interests in the area through the acquisitions of assets from Kerogen Resources, Inc. and additional working interests from Fidelity Exploration in June 2009 and September 2009, respectively. We control 102,786 net acres in the area, primarily in Mountrail and Burke counties in North Dakota.

We had average daily production of 1,643 net Boe/d for the year ended December 31, 2010, all of which was produced from the Bakken and Three Forks formations. As of December 31, 2010, we had an average working interest of 44% and operated 88% of our 29.3 net producing wells in the East Nesson project area. Additionally, as of December 31, 2010, we had 255 gross (127.6 net) identified drilling locations based almost entirely on 1280-acre spacing units, 80% gross (94% net) of which are estimated to be operated by us, all targeting the Bakken formation in the East Nesson project area, except for one proved undeveloped well targeting the Three Forks formation.

During the year ended December 31, 2010, we drilled and completed 22 gross (10.2 net) horizontal Bakken and Three Forks wells in the East Nesson project area. As of January 1, 2011, we were drilling or completing 5 gross (1.7 net) wells in the East Nesson project area. We have budgeted $51.4 million in capital expenditures in the East Nesson project area in 2011 for the drilling and completion of 16 gross (5.6 net) wells.

Sanish

We expanded into the Sanish project area through the acquisition of assets from Kerogen Resources, Inc. in June 2009. We control 8,729 net acres in the area, all of which are located in Mountrail county in North Dakota.

We had average daily production of 1,419 net Boe/d for the year ended December 31, 2010, all of which was produced from the Bakken and Three Forks formations. As of December 31, 2010, we had an average working interest of 8% in our 9.6 net wells in the Sanish project area. Additionally, as of December 31, 2010, we had 189 gross (16.6 net) identified drilling locations targeting the Bakken and Three Forks formations in the Sanish project area. Our properties in the Sanish project area are entirely operated by other operators, the largest of which are Whiting Petroleum Corporation and Fidelity Exploration.

During the year ended December 31, 2010, we participated in the drilling and completion of 62 gross (4.4 net) horizontal Bakken and Three Forks wells in the Sanish project area. As of January 1, 2011, we were participating in the drilling or completion of 12 gross (0.8 net) wells in the Sanish project area. We have budgeted $24.0 million in capital expenditures in the Sanish project area in 2011 for the drilling and completion of 60 gross (3.9 net) wells.

For more information on our reserves, operations and operating areas, please see Our operations.

Other operating areas

Barnett Shale

As part of the Kerogen Resources asset acquisition in June 2009, we acquired approximately 3,000 net acres with then-current net production of approximately 140 Boe/d in the Barnett shale play in Texas. In December 2009, we sold a portion of these wells and acreage. As of December 31, 2010, our estimated proved reserves in the Barnett shale were approximately 111 MBoe, representing less than 1% of our PV-10, and produced an average of 74 Boe/d for the year ended December 31, 2010. We do not consider the Barnett shale a focus area and we do not currently plan any development activities in the area.

Management experience with resource conversion plays and horizontal drilling techniques

Our senior management team has extensive expertise in the oil and gas industry as previous members of management at Burlington Resources. Our senior technical team has an average of more than 25 years of industry experience, including experience in multiple North American resource plays as well as experience in other North American and international basins. Specifically, our Chief Executive Officer, Chief Operating Officer and other executive officers were involved in the acquisition, operation or execution of a number of successful resource conversion plays, including Fruitland Coal, a coalbed methane development located in the San Juan Basin; Cedar Hills, a horizontal drilling development located in the Williston Basin; the Upper Bakken Shale, a horizontal drilling and development play located in the Williston Basin; tight gas sands developments in the San Juan Basin and Sichuan Basin; a basin-centered-gas resource conversion project

Table of Contents

located in the Western Canadian Sedimentary Basin; acquisitions of producing property and acreage in the Barnett Shale located in the Fort Worth Basin; and a coalbed methane development located in the Black Warrior Basin.

In addition, our senior management team possesses substantial expertise in horizontal drilling techniques and managing and acquiring large development programs, and also has prior experience in the Williston Basin, primarily while at Burlington Resources or its predecessors. At the time various members of our management team were at Burlington Resources, Burlington Resources was a significant lease and mineral holder in the Williston Basin. For example, Mr. Reid, our Chief Operating Officer, served in positions of varying responsibility including drilling engineer, drilling rig supervisor, asset manager and production superintendent with Burlington Resources in its Williston Basin operations over a six-year period from 1991 to 1997. Additionally, Mr. Beers, our Senior Vice President Land, held various land managerial positions in the Williston Basin for a ten-year period and Mr. Candito, our Senior Vice President Exploration, was a district geologist in the Williston Basin for a four-year period. While at Burlington Resources, various members of our management team also utilized horizontal drilling techniques extensively to develop reserves in multiple horizons. Much of Burlington Resources horizontal drilling activity during this period was in the Upper Bakken Black Shale and the Red River B horizons in the Williston Basin, where it drilled over 300 horizontal wells through the end of 1998.

Marketing and major customers

We principally sell our oil and natural gas production to marketers and other purchasers that have access to nearby pipeline facilities. In areas where there is no practical access to pipelines, oil is transported by truck to storage facilities. Our marketing of oil and natural gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted. For a description of some of these factors, please see Item 1A. Risk Factors Risks related to the oil and natural gas industry and our business Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production and Risk Factors Risks related to the oil and natural gas industry and our business Insufficient transportation or refining capacity in the Williston Basin could cause significant fluctuations in our realized oil and natural gas prices.

In an effort to improve price realizations from the sale of our oil and natural gas, we manage our commodities marketing activities in-house, which enables us to market and sell our oil and natural gas to a broader array of potential purchasers. Due to the availability of other markets and pipeline connections, we do not believe that the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations or cash flows.

For the year ended December 31, 2010, sales to Plains All American Pipeline, L.P., Texon L.P. and Whiting Petroleum Corporation accounted for approximately 28%, 19% and 11%, respectively, of our total sales. For the year ended December 31, 2009, sales to Tesoro Refining and Marketing Company and Texon L.P. accounted for approximately 32% and 30%, respectively, of our total sales. For the year ended December 31, 2008, sales to Tesoro Refining and Marketing Company and Texon L.P. accounted for approximately 57% and 14%, respectively, of our total sales. No other purchasers accounted for more than 10% of our total oil and natural gas sales for the years ended December 31, 2010, 2009 and 2008. We believe that the loss of any of these purchasers would not have a material adverse effect on our operations, as there are a number of alternative crude oil and natural gas purchasers in our producing regions.

We sell a substantial majority of our oil and condensate directly at the wellhead to a variety of purchasers at prevailing market prices under short-term contracts that normally provide for us to receive a market-based price, which incorporates regional differentials that include, but are not limited to, transportation costs and adjustments for product quality. Crude oil produced and sold in the Williston Basin has historically sold at a discount to the price quoted for West Texas Intermediate (WTI) crude oil due to transportation costs and takeaway capacity. In the past, there have been periods when this discount has substantially increased due to the production of oil in the area increasing to a point that it temporarily surpasses the available pipeline transportation and refining capacity in the area. The last such period was the fall and winter of 2008 and 2009, when the Tesoro Refining and Marketing Company North Dakota Sweet discount to WTI on an average monthly basis reached $14.80/Bbl.

Since most of our oil and natural gas production is sold under market-based or spot market contracts, the revenues generated by our operations are highly dependent upon the prices of and demand for oil and natural gas. The price we receive for our oil and natural gas production depends upon numerous factors beyond our control, including but not limited to seasonality, weather, competition, availability of transportation and gathering capabilities, the condition of the United States economy, foreign imports, political conditions in other oil-producing and natural gas-producing regions, the actions of the Organization of Petroleum Exporting Countries, or OPEC, and domestic government regulation, legislation and policies. Please see Risk Factors Risks related to the oil and natural gas industry and our business A substantial or extended decline in oil and, to a lesser extent, natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments. Furthermore, a decrease in the price of oil and natural gas could have an adverse effect on the carrying value of our proved reserves and on our revenues, profitability and cash flows. Please see Item 1A. Risk Factors Risks related to the oil and natural gas industry and our business If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas properties.

Although we are not currently experiencing any significant involuntary curtailment of our oil or natural gas production, market, economic, transportation and regulatory factors may in the future materially affect our ability to market our oil or natural gas production. Please see Item 1A. Risk Factors Risks related to the oil and natural gas industry and our business Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

Competition

The oil and natural gas industry is highly competitive in all phases. We encounter competition from other oil and natural gas companies in all areas of operation, including the acquisition of leasing options on oil and natural gas properties to the exploration and development of those properties. Our competitors include major integrated oil and natural gas companies, numerous independent oil and natural gas companies, individuals and drilling and income programs. Many of our competitors are large, well established companies that have substantially larger operating staffs and greater capital resources than we do. Such companies may be able to pay more for lease options on oil and natural gas properties and exploratory locations and to define, evaluate, bid for and purchase a greater number of properties and locations than our financial or human resources permit. Our ability to acquire additional properties and to discover reserves in the future will depend upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Please see Item 1A. Risk Factors Risks related to the oil and natural gas industry and our business Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel.

Title to properties

As is customary in the oil and gas industry, we initially conduct a preliminary review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and gas industry. Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of the properties, we may obtain a title opinion or review previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens to secure borrowings under our revolving credit facility, liens for current taxes and other burdens which we believe do not materially interfere with the use or affect our carrying value of the properties. Please see Item 1A. Risk Factors Risks related to the oil and natural gas industry and our business We may incur losses as a result of title defects in the properties in which we invest.

Seasonality

Winter weather conditions and lease stipulations can limit or temporarily halt our drilling and producing activities and other oil and natural gas operations. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operating and capital costs. Such seasonal anomalies can also pose challenges for meeting our well drilling objectives and may increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay or temporarily halt our operations.

Regulation of the oil and natural gas industry

Our operations are substantially affected by federal, state and local laws and regulations. In particular, oil and natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate properties for oil and natural gas production have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of oil and natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations, such laws and regulations are frequently amended or reinterpreted. Additionally, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission, or FERC, and the courts. We cannot predict when or whether any such proposals may become effective.

Regulation of transportation of oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil by common carrier pipelines is also subject to rate and access regulation. The FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil pipelines that allows a pipeline to increase its rates annually up to a prescribed ceiling, without making a cost of service filing. Every five years, the FERC reviews the appropriateness of the index level in relation to changes in industry costs. Most recently, on December 16, 2010, the FERC established a new price index for the five-year period beginning July 1, 2011.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is generally governed by prorationing provisions set forth in the pipelines published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

Regulation of transportation and sales of natural gas

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by the FERC under the Natural Gas Act of 1938, or NGA, the Natural Gas Policy Act of 1978, or NGPA, and regulations issued under those statutes. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed all price controls affecting wellhead sales of natural gas effective January 1, 1993.

FERC regulates interstate natural gas transportation rates, and terms and conditions of service, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, the FERC issued a series of orders, beginning with Order No. 636, to implement its open access policies. As a result, the interstate pipelines traditional role of providing the sale and transportation of natural gas as a single service has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although the FERC s orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised the FERC s pricing policy by waiving price ceilings for short-term released capacity for a two-year experimental period, and effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting.

The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by the FERC under Order No. 637 will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

The price at which we sell natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical sales of these energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC and/or the Commodity Futures Trading Commission, or the CFTC, and the Federal Trade Commission, or FTC. Please see below the discussion of

Other federal laws and regulations affecting our industry Energy Policy Act of 2005. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities. In addition, pursuant to Order No. 704, some of our operations may be required to annually report to FERC on May 1 of each year for the previous calendar year. Order No. 704 requires certain natural gas market participants to report information regarding their reporting of transactions to price index publishers and their blanket sales certificate status, as well as certain information regarding their wholesale, physical natural gas transactions for the previous calendar year depending on the volume of natural gas transacted. Please see below the discussion of Other federal laws and regulations affecting our industry FERC Market Transparency Rules.

Gathering services, which occur upstream of FERC jurisdictional transmission services, are regulated by the states onshore and in state waters. Although the FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, the FERC s determinations as to the classification of facilities is done on a case by case basis. State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Intrastate natural gas transportation and facilities are also subject to regulation by state regulatory agencies, and certain transportation services provided by intrastate pipelines are also regulated by FERC. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Regulation of production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Other federal laws and regulations affecting our industry

Energy Policy Act of 2005. On August 8, 2005, President Bush signed into law the Energy Policy Act of 2005, or the EPAct 2005. EPAct 2005 is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, EPAct 2005 amends the NGA to add an anti-manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. EPAct 2005 provides the FERC with the power to assess civil penalties of up to $1,000,000 per day for violations of the NGA and increases the FERC s civil penalty authority under the NGPA from $5,000 per violation per day to $1,000,000 per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-manipulation provision of EPAct 2005, and subsequently denied rehearing. The rule makes it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, (1) to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act, practice, or course of business that operates as a fraud or deceit upon any person. The new anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but do apply to activities of gas pipelines and storage companies that provide interstate services, such as Section 311 service, as well as otherwise non-jurisdictional entities to the extent the activities are conducted in connection with gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order No. 704. The anti-manipulation rules and enhanced civil penalty authority reflect an expansion of FERC s NGA enforcement authority. Should we fail to comply with all applicable FERC administered statutes, rules, regulations, and orders, we could be subject to substantial penalties and fines.

FERC Market Transparency Rules. On December 26, 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing, or Order No. 704. Under Order No. 704, wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors, natural gas marketers and natural gas producers, are required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC s policy statement on price reporting.

Effective November 4, 2009, pursuant to the Energy Independence and Security Act of 2007, the FTC issued a rule prohibiting market manipulation in the petroleum industry. The FTC rule prohibits any person, directly or indirectly, in connection with the purchase or sale of crude oil, gasoline or petroleum distillates at wholesale from: (a) knowingly engaging in any act, practice or course of business, including the making of any untrue statement of material fact, that operates or would operate as a fraud or deceit upon any person; or (b) intentionally failing to state a material fact that under the circumstances renders a statement made by such person misleading, provided that such omission distorts or is likely to distort market conditions for any such product. A violation of this rule may result in civil penalties of up to $1 million per day per violation, in addition to any applicable penalty under the Federal Trade Commission Act.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such action materially differently than similarly situated competitors.

Environmental, health and safety regulation

Our exploration, development and production operations are subject to various federal, regional, state and local laws and regulations governing occupational health and safety, the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may, among other things, require the acquisition of permits to conduct exploration, drilling and production operations; govern the amounts and types of substances that may be released into the environment; limit or prohibit construction or drilling activities in sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered species; require investigatory and remedial actions to mitigate pollution conditions; impose obligations to reclaim and abandon well sites and pits; and impose specific criteria addressing worker protection. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of orders enjoining some or all of our operations in affected areas. These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability.

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in federal or state environmental laws and regulations or re-interpretation of applicable enforcement policies that result in more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations and financial position. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third party claims for damage to property, natural resources or persons. While we believe that we are in substantial compliance with existing environmental laws and regulations and that continued compliance with current requirements would not have a material adverse effect on our financial condition or results of operations, there is no assurance that this trend will continue in the future.

The following is a summary of the more significant existing environmental, health and safety laws and regulations to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous substances and waste

The Comprehensive Environmental Response, Compensation, and Liability Act, as amended, or CERCLA, also known as the Superfund law and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These classes of persons include current and prior owners or operators of the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these responsible persons may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants into the environment. We generate materials in the course of our operations that may be regulated as hazardous substances.

We also are subject to the requirements of the Resource Conservation and Recovery Act, as amended, or RCRA, and comparable state statutes. RCRA imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. In the course of our operations we generate petroleum hydrocarbon wastes and ordinary industrial wastes that may be regulated as hazardous wastes.

We currently own or lease, and have in the past owned or leased, properties that have been used for numerous years to explore and produce oil and natural gas. Although we have utilized operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons and wastes may have been disposed of or released on or under the properties owned or leased by us or on or under other locations where these petroleum hydrocarbons and wastes have been taken for treatment or disposal. In addition, certain of these properties have been operated by the third parties whose treatment and disposal or release of petroleum hydrocarbons and wastes was not under our control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) and to perform remedial operations to prevent future contamination.

Air emissions

The Clean Air Act, as amended, and comparable state laws and regulations restrict the emission of air pollutants from many sources and also impose various monitoring and reporting requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. Obtaining permits has the potential to delay the development of oil and natural gas projects. While we may be required to incur certain capital expenditures in the next few years for air pollution control equipment or other air emissions-related issues, we do not believe that such requirements will have a material adverse effect on our operations.

Climate change

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases, or GHGs, present an endangerment to public health and the environment because emissions of such gases are contributing to warming of the earth s atmosphere and other climatic changes, the U.S Environmental Protection Agency, or EPA, adopted regulations under existing provisions of the federal Clean Air Act that require a reduction in emissions of GHGs from motor vehicles, effective January 2, 2011, and thereby triggered construction and operating permit requirements for GHG emissions from stationary sources. The EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration, or PSD, and Title V permitting programs, pursuant to which these permitting programs have been tailored to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet best available control technology standards, which will be established by the states or, in some instances, by the EPA on a case-by-case basis. The EPA s rules relating to emissions of GHGs from large stationary sources of emissions are currently subject to a number of legal challenges but the federal courts have thus far declined to issue any injunctions to prevent EPA from implementing or requiring state environmental agencies to implement the rules. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities. With regards to the monitoring and reporting of GHGs, on November 30, 2010, the EPA published a final rule expanding its existing GHG emissions reporting rule published in October 2009 to include onshore oil and natural gas production activities, which includes certain of our operations. In addition, Congress has from time to time considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. The adoption and implementation of any legislation or regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic event; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

Water discharges

The Federal Water Pollution Control Act, as amended, or the Clean Water Act, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters. Pursuant to the Clean Water Act and analogous state laws, permits must be obtained to discharge pollutants into state waters or waters of the U.S. Any such discharge of pollutants into regulated waters must be performed in accordance with the terms of the permit issued by the EPA or the analogous state agency. Spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities.

Table of Contents

The Oil Pollution Act of 1990, as amended, or the OPA, which amends the Clean Water Act, establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the U.S. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A responsible party under the OPA includes owners and operators of certain onshore facilities from which a release may affect waters of the U.S.

Endangered Species Act

The federal Endangered Species Act, as amended, or the ESA, restricts activities that may affect endangered and threatened species or their habitats. While some of our facilities may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Employee health and safety

We are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, as amended, or the OSHA, and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Hydraulic fracturing activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from unconventional formations, including shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. However, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the federal Safe Drinking Water Act s Underground Injection Program. While the EPA has yet to take any action to enforce or implement this newly asserted regulatory authority, industry groups have filed suit challenging the EPA s recent decision. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with results of the study anticipated to be available by late 2012, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. In addition, legislation was proposed in the recently ended session of Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process, and such legislation could be introduced in the current session of Congress. Also, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances or otherwise require the public disclosure of chemicals used in the hydraulic fracturing process. For example, Wyoming has adopted legislation requiring drilling operators conducting hydraulic fracturing activities in that state to publicly disclose the chemicals used in the hydraulic fracturing process. If new federal or state laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

Employees

As of December 31, 2010, we employed 62 people, including 7 employees in geology, 23 in operations and engineering, and 15 in accounting and finance. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and

Table of Contents

have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory. From time to time we utilize the services of independent contractors to perform various field and other services.

Offices

As of December 31, 2010, we leased 26,816 square feet of office space in Houston, Texas at 1001 Fannin, Suite 1500, where our principal offices are located. On January 12, 2011, we executed a lease amendment for 11,638 square feet of additional office space. The lease for our Houston office expires in September 2017. We also have a lease for a field office in Williston, North Dakota.

Available information

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any documents filed by us with the SEC at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Our filings with the SEC are also available to the public from commercial document retrieval services and at the SEC s website at http://www.sec.gov.

Our common stock is listed and traded on the New York Stock Exchange under the symbol OAS. Our reports, proxy statements and other information filed with the SEC can also be inspected and copied at the New York Stock Exchange, 20 Broad Street, New York, New York 10005.

We also make available on our website at http://www.oasispetroleum.com all of the documents that we file with the SEC, free of charge, as soon as reasonably practicable after we electronically file such material with the SEC. Information contained on our website, other than the documents listed below, is not incorporated by reference into this Annual Report on Form 10-K.

Item 1A. ***Risk Factors***

Our business involves a high degree of risk. If any of the following risks, or any risk described elsewhere in this Annual Report on Form 10-K, actually occurs, our business, financial condition or results of operations could suffer. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we currently consider immaterial also may adversely affect us.

Risks related to the oil and natural gas industry and our business

A substantial or extended decline in oil and, to a lesser extent, natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil and, to a lesser extent, natural gas, heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil and natural gas;

the actions of OPEC;

the price and quantity of imports of foreign oil and natural gas;

political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and conditions in South America and Russia;

the level of global oil and natural gas exploration and production;

- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals and transportation availability;
- weather conditions and natural disasters;
- domestic and foreign governmental regulations;
- speculation as to the future price of oil and the speculative trading of oil and natural gas futures contracts;
- price and availability of competitors supplies of oil and natural gas;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Substantially all of our production is sold to purchasers under short-term (less than 12-month) contracts at market based prices. Lower oil and natural gas prices will reduce our cash flows, borrowing ability and the present value of our reserves. See Our exploration, development and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to expiration of our leases or a decline in our oil and natural gas reserves. Lower oil and natural gas prices may also reduce the amount of oil and natural gas that we can produce economically and may affect our proved reserves. See also The present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves below.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit drilling locations or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves below. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- shortages of or delays in obtaining equipment and qualified personnel;
- facility or equipment malfunctions;
- unexpected operational events;
- pressure or irregularities in geological formations;

adverse weather conditions, such as blizzards and ice storms;

reductions in oil and natural gas prices;

delays imposed by or resulting from compliance with regulatory requirements;

proximity to and capacity of transportation facilities;

title problems; and

limitations in the market for oil and natural gas.

Table of Contents

Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10-K. See Business Our operations for information about our estimated oil and natural gas reserves and the PV-10 and Standardized Measure of discounted future net revenues as of December 31, 2010, 2009 and 2008.

In order to prepare our estimates, we must project production rates and the timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Although the reserve information contained herein is reviewed by independent reserve engineers, estimates of oil and natural gas reserves are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10-K. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control. Due to the limited production history of our undeveloped acreage, the estimates of future production associated with such properties may be subject to greater variance to actual production than would be the case with properties having a longer production history.

The present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves.

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with new SEC requirements for the years ended December 31, 2010 and 2009, we based the estimated discounted future net revenues from our proved reserves on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months without giving effect to derivative transactions. For the year ended December 31, 2008, we based the estimated discounted future net revenues from our proved reserves on prices and costs in effect on the day of the estimate in accordance with previous SEC requirements. Actual future net revenues from our oil and natural gas properties will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual cost of development and production expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

Actual future prices and costs may differ materially from those used in the present value estimates included in this Annual Report on Form 10-K. If oil prices decline by $1.00/Bbl, then our PV-10 as of December 31, 2010 would decrease approximately $15.9 million.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

Shortages or the high cost of drilling rigs, equipment, supplies, personnel or oilfield services could delay or adversely affect our development and exploration operations or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

Part of our strategy involves drilling in existing or emerging shale plays using some of the latest available horizontal drilling and completion techniques. The results of our planned exploratory drilling in these plays are subject to drilling and completion technique risks and drilling results may not meet our expectations for reserves or production. As a result, we may incur material write-downs and the value of our undeveloped acreage could decline if drilling results are unsuccessful.

Operations in the Bakken and the Three Forks formations involve utilizing the latest drilling and completion techniques as developed by us and our service providers in order to maximize cumulative recoveries and therefore generate the highest possible returns. Risks that we face while drilling include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we face while completing our wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage.

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

Our exploration, development and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to expiration of our leases or a decline in our oil and natural gas reserves.

Our exploration and development activities are capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development, exploitation, production and acquisition of oil and natural gas reserves. Our cash flows used in investing activities were $312.9 million and $82.6 million (including $86.4 million and $35.2 million for the acquisition of oil and gas properties) related to capital and exploration expenditures for the years ended December 31, 2010 and 2009, respectively. Our capital expenditure budget for 2011 is approximately $490 million, with approximately $441 million allocated for drilling and completion operations. Since our IPO, our capital expenditures have been financed with proceeds from our IPO, net cash provided by operating activities and proceeds from our private placement of $400 million of 7.25% senior unsecured notes. DeGolyer and MacNaughton projects that we will incur capital costs in excess of $349 million over the next four years to develop the proved undeveloped reserves in the Williston Basin covered by its December 31, 2010 reserve report. Because these costs cover less than 10% of our total drilling locations, we will be required to generate or raise multiples of this amount of capital to develop all of our potential drilling locations should we elect to do so. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

A significant improvement in product prices could result in an increase in our capital expenditures. We intend to finance our future capital expenditures primarily through cash flows provided by operating activities, borrowings under our revolving credit facility and net proceeds from our private placement of $400 million of 7.25% senior unsecured notes; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of additional debt or equity securities or the sale of non-strategic assets. The issuance of additional debt or equity may require that a portion of our cash flows provided by operating activities be used for the payment of principal and interest on our debt, thereby reducing our ability to use cash flows to fund working capital, capital expenditures and acquisitions. The issuance of additional equity securities could have a dilutive effect on the value of our common stock. In addition, upon the issuance of certain debt securities (other than on a borrowing base redetermination date), our borrowing base under our revolving credit facility will be automatically reduced by an amount equal to 25% of the aggregate principal amount of such debt securities.

Our cash flows provided by operating activities and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- the prices at which our oil and natural gas are sold;
- the costs of developing and producing our oil and natural gas production;
- our ability to acquire, locate and produce new reserves;
- the ability and willingness of our banks to lend; and
- our ability to access the equity and debt capital markets.

If the borrowing base under our revolving credit facility or our revenues decrease as a result of lower oil or natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or cash available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our drilling locations, which in turn could lead to a possible expiration of our leases and a decline in our oil and natural gas reserves, and could adversely affect our business, financial condition and results of operations.

If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas properties.

We review our proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties, which may result in a decrease in the amount available under our revolving credit facility. A write-down constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our ability to borrow under our revolving credit facility and our results of operations for the periods in which such charges are taken.

We will not be the operator on all of our drilling locations, and, therefore, we will not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of any non-operated assets.

We expect that we will not be the operator on approximately 41% of our identified gross drilling locations (approximately 10% of our identified net drilling locations). As we carry out our exploration and development programs, we may enter into arrangements with respect to existing or future drilling locations that result in a greater proportion of our locations being operated by others. As a result, we may have limited ability to exercise influence over the operations of the drilling locations operated by our partners. Dependence on the operator could prevent us from realizing our target returns for those locations. The success and timing of exploration and development activities operated by our partners will depend on a number of factors that will be largely outside of our control, including:

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

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

Substantially all of our producing properties and operations are located in the Williston Basin region, making us vulnerable to risks associated with operating in one major geographic area.

As of December 31, 2010, approximately 99.7% of our proved reserves and approximately 98.6% of our production were located in the Williston Basin in northeastern Montana and northwestern North Dakota. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production from these wells caused by transportation capacity constraints, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions, plant closures for scheduled maintenance or interruption of transportation of oil or natural gas produced from the wells in this area. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and gas producing areas such as the Williston Basin, which may cause these conditions to occur with greater frequency or magnify the effect of these conditions. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

Our business depends on oil and natural gas gathering and transportation facilities, most of which are owned by third parties.

The marketability of our oil and natural gas production depends in part on the availability, proximity and capacity of gathering and pipeline systems owned by third parties. The unavailability of, or lack of, available capacity on these systems and facilities could result in the shut-in of producing wells or the delay, or discontinuance of, development plans for properties. See also Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production and Insufficient transportation or refining capacity in the Williston Basin could cause significant fluctuations in our realized oil and natural gas prices. We generally do not purchase firm transportation on third party pipeline facilities and, therefore, the transportation of our production can be interrupted by other customers that have firm arrangements.

The disruption of third-party facilities due to maintenance, weather or other interruptions of service could also negatively impact our ability to market and deliver our products. We have no control over when or if such facilities are restored. A total shut-in of our production could materially affect us due to a resulting lack of cash flow, and if a substantial portion of the production is hedged at lower than market prices, those financial hedges would have to be paid from borrowings absent sufficient cash flow.

Insufficient transportation or refining capacity in the Williston Basin could cause significant fluctuations in our realized oil and natural gas prices.

The Williston Basin crude oil business environment has historically been characterized by periods when oil production has surpassed local transportation and refining capacity, resulting in substantial discounts in the price received for crude oil versus prices quoted for West Texas Intermediate (WTI) crude oil. For example, the difference between the WTI crude oil price and the Flint Hills Resources North Dakota Sweet oil price as of December 31, 2009 and 2010 was $7.96/Bbl and $8.38/Bbl, respectively. Although additional Williston Basin transportation takeaway capacity was added in 2009 and 2010, production has also increased due to the elevated drilling activity in 2010. The increased production coupled with the planned turnaround at the Tesoro Corporation Mandan refinery and outages and disruptions on Enbridge s 6A and 6B lines caused price differentials at times to be at the high-end of the historical average range of approximately 10% to 15% of the WTI crude oil index price in 2010. Such fluctuations and discounts could have a material adverse effect on our financial condition and results of operations.

The development of our proved undeveloped reserves in the Williston Basin and other areas of operation may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our undeveloped reserves may not be ultimately developed or produced.

Approximately 57% of our total proved reserves were classified as proved undeveloped as of December 31, 2010. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved reserves as unproved reserves.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our business, financial condition and results of operations.

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flows and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire additional reserves to replace our current and future production at acceptable costs. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends, in substantial part, on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third-parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of crude oil or natural gas pipelines or gathering system capacity. If our production becomes shut-in for any of these or other reasons, we would be unable to realize revenue from those wells until other arrangements were made to deliver the products to market.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Drilling locations that we decide to drill may not yield oil or natural gas in commercially viable quantities.

We describe some of our drilling locations and our plans to explore those drilling locations in this Annual Report on Form 10-K. Our drilling locations are in various stages of evaluation, ranging from a location which is ready to drill to a location that will require substantial additional interpretation. There is no way to predict in advance of drilling and testing whether any particular location will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. If we drill additional wells that we identify as dry holes in our current and future drilling locations, our drilling success rate may decline and materially harm our business. We cannot assure you that the analogies we draw from available data from other wells, more fully explored locations or producing fields will be applicable to our drilling locations. Further, initial production rates reported by us or other operators in the Williston Basin may not be indicative of future or long-term production rates. In sum, the cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive.

We have incurred losses since our inception and may continue to do so in the future.

We incurred net losses of $29.7 million, $15.2 million and $34.4 million for the years ended December 31, 2010, 2009 and 2008, respectively. Our development of and participation in an increasingly larger number of drilling locations has required and will continue to require substantial capital expenditures, including planned capital expenditures for 2011 of approximately $490 million.

The uncertainty and risks described in this Annual Report on Form 10-K may impede our ability to economically find, develop, exploit and acquire oil and natural gas reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows provided by operating activities in the future.

Our potential drilling location inventories are scheduled to be drilled over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill a substantial portion of our potential drilling locations.

Our management has identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. As of December 31, 2010, only 124 of our 1,303 specifically identified potential future gross drilling locations were attributed to proved undeveloped reserves. These potential drilling locations, including those without proved undeveloped reserves, represent a significant part of our growth strategy. Our ability to drill and develop these locations is subject to a number of uncertainties, including the availability of capital, seasonal conditions, regulatory approvals, oil and natural gas prices, costs and drilling results. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. Pursuant to existing SEC rules and guidance, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. These rules and guidance may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program.

Our acreage must be drilled before lease expiration, generally within three to five years, in order to hold the acreage by production. In the highly competitive market for acreage, failure to drill sufficient wells in order to hold acreage will result in a substantial lease renewal cost, or if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire. As of December 31, 2010, we had leases representing 53,937 net acres expiring in 2011, 23,994 net acres expiring in 2012 and 42,147 net acres expiring in 2013. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. In addition, on certain portions of our acreage, third-party leases become immediately effective if our leases expire. As such, our actual drilling activities may materially differ from our current expectations, which could adversely affect our business. During the years ended December 31, 2010, 2009 and 2008, we recorded non-cash impairment charges of $12.0 million, $5.4 million and $1.6 million, respectively, for unproved property leases that expired during the period.

Our operations are subject to environmental and occupational health and safety laws and regulations that may expose us to significant costs and liabilities.

Our oil and natural gas exploration and production operations are subject to stringent and complex federal, state and local laws and regulations governing health and safety aspects of our operations, the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations that are applicable to our operations including the acquisition of a permit before conducting drilling or underground injection activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from operations. Numerous governmental authorities, such as the U.S. Environmental Protection Agency, or the EPA, and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties; the imposition of investigatory or remedial obligations; and the issuance of injunctions limiting or preventing some or all of our operations.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations as a result of our handling of petroleum hydrocarbons and wastes, air emissions and waste water discharges related to our operations, and historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we could be subject to joint and several, strict liability for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or contamination or if the operations were in compliance with all applicable laws at the time those actions were taken. Private parties, including the owners of properties upon which our wells are drilled and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. In addition, the risk of accidental spills or releases could expose us to significant liabilities that could have a material adverse effect on our financial condition or results of operations. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our own results of operations, competitive position or financial condition. We may not be able to recover some or any of these costs from insurance.

Failure to comply with federal, state and local laws could adversely affect our ability to produce, gather and transport our oil and natural gas and may result in substantial penalties.

Our operations are substantially affected by federal, state and local laws and regulations, particularly as they relate to the regulation of oil and natural gas production and transportation. These laws and regulations include regulation of oil and natural gas exploration and production and related operations, including a variety of activities related to the drilling of wells, the interstate transportation of oil and natural gas by federal agencies such as the FERC, as well as state agencies. In addition, federal laws prohibit market manipulation in connection with the purchase or sale of oil and/or natural gas. Failure to comply with federal, state and local laws could adversely affect our ability to produce, gather and transport our oil and natural gas and may result in substantial penalties. Please see Other federal laws and regulations affecting our industry.

Climate change laws and regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas that we produce while the physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases, or GHGs, present an endangerment to public health and the environment because emissions of such gases are contributing to warming of the earth s atmosphere and other climatic changes, the EPA adopted regulations under existing provisions of the federal Clean Air Act that require a reduction in emissions of GHGs from motor vehicles effective January 2, 2011 and thereby triggered permit review for GHG emissions from certain stationary sources. The EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration, or PSD, and Title V permitting programs. This rule tailors these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet best available control technology standards, which will be established by the states or, in some instances, by the EPA on a case-by-case basis. The EPA s rules relating to emissions of GHGs from large stationary sources of emissions are currently subject to a number of legal challenges but the federal courts have thus far declined to issue any injunctions to prevent EPA from implementing or requiring state environmental agencies to implement the rules. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities. With regards to the monitoring and reporting of GHGs, on November 30, 2010, the EPA published a final rule expanding its existing GHG emissions reporting rule published in October 2009 to include onshore oil and natural gas production activities, which includes certain of our operations. In addition, Congress has from time to time considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. The adoption and implementation of any legislation or regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic event; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. Nonetheless, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with results of the study anticipated to be available by late 2012, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. In addition, legislation was proposed in the recently completed session of Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process and similar legislation could be introduced in the current session of Congress. Also, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. However, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the federal Safe Drinking Water Act s Underground Injection Program. While the EPA has yet to take any action to enforce or implement this newly asserted regulatory authority, industry groups have filed suit challenging the EPA s recent decision. At the same time, if new federal or state laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel.

Our ability to acquire additional drilling locations and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing equipment and trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive oil and natural gas properties and exploratory drilling locations or to identify, evaluate, bid for and purchase a greater number of properties and locations than our financial or personnel resources permit. Furthermore, these companies may also be better able to withstand the financial pressures of unsuccessful drilling attempts, sustained periods of volatility in financial markets and generally adverse global and industry-wide economic conditions, and may be better able to absorb the burdens resulting from changes in relevant laws and regulations, which would adversely affect our competitive position. In addition, companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past few years due to competition and may increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

The loss of senior management or technical personnel could adversely affect our operations.

To a large extent, we depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including Thomas B. Nusz, our Chairman, President and Chief Executive Officer, and Taylor L. Reid, our Executive Vice President and Chief Operating Officer, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

Seasonal weather conditions adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and natural gas operations in the Williston Basin are adversely affected by seasonal weather conditions. In the Williston Basin, drilling and other oil and natural gas activities cannot be conducted as effectively during the winter months. Severe winter weather conditions limit and may temporarily halt our ability to operate during such conditions. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operating and capital costs.

Our derivative activities could result in financial losses or could reduce our income.

To achieve more predictable cash flows and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we currently, and may in the future, enter into derivative arrangements for a portion of our oil and natural gas production, including collars and fixed-price swaps. We have not designated any of our derivative instruments as hedges for accounting purposes and record all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Derivative arrangements also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contract obligations; or
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received.

In addition, these types of derivative arrangements limit the benefit we would receive from increases in the prices for oil and natural gas and may expose us to cash margin requirements.

The recent adoption of derivatives legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The United States Congress recently adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The new legislation was signed into law by the President on July 21, 2010 and requires the Commodities Futures Trading Commission (the CFTC) and the Securities and Exchange Commission (the SEC) to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The CFTC has also proposed regulations to set position limits for certain futures and option contracts in the major energy markets, although it is not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the new legislation. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with its derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if commodity prices decline as a consequence of the legislation and regulations. Any of these consequences could have a material adverse effect on us, our financial condition, and our results of operations.

Increased costs of capital could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in credit rating. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows available for drilling and place us at a competitive disadvantage. Recent and continuing disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

We may not be able to generate enough cash flow to meet our debt obligations.

We expect our earnings and cash flow to vary significantly from year to year due to the nature of our industry. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. Additionally, our future cash flow may be insufficient to meet our debt obligations and other commitments. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and to pay our debt obligations. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy and initiatives of our competitors, are beyond our control. If we do not generate enough cash flow from operations to satisfy our debt obligations, we may have to undertake alternative financing plans, such as:

- selling assets;
- reducing or delaying capital investments;
- seeking to raise additional capital; or
- refinancing or restructuring our debt.

If for any reason we are unable to meet our debt service and repayment obligations, we would be in default under the terms of the agreements governing our debt, which would allow our creditors at that time to declare all outstanding indebtedness to be due and payable, which would in turn trigger cross-acceleration or cross-default rights between the relevant agreements. In addition, our lenders could compel us to apply all of our available cash to repay our borrowings or they could prevent us from making payments on the senior unsecured notes. If amounts outstanding under our revolving credit facility or our senior unsecured notes were

Table of Contents

to be accelerated, we cannot be certain that our assets would be sufficient to repay in full the money owed to the lenders or to our other debt holders. Please see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and capital resources.

Our revolving credit facility and the indenture governing our senior unsecured notes both contain operating and financial restrictions that may restrict our business and financing activities.

Our revolving credit facility and the indenture governing our senior unsecured notes contain a number of restrictive covenants that will impose significant operating and financial restrictions on us, including restrictions on our ability to, among other things:

- sell assets, including equity interests in our subsidiaries;
- pay distributions on, redeem or repurchase our common stock or redeem or repurchase our subordinated debt;
- make investments;
- incur or guarantee additional indebtedness or issue preferred stock;
- create or incur certain liens;
- make certain acquisitions and investments;
- redeem or prepay other debt;
- enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets;
- engage in transactions with affiliates;
- create unrestricted subsidiaries;
- enter into sale and leaseback transactions; and
- engage in certain business activities.

As a result of these covenants, we will be limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs.

Our ability to comply with some of the covenants and restrictions contained in our revolving credit facility and the indenture governing our senior unsecured notes may be affected by events beyond our control. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. A failure to comply with the covenants, ratios or tests in our revolving credit facility, the indenture governing our senior unsecured notes or any future indebtedness could result in an event of default under our revolving credit facility, the indenture governing our senior unsecured notes or our future indebtedness, which, if not cured or waived, could have a material adverse affect on our business, financial condition and results of operations.

If an event of default under our revolving credit facility occurs and remains uncured, the lenders thereunder:

- would not be required to lend any additional amounts to us;
- could elect to declare all borrowings outstanding, together with accrued and unpaid interest and fees, to be due and payable;
- may have the ability to require us to apply all of our available cash to repay these borrowings; or
- may prevent us from making debt service payments under our other agreements.

A payment default or an acceleration under our revolving credit facility could result in an event of default and an acceleration under the indenture for our senior unsecured notes.

Table of Contents

If the indebtedness under the notes were to be accelerated, there can be no assurance that we would have, or be able to obtain, sufficient funds to repay such indebtedness in full. In addition, our obligations under our revolving credit facility are collateralized by perfected first priority liens and security interests on substantially all of our assets, including mortgage liens on oil and natural gas properties having at least 80% of the reserve value as determined by reserve reports, and if we are unable to repay our indebtedness under the revolving credit facility, the lenders could seek to foreclose on our assets. Please see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and capital resources.

Our level of indebtedness may increase and reduce our financial flexibility.

As of February 2, 2011, we had no indebtedness outstanding under our revolving credit facility, $137.5 million available for future secured borrowings under our revolving credit facility and $400.0 million outstanding in senior unsecured notes. Please see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Reserve-based credit facility and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Senior unsecured notes. In the future, we may incur significant indebtedness in order to make future acquisitions or to develop our properties.

Our level of indebtedness could affect our operations in several ways, including the following:

- a significant portion of our cash flows could be used to service our indebtedness;
- a high level of debt would increase our vulnerability to general adverse economic and industry conditions;
- the covenants contained in the agreements governing our outstanding indebtedness will limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments;
- a high level of debt may place us at a competitive disadvantage compared to our competitors that are less leveraged and therefore, may be able to take advantage of opportunities that our indebtedness would prevent us from pursuing;
- our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- a high level of debt may make it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then-outstanding bank borrowings; and
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes.

A high level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, oil and natural gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flows to pay the interest on our debt and future working capital, borrowings or equity financing may not be available to pay or refinance such debt. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, the value of our assets and our performance at the time we need capital.

In addition, our bank borrowing base is subject to periodic redeterminations. We could be forced to repay a portion of our bank borrowings due to redeterminations of our borrowing base. If we are forced to do so, we may not have sufficient funds to make such repayments. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

The inability of one or more of our customers to meet their obligations to us may adversely affect our financial results.

Our principal exposures to credit risk are through receivables resulting from the sale of our oil and natural gas production ($25.9 million in receivables at December 31, 2010), which we market to energy marketing companies, refineries and affiliates, advances to joint interest parties ($3.6 million at December 31, 2010) and joint interest receivables ($28.6 million at December 31, 2010).

We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. This concentration of customers may impact our overall credit risk since these entities may be similarly affected by changes in economic and other conditions. For the year ended December 31, 2010, sales to Plains All American Pipeline, L.P., Texon L.P. and Whiting Petroleum Corporation accounted for approximately 28%, 19% and 11%, respectively, of our total sales. For the year ended December 31, 2009, sales to Tesoro Refining and Marketing Company and Texon L.P. accounted for approximately 32% and 30%, respectively, of our total sales. For the year ended December 31, 2008, sales to Tesoro Refining and Marketing Company and Texon L.P. accounted for approximately 57% and 14%, respectively, of our total sales. We do not require our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Joint interest receivables arise from billing entities who own a partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We have limited ability to control participation in our wells. In addition, our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties.

We may be subject to risks in connection with acquisitions and the integration of significant acquisitions may be difficult.

We periodically evaluate acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions that appear to fit within our overall business strategy. The successful acquisition of producing properties requires an assessment of several factors, including:

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

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

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

diversion of our management s attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;

the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of ours while carrying on our ongoing business;

difficulty associated with coordinating geographically separate organizations; and

the challenge of attracting and retaining personnel associated with acquired operations.

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

If we fail to realize the anticipated benefits of a significant acquisition, our results of operations may be lower than we expect.

The success of a significant acquisition will depend, in part, on our ability to realize anticipated growth opportunities from combining the acquired assets or operations with those of ours. Even if a combination is successful, it may not be possible to realize the full benefits we may expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame. Anticipated benefits of an acquisition may be offset by operating losses relating to changes in commodity prices, or in oil and natural gas industry conditions, or by risks and uncertainties relating to the exploratory prospects of the combined assets or operations, or an increase in operating or other costs or other difficulties. If we fail to realize the benefits we anticipate from an acquisition, our results of operations may be adversely affected.

We may incur losses as a result of title defects in the properties in which we invest.

It is our practice in acquiring oil and gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest. Rather, we rely upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest.

Prior to the drilling of an oil or gas well, however, it is the normal practice in our industry for the person or company acting as the operator of the well to obtain a preliminary title review to ensure there are no obvious defects in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct defects in the marketability of the title, and such curative work entails expense. Our failure to cure any title defects may adversely impact our ability in the future to increase production and reserves. There is no assurance that we will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

The requirements of being a public company, including compliance with the reporting requirements of the Exchange Act and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management and we may be unable to comply with these requirements in a timely or cost-effective manner.

As a new public company with listed equity securities, we are required to comply with laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002, related regulations of the SEC and the requirements of the New York Stock Exchange (NYSE), with which we were not required to comply with as a private company. Complying with these statutes, regulations and requirements will occupy a significant amount of time of our Board of Directors and management and will significantly increase our costs and expenses. We will need to:

- design, establish, document, evaluate and maintain a system of internal controls over financial reporting in compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002 and the related rules and regulations of the SEC and the Public Company Accounting Oversight Board;

establish new internal policies, such as those relating to disclosure controls and procedures and insider trading; and

involve and retain to a greater degree outside counsel and accountants in the above activities.

In addition, as a public company we are subject to these rules and regulations, which could require us to accept less director and officer liability insurance coverage than we desire or to incur substantial costs to obtain coverage. These factors could also make it more difficult for us to attract and retain qualified members of our Board of Directors, particularly to serve on our Audit Committee, and qualified executive officers.

In connection with past audits and reviews of our financial statements, our independent registered public accounting firm identified and reported adjustments to management. Certain of these adjustments were deemed to be the result of internal control deficiencies that constituted a material weakness in our internal control over financial reporting. If this material weakness persists or if we fail to establish and maintain effective internal control over financial reporting, our ability to accurately report our financial results could be adversely affected.

Prior to the completion of our IPO, we were a private company with limited accounting personnel to adequately execute our accounting processes and other supervisory resources with which to address our internal control over financial reporting. As such, we have not maintained an effective control environment in that the design and execution of our controls have not consistently resulted in effective review and supervision by individuals with financial reporting oversight roles. The lack of adequate staffing levels resulted in insufficient time spent on review and approval of certain information used to prepare our financial statements. We concluded that these control deficiencies constitute a material weakness in our control environment. A material weakness is a control deficiency, or a combination of control deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis. The control deficiencies described above, at varying degrees of severity, contributed to the material weakness in the control environment, as further described in Item 9A. Controls and Procedures.

To address these control deficiencies, we have hired additional accounting and financial reporting staff since the IPO, implemented additional analysis and reconciliation procedures and increased the levels of review and approval. Additionally, we have begun taking steps to comprehensively document and analyze our system of internal control over financial reporting in preparation for our first management report on internal control over financial reporting, which is required for our annual report for the year ended December 31, 2011. Due to the recent implementation of these changes to our control environment, management continues to evaluate the design and effectiveness of these control changes in connection with its ongoing evaluation, review, formalization and testing of our internal control environment over the remainder of 2011. We will not complete our review until after this Annual Report on Form 10-K is filed and we cannot predict the outcome of our review at this time. During the course of the review, we may identify additional control deficiencies, which could give rise to additional significant deficiencies and other material weaknesses.

For the years ended December 31, 2007 through 2010, we were not required to comply with the SEC s rules implementing Section 404 of the Sarbanes-Oxley Act of 2002, which require a formal assessment of the effectiveness of our internal control over financial reporting. As a public company, we are required to comply with the SEC s rules implementing Section 302 of the Sarbanes-Oxley Act of 2002, which require our management to certify financial and other information in our quarterly and annual reports and provide an annual management report on the effectiveness of our internal control over financial reporting. However, we are not required to make our report regarding our internal control over financial reporting until our annual report for the year ended December 31, 2011. To comply with the requirements of being a public company, we have upgraded our systems, including information technology, implemented additional financial and management controls, reporting systems and procedures and hired additional accounting, finance and legal staff.

Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain effective controls over our financial processes and reporting in the future and comply with the certification and reporting obligations under Sections 302 and 404 of the Sarbanes-Oxley Act. Further, our remediation efforts may not enable us to remedy or avoid material weaknesses or significant deficiencies in the future. Any failure to remediate deficiencies and to develop or maintain effective controls, or any difficulties encountered in our implementation or improvement of our internal control over financial reporting could result in material misstatements that are not prevented or detected on a timely basis, which could potentially subject us to sanctions or investigations by the SEC, the NYSE or other regulatory authorities. Ineffective internal controls could also cause investors to lose confidence in our reported financial information.

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

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

Risks Relating to our Common Stock

We do not intend to pay, and we are currently prohibited from paying, dividends on our common stock and, consequently, our shareholders only opportunity to achieve a return on their investment is if the price of our stock appreciates.

We do not plan to declare dividends on shares of our common stock in the foreseeable future. Additionally, we are currently prohibited from making any cash dividends pursuant to the terms of our revolving credit facility and the indenture governing our senior unsecured notes. Consequently, our shareholders only opportunity to achieve a return on their investment in us will be if the market price of our common stock appreciates, which may not occur, and the shareholder sells their shares at a profit. There is no guarantee that the price of our common stock will ever exceed the price that the shareholder paid.

Our amended and restated certificate of incorporation and amended and restated bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Our amended and restated certificate of incorporation authorizes our Board of Directors to issue preferred stock without stockholder approval. If our Board of Directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our amended and restated certificate of incorporation and amended and restated bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- a classified Board of Directors, so that only approximately one-third of our directors are elected each year;
- limitations on the removal of directors; and
- limitations on the ability of our stockholders to call special meetings and establish advance notice provisions for stockholder proposals and nominations for elections to the Board of Directors to be acted upon at meetings of stockholders.

Delaware law prohibits us from engaging in any business combination with any interested stockholder, meaning generally that a stockholder who beneficially owns more than 15% of our stock cannot acquire us for a period of three years from the date this person became an interested stockholder, unless various conditions are met, such as approval of the transaction by our Board of Directors.

Item 1B. ***Unresolved Staff Comments***

None.

Table of Contents

Item 2. *Properties*

The information required by Item 2. is contained in Item 1. Business.

Item 3. *Legal Proceedings*

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material legal proceeding. In addition, we are not aware of any material legal or governmental proceedings against us, or contemplated to be brought against us.

Item 4. *(Removed and Reserved.)*

PART II

Item 5. *Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Market for Registrant s Common Equity. Our common stock is listed on the New York Stock Exchange (NYSE) under the symbol OAS .

The following table sets forth the range of high and low sales prices of our common stock as reported by the NYSE:

2010	**High**	**Low**
2nd Quarter(1)	$ 17.03	$ 14.27
3rd Quarter	$ 19.55	$ 13.88
4th Quarter	$ 29.36	$ 18.99

(1) Represents the period from June 17, 2010, the date on which our common stock began trading on the NYSE, through June 30, 2010.

Holders. The number of shareholders of record of our common stock was approximately 14,661 on March 4, 2011.

Dividends. We have not paid any cash dividends since our inception. Covenants contained in our revolving credit facility and the indenture governing our senior unsecured notes restrict the payment of cash dividends on our common stock. We currently intend to retain all future earnings for the development and growth of our business, and we do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future.

On March 9, 2011, the last sale price of our common stock, as reported on the NYSE, was $32.42 per share.

Repurchase of Equity Securities. Neither we nor any affiliated purchaser repurchased any of our equity securities in the quarter ended December 31, 2010.

Table of Contents

Stock Performance Graph. The following performance graph and related information shall not be deemed soliciting material or to be filed with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended, or Securities Exchange Act of 1934, as amended, except to the extent that we specifically request that such information be treated as soliciting material or specifically incorporate such information by reference into such a filing.

The performance graph shown below compares the cumulative five-year total return to Oasis common stockholders as compared to the cumulative five-year total returns on the Standard and Poor s 500 Index (S&P 500) and the Standard and Poor s 500 Oil & Gas Exploration & Production Index (S&P O&G E&P). The comparison was prepared based upon the following assumptions:

1. $100 was invested in our common stock at its initial public offering price of $14 per share and invested in the S&P 500 and the S&P O&G E&P on June 16, 2010 at the closing price on such date; and

2. Dividends are reinvested.

Table of Contents

Item 6. *Selected Financial Data*

Set forth below is our summary historical consolidated financial data for the years ended December 31, 2010, 2009 and 2008 and for the period from February 26, 2007, the date of our inception, through December 31, 2007, and balance sheet data at December 31, 2010, 2009, 2008 and 2007. This information may not be indicative of our future results of operations, financial position and cash flows and should be read in conjunction with the consolidated financial statements and notes thereto and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations presented elsewhere in this Annual Report on Form 10-K. We believe that the assumptions underlying the preparation of our historical consolidated financial statements are reasonable.

	Year Ended December 31,			Period from February 26, 2007 (Inception) through December 31, 2007(1)
	2010	2009(2)	2008	
	(In thousands, except per share data)			
Statement of operations data:				
Oil and gas revenues	$ 128,927	$ 37,755	$ 34,736	$ 13,791
Expenses:				
Lease operating expenses	14,582	8,691	7,073	2,946
Production taxes	13,768	3,810	3,001	1,211
Depreciation, depletion and amortization	37,832	16,670	8,686	4,185
Exploration expenses	297	1,019	3,222	1,164
Rig termination(3)		3,000		
Impairment of oil and gas properties(4)	11,967	6,233	47,117	1,177
Gain on sale of properties		(1,455)		
Stock-based compensation expenses(5)	8,743			
General and administrative expenses(6)	19,745	9,342	5,452	3,181
Total expenses	106,934	47,310	74,551	13,864
Operating income (loss)	21,993	(9,555)	(39,815)	(73)
Other income (expense):				
Change in unrealized gain (loss) on derivative instruments	(7,533)	(7,043)	14,769	(10,679)
Realized gain (loss) on derivative instruments	(120)	2,296	(6,932)	(1,062)
Interest expense	(1,357)	(912)	(2,404)	(1,776)
Other income (expense)	284	5	(9)	40
Total other income (expense)	(8,726)	(5,654)	5,424	(13,477)
Income (loss) before income taxes	13,267	(15,209)	(34,391)	(13,550)
Income tax expense(7)	42,962			
Net loss	$ (29,695)	$ (15,209)	$ (34,391)	$ (13,550)

Loss per share:		
Basic and diluted(8)	$	(0.61)

(1) For the period from February 26, 2007 through June 30, 2007, we did not engage in oil and gas operating or producing activities.

(2) Our statement of operations data for the year ended December 31, 2009 does not include the effects of the acquisition of interests in certain oil and gas properties from Kerogen Resources, Inc. for the full twelve months of 2009. We acquired such interests on June 15, 2009.

(3) For a discussion of our rig termination expenses, see Note 14 to our audited consolidated financial statements.

(4) For the years ended December 31, 2010, 2009 and 2008 and for the period from February 26, 2007 (inception) through December 31, 2007, we recognized non-cash impairment charges on our unproved properties due to expiring leases of $12.0 million, $5.4 million, $1.6 million and $1.2 million, respectively. In 2009 and 2008, we recognized a $0.8 million and a $45.5 million non-cash impairment charge on our proved properties, respectively. See Note 2 to our audited consolidated financial statements.

(5) In March 2010, we recorded a $5.2 million stock-based compensation charge associated with OPM granting 1.0 million C Units to certain of our employees. During the fourth quarter of 2010, we recorded an additional $3.5 million in stock-based compensation expense primarily associated with OPM granting discretionary shares of our common stock to certain of our employees who were not C Unit holders and certain contractors. See Note 10 to our audited consolidated financial statements.

(6) For the year ended December 31, 2010, our general and administrative expenses included approximately $4.2 million of IPO-related costs and approximately $1.2 million of amortization of our restricted stock awards. No stock-based compensation expense was recorded for the years ended December 31, 2009 and 2008 and for the period from February 26, 2007 (inception) through December 31, 2007 as we had not historically issued stock-based compensation awards to our employees (see Note 10 to our audited consolidated financial statements).

(7) Prior to our corporate reorganization, we were a limited liability company not subject to entity-level income tax. Accordingly, no provision for federal or state corporate income taxes was recorded for the years ended December 31, 2009 and 2008 and for the period from February 26, 2007 (inception) through December 31, 2007 as the taxable income was allocated directly to our equity holders. In connection with the closing of our IPO, we merged into a corporation and became subject to federal and state entity-level taxation. See Note 11 to our audited consolidated financial statements.

(8) Because we reported a net loss for the year ended December 31, 2010, no unvested stock awards were included in the computation of loss per share because the effect would be anti-dilutive. See Note 12 to our audited consolidated financial statements.

	At December 31,			
	2010	**2009**	**2008**	**2007**
	(In thousands)			
Balance sheet data:				
Cash and cash equivalents	$ 143,520	$ 40,562	$ 1,570	$ 6,282
Net property, plant and equipment	483,683	181,573	114,220	92,918
Total assets	691,852	239,553	129,068	104,145
Long-term debt		35,000	26,000	46,500
Total members /stockholders equity	551,794	171,850	82,459	36,350

	Year Ended December 31,	Period from February 26, 2007

	2010	2009	2008	(Inception) through December 31, 2007
		(In thousands)		
Other financial data:				
Net cash provided by operating activities	$ 49,612	$ 6,148	$ 13,766	$ 2,284
Net cash used in investing activities	(309,535)	(80,756)	(78,478)	(91,988)
Net cash provided by financing activities	362,881	113,600	60,000	95,986

Item 7. *Management s Discussion and Analysis of Financial Condition and Results of Operations*

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes appearing elsewhere in this Annual Report on Form 10-K. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions, or beliefs about future events may, and often do, vary from actual results and the differences can be material. Some of the key factors which could cause actual results to vary from our expectations include changes in oil and natural gas prices, the timing of planned capital expenditures, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, the proximity to and capacity of transportation facilities, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below and elsewhere in this Annual Report on Form 10-K, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See Cautionary note regarding forward-looking statements.

Overview

We are an independent exploration and production company focused on the development and acquisition of unconventional oil and natural gas resources primarily in the Williston Basin. Since our inception, we have emphasized the acquisition of properties that provide current production and significant upside potential through further development. Our drilling activity is primarily directed toward projects that we believe can provide us with repeatable successes in the Bakken formation.

Our use of capital for acquisitions and development allows us to direct our capital resources to what we believe to be the most attractive opportunities as market conditions evolve. We have historically acquired properties that we believe will meet or exceed our rate of return criteria. For acquisitions of properties with additional development, exploitation and exploration potential, we have focused on acquiring properties that we expect to operate so that we can control the timing and implementation of capital spending. In some instances, we have acquired non-operated property interests at what we believe to be attractive rates of return either because they provided a foothold in a new area of interest or complemented our existing operations. We intend to continue to acquire both operated and non-operated properties to the extent we believe they meet our return objectives. In addition, our willingness to acquire non-operated properties in new areas provides us with geophysical and geologic data that may lead to further acquisitions in the same area, whether on an operated or non-operated basis.

Our predecessor company was formed in February 2007. We began active oil and natural gas operations in July 2007 following the acquisition of properties in the Williston Basin consisting of approximately 175,000 net leasehold acres and approximately 1,000 Boe/d of then-current net production, substantially forming our core leasehold position in the West Williston project area. In May 2008, we entered into a farm-in and purchase arrangement under which we earned or acquired approximately 48,000 net leasehold acres, establishing our initial position in the East Nesson project area. In June 2009, we acquired approximately 37,000 net leasehold acres with then-current net production of approximately 800 Boe/d, approximately 92% of which was from the Williston Basin. This acquisition consolidated our acreage in the East Nesson project area and established our Sanish project area. In September 2009, we acquired an additional 46,000 net leasehold acres with then-current production of approximately 300 Boe/d. This acquisition further consolidated our acreage in the East Nesson project area. In June 2010, we completed our IPO. In November 2010, we acquired approximately 16,700 net leasehold acres located in Roosevelt County, Montana with then-current net production of approximately 300 Boe/d. This acreage is part of our West Williston project area. In December 2010, we acquired approximately 10,000 net leasehold acres primarily located in Richland County, Montana with then-current net production of approximately 200 Boe/d. This acreage is part of our West Williston project area. Our acquisitions were financed with a

combination of borrowings under our revolving credit facility, cash flows provided by operating activities, capital contributions made by EnCap and other private investors and proceeds from our IPO.

Project Areas of Acquired Properties	Closing Date of Acquisition	Adjusted Purchase Price(1) (In millions)	Production at Acquisition (Boe/d)	Approximate Net Acreage at Acquisition
West Williston(2)	June 22, 2007	$ 83	1,000	175,000
East Nesson(3)	May 16, 2008	16		48,000
East Nesson/Sanish	June 15, 2009	27	800	37,000
East Nesson	September 30, 2009	11	300	46,000
West Williston	November 5, 2010	52	300	16,700
West Williston	December 10, 2010	30	200	10,000

(1) Represents initial purchase price plus closing adjustments.

(2) For accounting purposes, results from this West Williston acquisition are included in our results of operations effective July 1, 2007.

(3) Our farm-in and purchase arrangement required an initial payment of $15.6 million and obligated us to spend $15.1 million of drilling costs on behalf of the other parties.

Because of our substantial acquisition activity, our discussion and analysis of our historical financial condition and results of operations for the periods discussed below may not necessarily be comparable with or applicable to our future results of operations. Our initial acquisition of properties in the Williston Basin was completed in June 2007 from Bill Barrett Corporation, which constitutes our accounting predecessor. For acquisitions that occurred prior to December 31, 2010, our historical results include the results from our acquisitions beginning on the closing dates indicated in the table above.

Our 2010 and 2009 activities included development and exploration drilling in each of our primary project areas. Our current activities are focused on evaluating and developing our asset base, optimizing our acreage positions and evaluating potential acquisitions. At December 31, 2010, based on the reserve report prepared by our independent reserve engineers, we had 39.8 MMBoe of estimated net proved reserves with a PV-10 of $697.8 million and a Standardized Measure of $485.7 million. At December 31, 2009, based on the reserve report prepared by our independent reserve engineers, we had 13.3 MMBoe of estimated net proved reserves with a PV-10 of $133.5 million and a Standardized Measure of $133.5 million. At December 31, 2008, we had 2.3 MMBoe of estimated net proved reserves with a PV-10 of $17.7 million and a Standardized Measure of $17.7 million. Our estimated proved reserves and related future net revenues, PV-10 and Standardized Measure were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $79.40/Bbl for oil and $4.38/MMBtu for natural gas for the year ended December 31, 2010 and $61.04/Bbl for oil and $3.87/MMBtu for natural gas for the year ended December 31, 2009. The index prices were $44.60/Bbl for oil and

$5.63/MMBtu for natural gas at December 31, 2008. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

Our revenue, profitability and future growth rate depend substantially on factors beyond our control, such as economic, political and regulatory developments as well as competition from other sources of energy. Oil and natural gas prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital.

Prices for oil and natural gas can fluctuate widely in response to relatively minor changes in the global and regional supply of and demand for oil and natural gas, market uncertainty, economic conditions and a variety of additional factors. Since the inception of our oil and gas activities, commodity prices have

Table of Contents

experienced significant fluctuations. Our quarterly average net realized oil prices and average price differentials are shown in the table below.

	2008			Year Ended December 31,	2009				Year Ended December 31,	2010		
	Q2	Q3	Q4	2008	Q1	Q2	Q3	Q4	2009	Q1	Q2	
	$ 114.30	$ 108.73	$ 44.99	$ 88.07	$ 30.68	$ 52.47	$ 57.00	$ 65.09	$ 55.32	$ 70.21	$ 67.19	$ 6
	8%	8%	23%	11%	29%	13%	17%	14%	17%	11%	14%	

(1) Realized oil prices do not include the effect of realized derivative contract settlements.

(2) Price differential compares realized oil prices to West Texas Intermediate crude oil index prices.

Changes in commodity prices may also significantly affect the economic viability of drilling projects as well as the economic valuation and economic recovery of oil and gas reserves. From December 31, 2007 to December 31, 2008, our Standardized Measure of discounted future net cash flows attributable to proved oil and natural gas reserves declined from $121.8 million to $17.7 million primarily due to net decreases of both value and reserve quantities from the decline in oil and gas commodity prices described above.

During the fourth quarter of 2008, we recorded a non-cash impairment charge of $45.5 million to recognize an impairment to the carrying value of our proved oil and gas properties as a result of the decline in oil and gas commodity prices. In response to the commodity pricing environment in the fourth quarter of 2008, we reduced our planned 2009 capital expenditure program and also initiated discussions for early termination of two of our drilling rig contracts. In addition, although we drilled ten wells in the second half of 2008, we elected to delay the completion of five of the wells until mid-2009, as a result of lower commodity prices without a corresponding decrease in completion costs available from our vendors. We subsequently completed these wells in mid-2009 when completion costs were lower.

While we experienced reduced cash flows from operations during this period due to lower oil and gas commodity prices, we had access to $69.6 million of remaining private equity funding capacity and $3.5 million of unused borrowing base capacity at December 31, 2008 under our previous revolving credit facility. Our financial position allowed us to pursue the preservation of our leasehold acreage positions by extending leases and purchasing leases instead of drilling. In addition, we maintained the financial capacity to endure the downturn in the commodity and financial markets as well as to position ourselves for acquisitions in 2009.

Oil prices increased significantly during 2009 and 2010 as compared to the fourth quarter of 2008. The higher commodity prices, as well as continued successes in the application of completion technologies in the Bakken formation, caused the active drilling rig count in the Williston Basin to exceed 165 rigs at December 31, 2010. Although additional Williston Basin transportation takeaway capacity was added in 2009 and 2010, production has also increased due to the elevated drilling activity in 2010. The increased production coupled with the planned turnaround at the Tesoro Corporation Mandan refinery and outages and disruptions on Enbridge s 6A and 6B lines caused price differentials at times to be at the high end of the historical average range of approximately 10% to 15% of the West Texas Intermediate crude oil index price in 2010.

Recent Events

Our 2011 capital expenditure budget is $490 million, a 40% increase over our 2010 capital budget of $350 million. The 2011 budget consists of:

$402 million for drilling and completing operated wells;

$39 million for drilling and completing non-operated wells;

$19 million for maintaining and expanding our leasehold position;

$21 million for constructing infrastructure to support production in our core project areas; and

$9 million for micro-seismic work, purchasing seismic data and other test work.

Table of Contents

In connection with the most recent amendment to our revolving credit facility, a redetermination of our borrowing base was completed at our request on January 21, 2011 in lieu of the scheduled April 1, 2011 semi-annual redetermination. As a result of this redetermination, our borrowing base increased from $120 million to $150 million. However, in connection with the issuance of our senior unsecured notes discussed below, our borrowing base was automatically decreased to $137.5 million.

On February 2, 2011, we issued $400 million of 7.25% senior unsecured notes due February 1, 2019. The issuance of these notes resulted in net proceeds to us of approximately $390 million, which we will use to fund our exploration, development and acquisition program and for general corporate purposes.

In 2011, we entered into new two-way and three-way collar option contracts, all of which settle monthly based on the West Texas Intermediate crude oil index price, for a total notional amount of 974,000 barrels in 2011, 915,000 barrels in 2012 and 730,000 barrels in 2013.

Sources of our revenue

Our revenues are derived from the sale of oil and natural gas production and do not include the effects of derivatives. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

The following table summarizes our revenues and production data for the periods indicated.

	Year Ended December 31, 2010	2009	2008	Period from February 26, 2007 (Inception) through December 31, 2007(1)
Operating results (in thousands):				
Revenues				
Oil	$ 124,682	$ 36,376	$ 33,396	$ 13,335
Natural gas	4,245	1,379	1,340	456
Total oil and gas revenues	128,927	$ 37,755	$ 34,736	$ 13,791
Production data:				
Oil (MBbls)	1,792	658	379	159
Natural gas (MMcf)	651	326	123	73
Oil equivalents (MBoe)	1,900	712	400	171
Average daily production (Boe/d)	5,206	1,950	1,092	929
Average sales prices:				
Oil, without realized derivatives (per Bbl)	$ 69.60	$ 55.32	$ 88.07	$ 83.96
Oil, with realized derivatives (per Bbl)(2)	69.53	58.82	69.79	77.27
Natural gas (per Mcf)	6.52	4.24	10.91	6.25

(1) For the period from February 26, 2007 through June 30, 2007, we did not engage in oil and gas operating or producing activities. Average daily production includes production from July 1, 2007 through December 31, 2007.

(2) Realized prices include realized gains or losses on cash settlements for our commodity derivatives, which do not qualify for and were not designated as hedging instruments for accounting purposes.

Year ended December 31, 2010 as compared to year ended December 31, 2009

Oil and natural gas revenues. Our oil and natural gas sales revenues increased $91.2 million, or 241%, to $128.9 million during the year ended December 31, 2010 as compared to the year ended December 31, 2009. Our revenues are a function of oil and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 3,256 Boe per day, or 167%, to 5,206 Boe per day during the year ended December 31, 2010 as compared to the year ended December 31, 2009. The increase in average daily production sold was primarily a result of our well completions during 2010. These well completions in our Sanish, East Nesson and West Williston project areas increased average daily production by approximately 748 Boe per day, 975 Boe per day and 1,181 Boe per day, respectively, during 2010. The higher production amounts sold increased revenues by $81.1 million, and the remaining $10.1 million increase in revenues was attributable to higher oil sales prices during the year ended December 31, 2010. Average oil sales prices, without realized derivatives, increased by $14.28/Bbl, or 26%, to an average of $69.60/Bbl for the year ended December 31, 2010 as compared to the year ended December 31, 2009.

Year ended December 31, 2009 as compared to year ended December 31, 2008

Oil and natural gas revenues. Our oil and natural gas sales revenues increased $3.0 million, or 9%, to $37.8 million during the year ended December 31, 2009 as compared to the year ended December 31, 2008. Average daily production sold increased by 858 Boe per day or 79% to 1,950 Boe per day during the year ended December 31, 2009 as compared to the year ended December 31, 2008. The increase in average daily production sold was primarily due to the Sanish and East Nesson acquisitions completed in 2009, which contributed approximately 390 Boe per day, and well completions in our Sanish and East Nesson project areas, which contributed 168 Boe per day and 213 Boe per day, respectively. This $16.2 million revenue increase attributable to higher production sold was almost entirely offset by a $13.2 million revenue reduction attributable to lower oil sales prices during the year ended December 31, 2009. Average oil sales prices, without realized derivatives, declined by $32.75/Bbl, or 37%, to an average of $55.32/Bbl for the year ended December 31, 2009 as compared to the year ended December 31, 2008.

Year ended December 31, 2008 as compared to period from February 26, 2007 (Inception) through December 31, 2007

Oil and natural gas revenues. Our oil and natural gas sales revenues increased $20.9 million, or 152%, to $34.7 million for the year ended December 31, 2008 compared to the period from February 26, 2007 (inception) through December 31, 2007. This increase was primarily a result of production from properties acquired in our West Williston project area, which we owned for all of 2008 as compared to only the last six months in 2007. Average oil sales prices, without realized derivatives, increased by $4.11/Bbl or 5% to an average of $88.07/Bbl for the year ended December 31, 2008 as compared to the period ended December 31, 2007.

Expenses

Lease operating expenses. Lease operating expenses are daily costs incurred to bring oil and natural gas out of the ground and to the market, together with the daily costs incurred to maintain our producing properties. Such costs also include field personnel compensation, utilities, maintenance, repairs and workover expenses related to our oil and natural gas properties.

Production taxes. Production taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at market prices (not hedged prices) or at fixed rates established by federal, state or local taxing authorities. We take full advantage of all credits and exemptions in our various taxing jurisdictions. In general, the production taxes we pay correlate to the changes in oil and natural gas revenues.

Depreciation, depletion and amortization. Depreciation, depletion and amortization includes the systematic expensing of the capitalized costs incurred to acquire, explore and develop oil and natural gas. As a successful efforts company, we capitalize all costs associated with our development and acquisition efforts and all successful exploration efforts, and allocate these costs to each unit of production using the units-of-production method.

Exploration expenses. Exploration expenses consist of exploratory dry hole expenses and costs incurred in evaluating areas that are considered to have prospective oil and natural gas reserves, including costs for topographical, geological and geophysical studies, rights of access to properties and costs of carrying and retaining undeveloped properties, such as delay rentals.

Impairment of unproved and proved properties. These costs include unproved property impairment and costs associated with lease expirations. We could also record impairment charges for proved properties if the carrying value exceeds estimated future cash flows. See Critical accounting policies and estimates Impairment of proved properties.

Stock-based compensation expenses. This expense includes a non-cash charge for stock-based compensation associated with OPM granting C Units to certain of our employees in March 2010. This expense also includes non-cash charges for stock-based compensation associated with OPM granting discretionary shares of our common stock to certain of our employees who were not C Unit holders and certain contractors in the fourth quarter of 2010. See Critical accounting policies and estimates Stock-based compensation.

General and administrative expenses. General and administrative expenses include overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, audit and other professional fees and legal compliance.

Other income (expense)

Change in unrealized gain (loss) on derivative instruments. We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in the price of crude oil. This account activity represents the recognition of gains and losses associated with our outstanding derivative contracts as commodity prices and commodity derivative contracts change.

Realized gain (loss) on derivative instruments, net. We utilize commodity derivative instruments to reduce our exposure to fluctuations in the price of crude oil. This account activity represents our realized gains and losses on the settlement of these commodity derivative instruments.

Interest expense. We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under our revolving credit facility. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We reflect interest paid to the lenders under our revolving credit facility in interest expense. In addition, we include the amortization of deferred financing costs (including origination and amendment fees), commitment fees and annual agency fees as interest expense.

Income tax expense. Our provision for taxes includes both federal and state taxes. We record our federal income taxes in accordance with accounting for income taxes under GAAP which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

Table of Contents

The following table summarizes our operating expenses for the periods indicated.

	Year Ended December 31,			Period from February 26, 2007 (Inception) through December 31,
	2010	2009(2)	2008	2007(1)
	(In thousands, except per Boe of production)			
Statement of operations data:				
Expenses:				
Lease operating expenses	$ 14,582	$ 8,691	$ 7,073	$ 2,946
Production taxes	13,768	3,810	3,001	1,211
Depreciation, depletion and amortization	37,832	16,670	8,686	4,185
Exploration expenses	297	1,019	3,222	1,164
Rig termination(3)		3,000		
Impairment of oil and gas properties(4)	11,967	6,233	47,117	1,177
Gain on sale of properties		(1,455)		
Stock-based compensation expenses(5)	8,743			
General and administrative expenses(6)	19,745	9,342	5,452	3,181
Total expenses	$ 106,934	$ 47,310	$ 74,551	$ 13,864
Operating income (loss)	21,993	(9,555)	(39,815)	(73)
Other income (expense):				
Change in unrealized gain (loss) on derivative instruments	(7,533)	(7,043)	14,769	(10,679)
Realized gain (loss) on derivative instruments, net	(120)	2,296	(6,932)	(1,062)
Interest expense	(1,357)	(912)	(2,404)	(1,776)
Other income (expense)	284	5	(9)	40
Total other income (expense)	(8,726)	(5,654)	5,424	(13,477)
Income (loss) before income taxes	13,267	(15,209)	(34,391)	(13,550)
Income tax expense(7)	42,962			
Net loss	$ (29,695)	$ (15,209)	$ (34,391)	$ (13,550)
Cost and expense (per Boe of production):				
Lease operating expenses	$ 7.67	$ 12.21	$ 17.70	$ 17.23
Production taxes	7.25	5.35	7.51	7.08
Depreciation, depletion and amortization	19.91	23.42	21.73	24.47
General and administrative expenses	10.39	13.12	13.64	18.60
Stock-based compensation expenses(5)	4.60			

(1) For the period from February 26, 2007 through June 30, 2007, we did not engage in oil and gas operating or producing activities.

(2) Our statement of operations data for the year ended December 31, 2009 does not include the effects of the acquisition of interests in certain oil and gas properties from Kerogen Resources, Inc. for the full twelve months of 2009. We acquired such interests on June 15, 2009.

(3) For a discussion of our rig termination expenses, see Note 14 to our audited consolidated financial statements.

(4) For the years ended December 31, 2010, 2009 and 2008 and for the period from February 26, 2007 (inception) through December 31, 2007, we recognized non-cash impairment charges on our unproved properties due to expiring leases of $12.0 million, $5.4 million, $1.6 million and $1.2 million, respectively. In 2009

and 2008, we recognized a $0.8 million and a $45.5 million non-cash impairment charge on our proved properties, respectively. See Note 2 to our audited consolidated financial statements.

(5) In March 2010, we recorded a $5.2 million stock-based compensation charge associated with OPM granting 1.0 million C Units to certain of our employees. During the fourth quarter of 2010, we recorded an additional $3.5 million in stock-based compensation expense primarily associated with OPM granting discretionary shares of our common stock to certain of our employees who were not C Unit holders and certain contractors. See Note 10 to our audited consolidated financial statements.

(6) For the year ended December 31, 2010, our general and administrative expenses included approximately $4.2 million of IPO-related costs and approximately $1.2 million of amortization of our restricted stock awards. No stock-based compensation expense was recorded for the years ended December 31, 2009 and 2008 and for the period from February 26, 2007 (inception) through December 31, 2007 as we had not historically issued stock-based compensation awards to our employees (see Note 10 to our audited consolidated financial statements).

(7) Prior to our corporate reorganization, we were a limited liability company not subject to entity-level income tax. Accordingly, no provision for federal or state corporate income taxes was recorded for the years ended December 31, 2009 and 2008 and for the period from February 26, 2007 (inception) through December 31, 2007 as our taxable income was allocated directly to our equity holders. In connection with the closing of our IPO, we merged into a corporation and became subject to federal and state entity-level taxation. See Note 11 to our audited consolidated financial statements.

Year ended December 31, 2010 compared to year ended December 31, 2009

Lease operating expenses. Lease operating expenses increased $5.9 million to $14.6 million for the year ended December 31, 2010 compared to the year ended December 31, 2009. This increase was primarily due to our 2010 well completions. The 167% increase in production volumes from the year ended December 31, 2009 to the year ended December 31, 2010 resulted in a 37% decrease in unit operating costs to $7.67 per Boe.

Production taxes. Our production taxes for the years ended December 31, 2010 and 2009 were 10.7% and 10.1%, respectively, as a percentage of oil and natural gas sales. The 2010 production tax rate was higher than the 2009 production tax rate due to the increased weighting of oil revenues in North Dakota, which imposes an 11.5% production tax rate. Our production taxes for the year ended December 31, 2009 were primarily for oil and natural gas sales revenue associated with properties in the Montana portion of our West Williston project area, which generate revenues subject to lower production tax rates in Montana.

Depreciation, depletion and amortization (DD&A). Depreciation, depletion and amortization expense increased $21.2 million to $37.8 million for the year ended December 31, 2010 compared to the year ended December 31, 2009. The increase in DD&A expense for the year ended December 31, 2010 was primarily due to the production increases from the Sanish and East Nesson acquisitions completed at the end of the second and third quarters of 2009, respectively, and as a result of our well completions during the fourth quarter of 2009 and all of 2010. The DD&A rate for the year ended December 31, 2010 was $19.91 per Boe compared to $23.42 per Boe for the year ended December 31, 2009. The lower DD&A rate was due to the lower cost of reserve additions associated with our 2009 Sanish and East Nesson acquisitions and our 2010 drilling activities.

Rig termination. During the first quarter of 2009, we paid a total of $3.0 million in rig termination expenses in connection with the early termination of two drilling rig contracts entered into in 2008. We did not have any rig termination expenses during the year ended December 31, 2010.

Impairment of oil and gas properties. No impairment on proved oil and natural gas properties was recorded for the year ended December 31, 2010. During the year ended December 31, 2009, we recorded a non-cash impairment charge of $0.8 million on our proved oil and gas properties. During the years ended December 31, 2010 and 2009, we recorded non-cash impairment charges of $12.0 million and $5.4 million, respectively, for unproved property leases that expired during the period. In determining the amount of the non-cash impairment charges for such periods, we considered the application of the factors described under

Critical accounting policies and estimates Impairment of proved properties and Critical accounting policies and estimates Impairment of unproved properties. As of December 31, 2010, we did not record an impairment charge with respect to any acreage expiring in 2011 based primarily on our ability to actively manage and prioritize our capital expenditures to drill leases and to make payments to extend leases that would otherwise expire.

Stock-based compensation expenses. For the year ended December 31, 2010, we recorded $8.7 million of primarily non-cash charges for stock-based compensation expense associated with OPM s grant of C Units to certain of our employees in March 2010 and grant of discretionary shares of our common stock to certain of our employees who were not C Unit holders and certain contractors in the fourth quarter of 2010. Based on the characteristics of these awards, we concluded that they represented equity-type awards and we accounted for the value of these awards as if they had been awarded by us. We used fair-value-based methods to determine the value of stock-based compensation awarded to our employees and contractors and recognized the entire amount as expense due to the immediate vesting of the awards, with no future requisite service period required by the employees. No stock-based compensation expense was recorded for the year ended December 31, 2009 because we had not historically issued stock-based compensation awards to our employees.

General and administrative. Our general and administrative expenses increased $10.4 million for the year ended December 31, 2010 from $9.3 million for the year ended December 31, 2009. Of this increase, approximately $4.2 million was due to higher advisory, audit, legal, tax and filing fees primarily related to our IPO and additional costs of being a public entity. In addition, we recorded approximately $1.2 million of amortization of our restricted stock awards for the year ended December 31, 2010. The remaining increase was primarily due to higher costs related to employee compensation (including bonuses paid during the first quarter of 2010 and accrued bonuses to be paid in the first quarter of 2011) and contract labor. As of December 31, 2010, we had 62 full-time employees compared to 27 full-time employees as of December 31, 2009.

Derivatives. As a result of our derivative activities, we incurred a cash settlement loss of $0.1 million for the year ended December 31, 2010 and a cash settlement gain of $2.3 million for the year ended December 31, 2009. In addition, as a result of forward oil price changes, we recognized $7.5 million and $7.0 million of non-cash unrealized mark-to-market derivative losses during the years ended December 31, 2010 and 2009, respectively.

Interest expense. Interest expense increased $0.4 million to $1.4 million for the year ended December 31, 2010 compared to the year ended December 31, 2009. The increase was the result of higher monthly amortization on our deferred financing costs related to our amended revolving credit facility coupled with the write-off of the deferred financing costs related to the original revolving credit facility in February 2010. Our weighted average debt balance decreased to $15.3 million for the year ended December 31, 2010 from $22.8 million for the year ended December 31, 2009 as we incurred no borrowings during the last six months of 2010. The weighted average interest rate on our revolving credit facility borrowings decreased to 3.1% for the year ended December 31, 2010 from 3.5% for the year ended December 31, 2009.

Income tax expense. Prior to our corporate reorganization, we were a limited liability company not subject to entity-level income tax. Accordingly, no provision for federal or state corporate income taxes was recorded for the year ended December 31, 2009 as our taxable income was allocated directly to our equity holders. In connection with the closing of our IPO, we merged into a corporation and became subject to federal and state entity-level taxation. In connection with our corporate reorganization, an initial net deferred tax liability of $29.2 million was established for differences between the tax and book basis of our assets and liabilities and a corresponding deferred tax expense was recorded in our Consolidated Statement of Operations. We recorded additional deferred tax expenses of $6.2 million and $0.2 million in September 2010 and December 2010, respectively, for discrete adjustments related to changes in estimate of the initial deferred tax liability recorded in June 2010 and certain non-deductible IPO and non-deductible stock-based compensation related expenses. Subsequent to our corporate reorganization, we recorded federal and state income tax expense of $7.4 million on pre-tax income earned in the post-reorganization period from June 17, 2010 (the effective date of the reorganization) to December 31, 2010. Prospectively, we expect our effective tax rate to be between 37% and 39%.

Year ended December 31, 2009 compared to year ended December 31, 2008

Lease operating expenses. Lease operating expenses increased $1.6 million to $8.7 million for the year ended December 31, 2009 compared to the year ended December 31, 2008. This increase was primarily due to the higher number of productive wells from our Sanish and East Nesson acquisitions that were completed in 2009. The 73% increase in oil volumes from 2008 to 2009 resulted in a 31% decrease in unit operating costs to $12.21 per Boe. Our lease operating expenses for 2008 were also higher on a per barrel basis due to increased equipment repair and salt water disposal costs for the properties in our West Williston project area. Equipment repair costs were higher in 2008 due to the replacement and upgrading of equipment that had been deferred by the previous owner of the properties we acquired in 2007. Salt water disposal costs were higher in 2008 from the use of higher volume pumps resulting in increases of produced salt water volumes and the use of third-party salt water disposal facilities while we developed our own salt water disposal wells and centralized our salt water disposal facilities. As compared to the properties in our West Williston project area that produce primarily from the Madison formation, the properties we acquired in the Sanish acquisition produce primarily from the Bakken formation and have higher production volumes per well and lower per Boe operating costs than our Madison wells. The 2009 lease operating costs per Boe decreased in the West Williston project area due to our previously mentioned 2008 construction and centralization of our salt water disposal facilities.

Production taxes. Our production taxes for the years ended December 31, 2009 and 2008 were 10.1% and 8.6%, respectively, as a percentage of oil and natural gas sales. The 2009 production tax rate was higher than the 2008 production tax rate due to the increased weighting of revenues in North Dakota which imposes an 11.5% production tax rate. The 2008 production taxes were primarily for oil and natural gas sales revenue associated with the properties in our West Williston project area acquired in 2007. A portion of the properties in our West Williston project area generate revenues that are subject to lower Montana production tax rates and certain North Dakota exemptions.

Depreciation, depletion and amortization (DD&A). Depreciation, depletion and amortization expense increased $8.0 million for the year ended December 31, 2009 compared to the year ended December 31, 2008. The 2009 expense increase is primarily due to a 73% production increase from the 2009 East Nesson and Sanish acquisitions. The 2009 DD&A rate was $23.42 per Boe compared to $21.73 per Boe in 2008. The increase from 2008 to 2009 was due to higher acquisition, leasehold, drilling and completion costs in the East Nesson and Sanish project areas.

Exploration expenses. Exploration expenses of $1.0 million in the year ended December 31, 2009 were primarily composed of exploratory geological and geophysical costs. The comparable period in 2008 contained exploratory dry hole costs of $1.3 million and higher expenditures for exploratory geological and geophysical costs.

Rig termination. During 2008, we entered into drilling rig contracts with two drilling contractors. In the fourth quarter of 2008, we reduced our planned 2009 capital expenditure program and entered into discussions regarding early termination of these contracts. In the first quarter of 2009, we paid a total of $3.0 million in rig termination expenses in connection with the termination of our remaining commitment under one drilling rig contract and the extension of the other drilling rig contract until June 2010.

Impairment of oil and gas properties. During the years ended December 31, 2009 and 2008, we recorded $0.8 million and $45.5 million, respectively, in non-cash impairment charges on our proved oil and gas properties. The 2008 charges reflected the impact of significantly lower oil prices reflected in our 2008 reserve report.

During the years ended December 31, 2009 and 2008, we recorded non-cash impairment charges of $5.4 million and $1.6 million, respectively, for unproved property leases that expired during the period. As of December 31, 2009, we did not record an impairment charge with respect to any acreage expiring in 2010 based primarily on our ability to actively manage and prioritize our capital expenditures to drill leases and to make payments to extend leases that would otherwise expire.

Gain on sale of properties. In December 2009, we sold our interests in non-core oil and natural gas producing properties located in the Barnett shale in Texas for $1.5 million. We recognized a gain of $1.4 million from the sale of these divested properties.

General and administrative. Our general and administrative expenses increased to $9.3 million for the year ended December 31, 2009 from $5.5 million for the year ended December 31, 2008. This increase was primarily due to higher costs related to employee bonus compensation, additional employees and higher advisory, audit, legal and tax fees related to our IPO. As of December 31, 2009, we had 27 full-time employees compared to 20 employees as of December 31, 2008. General and administrative expenses were $13.12 per Boe compared to $13.64 per Boe for the years ended December 31, 2009 and 2008, respectively.

Derivatives. As a result of our derivative activities, we incurred cash settlement gains of $2.3 million for the year ended December 31, 2009 and cash settlement losses of $6.9 million for the year ended December 31, 2008. In addition, as a result of forward oil price changes, we recognized $7.0 million of unrealized mark-to-market non-cash derivative losses in 2009 and $14.8 million of unrealized mark-to-market non-cash derivative gains in 2008.

Interest expense. Interest expense decreased $1.5 million, or 62%, for the year ended December 31, 2009 compared to the year ended December 31, 2008, due to a lower weighted average outstanding debt balance and a lower weighted average interest rate during 2009. Our weighted average debt balance decreased to $22.8 million for the year ended December 31, 2009 compared to $37.7 million for the year ended December 31, 2008. The weighted average interest rate on our revolving credit facility borrowings was 3.5% for the year ended December 31, 2009 compared to 6.3% for the same period in 2008. At December 31, 2009, our outstanding debt balance under our revolving credit facility was $35.0 million with a weighted average interest rate of 2.95%.

Year ended December 31, 2008 compared to period from February 26, 2007 (Inception) through December 31, 2007

Lease operating expenses. Lease operating expenses increased $4.1 million for the year ended December 31, 2008 compared to the period from February 26, 2007 to December 31, 2007. The West Williston oil and natural gas producing properties were purchased in June 2007 and are reflected in only six months of our 2007 operating results as compared to a full twelve months in 2008. Lease operating expenses were $17.70 per Boe and $17.23 per Boe for the year ended December 31, 2008 and for the period from February 26, 2007 (inception) through December 31, 2007, respectively. The unit operating costs for the year ended December 31, 2008 were higher on a Boe unit basis due to increased equipment repair and salt water disposal costs for our West Williston properties. Equipment repair costs were higher in 2008 due to the replacement and upgrading of equipment that had been deferred by the previous owner of the properties we acquired in 2007. Salt water disposal costs were higher in 2008 from the use of higher volume pumps resulting in increases of produced salt water volumes and the use of third-party salt water disposal facilities while we developed our own salt water disposal wells and centralized our salt water disposal facilities.

Production taxes. Our production taxes for the year ended December 31, 2008 and the period from February 26, 2007 (inception) through December 31, 2007 were 8.6% and 8.8%, respectively, of oil and natural gas sales for our West Williston oil and gas producing properties.

Depreciation, depletion and amortization (DD&A). Depreciation, depletion and amortization expense increased $4.5 million for the year ended December 31, 2008 compared to the period from February 26, 2007 to December 31, 2007. The West Williston oil and gas producing properties were purchased in June 2007 and are reflected in only six months of our 2007 operating results as compared to a full twelve months in 2008. The depreciation, depletion and amortization rate was $21.73 per Boe for the year ended December 31, 2008 as compared to $24.47 per Boe in the period from February 26, 2007 (inception) through December 31, 2007. The decrease in the per Boe rate from 2007 to

2008 was primarily due to the $45.5 million impairment charge that we recorded on our proved oil and gas properties as a result of lower crude oil prices at December 31, 2008. The decrease in the per Boe rate from the reduction in carrying value of our proved oil and gas properties was partially offset by the corresponding decrease in our proved reserve quantities as a result of lower crude oil prices at December 31, 2008.

Exploration expenses. Exploration expenses of $3.2 million in the year ended December 31, 2008 included $1.3 million of dry hole costs with the remaining geological and geophysical costs comparable to those incurred from February 26, 2007 to December 31, 2007. For the period ended December 31, 2007, we did not incur any dry hole costs.

Impairment of oil and gas properties. During the year ended December 31, 2008, we recorded a noncash impairment charge of $45.5 million on our proved oil and gas properties as a result of lower crude oil prices at December 31, 2008, without a comparable charge for the period ended December 31, 2007. During the year ended December 31, 2008 and the period from February 26, 2007 to December 31, 2007, we recorded non-cash impairment charges of $1.6 million and $1.2 million, respectively, for unproved property leases that expired during the period.

General and administrative. General and administrative expenses increased to $5.5 million for the year ended December 31, 2008 from $3.2 million during the period from February 26, 2007 through December 31, 2007. This increase was due both to a full 12 months of operations in 2008 as well as to the start-up nature of our activities in the 2007 period. General and administrative expenses were $13.64 per Boe for the year ended December 31, 2008 compared to $18.60 per Boe for the period ended 2007. The improvement was due to a full year of production volumes in 2008 versus only six months of volumes in the 2007 period.

Derivatives. In connection with the West Williston acquisition in June 2007, we entered into fixed-price swap and collar contracts. As a result, only five contract settlement periods occurred during the period from February 26, 2007 through December 31, 2007 as compared to twelve contract settlement periods for the year ended December 31, 2008. We incurred cash settlement losses of $6.9 million and $1.1 million during the year ended December 31, 2008 and the period from February 26, 2007 to December 31, 2007, respectively, on contract settlements of our crude oil derivative transactions. In addition, we recognized $14.8 million of unrealized mark-to-market non-cash derivative gains during the year ended December 31, 2008 as compared to $10.7 million of unrealized mark-to-market non-cash derivative losses during the period from February 26, 2007 through December 31, 2007 due to increases in forward oil prices during 2008.

Interest expense. Interest expense increased $0.6 million, or 35%, for the year ended December 31, 2008 compared to the period from February 26 through December 31, 2007, primarily due to our revolving credit facility borrowings being outstanding for a full 12 months in 2008. The weighted average outstanding debt balance and weighted average interest rates were $37.7 million and 6.3% during for the year ended December 31, 2008. The weighted average outstanding debt balance and weighted average interest rates were $22.8 million and 7.81% during the period from February 26 through December 31, 2007.

Liquidity and capital resources

Our primary sources of liquidity as of the date of this report have been capital contributions from EnCap and other private investors, borrowings under our revolving credit facility, cash flows from operations, proceeds from our IPO and proceeds from our private placement of senior unsecured notes in February 2011. Our primary use of capital has been for the acquisition, development and exploration of oil and natural gas properties. We continually monitor potential capital sources, including equity and debt financings, in order to meet our planned capital expenditures and liquidity requirements. Our future success in growing proved reserves and production will be highly dependent on our ability to access outside sources of capital.

On June 22, 2010, we completed an IPO of 48,300,000 shares of common stock at $14.00 per share. We sold 30,370,000 shares of common stock in the offering, and OAS Holding Company LLC (OAS Holdco), the selling stockholder, sold 17,930,000 shares of common stock, including 6,300,000 shares sold by OAS Holdco pursuant to the full exercise of the underwriters over-allotment option. We received net proceeds from the offering of $399.7 million, after deducting underwriting discounts and estimated offering expenses. We used a portion of these net proceeds to repay all outstanding indebtedness of $75.0 million under our revolving credit facility, and the remaining proceeds are being used to fund our exploration and development program. We did not receive any proceeds from the sale of shares by OAS Holdco.

On February 2, 2011, we issued $400 million of 7.25% senior unsecured notes due February 1, 2019. Interest is payable on the notes semi-annually in arrears on each February 1 and August 1, commencing August 1, 2011. These notes are guaranteed on a senior unsecured basis by our material subsidiaries. The issuance of these notes resulted in net proceeds to us of approximately $390 million, which we will use to fund our exploration, development and acquisition program and for general corporate purposes. See Senior unsecured notes below.

In connection with the most recent amendment to our revolving credit facility, a redetermination of our borrowing base was completed at our request on January 21, 2011 in lieu of the scheduled April 1, 2011 semi-annual redetermination. As a result of this redetermination, our borrowing base increased from $120 million to $150 million. However, in connection with the issuance of $400 million of senior unsecured notes on February 2, 2011, our borrowing base was automatically decreased by $12.5 million to $137.5 million. As of December 31, 2010, we had no outstanding indebtedness under our revolving credit facility. See Reserve-based credit facility below.

In 2010, we spent $345.6 million on capital expenditures, which represented an approximate 287% increase over the $89.3 million invested during 2009. This increase was a result of (i) improved industry conditions and technology in the Bakken formation as well as increased economics in the area, (ii) an increase in total net wells drilled in 2010 and (iii) additional lease acquisitions. See Cash flows used in investing activities below.

Our total 2011 capital expenditure budget is $490 million, which consists of:

- $402 million for drilling and completing operated wells;
- $39 million for drilling and completing non-operated wells;
- $19 million for maintaining and expanding our leasehold position;
- $21 million for constructing infrastructure to support production in our core project areas; and
- $9 million for micro-seismic work, purchasing seismic data and other test work.

While we have budgeted $490 million for these purposes, the ultimate amount of capital we will expend may fluctuate materially based on market conditions and the success of our drilling and operations results as the year progresses. We believe that the net proceeds from our private offering of senior unsecured notes, which closed on February 2, 2011, together with cash on hand and cash flows from operating activities should be more than sufficient to fund our 2011 capital expenditure budget. However, because the operated wells funded by our 2011 drilling plan represent only a small percentage of our gross identified drilling locations, we will be required to generate or raise multiples of this amount of capital to develop our entire inventory of identified drilling locations should we elect to do so.

We expect that in the future our commodity derivative positions will help us stabilize a portion of our expected cash flows from operations despite potential declines in the price of oil and natural gas. Please see Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

We actively review acquisition opportunities on an ongoing basis. Our ability to make significant additional acquisitions for cash would require us to obtain additional equity or debt financing, which we may not be able to obtain on terms acceptable to us or at all.

65

Table of Contents

Cash flow activity

Our cash flows for the years ended December 31, 2010, 2009 and 2008 are presented below:

	Year Ended December 31, 2010	2009	2008
	(In thousands)		
Net cash provided by operating activities	$ 49,612	$ 6,148	$ 13,766
Net cash used in investing activities	(309,535)	(80,756)	(78,478)
Net cash provided by financing activities	362,881	113,600	60,000
Net change in cash	$ 102,958	$ 38,992	$ (4,712)

Cash flows provided by operating activities

Our cash flows depend on many factors, including the price of oil and natural gas and the success of our development and exploration activities as well as future acquisitions. We actively manage our exposure to commodity price fluctuations by executing derivative transactions to mitigate the change in prices of a portion of our production, thereby mitigating our exposure to price declines, but these transactions may also limit our earnings potential in periods of rising oil prices. For additional information on the impact of changing prices on our financial position, see Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

Net cash provided by operating activities was $49.6 million, $6.1 million and $13.8 million for the years ended December 31, 2010, 2009 and 2008, respectively. The increase in cash flows provided by operating activities for the year ended December 31, 2010 as compared to 2009 was primarily the result of an increase in oil and natural gas production of 167%. In addition, at December 31, 2010, we had a working capital surplus of $123.6 million. This surplus for 2010 was primarily attributable to our cash balance as a result of the proceeds from the sale of common stock in our IPO. Cash flows provided by operating activities during the year ended December 31, 2009 decreased compared to 2008 primarily as a result of a $3.0 million rig termination payment and $3.9 million increase in general and administration expenses related to our IPO.

Cash flows used in investing activities

We had cash flows used in investing activities of $309.5 million, $80.8 million and $78.5 million during the years ended December 31, 2010, 2009 and 2008, respectively, as a result of our capital expenditures for drilling, development and acquisition costs. The increase in cash used in investing activities for the year ended December 31, 2010 compared to 2009 of $228.7 million was attributable to our acquisitions of properties in the West Williston project area, as well as increased levels of expenditures for the development of our properties. The $2.3 million increase in cash used in investing activities for the year ended December 31, 2009 compared to December 31, 2008 was attributable to our acquisitions of properties in the East Nesson and Sanish project areas, as well as increased levels of expenditures for the development of our properties.

Our capital expenditures for drilling, development and acquisition costs for the years ended December 31, 2010, 2009 and 2008 are summarized in the following table:

	Year Ended December 31, 2010	2009	2008
	(In thousands)		
Project Area:			
West Williston	$ 240,830	$ 15,521	$ 12,703
East Nesson	73,529	40,208	66,513
Sanish	30,854	32,952	
Other(1)	429	582	
Total(2)	$ 345,642	$ 89,263	$ 79,216

(1) Represents data relating to our properties in the Barnett shale.

(2) Capital expenditures reflected in the table above differ from the amounts shown in the statement of cash flows in our consolidated financial statements because amounts reflected in the table include changes in accrued liabilities from the previous reporting period for capital expenditures, while the amounts presented in the statement of cash flows are presented on a cash basis. The capital expenditures amount presented in the statement of cash flows also includes cash paid for other property and equipment as well as cash paid for asset retirement costs.

Our initial 2010 capital expenditure budget was $220 million, which represented a 147% increase over the $89 million spent during 2009. This increase was a result of improved industry conditions and technology in the Bakken formation as well as increased economics in the area. On August 9, 2010, our Board of Directors increased our 2010 capital expenditure budget to $270 million. This increase was primarily due to an increase in total net wells expected to be drilled in 2010 and an increase for potential additional lease acquisitions. On November 4, 2010, our Board of Directors further increased our 2010 capital budget to $328.5 million. This increase was primarily due to the $49.9 million of cash paid at closing (subject to customary post-close purchase price adjustments) for the acquisition of approximately 16,700 net acres of land in Montana on November 5, 2010 and an increase in the number of wells expected to be drilled within the acreage acquired from the effective date of the acquisition until the end of 2010. On December 15, 2010, our Board of Directors further increased our 2010 capital expenditures budget to $350 million due to the acquisition of approximately 10,000 net acres of land in Montana on December 10, 2010, which was approved by our Board of Directors on November 22, 2010.

During 2010, we participated in drilling and completion of 116 gross wells (28.5 net) and, as operator, we drilled and completed 26 gross (20.1 net) of these wells. In addition, as of December 31, 2010, there were 35 gross (14.7 net) wells awaiting completion or in the process of drilling. Our land leasing and acquisition activity is focused in and around our existing core consolidated land positions, primarily in the West Williston.

Our capital budget may be adjusted as business conditions warrant. The amount, timing and allocation of capital expenditures is largely discretionary and within our control. If oil and natural gas prices decline or costs increase significantly, we could defer a significant portion of our budgeted capital expenditures until later periods to prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flows and other factors both within and outside our control.

Expenditures for exploration and development of oil and natural gas properties are the primary use of our capital resources. We anticipate investing $490 million for capital and exploration expenditures in 2011 as follows:

	(In thousands)
Drilling and completing operated wells	$ 402,000
Drilling and completing non-operated wells	39,000
Maintaining and expanding our leasehold position	19,000
Constructing infrastructure to support production in our core project areas	21,000
Micro-seismic work, purchasing seismic data and other test work	9,000
Total	$ 490,000

Cash flows provided by financing activities

Net cash provided by financing activities was $362.9 million, $113.6 million and $60.0 million for the years ended December 31, 2010, 2009 and 2008, respectively. For the year ended December 31, 2010, cash sourced through financing activities was primarily provided by net proceeds from the sale of the common stock in our IPO. For the years ended December 31, 2009 and 2008, cash sourced through financing activities was primarily provided by capital contributions from EnCap and other private investors and borrowings under our revolving credit facility.

As of December 31, 2010, we had no borrowings under our revolving credit facility and $25,000 of outstanding letters of credit issued under our revolving credit facility, resulting in an unused borrowing base capacity of $120.0 million. Our long-term debt, including the current portion, was $35.0 million at December 31, 2009. The weighted average debt outstanding for the year ended 2010 and 2009 was $15.3 million and $22.8 million, respectively. The weighted average interest rate incurred on the outstanding revolving credit facility borrowings for the year ended December 31, 2010 and 2009 was 3.1% and 3.5%, respectively. We were in compliance with the financial covenants of our revolving credit facility as of December 31, 2010.

Reserve-based credit facility

On February 26, 2010, we entered into an amended and restated reserve-based revolving credit facility under which our initial borrowing base was set at $85 million. On June 22, 2010, the closing date of our IPO, the $15 million non-conforming portion of the borrowing base was terminated, reducing our borrowing base to $70 million, with a maturity of February 26, 2014. The borrowing base under our revolving credit facility is subject to redetermination on a semi-annual basis, effective April 1 and October 1, and at up to one additional time per year, as may be requested by either us or the administrative agent, acting at the direction of the majority of the lenders. The borrowing base will be determined by the administrative agent in its sole discretion and consistent with its normal oil and gas lending criteria in existence at that particular time. In addition, in the event that we elect to issue senior secured or unsecured notes (other than on a borrowing base redetermination date), our borrowing base will be automatically reduced by an amount equal to 25% of the aggregate principal amount of such notes, unless otherwise waived by the lenders. Our revolving credit facility is available for our general corporate purposes, including, without limitation, working capital for exploration and production operations. Borrowings under the revolving credit facility are collateralized by perfected first priority liens and security interests on substantially all of our assets, including mortgage liens on oil and natural gas properties having at least 80% of the reserve value as determined by reserve reports.

At our request, our semi-annual redetermination was completed on August 11, 2010, and our borrowing base increased from $70 million to $120 million. On January 21, 2011, in connection with the third amendment to our revolving credit facility described below, a redetermination of our borrowing base was completed, at our request, in lieu of the April 1, 2011 redetermination. As a result of this redetermination, our borrowing base increased from $120 million to $150 million. However, on February 2, 2011, in connection with the issuance of $400 million of our 7.25% senior unsecured notes due 2019, our borrowing base was decreased by $12.5 million to $137.5 million.

Contemporaneously with our January 21, 2011 redetermination, we entered into a third amendment to our revolving credit facility in order to:

- eliminate the $200 million limit for unsecured notes;
- reduce the interest rates payable on borrowings under our revolving credit facility;
- modify the debt coverage ratio covenant described below to be net of cash and cash equivalents on our balance sheet;
- extend the maturity date of our revolving credit facility from February 26, 2014 to February 26, 2015;
- increase the size of our revolving credit facility from $250 million to $600 million; and
- add an additional lender to the bank group for our revolving credit facility.

At our election, interest is generally determined by reference to:

the London interbank offered rate, or LIBOR, plus an applicable margin between 2.00% and 2.75% per annum; or

- a domestic bank prime rate plus an applicable margin between 0.50% and 1.25% per annum.

Interest is generally payable quarterly for domestic bank rate loans and on the last day of the applicable interest period for LIBOR loans, but not less frequently than quarterly.

Our revolving credit facility contains various covenants that limit our ability to:

- incur indebtedness;
- make dividends, distributions or redemptions;
- make certain investments, loans and advances;
- create certain liens and leases;
- merge and sell assets outside the ordinary course of business;
- enter into certain transactions with affiliates; and
- enter into certain oil and natural gas derivative financial instruments.

Our revolving credit facility also contains covenants that, among other things, require us to maintain specified ratios or conditions as follows:

- a current ratio, consisting of consolidated current assets, including the unused amount of the total commitments, to consolidated current liabilities of not less than 1.0 to 1.0, excluding non-cash derivative assets and liabilities, as of the last day of any fiscal quarter; and
- a debt coverage ratio, consisting of consolidated debt (excluding non-cash obligations, accounts payable and other certain accrued liabilities) to consolidated net income plus interest expense, income taxes, depreciation, depletion, amortization, exploration expenses and other similar non-cash charges, minus all non-cash income added to consolidated net income, of not more than 4.0 to 1.0 for the four quarters ended on the last day of each fiscal quarter.

We believe that we are in compliance with the terms of our revolving credit facility. If an event of default exists under the credit agreement, the lenders will be able to accelerate the maturity of the credit agreement and exercise other rights and remedies. Each of the following will be an event of default:

- failure to pay any principal or any reimbursement obligation under any letter of credit when due or any interest, fees or other amount within certain grace periods;
- a representation or warranty is proven to be incorrect in any material respect when made;
- failure to perform or otherwise comply with the covenants in the credit agreement or other loan documents, subject, in certain instances, to certain grace periods;
- default by us on the payment of any other indebtedness in excess of $2.5 million, or any event occurs that permits or causes the acceleration of the indebtedness;

bankruptcy or insolvency events involving us or our subsidiaries;

the entry of, and failure to pay, one or more adverse judgments in excess of $2.0 million or one or more non-monetary judgments that could reasonably be expected to have a material adverse effect and for which enforcement proceedings are brought or that are not stayed pending appeal; and

a change of control, as defined in the credit agreement.

Senior unsecured notes

On February 2, 2011, we issued $400 million of 7.25% senior unsecured notes (the Notes) due February 1, 2019. Interest is payable on the Notes semi-annually in arrears on each February 1 and August 1, commencing August 1, 2011. The Notes are guaranteed on a senior unsecured basis by our material subsidiaries. The issuance of these Notes resulted in net proceeds to us of approximately $390 million, which we will use to fund our exploration, development and acquisition program and for general corporate purposes.

At any time prior to February 1, 2014, we may redeem up to 35% of the Notes at a redemption price of 107.25% of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings so long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the Notes remains outstanding after such redemption. Prior to February 1, 2015, we may redeem some or all of the Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and after February 1, 2015, we may redeem some or all of the Notes at redemption prices (expressed as percentages of principal amount) equal to 103.625% for the twelve-month period beginning on February 1, 2015, 101.813% for the twelve-month period beginning February 1, 2016 and 100.00% beginning on February 1, 2017, plus accrued and unpaid interest to the redemption date.

The indenture governing the Notes restricts our ability and the ability of certain of our subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay distributions on, redeem or repurchase, equity interests; (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when the Notes are rated investment grade by both Moody s Investors Service, Inc. and Standard & Poor s Ratings Services and no default (as defined in the Indenture) has occurred and is continuing, many of such covenants will terminate and we will cease to be subject to such covenants.

Obligations and commitments

We have the following contractual obligations and commitments as of December 31, 2010 (in thousands):

	Payments due by period				
Contractual Obligations	**Total**	**Less than 1 Year**	**1-3 Years**	**3-5 Years**	**More than 5 Years**
Operating leases(1)	6,159	909	1,834	1,814	1,602
Drilling rig commitments(2)	2,520	2,520			
Volume commitment agreements(3)	5,250			5,250	
Long-term debt(4)					
Asset retirement obligations(5)	7,640		244	741	6,655
Total contractual cash obligations	$ 21,569	$ 3,429	$ 2,078	$ 7,805	$ 8,257

(1) See Note 14 to our audited consolidated financial statements for a description of our operating lease obligations. On January 12, 2011, we executed an additional amendment to our office space lease agreement. See Note 15 to our audited consolidated financial statements for a description of our 2011 amended lease agreement.

(2) At December 31, 2010, we had $2.5 million in obligations related to our drilling rig commitments with initial terms greater than one year. See Note 14 to our audited consolidated financial statements for a description of our drilling rig commitments. During 2011, we entered into new long-term drilling rig contracts for $15.9 million in

obligations. See Note 15 to our audited consolidated financial statements for a description of our 2011 drilling rig commitments.

(3) See Notes 14 and 15 to our audited consolidated financial statements for a description of our volume commitment agreements.

(4) At December 31, 2010, we had no outstanding debt under our revolving credit facility. On February 2, 2011, we issued $400 million of 7.25% senior unsecured notes due on February 1, 2019. The notes are guaranteed on a senior unsecured basis by our material subsidiaries. See Note 8 to our audited consolidated financial statements.

(5) Amounts represent our estimate of future asset retirement obligations on an undiscounted basis. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment. See Note 9 to our audited consolidated financial statements.

Critical accounting policies and estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. We provide expanded discussion of our more significant accounting policies, estimates and judgments below. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our consolidated financial statements. See Note 2 to our audited consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

Method of accounting for oil and natural gas properties

Oil and natural gas exploration and development activities are accounted for using the successful efforts method. Under this method, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well has found proved reserves. If an exploratory well does not find proved reserves, the costs of drilling the well are charged to expense. The costs of development wells are capitalized whether productive or nonproductive. All capitalized well costs and leasehold costs of proved properties are amortized on a unit-of-production basis over the remaining life of proved developed reserves and proved reserves, respectively.

Costs of retired, sold or abandoned properties that constitute a part of an amortization base (partial field) are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate for an entire field, in which case a gain or loss is recognized currently. Gains or losses from the disposal of properties are recognized currently.

Expenditures for maintenance, repairs and minor renewals necessary to maintain properties in operating condition are expensed as incurred. Major betterments, replacements and renewals are capitalized to the appropriate property and equipment accounts. Estimated dismantlement and abandonment costs for oil and natural gas properties are capitalized, net of salvage, at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves.

Unproved properties consist of costs incurred to acquire unproved leases, or lease acquisition costs. Unproved lease acquisition costs are capitalized until the leases expire or when we specifically identify leases that will revert to the lessor, at which time we expense the associated unproved lease acquisition costs. The expensing of the unproved lease acquisition costs is recorded as impairment expense in the statement of operations in our consolidated financial statements. Lease acquisition costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis.

For sales of entire working interests in unproved properties, gain or loss is recognized to the extent of the difference between the proceeds received and the net carrying value of the property. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of costs unless the proceeds exceed the entire cost of the property.

Oil and natural gas reserve quantities and standardized measure of future net revenue

Our independent engineers and technical staff prepare our estimates of oil and natural gas reserves and associated future net revenues. While the SEC has recently adopted rules which allow us to disclose proved, probable and possible reserves, we have elected to disclose only proved reserves in this Annual Report on Form 10-K. The SEC s revised rules define proved reserves as the quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Our independent engineers and technical staff must make a number of subjective assumptions based on their professional judgment in developing reserve estimates. Reserve estimates are updated annually and consider recent production levels and other technical information about each field. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment.

Periodic revisions to the estimated reserves and future cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. Accordingly, reserve estimates are generally different from the quantities of oil and natural gas that are ultimately recovered. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material.

Revenue recognition

Revenue from our interests in producing wells is recognized when the product is delivered, at which time the customer has taken title and assumed the risks and rewards of ownership, and collectability is reasonably assured. Substantially all of our production is sold to purchasers under short-term (less than 12 month) contracts at market-based prices. The sales prices for oil and natural gas are adjusted for transportation and other related deductions. These deductions are based on contractual or historical data and do not require significant judgment.

Subsequently, these revenue deductions are adjusted to reflect actual charges based on third-party documents. Since there is a ready market for oil and natural gas, we sell the majority of production soon after it is produced at various locations. As a result, we maintain a minimum amount of product inventory in storage.

Impairment of proved properties

We review our proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. We estimate the expected undiscounted future cash flows of our oil and natural gas properties and compare such undiscounted future cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value are subject to our judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and various discount rates commensurate with the risk and current market conditions associated with realizing the expected cash flows projected. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges for proved properties will be recorded.

Impairment of unproved properties

We assess our unproved properties periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results or future plans to develop acreage and record impairment expense for any decline in value.

We have historically recognized impairment expense for unproved properties at the time when the lease term has expired or sooner if, in management s judgment, the unproved properties have lost some or all of their carrying value. We consider the following factors in our assessment of the impairment of unproved properties:

- the remaining amount of unexpired term under our leases;
- our ability to actively manage and prioritize our capital expenditures to drill leases and to make payments to extend leases that may be closer to expiration;
- our ability to exchange lease positions with other companies that allow for higher concentrations of ownership and development;
- our ability to convey partial mineral ownership to other companies in exchange for their drilling of leases; and
- our evaluation of the continuing successful results from the application of completion technology in the Bakken formation by us or by other operators in areas adjacent to or near our unproved properties.

The assessment of unproved properties to determine any possible impairment requires significant judgment.

Asset retirement obligations

We record the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred with the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. For oil and gas properties, this is the period in which the well is drilled or acquired. The asset retirement obligation, or ARO, represents the estimated amount we will incur to plug, abandon and remediate the properties at the end of their productive lives, in accordance with applicable state laws. The liability is accreted to its present value each period and the capitalized cost is depreciated on the unit-of-production method. The accretion expense is recorded as a component of Depreciation, depletion and amortization in our Consolidated Statement of Operations.

We determine the ARO by calculating the present value of estimated cash flows related to the liability. Estimating the future ARO requires management to make estimates and judgments regarding timing, existence of a liability, as well as what constitutes adequate restoration. Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

Derivatives

We record all derivative instruments on the balance sheet as either assets or liabilities measured at their estimated fair value. We have not designated any derivative instruments as hedges for accounting purposes and we do not enter into such instruments for speculative trading purposes. Realized gains and realized losses from the settlement of commodity derivative instruments and unrealized gains and unrealized losses from valuation changes in the remaining unsettled commodity derivative instruments are reported under Other Income (Expense) in our Consolidated Statement of Operations.

Stock-based compensation

Restricted Stock Awards. We recognize compensation expense for all restricted stock awards made to employees and directors. Stock-based compensation expense is measured at the grant date based on the fair value of the award and is recognized as expense on a straight-line basis over the requisite service period, which is generally the vesting period. The fair value of restricted stock grants is based on the value of our common stock on the date of grant. Assumptions regarding forfeiture rates are subject to change. Any such changes could result in different valuations and thus impact the amount of stock-based compensation expense recognized. Stock-based compensation expense recorded for restricted stock awards is included in General and administrative expenses on our Consolidated Statement of Operations.

Class C Common Unit Interests. In March 2010, we recorded a $5.2 million stock-based compensation charge associated with OPM granting 1.0 million C Units to certain of our employees. The C Units were granted on March 24, 2010 to individuals who were employed as of February 1, 2010 and who were not executive officers or key employees with an existing capital investment in OPM, or OPM Capital Members. All of the C Units vested immediately on the grant date. Based on the characteristics of the C Units awarded to employees, we concluded that the C Units represented an equity-type award and accounted for the value of this award as if it had been awarded by us. The C Units were membership interests in OPM and not a direct interest in us. The C Units are non-transferable and have no voting power. As of December 31, 2010, OPM had distributed substantially all cash or requisite common stock to its members based on membership interests and distribution percentages.

In accordance with the FASB s authoritative guidance for share-based payments, we used a fair-value-based method to determine the value of stock-based compensation awarded to our employees and recognized the entire grant date fair value of $5.2 million as stock-based compensation expense due to the immediate vesting of the awards with no future requisite service period required of the employees. We used a probability weighted expected return method to evaluate the potential return and associated fair value allocable to the C Unit shareholders using selected hypothetical future outcomes (continuing operations, private sale and an initial public offering). Approximately 95% of the fair value allocable to the C Unit holders comes from the IPO scenario.

The IPO fair value of the C Units awarded to our employees was estimated on the date of the grant using the Black-Scholes option-pricing model. The exercise price of the option used in the option-pricing model was set equal to the maximum value of OPM s current capital investment in Oasis as that value must be returned to OPM Capital Members before distributions are made to the C Unit shareholders. Since we were not a public entity on the grant date, we did not have historical stock trading data to be used to compute volatilities associated with certain expected terms so the expected volatility value of 60% was estimated based on an average of volatilities of similar sized oil and gas companies with operations in the Williston Basin whose common stocks are publicly traded. The allocable fair value to the C Units occurs in an estimated timing of four years based on a future potential secondary offering or distribution of common stock of Oasis. The 2.08% risk-free rate used in the pricing model is based on the U.S. Treasury yield for a government bond with a maturity equal to the time to liquidity of four years. We did not estimate forfeiture rates due to the immediate vesting of the award and did not estimate future dividend payments as we do not expect to declare or pay dividends in the foreseeable future.

Discretionary Stock Awards. During the fourth quarter of 2010, we recorded a $3.5 million stock-based compensation charge primarily associated with OPM s grant of discretionary shares of our common stock to certain of our employees who were not C Unit holders and certain contractors. Based on the characteristics of these awards, we concluded that they represented an equity-type award and accounted for the value of these awards as if they had been awarded by us.

The fair value of these awards was based on the value of our common stock on the date of grant. All of these awards vested immediately on the grant date with no future requisite service period required of the employees and contractors and are non-dilutive to us.

Income taxes

Our provision for taxes includes both federal and state taxes. We record our federal income taxes in accordance with accounting for income taxes under GAAP which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

We apply significant judgment in evaluating our tax positions and estimating our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from our estimates, which could impact our financial position, results of operations and cash flows.

We also account for uncertainty in income taxes recognized in the financial statements in accordance with GAAP by prescribing a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return. Authoritative guidance for accounting for uncertainty in income taxes requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority. We did not have uncertain tax positions outstanding and, as such, did not record a liability for year ended December 31, 2010.

Recent accounting pronouncements

Goodwill. In December 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2010-28, Intangibles Goodwill and Other: When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts (ASU 2010-28). ASU 2010-28 requires step two of the goodwill impairment test to be performed when the carrying value of a reporting unit is zero or negative, if it is more likely than not that a goodwill impairment exists. The requirements of this update are effective for fiscal years beginning after December 15, 2010. We do not expect the adoption of this new guidance to have an impact on our financial position, cash flows or results of operations.

Business combinations. In December 2010, the FASB issued ASU 2010-29, Business Combinations: Disclosure of Supplementary Pro Forma Information for Business Combinations (ASU 2010-29). ASU 2010-29 clarifies that when presenting comparative pro forma financial statements in conjunction with business combination disclosures, revenue and earnings of the combined entity should be presented as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period. In addition, the update requires a description of the nature and amount of material, nonrecurring pro forma adjustments included in pro forma revenue and earnings that are directly attributable to the business combination. This update is effective prospectively for business combinations that occur on or after the beginning of the first annual reporting period after December 15, 2010. As ASU 2010-29 relates to disclosure requirements, there will be no impact on our financial position, cash flows or results of operations.

Financial receivables. On July 21, 2010, the FASB issued ASU 2010-20 Receivables (Topic 310) Disclosures about the Credit Quality of Financial Receivables and the Allowance for Credit Losses. This new ASU requires disclosure of additional information to assist financial statement users to understand more clearly an entity s credit risk exposures to finance receivables and the related allowance for credit losses. This ASU is effective for all public companies for interim and annual reporting periods ending on or after

December 15, 2010 with specific items, such as the allowance rollforward and modification disclosures, effective for periods beginning after December 15, 2010. The adoption of this new guidance did not have an impact on our financial position, cash flows or results of operations.

Fair value. In January 2010, the FASB issued authoritative guidance to update certain disclosure requirements and added two new disclosure requirements related to fair value measurements. The guidance requires a gross presentation of activities within the Level 3 roll forward and adds a new requirement to disclose details of significant transfers in and out of Level 1 and 2 measurements and the reasons for the transfers. The new disclosures are required for all companies that are required to provide disclosures about recurring and nonrecurring fair value measurements, and is effective the first interim or annual reporting period beginning after December 15, 2009, except for the gross presentation of the Level 3 roll forward information, which is required for annual reporting periods beginning after December 15, 2010 and for interim reporting periods within those years. The adoption of this new guidance did not have an impact on our financial position, cash flows or results of operations.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2010, 2009 and 2008. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and we tend to experience inflationary pressure on the cost of oilfield services and equipment as increasing oil and gas prices increase drilling activity in our areas of operations.

Off-balance sheet arrangements

Currently, we do not have any off-balance sheet arrangements.

Item 7A. *Quantitative and Qualitative Disclosures about Market Risk*

We are exposed to a variety of market risks including commodity price risk, interest rate risk and counterparty and customer risk. We address these risks through a program of risk management including the use of derivative instruments.

Commodity price exposure risk. We are exposed to market risk as the prices of oil and natural gas fluctuate as a result of changes in supply and demand and other factors. To partially reduce price risk caused by these market fluctuations, we have entered into derivative instruments in the past and expect to enter into derivative instruments in the future to cover a significant portion of our future production.

We utilize derivative financial instruments to manage risks related to changes in oil prices. As of December 31, 2010, we utilized two-way and three-way collar options to reduce the volatility of oil prices on a significant portion of our future expected oil production. A two-way collar is a combination of options: a sold call and a purchased put. The purchased put establishes a minimum price (floor) and the sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The purchased put establishes a minimum price, unless the market price falls below the sold put, at which point the minimum price would be NYMEX-WTI plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (ceiling) we will receive for the volumes under contract.

We record all derivative instruments at fair value. The credit standing of our counterparties is analyzed and factored into the fair value amounts recognized on the balance sheet. Derivative assets and liabilities arising from our derivative contracts with the same counterparty are also reported on a net basis, as all counterparty contracts provide for net settlement.

Table of Contents

The following is a summary of our derivative contracts as of December 31, 2010:

Settlement Period	Derivative Instrument	Total Notional Amount of Oil (Barrels)	Average Sub-Floor Price	Average Floor Price	Average Ceiling Price	Fair Value Asset (Liability) (In thousands)
2011	Two-Way Collars	1,264,944		$ 76.56	$ 93.89	$ (5,877)
2011	Three-Way Collars	167,000	$ 60.00	$ 80.00	$ 94.98	(666)
2012	Two-Way Collars	444,718		$ 79.21	$ 95.86	(2,049)
2012	Three-Way Collars	685,500	$ 62.44	$ 82.44	$ 104.32	(1,603)
2013	Two-Way Collars	31,000		$ 80.00	$ 96.38	(122)
2013	Three-Way Collars	62,000	$ 62.50	$ 82.50	$ 104.54	(169)
						$ (10,486)

Interest rate risk. At December 31, 2010, we had no indebtedness outstanding under our revolving credit facility. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Counterparty and customer credit risk. Joint interest receivables arise from billing entities which own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We have limited ability to control participation in our wells. We are also subject to credit risk due to concentration of our oil and natural gas receivables with several significant customers. See Item 1. Business Our operations Marketing and major customers for further detail about our significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. In addition, our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. However, in order to mitigate the risk of nonperformance, we only enter into derivative contracts with counterparties that are high credit-quality financial institutions, all of which are lenders under our revolving credit facility. This risk is also managed by spreading our derivative exposure across several institutions and limiting the hedged volumes placed under individual contracts.

While we do not require our customers to post collateral and we do not have a formal process in place to evaluate and assess the credit standing of our significant customers for oil and natural gas receivables and the counterparties on our derivative instruments, we do evaluate the credit standing of such counterparties as we deem appropriate under the circumstances. This evaluation may include reviewing a counterparty s credit rating, latest financial information and, in the case of a customer with which we have receivables, their historical payment record, the financial ability of the customer s parent company to make payment if the customer cannot and undertaking the due diligence necessary to determine credit terms and credit limits. Several of our significant customers for oil and natural gas receivables have a credit rating below investment grade or do not have rated debt securities. In these circumstances, we have considered the lack of investment grade credit rating in addition to the other factors described above.

The counterparties on our derivative instruments currently in place are lenders under our revolving credit facility with investment grade ratings. We are likely to enter into any future derivative instruments with these or other lenders under our revolving credit facility, which also carry investment grade ratings. Furthermore, the agreements with each of the counterparties on our derivative instruments contain netting provisions. As a result of these netting provisions, our maximum amount of loss due to credit risk is limited to the net amounts due to and from the counterparties under the derivative contracts.

Table of Contents

Item 8. *Financial Statements and Supplementary Data*

Index to Financial Statements

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Oasis Petroleum Inc.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, changes in stockholders /members equity, and cash flows present fairly, in all material respects, the financial position of Oasis Petroleum Inc. and its subsidiaries at December 31, 2010 and December 31, 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
March 10, 2011

Table of Contents

Oasis Petroleum Inc.

Consolidated Balance Sheet

	December 31, 2010	December 31, 2009
	(In thousands)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 143,520	$ 40,562
Accounts receivable oil and gas revenues	25,909	9,142
Accounts receivable joint interest partners	28,596	1,250
Inventory	1,323	1,258
Prepaid expenses	490	134
Advances to joint interest partners	3,595	4,605
Derivative instruments		219
Deferred income taxes	2,470	
Total current assets	205,903	57,170
Property, plant and equipment		
Oil and gas properties (successful efforts method)	580,968	243,350
Other property and equipment	1,970	866
Less: accumulated depreciation, depletion, amortization and impairment	(99,255)	(62,643)
Total property, plant and equipment, net	483,683	181,573
Deferred costs and other assets	2,266	810
Total assets	$ 691,852	$ 239,553
LIABILITIES AND STOCKHOLDERS /MEMBERS EQUITY		
Current liabilities		
Accounts payable	$ 8,198	$ 1,577
Advances from joint interest partners	3,101	589
Revenues payable and production taxes	6,180	2,563
Accrued liabilities	58,239	18,038
Accrued interest payable	2	144
Derivative instruments	6,543	1,087
Total current liabilities	82,263	23,998
Long-term debt		35,000
Asset retirement obligations	7,640	6,511
Derivative instruments	3,943	2,085
Deferred income taxes	45,432	

Other liabilities	780	109
Total liabilities	140,058	67,703
Commitments and contingencies (Note 14)		
Stockholders /members equity		
Capital contributions		235,000
Common stock, $0.01 par value; 300,000,000 shares authorized; 92,240,345 shares issued and outstanding	920	
Additional paid-in-capital	643,719	
Retained deficit/accumulated loss	(92,845)	(63,150)
Total stockholders /members equity	551,794	171,850
Total liabilities and stockholders /members equity	$ 691,852	$ 239,553

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

Table of Contents

Oasis Petroleum Inc.

Consolidated Statement of Operations

	Year Ended December 31, 2010	2009	2008
	(In thousands)		
Oil and gas revenues	$ 128,927	$ 37,755	$ 34,736
Expenses			
Lease operating expenses	14,582	8,691	7,073
Production taxes	13,768	3,810	3,001
Depreciation, depletion and amortization	37,832	16,670	8,686
Exploration expenses	297	1,019	3,222
Rig termination		3,000	
Impairment of oil and gas properties	11,967	6,233	47,117
Gain on sale of properties		(1,455)	
Stock-based compensation expenses	8,743		
General and administrative expenses	19,745	9,342	5,452
Total expenses	106,934	47,310	74,551
Operating income (loss)	21,993	(9,555)	(39,815)
Other income (expense)			
Change in unrealized gain (loss) on derivative instruments	(7,533)	(7,043)	14,769
Realized gain (loss) on derivative instruments	(120)	2,296	(6,932)
Interest expense	(1,357)	(912)	(2,404)
Other income (expense)	284	5	(9)
Total other income (expense)	(8,726)	(5,654)	5,424
Income (loss) before income taxes	13,267	(15,209)	(34,391)
Income tax expense	42,962		
Net loss	$ (29,695)	$ (15,209)	$ (34,391)
Loss per share:			
Basic and diluted (Note 12)	$ (0.61)	$	$
Weighted average shares outstanding:			
Basic and diluted (Note 12)	48,395		

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

Table of Contents

Oasis Petroleum Inc.

Consolidated Statement of Changes in Stockholders /Members Equity

	Common Stock Number of Shares	Amount	Capital Contributions	Additional Paid-in-Capital	Retained Deficit/ Accumulated Loss	Total Stockholders / Members Equity
	(In thousands)					
Balance as of December 31, 2007		$	$ 49,900	$	$ (13,550)	$ 36,350
Capital Contributions			80,500			80,500
Net loss					(34,391)	(34,391)
Balance as of December 31, 2008			130,400		(47,941)	82,459
Capital Contributions			104,600			104,600
Net loss					(15,209)	(15,209)
Balance as of December 31, 2009			235,000		(63,150)	171,850
Issuance of common stock	92,000	920				920
Proceeds from the sale of common stock				398,749		398,749
Reclassification of members contributions			(235,000)	235,000		
Stock-based compensation	240			9,970		9,970
Net loss					(29,695)	(29,695)
Balance as of December 31, 2010	92,240	$ 920	$	$ 643,719	$ (92,845)	$ 551,794

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

Table of Contents

Oasis Petroleum Inc.

Consolidated Statement of Cash Flows

	2010	December 31, 2009 (In thousands)	2008
Cash Flows from Operating Activities:			
Net loss	$ (29,695)	$ (15,209)	$ (34,391)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation, depletion and amortization	37,832	16,670	8,686
Exploration expenses			1,280
Impairment of oil and gas properties	11,967	6,233	47,117
Gain on sale of properties		(1,455)	
Deferred income taxes	42,962		
Derivative instruments	7,653	4,747	(7,837)
Stock-based compensation expenses	9,970		
Debt discount amortization and other	470	95	107
Working capital and other changes:			
Change in accounts receivable	(44,450)	(6,409)	(988)
Change in inventory	(498)	(218)	(1,191)
Change in prepaid expenses	(356)	(40)	(6)
Change in other assets	(164)	(667)	
Change in accounts payable and accrued liabilities	13,917	2,440	968
Change in other liabilities	4	(39)	21
Net cash provided by operating activities	49,612	6,148	13,766
Cash flows from investing activities:			
Capital expenditures	(226,544)	(47,396)	(70,427)
Acquisition of oil and gas properties	(86,393)	(35,215)	
Derivative settlements	(120)	2,296	(6,932)
Advances to joint interest partners	1,010	(2,331)	(1,430)
Advances from joint interest partners	2,512	383	206
Proceeds from equipment and property sales		1,507	105
Net cash used in investing activities	(309,535)	(80,756)	(78,478)
Cash flows from financing activities:			
Proceeds from members contributions		104,600	80,500
Proceeds from sale of common stock	399,669		
Proceeds from issuance of debt	72,000	22,000	6,750
Reduction in debt	(107,000)	(13,000)	(27,250)
Debt issuance costs	(1,788)		
Net cash provided by financing activities	362,881	113,600	60,000

Increase (decrease) in cash and cash equivalents		102,958		38,992		(4,712)
Cash and cash equivalents						
Beginning of period		40,562		1,570		6,282
End of period	$	143,520	$	40,562	$	1,570
Supplemental cash flow Information:						
Cash interest paid	$	1,002	$	674	$	2,485
Supplemental non-cash transactions:						
Change in accrued capital expenditures	$	35,181	$	4,134	$	8,173
Asset retirement obligations		1,227		2,156		410

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

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements

1. Organization and Operations of the Company

Organization

Oasis Petroleum Inc. (Oasis or the Company) was formed on February 25, 2010, pursuant to the laws of the State of Delaware to become a publicly traded entity and the parent company of Oasis Petroleum LLC, the Company s predecessor. Oasis Petroleum LLC was formed as a Delaware limited liability company on February 26, 2007 by certain members of the Company s senior management team and through investments made by Oasis Petroleum Management LLC (OPM) and certain private equity funds managed by EnCap Investments L.P. (EnCap). OPM, a Delaware limited liability company, was formed in February 2007 to allow Company employees to become indirect investors in the company. In April 2008, the Company formed Oasis Petroleum International LLC (OPI), a Delaware limited liability company, to conduct business development activities outside of the United States of America. OPI currently has no assets or business activities.

A corporate reorganization occurred concurrently with the completion of the Company s initial public offering (IPO) of its common stock on June 22, 2010. The Company sold 30,370,000 shares and OAS Holding Company LLC (OAS Holdco), the selling stockholder, sold 17,930,000 shares of the Company s common stock, in each case, at $14.00 per share. After deducting estimated expenses and underwriting discounts and commissions of approximately $25.5 million, the Company received net proceeds of $399.7 million. The selling stockholder received aggregate net proceeds of approximately $236.0 million. The Company did not receive any proceeds from the sale of the shares by OAS Holdco. As a part of this corporate reorganization, the Company acquired all of the outstanding membership interests in Oasis Petroleum LLC, in exchange for shares of the Company s common stock. The Company s business continues to be conducted through Oasis Petroleum LLC, as a wholly owned subsidiary.

Nature of Business

The Company is an independent exploration and production company focused on the acquisition and development of unconventional oil and natural gas resources primarily in the Williston Basin. The Company s assets, which consist of proved and unproved oil and natural gas properties, are located primarily in the Montana and North Dakota areas of the Williston Basin, and are owned by Oasis Petroleum North America LLC (OPNA), a wholly owned subsidiary of the Company, which was formed on May 17, 2007 as a Delaware limited liability company.

2. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying consolidated financial statements of the Company include the accounts of Oasis and its wholly owned subsidiaries: Oasis Petroleum LLC, OPI and OPNA. These statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). All significant intercompany transactions have been eliminated in consolidation.

Use of Estimates

Preparation of the Company s consolidated financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil and natural gas reserves and related cash flow estimates used in impairment tests of long-lived assets, estimates of future development, dismantlement and abandonment costs, estimates relating to certain oil and natural gas revenues and expenses and estimates of expenses related to legal, environmental and other contingencies. Certain of these estimates require

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

assumptions regarding future commodity prices, future costs and expenses and future production rates. Actual results could differ from those estimates.

As an oil and natural gas producer, the Company s revenue, profitability and future growth are substantially dependent upon the prevailing and future prices for oil and natural gas, which are dependent upon numerous factors beyond its control such as economic, political and regulatory developments and competition from other energy sources. The energy markets have historically been very volatile and there can be no assurance that oil and natural gas prices will not be subject to wide fluctuations in the future. A substantial or extended decline in oil and natural gas prices could have a material adverse effect on the Company s financial position, results of operations, cash flows and quantities of oil and natural gas reserves that may be economically produced.

Estimates of oil and natural gas reserves and their values, future production rates and future costs and expenses are inherently uncertain for numerous reasons, including many factors beyond the Company s control. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of data available and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based on actual production, results of subsequent exploitation and development activities, prevailing commodity prices, operating cost and other factors. These revisions may be material and could materially affect future depletion, depreciation and amortization expense, dismantlement and abandonment costs, and impairment expense.

Cash and Cash Equivalents

All short-term investments purchased with an original maturity of three months or less are considered cash equivalents. The Company s short-term investments are composed of overnight bank transfers of funds from bank accounts to an offshore United States Dollar denominated interest bearing account. Invested funds and earned interest amounts are returned to the Company s accounts the next business day. Cash equivalents are stated at cost, which approximates market value.

Accounts Receivable

Accounts receivable are carried on a gross basis, with no discounting. The Company regularly reviews all aged accounts receivable for collectability and establishes an allowance as necessary for individual customer balances. No allowance for doubtful accounts was recorded for the years ended December 31, 2010 and 2009.

Inventory

Equipment and materials consist primarily of tubular goods and well equipment to be used in future drilling or repair operations and are stated at the lower of cost or market with cost determined on an average cost method. Crude oil inventories are valued at the lower of average cost or market value. Inventory consists of the following:

	December 31,	
	2010	2009
	(In thousands)	

Equipment and materials	$ 640	$ 588
Crude oil inventory	683	670
	$ 1,323	$ 1,258

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

Joint Interest Partner Advances

The Company participates in the drilling of oil and natural gas wells with other working interest partners. Due to the capital intensive nature of oil and natural gas drilling activities, the working interest partner responsible for conducting the drilling operations may request advance payments from other working interest partners for their share of the costs. The Company expects such advances to be applied by working interest partners against joint interest billings for its share of drilling operations within 90 days from when the advance is paid.

Property, Plant and Equipment

Proved Oil and Gas Properties

Oil and natural gas exploration and development activities are accounted for using the successful efforts method. Under this method, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well has found proved reserves. If an exploratory well does not find proved reserves, the costs of drilling the well are charged to expense. The costs of development wells are capitalized whether productive or nonproductive. All capitalized well costs and leasehold costs of proved properties are amortized on a unit-of-production basis over the remaining life of proved developed reserves and proved reserves, respectively.

The provision for depreciation, depletion and amortization (DD&A) of oil and natural gas properties is calculated on a field-by-field basis using the unit-of-production method. Natural gas is converted to barrel equivalents at the rate of six thousand cubic feet of natural gas to one barrel of oil. The calculation for the unit-of-production DD&A method takes into consideration estimated future dismantlement, restoration and abandonment costs, which are net of estimated salvage values.

Costs of retired, sold or abandoned properties that constitute a part of an amortization base (partial field) are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate for an entire field, in which case a gain or loss is recognized currently. No gain or loss for the sale of oil and natural gas properties was recorded for the years ended December 31, 2010 and 2008. In December 2009, the Company sold its interests in non-core oil and natural gas producing properties located in the Barnett shale in Texas for an aggregate $1.5 million in cash. The Company recognized a gain of $1.4 million from the sale of these divested properties.

Expenditures for maintenance, repairs and minor renewals necessary to maintain properties in operating condition are expensed as incurred. Major betterments, replacements and renewals are capitalized to the appropriate property and equipment accounts. Estimated dismantlement and abandonment costs for oil and natural gas properties are capitalized, net of salvage, at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves.

The Company reviews its proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. The Company estimates the expected undiscounted future cash flows of its oil and natural gas properties and compares such undiscounted future cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value are subject to management s judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with the risk and current market conditions associated with realizing the expected cash flows projected. These assumptions represent Level 3 inputs, as further discussed in Note 3 Fair Value Measurements. No

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

impairment on proved oil and natural gas properties was recorded for the year ended December 31, 2010. During the years ended December 31, 2009 and 2008, the Company recorded a $0.8 million and a $45.5 million non-cash impairment charge, respectively, on its proved oil and natural gas properties.

Unproved Oil and Gas Properties

Unproved properties consist of costs incurred to acquire unproved leases (lease acquisition costs). Lease acquisition costs are capitalized until the leases expire or when the Company specifically identifies leases that will revert to the lessor, at which time the Company expenses the associated lease acquisition costs. The expensing of the lease acquisition costs is recorded as Impairment of oil and gas properties in the Consolidated Statement of Operations. Lease acquisition costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis.

The Company assesses its unproved properties periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results or future plans to develop acreage and records impairment expense for any decline in value. As a result of expiring unproved property leases, the Company recorded non-cash impairment charges of $12.0 million, $5.4 million and $1.6 million for the years ended December 31, 2010, 2009 and 2008, respectively.

For sales of entire working interests in unproved properties, gain or loss is recognized to the extent of the difference between the proceeds received and the net carrying value of the property. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of costs unless the proceeds exceed the entire cost of the property.

Other Property and Equipment

Furniture, equipment and leasehold improvements are recorded at cost and are depreciated on the straight-line method based on expected lives of the individual assets. The Company uses estimated lives of three to five years for these types of assets. The cost of assets disposed of and the associated accumulated depletion, depreciation and amortization are removed from the Company s Consolidated Balance Sheet with any gain or loss realized upon the sale or disposal included in the Company s Consolidated Statement of Operations.

Exploration Expenses

Exploration costs, including certain geological and geophysical expenses and the costs of carrying and retaining undeveloped acreage, are charged to expense as incurred.

Costs from drilling exploratory wells are initially capitalized, but charged to expense if and when a well is determined to be unsuccessful. Determination is usually made on or shortly after drilling or completing the well, however, in certain situations a determination cannot be made when drilling is completed. The Company defers capitalized exploratory drilling costs for wells that have found a sufficient quantity of producible hydrocarbons but cannot be classified as proved because they are located in areas that require major capital expenditures or governmental or other regulatory approvals before production can begin. These costs continue to be deferred as wells-in-progress as long as development is underway, is firmly planned for the near future or the necessary approvals are actively being sought.

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

Net changes in capitalized exploratory well costs are reflected in the following table for the periods presented:

	December 31, 2010	December 31, 2009 (In thousands)	December 31, 2008
Beginning of period	$ 427	$ 324	$
Exploratory well cost additions (pending determination of proved reserves)	39,708	72,972	38,666
Exploratory well cost reclassifications (successful determination of proved reserves)	(34,959)	(72,869)	(37,633)
Exploratory well dry hole costs (unsuccessful in adding proved reserves)			(709)
End of period	$ 5,176	$ 427	$ 324

As of December 31, 2010, the Company had no exploratory well costs that were capitalized for a period greater than one year.

Deferred Costs

The Company capitalizes costs incurred in connection with obtaining financing. These costs are included in Deferred costs and other assets on the Company s Consolidated Balance Sheet and are amortized over the term of the related financing using the straight-line method, which approximates the effective interest method.

Asset Retirement Obligations

In accordance with the FASB s authoritative guidance on asset retirement obligations (ARO), the Company records the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred with the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. For oil and gas properties, this is the period in which the well is drilled or acquired. The ARO represents the estimated amount the Company will incur to plug, abandon and remediate the properties at the end of their productive lives, in accordance with applicable state laws. The liability is accreted to its present value each period and the capitalized costs are depreciated using the unit-of-production method. The accretion expense is recorded as a component of Depreciation, depletion and amortization in the Company s Consolidated Statement of Operations.

The Company determines the ARO by calculating the present value of estimated cash flows related to the liability. Estimating the future ARO requires management to make estimates and judgments regarding timing, and existence of a liability, as well as what constitutes adequate restoration. Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. These assumptions represent Level 3 inputs, as further discussed in Note 3 Fair Value Measurements. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

Revenue Recognition

Revenue from the Company s interests in producing wells is recognized when the product is delivered, at which time the customer has taken title and assumed the risks and rewards of ownership, and collectability is reasonably assured. Substantially all of the Company s production is sold to purchasers under short-term (less than 12 months) contracts at market based prices. The sales prices for oil and natural gas are adjusted for transportation and quality differentials. These differentials are based on contractual or historical data and do

88

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

not require significant judgment. Subsequently, these revenue differentials are adjusted to reflect actual charges based on third-party documents. Since there is a ready market for oil and natural gas, the Company sells the majority of its production soon after it is produced at various locations. As a result, the Company maintains a minimum amount of product inventory in storage.

Revenues Payable and Production Taxes

The Company calculates and pays taxes and royalties on oil and natural gas in accordance with the particular contractual provisions of the lease, license or concession agreements and the laws and regulations applicable to those agreements.

Concentrations of Market Risk

The future results of the Company s oil and natural gas operations will be affected by the market prices of oil and natural gas. The availability of a ready market for oil and natural gas products in the future will depend on numerous factors beyond the control of the Company, including weather, imports, marketing of competitive fuels, proximity and capacity of oil and natural gas pipelines and other transportation facilities, any oversupply or undersupply of oil, natural gas and liquid products, the regulatory environment, the economic environment, and other regional and political events, none of which can be predicted with certainty.

The Company operates in the exploration, development and production sector of the oil and gas industry. The Company s receivables include amounts due from purchasers of its oil and natural gas production and amounts due from joint venture partners for their respective portions of operating expenses and exploration and development costs. While certain of these customers and joint venture partners are affected by periodic downturns in the economy in general or in their specific segment of the oil or natural gas industry, the Company believes that its level of credit-related losses due to such economic fluctuations has been and will continue to be immaterial to the Company s results of operations over the long-term. Trade receivables are generally not collateralized.

Concentrations of Credit Risk

The Company manages and controls market and counterparty credit risk. In the normal course of business, collateral is not required for financial instruments with credit risk. Financial instruments which potentially subject the Company to credit risk consist principally of temporary cash balances and derivative financial instruments. The Company maintains cash and cash equivalents in bank deposit accounts which, at times, may exceed the federally insured limits. The Company has not experienced any significant losses from such investments. The Company attempts to limit the amount of credit exposure to any one financial institution or company. The Company believes the credit quality of its customers is generally high. In the normal course of business, letters of credit or parent guarantees are required for counterparties which management perceives to have a higher credit risk.

Risk Management

The Company utilizes derivative financial instruments to manage risks related to changes in oil prices. As of December 31, 2010, the Company utilized two-way and three-way collar options to reduce the volatility of oil prices on a significant portion of the Company s future expected oil production (see Note 4 Derivative Instruments).

The Company records all derivative instruments on the balance sheet as either assets or liabilities measured at their estimated fair value. The Company has not designated any derivative instruments as hedges for accounting purposes and does not enter into such instruments for speculative trading purposes. Realized gains and losses from the settlement of commodity derivative instruments and unrealized gains and losses from

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

valuation changes in the remaining unsettled commodity derivative instruments are reported in the Other Income (Expense) section of the Company s Consolidated Statement of Operations. Unrealized gains are included in current and noncurrent assets and unrealized losses are included in current and noncurrent liabilities on the Consolidated Balance Sheet, respectively.

Derivative financial instruments that hedge the price of oil are executed with major financial institutions that expose the Company to market and credit risks and which may, at times, be concentrated with certain counterparties or groups of counterparties. The Company has derivatives in place with three counterparties, all of which are lenders under the Company s revolving credit facility. Although notional amounts are used to express the volume of these contracts, the amounts potentially subject to credit risk in the event of nonperformance by the counterparties are substantially smaller. The credit worthiness of the counterparties is subject to continual review. The Company believes the risk of nonperformance by its counterparties is low. Full performance is anticipated, and the Company has no past-due receivables from its counterparties. The Company s policy is to execute financial derivatives only with major, credit-worthy financial institutions.

The Company s derivative contracts are documented with industry standard contracts known as a Schedule to the Master Agreement and International Swaps and Derivative Association, Inc. Master Agreement (ISDA). Typical terms for the ISDAs include credit support requirements, cross default provisions, termination events and set-off provisions. The Company is not required to provide any credit support to its counterparties other than cross collateralization with the properties securing the Company s revolving credit facility (see Note 8 Long-Term Debt). As of December 31, 2010, the revolving credit facility had a provision limiting the total amount of production that may be hedged by the Company. As of December 31, 2010, the Company was in compliance with these limitations as its contractual commodity derivative volumes for 2011 and 2012 represent approximately 57% and 42%, respectively, of the Company s average daily oil production for the three months ended December 31, 2010.

Environmental Costs

Environmental expenditures are expensed or capitalized, as appropriate, depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and which do not have future economic benefit, are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated.

Restricted Stock Awards

The Company has granted restricted stock awards to employees and directors under its 2010 Long-Term Incentive Plan, the majority of which vest over a three-year period. The fair value of restricted stock grants is based on the value of the Company s common stock on the date of grant. Compensation expense is recognized ratably over the requisite service period. As of December 31, 2010, the Company assumed no annual forfeiture rate because of the Company s lack of turnover and lack of history for this type of award.

Any excess tax benefit arising from our stock-based compensation plan is recognized as a credit to additional paid-in-capital when realized and is calculated as the amount by which the tax deduction received exceeds the deferred tax asset associated with the recorded stock-based compensation expense. As of December 31, 2010, none of the Company s restricted stock awards had vested, and therefore, there was no required measurement of tax deduction compared to the deferred tax assets associated with the recorded stock-based compensation expense as of

December 31, 2010.

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

Income Taxes

The Company s provision for taxes includes both federal and state taxes. The Company records its federal income taxes in accordance with accounting for income taxes under GAAP which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

The Company applies significant judgment in evaluating its tax positions and estimating its provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from our estimates, which could impact our financial position, results of operations and cash flows.

The Company also accounts for uncertainty in income taxes recognized in the financial statements in accordance with GAAP by prescribing a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return. Authoritative guidance for accounting for uncertainty in income taxes requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not-threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority. The Company does not have uncertain tax positions outstanding and, as such, did not record a liability for the year ended December 31, 2010.

Fair Value of Financial and Non-Financial Instruments

The carrying value of cash and cash equivalents, accounts receivable, accounts payable and other payables approximate their respective fair market values due to their short-term maturities. The Company s derivative instruments, long-term debt and asset retirement obligations are also recorded on the balance sheet at amounts which approximate fair market value. See Note 3 Fair Value Measurements.

Recent Accounting Pronouncements

Goodwill. In December 2010, the FASB issued ASU 2010-28, Intangibles Goodwill and Other: When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts (ASU 2010-28). ASU 2010-28 requires step two of the goodwill impairment test to be performed when the carrying value of a reporting unit is zero or negative, if it is more likely than not that a goodwill impairment exists. The requirements of this update are effective for fiscal years beginning after December 15, 2010. The Company does not expect the adoption of this new guidance to have an impact on its financial position, cash flows or results of operations.

Business combinations. In December 2010, the FASB issued ASU 2010-29, Business Combinations: Disclosure of Supplementary Pro Forma Information for Business Combinations (ASU 2010-29). ASU 2010-29 clarifies that when presenting comparative pro forma financial statements in conjunction with business combination disclosures, revenue and earnings of the combined entity should be presented as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period. In addition, the update requires a description of the nature and amount of material, nonrecurring pro forma adjustments included in pro forma revenue and earnings that are directly

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

attributable to the business combination. This update is effective prospectively for business combinations that occur on or after the beginning of the first annual reporting period after December 15, 2010. As ASU 2010-29 relates to disclosure requirements, there will be no impact on the Company s financial position, cash flows or results of operations.

Financial receivables. On July 21, 2010, the FASB issued ASU 2010-20 Receivables (Topic 310) Disclosures about the Credit Quality of Financial Receivables and the Allowance for Credit Losses. This new ASU requires disclosure of additional information to assist financial statement users to understand more clearly an entity s credit risk exposures to finance receivables and the related allowance for credit losses. This ASU is effective for all public companies for interim and annual reporting periods ending on or after December 15, 2010 with specific items, such as the allowance rollforward and modification disclosures, effective for periods beginning after December 15, 2010. The adoption of this new guidance did not have an impact on the Company s financial position, cash flows or results of operations.

Fair value. In January 2010, the FASB issued authoritative guidance to update certain disclosure requirements and added two new disclosure requirements related to fair value measurements. The guidance requires a gross presentation of activities within the Level 3 roll forward and adds a new requirement to disclose details of significant transfers in and out of Level 1 and 2 measurements and the reasons for the transfers. The new disclosures are required for all companies that are required to provide disclosures about recurring and nonrecurring fair value measurements, and is effective the first interim or annual reporting period beginning after December 15, 2009, except for the gross presentation of the Level 3 roll forward information, which is required for annual reporting periods beginning after December 15, 2010 and for interim reporting periods within those years. The adoption of this new guidance did not have an impact on the Company s financial position, cash flows or results of operations.

3. Fair Value Measurements

The Company adopted the FASB s authoritative guidance on fair value measurements effective January 1, 2008 for financial assets and liabilities measured on a recurring basis. Beginning January 1, 2009, the Company also applied this guidance to non-financial assets and liabilities. The Company s financial assets and liabilities are measured at fair value on a recurring basis. The Company recognizes its non-financial assets and liabilities, such as asset retirement obligations and proved oil and natural gas properties upon impairment, at fair value on a non-recurring basis.

As defined in the authoritative guidance, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). To estimate fair value, the Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable.

The authoritative guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). The three levels of the fair value hierarchy are as follows:

Level 1 Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily

Table of Contents

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Level 3 Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management s best estimate of fair value.

As required, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The following tables set forth by level within the fair value hierarchy the Company s financial assets and liabilities that were accounted for at fair value on a recurring basis:

	At Fair Value as of December 31, 2010			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets (Liabilities):				
Commodity Derivative Instruments (see Note 4)	$	$	$ (10,486)	$ (10,486)
Total Derivative Instruments	$	$	$ (10,486)	$ (10,486)

	At Fair Value as of December 31, 2009			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets (Liabilities):				
Commodity Derivative Instruments (see Note 4)	$	$	$ (2,953)	$ (2,953)
Total Derivative Instruments	$	$	$ (2,953)	$ (2,953)

The Level 3 instruments presented in the tables above consist of oil collars. The fair values of the Company s oil collars are based upon mark-to-market valuation reports provided by its counterparties for monthly settlement purposes to determine the valuation of its derivative instruments. The Company has a third-party reviewer evaluate other readily available market prices for its derivative contracts as there is an active market for these contracts. However, the Company does not have access to the specific valuation models used by its counterparties or third party reviewer. The determination of the fair values presented above also incorporates a credit adjustment for non-performance risk, as required by GAAP. The Company calculated the credit adjustment for derivatives in an asset position using current credit default swap values for each counterparty. The credit adjustment for derivatives in a liability position is based on the Company s current cost of prime based borrowings (prime rate and associated margin effect). Based on these calculations, the Company recorded a downward adjustment to the fair value of its derivative instruments in the amount of $0.3 million and $0.08 million for the years ended December 31, 2010 and 2009, respectively.

Table of Contents

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

The following table presents a reconciliation of the changes in fair value of the derivative instruments classified as Level 3 in the fair value hierarchy for the years presented.

	2010	2009	2008
		(In thousands)	
Balance as of January 1	$ (2,953)	$ 4,090	$ (10,679)
Total gains or (losses) (realized or unrealized):			
Included in earnings	(7,653)	(4,747)	7,837
Included in other comprehensive income			
Purchases, issuances and settlements	120	(2,296)	6,932
Transfers in and out of level 3			
Balance as of December 31	$ (10,486)	$ (2,953)	$ 4,090
Change in unrealized gains (losses) included in earnings relating to derivatives still held at December 31	$ (7,533)	$ (7,043)	$ 14,769

At December 31, 2010, the Company s financial instruments, including cash and cash equivalents, accounts receivable and accounts payable, are carried at cost, which approximates fair value due to the short-term maturity of these instruments. The carrying amount of the Company s ARO in the Consolidated Balance Sheet at December 31, 2010 is $7.6 million, which also approximates fair value as the Company determines the ARO by calculating the present value of estimated cash flows related to the liability based on the calculation of the estimated value (see Note 2 Summary of Significant Accounting Policies).

The Company reviews its proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. Therefore, the Company s proved oil and natural gas properties are measured at fair value on a non-recurring basis. No impairment charge on proved oil and natural gas properties was recorded for the year ended December 31, 2010. During the years ended December 31, 2009 and 2008, the Company recorded a $0.8 million and a $45.5 million non-cash impairment charge, respectively, on its proved oil and natural gas properties, as further discussed in Note 2 Summary of Significant Accounting Policies. The 2009 impairment charge related to certain dry holes, which had a fair value of zero. The oil and natural gas properties related to the 2008 impairment charge had a fair value of $22.3 million and were evaluated for impairment primarily due to lower crude oil prices at December 31, 2008.

4. Derivative Instruments

The Company utilizes derivative financial instruments to manage risks related to changes in oil prices. As of December 31, 2010, the Company utilized two-way and three-way collar options to reduce the volatility of oil prices on a significant portion of the Company s future expected oil production. A two-way collar is a combination of options: a sold call and a purchased put. The purchased put establishes a minimum price (floor) and the sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The purchased put establishes a minimum price, unless the market price falls below the sold put, at which point the minimum price would be NYMEX-WTI plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (ceiling) we will receive for the volumes under contract.

All derivative instruments are recorded on the balance sheet as either assets or liabilities measured at their fair value (see Note 3 Fair Value Measurements). The Company has not designated any derivative instruments as hedges for accounting purposes and does not enter into such instruments for speculative trading purposes. If a derivative does not qualify as a hedge or is not designated as a hedge, the changes in the fair value, both realized and unrealized, are recognized in the Other Income (Expense) section of the Consolidated

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

Statement of Operations as a gain or loss on mark-to-market derivative contracts. The Company s cash flow is only impacted when the actual settlements under the derivative contracts result in making or receiving a payment to or from the counterparty. These cash settlements are reflected as investing activities in the Company s Consolidated Statement of Cash Flows.

As of December 31, 2010, the Company had the following outstanding commodity derivative contracts, all of which settle monthly based on the West Texas Intermediate crude oil index price, and none of which were designated as hedges:

Settlement Period	Derivative Instrument	Total Notional Amount of Oil (Barrels)	Average Sub-Floor Price	Average Floor Price	Average Ceiling Price	Fair Value Asset (Liability) (In thousands)
2011	Two-Way Collars	1,264,944		$ 76.56	$ 93.89	(5,877)
2011	Three Way Collars	167,000	$ 60.00	$ 80.00	$ 94.98	(666)
2012	Two-Way Collars	444,718		$ 79.21	$ 95.86	(2,049)
2012	Three-Way Collars	685,500	$ 62.44	$ 82.44	$ 104.32	(1,603)
2013	Two-Way Collars	31,000		$ 80.00	$ 96.38	(122)
2013	Three Way Collars	62,000	$ 62.50	$ 82.50	$ 104.54	(169)
						$ (10,486)

The following table summarizes the location and fair value of all outstanding commodity derivative contracts recorded in the balance sheet for the periods presented:

Fair Value of Derivative Instrument Assets (Liabilities)

Instrument Type	Balance Sheet Location		Fair Value December 31, 2010	2009
			(In thousands)	
Crude oil collar	Derivative Instruments	current assets	$	$ 219
Crude oil swap	Derivative Instruments	current liabilities		(26)
Crude oil collar	Derivative Instruments	current liabilities	(6,543)	(1,061)
Crude oil collar	Derivative Instruments	non-current liabilities	(3,943)	(2,085)
	Total Derivative Instruments		$ (10,486)	$ (2,953)

The following table summarizes the location and amounts of realized and unrealized gains and losses from the Company s commodity derivative contracts for the periods presented:

	Income Statement Location	2010	December 31, 2009 (In thousands)	2008
Derivative Contracts	Change in Unrealized Gain (Loss) on Derivative Instruments	$ (7,533)	$ (7,043)	$ 14,769
Derivative Contracts	Realized Gain (Loss) on Derivative Instruments	(120)	2,296	(6,932)
	Total Commodity Derivative Gain (Loss)	$ (7,653)	$ (4,747)	$ 7,837

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

5. Property, Plant and Equipment

The following table sets forth the Company s property, plant and equipment:

	December 31, 2010	December 31, 2009
	(In thousands)	
Proved oil and gas properties	$ 479,657	$ 195,546
Less: Accumulated depreciation, depletion, amortization and impairment	(98,821)	(62,330)
Proved oil and gas properties, net	380,836	133,216
Unproved oil and gas properties	101,311	47,804
Other property and equipment	1,970	866
Less: Accumulated depreciation	(434)	(313)
Other property and equipment, net	1,536	553
Total property, plant and equipment, net	$ 483,683	$ 181,573

Included in the Company s oil and gas properties are asset retirement costs of $6.3 million and $5.4 million at December 31, 2010 and 2009, respectively.

Asset Impairments As discussed in Note 2, as a result of expiring unproved property leases, the Company recorded non-cash impairment charges on its unproved oil and gas properties of $12.0 million and $5.4 million for the years ended December 31, 2010 and 2009, respectively. For the year ended December 31, 2009, the Company also recorded a non-cash impairment charge of $0.8 million on its proved oil and gas properties. No impairment on proved oil and natural gas properties was recorded for the year ended December 31, 2010.

6. Acquisitions

Asset Acquisitions During the fourth quarter of 2010, the Company acquired approximately 16,700 net acres of land in Roosevelt County, Montana and approximately 10,000 net leasehold acres primarily located in Richland County, Montana for $52.3 million and $30.1 million, respectively. This acreage is part of our West Williston project area. Based on the FASB s relative authoritative guidance, neither acquisition qualified as a business combination.

Kerogen Acquisition On June 15, 2009, the Company acquired interests in certain oil and gas properties primarily in the East Nesson area of the Williston Basin from Kerogen Resources, Inc. (the Kerogen Acquisition Properties) for $27.1 million. In addition to acquiring the interests in the East Nesson project area, the Company also acquired non-operated interests in the Sanish project area.

The Kerogen acquisition qualified as a business combination, and as such, the Company estimated the fair value of these properties as of the June 15, 2009 acquisition date. The fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). Fair value measurements also utilize assumptions of market participants. The Company used a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions represent Level 3 inputs, as further discussed in Note 3 Fair Value Measurements.

Table of Contents

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

The Company estimated the fair value of the Kerogen Acquisition Properties to be approximately $27.1 million, which the Company considered to be representative of the price paid by a typical market participant. This measurement resulted in no goodwill or bargain purchase being recognized. The acquisition related costs were insignificant.

The following table summarizes the consideration paid for the Kerogen Acquisition Properties and the fair value of the assets acquired and liabilities assumed as of June 15, 2009.

Consideration given to Kerogen Resources, Inc. (in thousands):	
Cash	$ 27,087
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Proved developed properties	$ 25,178
Proved undeveloped properties	1,647
Unproved lease acquisition costs	360
Seismic costs	667
Asset retirement obligations	(765)
Total identifiable net assets	$ 27,087

Summarized below are the consolidated results of operations for the years ended December 31, 2009 and 2008, on an unaudited pro forma basis, as if the acquisition had occurred on January 1 of each of the periods presented. The unaudited pro forma financial information was derived from the historical consolidated statement of operations of the Company and the statement of revenues and direct operating expenses for the Kerogen Acquisition Properties, which were derived from the historical accounting records of the seller. The unaudited pro forma financial information does not purport to be indicative of results of operations that would have occurred had the transaction occurred on the basis assumed above, nor is such information indicative of the Company s expected future results of operations.

	Year Ended December 31,			
	2009		2008	
	Actual	Pro Forma	Actual	Pro Forma
	(In thousands) Unaudited			
Kerogen Acquisition Properties:				
Revenues	$ 37,755	$ 41,999	$ 34,736	$ 51,314
Net Loss	$ (15,209)	$ (15,461)	$ (34,391)	$ (25,858)

Fidelity Acquisition On September 30, 2009, the Company acquired additional interests in the East Nesson project area of the Williston Basin from Fidelity Exploration and Production Company (the Fidelity Acquisition Properties) for $10.7 million.

The Fidelity acquisition qualified as a business combination, and as such, the Company estimated the fair value of these properties as of the September 30, 2009 acquisition date. The Company used a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions represent Level 3 inputs, as further discussed in Note 3 Fair Value Measurements.

The Company estimated the fair value of the Fidelity Acquisition Properties to be approximately $10.7 million, which the Company considers to be representative of the price paid by a typical market participant. This measurement resulted in no goodwill or bargain purchase being recognized. The acquisition related costs were insignificant.

Table of Contents

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

The following table summarizes the consideration paid for the Fidelity Acquisition Properties and the fair value of the assets acquired and liabilities assumed as of September 30, 2009.

Consideration given to Fidelity Exploration and Production Company (in thousands):	
Cash	$ 10,681
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Proved developed properties	$ 4,668
Proved undeveloped properties	2,415
Unproved lease acquisition costs	3,450
Seismic costs	667
Asset retirement obligations	(519)
Total identifiable net assets	$ 10,681

Summarized below are the consolidated results of operations for the years ended December 31, 2009 and 2008, on an unaudited pro forma basis as if the acquisition had occurred on January 1 of each of the periods presented. The pro forma financial information was derived from the historical consolidated statement of operations of the Company and the statement of revenues and direct operating expenses for the Fidelity Acquisition Properties, which were derived from the historical accounting records of the seller. The unaudited pro forma financial information does not purport to be indicative of results of operations that would have occurred had the transaction occurred on the basis assumed above, nor is such information indicative of the Company s expected future results of operations.

	Year Ended December 31,			
	2009		**2008**	
	Actual	**Pro Forma**	**Actual**	**Pro Forma**
	(In thousands) Unaudited			
Fidelity Acquisition Properties:				
Revenues	$ 37,755	$ 40,934	$ 34,736	$ 38,438
Net Loss	$ (15,209)	$ (15,872)	$ (34,391)	$ (33,065)

7. Accrued Liabilities

The Company s accrued liabilities consist of the following:

	December 31,	
	2010	**2009**
	(In thousands)	
Accrued capital costs	$ 49,935	$ 14,754

Accrued lease operating expense	3,305	1,560
Accrued general and administrative expense	3,014	1,056
Other	1,985	668
Total	$ 58,239	$ 18,038

In addition, the Company had production taxes payable of $3.2 million and $1.2 million and revenue suspense of $2.3 million and $1.1 million for the years ended December 31, 2010 and 2009, respectively, included in Production taxes and royalties payable on the Consolidated Balance Sheet.

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

8. Long-Term Debt

Oasis Petroleum LLC, as parent, and OPNA, as borrower, entered into a credit agreement dated June 22, 2007 (as amended, the Credit Facility). On February 26, 2010, the Company entered into an agreement that amended and restated the existing Credit Facility, as amended (the Amended Credit Facility). The Amended Credit Facility increased the initial borrowing base to a maximum of $70 million, extended the maturity date to February 26, 2014, and included BNP Paribas, JP Morgan Chase Bank, UBS Loan Finance LLC and Wells Fargo Bank as lenders (collectively, the Lenders). Borrowings under the Amended Credit Facility are collateralized by perfected first priority liens and security interests on substantially all of the Company s assets, including mortgage liens on oil and natural gas properties having at least 80% of the reserve value as determined by reserve reports. In connection with the IPO, the Company became a guarantor under the Amended Credit Facility on June 3, 2010.

The Amended Credit Facility provides for semi-annual redeterminations on April 1 and October 1 of each year, commencing October 2, 2010. At the Company s request, the semi-annual redetermination of the borrowing base under its Amended Credit Facility was completed on August 11, 2010. As a result of this redetermination, the Company s borrowing base increased from $70 million to $120 million. Contemporaneously with this redetermination, the Company amended its Amended Credit Facility to ease certain limitations on the Company s ability to enter into derivative financial instruments. All other rates, terms and conditions of the Amended Credit Facility remained the same.

Borrowings under the Amended Credit Facility are subject to varying rates of interest based on (1) the total outstanding borrowings (including the value of all outstanding letters of credit) in relation to the borrowing base and (2) whether the loan is a London Interbank Offered Rate (LIBOR) loan or a bank prime interest rate loan (defined in the Amended Credit Facility as an Alternate Based Rate or ABR loan). As of December 31, 2010, the LIBOR and ABR loans beared their respective interest rates plus the applicable margin indicated in the following table:

Ratio of Total Outstanding Borrowings to Borrowing Base	**Applicable Margin for LIBOR Loans**	**Applicable Margin for ABR Loans**
Less than .50 to 1	2.25%	0.75%
Greater than or equal to .50 to 1 but less than .75 to 1	2.50%	1.00%
Greater than or equal to .75 to 1 but less than .85 to 1	2.75%	1.25%
Greater than .85 to 1 but less than or equal 1	3.00%	1.50%

An ABR loan does not have a set maturity date and may be repaid at any time upon the Company providing advance notification to the Lenders. Interest is paid quarterly on ABR loans based on the number of days an ABR loan is outstanding as of the last business day in March, June, September and December. The Company has the option to convert an ABR loan to a LIBOR-based loan upon providing advance notification to the Lenders. The minimum available loan term is one month and the maximum loan term is six months for LIBOR-based loans. Interest for LIBOR loans is paid upon maturity of the loan term. Interim interest is paid every three months for LIBOR loans that have loan terms that are greater than three months in duration. At the end of a LIBOR loan term, the Amended Credit Facility allows the Company to elect to continue a LIBOR loan with the same or a differing loan term or convert the borrowing to an ABR loan.

On a quarterly basis, the Company also pays a 0.50% commitment fee on the daily amount of borrowing base capacity not utilized during the quarter and fees calculated on the daily amount of letter of credit balances outstanding during the quarter.

As of December 31, 2010, the Amended Credit Facility contained covenants that included, among others:

a prohibition against incurring debt, subject to permitted exceptions;

a prohibition against making dividends, distributions and redemptions, subject to permitted exceptions;

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

a prohibition against making investments, loans and advances, subject to permitted exceptions;

restrictions on creating liens and leases on the assets of the Company and its subsidiaries, subject to permitted exceptions;

restrictions on merging and selling assets outside the ordinary course of business;

restrictions on use of proceeds, investments, transactions with affiliates or change of principal business;

a provision limiting oil and natural gas derivative financial instruments;

a requirement that the Company not allow a ratio of Total Debt (as defined in the Amended Credit Facility) to consolidated EBITDAX (as defined in the Amended Credit Facility) to be greater than 4.0 to 1.0 for the four quarters ended on the last day of each quarter; and

a requirement that the Company maintain a Current Ratio of consolidated current assets (with exclusions as described in the Amended Credit Facility) to consolidated current liabilities (with exclusions as described in the Amended Credit Facility) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter.

The Amended Credit Facility contains customary events of default. If an event of default occurs and is continuing, the Lenders may declare all amounts outstanding under the Amended Credit Facility to be immediately due and payable.

As of December 31, 2010, the Company had no borrowings under the Amended Credit Facility and $25,000 of outstanding letters of credit issued under the Amended Credit Facility, resulting in an unused borrowing base capacity of $120.0 million. The weighted average interest rate incurred on the outstanding Amended Credit Facility borrowings during 2010 was 3.11%. The Company was in compliance with the financial covenants of the Amended Credit Facility as of December 31, 2010.

During 2010, the Company recorded $1.8 million of deferred financing costs related to costs incurred in connection with amending and restating the Credit Facility and the semi-annual redeterminations, which are being amortized over the term of the Amended Credit Facility. The deferred financing costs are included in Deferred costs and other assets on the Company s Consolidated Balance Sheet at December 31, 2010. The amortization of deferred financing costs is included in Interest expense on the Consolidated Statement of Operations. The Company also wrote off $132,000 of unamortized deferred financing costs related to the Credit Facility, included in Interest expense on the Company s Consolidated Statement of Operations, for the year ended December 31, 2010.

9. Asset Retirement Obligations

The following table reflects the changes in the Company s ARO during the years ended December 31, 2010 and 2009:

	December 31,	
	2010	2009
	(In thousands)	

Asset retirement obligation beginning of period	$ 6,511	$ 4,458
Liabilities incurred during period	1,747	2,144
Liabilities settled during period	(422)	(395)
Accretion expense during period	414	362
Revisions to estimates	(610)	(58)
Asset retirement obligation end of period	$ 7,640	$ 6,511

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

10. Stock-Based Compensation

Restricted Stock Awards The Company has granted restricted stock awards to employees and directors under its 2010 Long-Term Incentive Plan, the majority of which vest over a three-year period. The fair value of restricted stock grants is based on the value of the Company s common stock on the date of grant. Compensation expense is recognized ratably over the requisite service period. As of December 31, 2010, the Company assumed no annual forfeiture rate because of the Company s lack of turnover and lack of history for this type of award.

The following table summarizes information related to restricted stock held by the Company s employees and directors at December 31, 2010:

	Shares	Weighted Average Grant Date Fair Value
Non-vested shares outstanding at December 31, 2009		
Granted	240,345	$ 16.16
Vested		
Forfeited		
Non-vested shares outstanding at December 31, 2010	240,345	$ 16.16

Stock-based compensation expense recorded for restricted stock awards for the year ended December 31, 2010 was approximately $1.2 million and is included in General and administrative expenses on the Company s Consolidated Statement of Operations. Unrecognized expense as of December 31, 2010 for all outstanding restricted stock awards was $2.7 million and will be recognized over a weighted average period of 2.0 years. No stock-based compensation expense was recorded for the years ended December 31, 2009 and 2008 as the Company had not historically issued stock-based compensation awards to its employees and directors.

Class C Common Unit Interests In March 2010, the Company recorded a $5.2 million stock-based compensation charge associated with OPM s grant of 1.0 million Class C Common Unit interests (C Units) to certain employees of the Company. The C Units were granted on March 24, 2010 to individuals who were employed by the Company as of February 1, 2010, and who were not executive officers or key employees with an existing capital investment in OPM (Oasis Petroleum Management LLC Capital Members). All of the C Units vested immediately on the grant date, and based on the characteristics of the C Units awarded to employees, the Company concluded that the C Units represented an equity-type award and accounted for the value of this award as if it had been awarded by the Company.

The C Units were membership interests in OPM and not direct interests in the Company. The C Units are non-transferable and have no voting power. OPM has an interest in OAS Holdco, but neither OPM nor its members have a controlling interest or controlling voting power in OAS Holdco. OPM will distribute any cash or common stock it receives to its members based on membership interests and distribution percentages. OPM will only make distributions if it first receives cash or common stock from distributions made at the election of OAS Holdco. As of

December 31, 2010, OPM had distributed substantially all cash or requisite common stock to its members based on membership interests and distribution percentages.

In accordance with the FASB s authoritative guidance for share-based payments, the Company used a fair-value-based method to determine the value of stock-based compensation awarded to its employees and recognized the entire grant date fair value of $5.2 million as stock-based compensation expense on the Consolidated Statement of Operations due to the immediate vesting of the awards with no future requisite service period required of the employees.

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

The Company used a probability weighted expected return method to evaluate the potential return and associated fair value allocable to the C Unit shareholders using selected hypothetical future outcomes (continuing operations, private sale of the Company, and an IPO). Approximately 95% of the fair value allocated to the C Unit shareholders came from the IPO scenario. The IPO fair value of the C Units awarded to the Company s employees was estimated on the date of the grant using the Black-Scholes option-pricing model with the assumptions described below.

The exercise price of the option used in the option-pricing model was set equal to the maximum value of OPM s current capital investment in the Company as that value must be returned to Oasis Petroleum Management LLC Capital Members before distributions are made to the C Unit shareholders. Since the Company was not a public entity on the grant date, it did not have historical stock trading data that could be used to compute volatilities associated with certain expected terms; therefore, the expected volatility value of 60% was estimated based on an average of volatilities of similar sized oil and gas companies with operations in the Williston Basin whose common stocks are publicly traded. The allocable fair value to the C Units occurs in an assumed timing of four years based on a future potential secondary offering or distribution of common stock of the Company. The OAS Holdco agreement between its members required a complete distribution of all remaining shares held by OAS Holdco by 2014, the fourth year following the year of the IPO. The 2.08% risk-free rate used in the pricing model is based on the U.S. Treasury yield for a government bond with a maturity equal to the time to liquidity of four years. The Company did not estimate forfeiture rates due to the immediate vesting of the award and did not estimate future dividend payments as it does not expect to declare or pay dividends in the foreseeable future.

Discretionary Stock Awards During the fourth quarter of 2010, the Company recorded a $3.5 million stock-based compensation charge primarily associated with OPM granting discretionary shares of the Company s common stock to certain of the Company s employees who were not C Unit holders and certain contractors. Based on the characteristics of these awards, the Company concluded that they represented an equity-type award and accounted for the value of these awards as if they had been awarded by the Company. The fair value of these awards was based on the value of the Company s common stock on the date of grant. All of these awards vested immediately on the grant date with no future requisite service period required of the employees or contractors.

Stock-based compensation expense recorded for the C Units and discretionary stock awards for the year ended December 31, 2010 was $8.7 million. As the awards vested immediately, there was no unrecognized stock-based compensation expense as of December 31, 2010 related to these awards. No stock-based compensation expense was recorded for the years ended December 31, 2009 and 2008 as the Company had not historically issued stock-based compensation awards to its employees.

11. Income Taxes

Prior to its corporate reorganization in connection with the IPO (see Note 1), the Company was a limited liability company and not subject to federal or state income tax (in most states). Accordingly, no provision for federal or state income taxes was recorded prior to the corporate reorganization as the Company s equity holders were responsible for income tax on the Company s profits. In connection with the closing of the Company s IPO, the Company merged into a corporation and became subject to federal and state income taxes. The Company s book and tax basis in assets and liabilities differed at the time of the corporate reorganization due primarily to different cost recovery periods utilized for book and tax purposes for the Company s oil and natural gas properties.

At June 30, 2010, the Company recorded an estimated net deferred tax expense of $29.2 million to recognize a deferred tax liability for the initial book and tax basis differences. This deferred tax liability was preliminary and included significant estimates related to the pre-corporate reorganization period of 2010. The preliminary calculation was based on information that was available to management at the time such estimates

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

were made as further analysis was dependent upon the receipt of actual expenditure information in subsequent months.

At September 30, 2010, the Company increased its estimate of this deferred tax liability by $6.2 million to $35.4 million. After analyzing the book and tax basis differences for capital expenditure accruals made at June 30, 2010, management determined that an additional deferred tax liability of $5.2 million was needed as of the date of the corporate reorganization. In addition, new tax legislation was passed in September 2010, which extended bonus tax depreciation retroactive to January 1, 2010, resulting in an additional increase of the Company s deferred tax liability of $0.8 million. These adjustments, along with $0.2 million of other changes in estimates, were recorded as a discrete deferred tax expense for the three months ended September 30, 2010. The final adjustment to the Company s estimated deferred tax liability related to the pre-IPO period was recorded in the fourth quarter of 2010, which resulted in an additional discrete adjustment of $0.2 million.

The Company s effective tax rate differs from the federal statutory rate of 35% due to the initial deferred tax expense, state income taxes, certain non-deductible IPO-related costs and non-deductible stock-based compensation expense. The reconciliation of income taxes calculated at the U.S. federal tax statutory rate to the Company s effective tax rate for the year ended December 31, 2010 is set forth below:

		(In thousands)	
U.S. federal tax statutory rate	35.00%	$	4,644
State income taxes, net of federal income tax benefit	2.75%		364
Pass-through loss prior to IPO not subject to federal tax	3.85%		511
Initial deferred tax expense	268.43%		35,612
Non-deductible stock-based compensation	10.08%		1,338
Non-deductible IPO costs and other	3.72%		493
Annual effective tax rate	323.83%	$	42,962

Significant components of the Company s deferred tax assets and liabilities as of December 31, 2010 were as follows:

	(In thousands)	
Deferred tax assets		
Derivative instruments	$	3,958
Net operating loss carryforward		43,455
Total deferred tax assets		47,413
Deferred tax liabilities		
Oil and natural gas properties		90,375

Total deferred tax liabilities		90,375
Net deferred tax liability	$	42,962

The current portion of the Company s net deferred tax liability was an asset of $2.5 million at December 31, 2010.

The Company generated a net operating tax loss of $115.0 million for the year ended December 31, 2010, and therefore no current income taxes are anticipated to be paid. The opportunity to utilize such net operating loss in future periods will expire by 2030. As of December 31, 2010, the Company did not have any uncertain tax positions requiring adjustments to its tax liability.

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

The Company files income tax returns in the U.S. federal jurisdiction and in Montana, North Dakota and Texas. The Company has not been audited by the IRS or any state jurisdiction. Its statute of limitation for the year ended December 31, 2010 will expire in 2014.

12. Earnings (Loss) Per Share

Basic earnings (loss) per share is computed by dividing income available to common stockholders by the weighted average number of shares outstanding for the periods presented. The calculation of diluted earnings (loss) per share includes the potential dilutive impact of non-vested restricted shares outstanding during the periods presented, unless their effect is anti-dilutive.

The following is a calculation of the basic and diluted weighted-average shares outstanding for the year ended December 31, 2010:

	(In thousands)
Basic weighted average common shares outstanding(1)	48,395
Dilution effect of stock awards at end of period(2)	
Diluted weighted average common shares outstanding	48,395
Anti-dilutive stock-based compensation awards	120

(1) The basic weighted average shares outstanding calculation is based on the actual days in which the shares were outstanding for the period from June 22, 2010, the closing date of the IPO, to December 31, 2010.

(2) Because the Company reported a net loss for the year ended December 31, 2010, no unvested stock awards were included in computing loss per share because the effect was anti-dilutive.

13. Significant Concentrations

Purchasers that accounted for more than 10% of the Company s total sales for the periods presented are as follows:

	Year Ended December 31,		
	2010	2009	2008
Plains All American Pipeline L.P.	28%	N/A	N/A
Texon L.P.	19%	30%	14%
Whiting Petroleum Corporation	11%	N/A	N/A
Tesoro Refining and Marketing Company	N/A	32%	57%

N/A Not applicable as the sales to these purchasers did not account for more than 10% of the Company s total sales for such respective periods.

No other purchasers accounted for more than 10% of the Company s total oil and natural gas sales for the years ended December 31, 2010, 2009 and 2008. Management believes that the loss of any of these purchasers would not have a material adverse effect on the Company s operations, as there are a number of alternative oil and natural gas purchasers in the Company s producing regions.

Substantially all of the Company s accounts receivable result from sales of oil and natural gas as well as joint interest billings (JIB) to third-party companies who have working interest payment obligations in projects completed by the Company. Brigham Oil & Gas LP and Hess Corporation accounted for approximately 44% and 12%, respectively, of the Company s JIB receivables balance at December 31, 2010. Zenergy Operating Company LLC, Bristol Exploration LP and Abraxas Petroleum Corporation accounted for approximately 27%, 19% and 13%, respectively, of the Company s JIB receivables balance at December 31, 2009.

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

Hess Corporation and Windsor Bakken LLC accounted for approximately 41% and 13%, respectively, of the Company s JIB receivables balance at December 31, 2008. No other individual account balances accounted for more than 10% of the Company s total JIB receivables at December 31, 2010, 2009 and 2008.

This concentration of customers and joint interest owners may impact the Company s overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions.

14. Commitments and Contingencies

Lease Obligations The Company has operating leases for office space and other property and equipment. The Company incurred rental expense of $0.6 million, $0.4 million and $0.3 million for the years ended December 31, 2010, 2009 and 2008, respectively.

Future minimum annual rental commitments under non-cancelable leases at December 31, 2010 are as follows:

		(In thousands)
2011		909
2012		922
2013		912
2014		900
Thereafter		2,516
	$	6,159

Drilling Contracts During 2010, the Company entered into two new drilling rig contracts with initial terms greater than one year. In the event of early contract termination under these new contracts, the Company would be obligated to pay approximately $2.5 million as of December 31, 2010 for the days remaining through the end of the primary terms of the contracts.

Volume Commitment Agreements During 2010, the Company entered into certain agreements with an aggregate requirement to deliver a minimum quantity of approximately 3 Bcf from our West Williston project area within a specified timeframe. Future obligations under these agreements are approximately $5.3 million as of December 31, 2010. The Company also entered into an agreement with a requirement to deliver a minimum quantity of approximately 790 MBbl from our West Williston project area within a specified timeframe. Based on the terms of the agreement, the Company is unable to quantify its future obligation under this agreement as of December 31, 2010, as the margin on the replacement price is determined at the time of production shortfall, if any.

Litigation The Company is party to various legal and/or regulatory proceedings from time to time arising in the ordinary course of business. The Company believes all such matters are without merit or involve amounts which, if resolved unfavorably, either individually or in the aggregate, will not have a material adverse effect on its financial condition, results of operations or cash flows.

15. Subsequent Events

Lease Obligations On January 12, 2011, the Company executed an amendment to its office space lease agreement for an additional 11,638 square feet of space within its current office building. Under the terms of the amendment, the Company s rental obligation for the new premises will begin upon substantial completion of the remodeling work in the new premises, which is projected to be in May 2011. The amended lease agreement terminates on September 30, 2017.

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

Drilling Contracts On January 13, 2011, the Company entered into a new drilling rig contract with an initial term greater than one year. In the event of early contract termination under this new contract, the Company would be obligated to pay a maximum of approximately $12.2 million if terminated immediately at the beginning of the contract. On February 17, 2011, the Company extended one of its existing drilling rig contracts for an additional year. In the event of early contract termination under this extended contract, the Company would be obligated to pay an additional maximum of approximately $3.7 million if terminated immediately.

Senior Secured Revolving Line of Credit On January 21, 2011, a redetermination of the borrowing base under the Company s Amended Credit Facility was completed, at the request of the Company, in lieu of the April 2, 2011 redetermination. As a result of this redetermination, the Company s borrowing base increased from $120 million to $150 million. However, in connection with the issuance of the Company s private placement of $400 million of senior unsecured notes due 2019 on February 2, 2011, as described below, the Company s borrowing base under its Amended Credit Facility automatically decreased $12.5 million to $137.5 million.

Contemporaneously with this redetermination, the Company entered into a third amendment to its Amended Credit Facility in order to:

- eliminate the $200 million limit for unsecured notes;
- reduce the interest rates payable on borrowings under its Amended Credit Facility;
- modify the debt coverage ratio covenant to be net of cash and cash equivalents on the Company s Consolidated Balance Sheet;
- extend the maturity date from February 26, 2014 to February 26, 2015;
- increase the size of the Amended Credit Facility from $250 million to $600 million; and
- add an additional lender to the bank group for the Amended Credit Facility.

Borrowings under the Amended Credit Facility are subject to varying rates of interest based on (1) the total outstanding borrowings (including the value of all outstanding letters of credit) in relation to the borrowing base and (2) whether the loan is a London Interbank Offered Rate (LIBOR) loan or a bank prime interest rate loan (defined in the Amended Credit Facility as an Alternate Based Rate or ABR loan). The LIBOR and ABR loans bear their respective interest rates plus the applicable margin indicated in the following table:

Ratio of Total Outstanding Borrowings to Borrowing Base	Applicable Margin for LIBOR Loans	Applicable Margin for ABR Loans
Less than .50 to 1	2.00%	0.50%
Greater than or equal to .50 to 1 but less than .75 to 1	2.25%	0.75%
Greater than or equal to .75 to 1 but less than .85 to 1	2.50%	1.00%
Greater than .85 to 1 but less than or equal 1	2.75%	1.25%

All other rates, terms and conditions of the Amended Credit Facility dated February 26, 2010 remained the same (see Note 8).

Senior Unsecured Notes On February 2, 2011, the Company issued $400 million of 7.25% senior unsecured notes (the Notes) due February 1, 2019. Interest is payable on the Notes semi-annually in arrears on each February 1 and August 1, commencing August 1, 2011. The Notes are guaranteed on a senior unsecured basis by our material subsidiaries (Guarantors). The issuance of these Notes resulted in net proceeds to us of approximately $390 million, which we will use to fund our exploration, development and acquisition program and for general corporate purposes.

Table of Contents

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

At any time prior to February 1, 2014, the Company may redeem up to 35% of the Notes at a redemption price of 107.25% of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings so long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the Notes remains outstanding after such redemption. Prior to February 1, 2015, the Company may redeem some or all of the Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and after February 1, 2015, the Company may redeem some or all of the Notes at redemption prices (expressed as percentages of principal amount) equal to 103.625% for the twelve-month period beginning on February 1, 2015, 101.813% for the twelve-month period beginning February 1, 2016 and 100.00% beginning on February 1, 2017, plus accrued and unpaid interest to the redemption date.

The securities offered have not been registered under the Securities Act of 1933, as amended, (the Securities Act), or any state securities laws; and unless so registered, the securities may not be offered or sold in the United States except pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the Securities Act and applicable state securities laws. The senior unsecured notes are expected to be eligible for trading by qualified institutional buyers under Rule 144A and non-U.S. persons under Regulation S.

On February 2, 2011, in connection with the issuance of the Notes, the Company entered into an Indenture (the Base Indenture), among the Company and U.S. Bank National Association, as trustee (the Trustee), as amended and supplemented by the first supplemental indenture among the Company, the Guarantors and the Trustee, dated as of February 2, 2011 (the Supplemental Indenture ; the Base Indenture, as amended and supplemented by the Supplemental Indenture, the Indenture).

The Indenture restricts the Company s ability and the ability of certain of its subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay distributions on, redeem or repurchase, equity interests; (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when the Notes are rated investment grade by both Moody s Investors Service, Inc. and Standard & Poor s Ratings Services and no Default (as defined in the Indenture) has occurred and is continuing, many of such covenants will terminate and the Company and its subsidiaries will cease to be subject to such covenants.

The Indenture contains customary events of default, including:

- default in any payment of interest on any Note when due, continued for 30 days;
- default in the payment of principal of or premium, if any, on any Note when due;
- failure by the Company to comply with its other obligations under the Indenture, in certain cases subject to notice and grace periods;
- payment defaults and accelerations with respect to other indebtedness of the Company and its Restricted Subsidiaries (as defined in the Indenture) in the aggregate principal amount of $10.0 million or more;
- certain events of bankruptcy, insolvency or reorganization of the Company or a Significant Subsidiary (as defined in the Indenture) or group of Restricted Subsidiaries that, taken together, would constitute a Significant

Subsidiary;

failure by the Company or any Significant Subsidiary or group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary to pay certain final judgments aggregating in excess of $10.0 million within 60 days; and

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

any guarantee of the Notes by a Guarantor ceases to be in full force and effect, is declared null and void in a judicial proceeding or is denied or disaffirmed by its maker.

Derivative Instruments In 2011, the Company entered into new two-way and three-way collar option contracts, all of which settle monthly based on the West Texas Intermediate crude oil index price, for a total notional amount of 974,000 barrels in 2011, 915,000 barrels in 2012 and 730,000 barrels in 2013. These commodity derivatives do not qualify for and were not designated as hedging instruments for accounting purposes.

Volume Commitment Agreements In 2011, the Company entered into a marketing agreement with a requirement to deliver a minimum quantity of approximately 1.2 MMBbl from our West Williston project area within a specified timeframe. The future obligation under this agreement is approximately $1.2 million as of February 28, 2011.

16. Supplemental Oil and Gas Disclosures

The supplemental data presented herein reflects information for all of the Company s oil and natural gas producing activities.

Capitalized Costs

The following table sets forth the capitalized costs related to the Company s oil and natural gas producing activities at December 31, 2010 and 2009:

	December 31,	
	2010	**2009**
	(In thousands)	
Proved oil and gas properties	$ 479,657	$ 195,546
Less: Accumulated depreciation, depletion, amortization and impairment	(98,821)	(62,330)
Proved oil and gas properties, net	380,836	133,216
Unproved oil and gas properties	101,311	47,804
Total oil and gas properties, net	$ 482,147	$ 181,020

Pursuant to the FASB s authoritative guidance on asset retirement obligations, net capitalized costs include asset retirement costs of $6.3 million and $5.4 million at December 31, 2010 and 2009, respectively.

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities

The following table sets forth costs incurred related to the Company s oil and natural gas activities for the years ended December 31, 2010, 2009 and 2008:

	Year Ended December 31, 2010	2009	2008
	(In thousands)		
Acquisition costs:			
Proved oil and gas properties	$ 20,259	$ 35,134	$ 36,969
Unproved oil and gas properties	81,624	13,917	
Exploration costs	297	1,019	3,222
Development costs	243,758	38,526	39,025
Asset retirement costs	968	1,314	
Total costs incurred	$ 346,906	$ 89,910	$ 79,216

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

Results of Operations for Oil and Natural Gas Producing Activities

Results of operations for oil and natural gas producing activities, which excludes straight-line depreciation, general and administrative expense and interest expense, are presented below.

	2010	December 31, 2009 (In thousands)	2008
Revenues	$ 128,927	$ 37,755	$ 34,736
Production costs	28,350	12,501	10,074
Depreciation, depletion and amortization	37,583	16,592	8,581
Exploration costs	297	1,019	3,222
Rig termination		3,000	
Impairment of oil and gas properties	11,967	6,233	47,117
Gain on sale of properties		(1,455)	
Income tax expenses	17,756		
Results of operations for oil and gas producing activities	$ 32,974	$ (135)	$ (34,258)

17. Supplemental Oil and Gas Reserve Information Unaudited

The reserve estimates at December 31, 2010 and 2009 presented in the table below are based on reports prepared by DeGolyer and MacNaughton, independent reserve engineers, in accordance with the FASB s new authoritative guidance on oil and gas reserve estimation and disclosures. The reserve estimates at December 31, 2008 presented in the table below are based on a report prepared by W.D. Von Gonten & Co. using the FASB s rules in effect at that time. At December 31, 2010, all of the Company s oil and natural gas producing activities were conducted within the continental United States.

The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and natural gas properties. Accordingly, these estimates are expected to change as future information becomes available.

Proved oil and natural gas reserves are the estimated quantities of oil and natural gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions (i.e., prices and costs) existing at the time the estimate is made. Proved developed oil and natural gas reserves are proved reserves that can be expected to be recovered through existing wells and equipment in place and under operating methods being utilized at the time the estimates were made.

Table of Contents

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

Estimated Quantities of Proved Oil and Natural Gas Reserves Unaudited

The following table sets forth the Company s net proved, proved developed and proved undeveloped reserves at December 31, 2010, 2009 and 2008:

	Oil (MBbl)	Gas (MMcf)	MBoe
2008			
Proved reserves			
Beginning balance	4,044	1,239	4,251
Revisions of previous estimates	(1,604)	(479)	(1,684)
Extensions, discoveries and other additions	132	34	137
Sales of reserves in place			
Purchases of reserves in place			
Production	(379)	(123)	(400)
Net proved reserves at December 31, 2008	2,193	671	2,304
Proved developed reserves, December 31, 2008	2,193	671	2,304
Proved undeveloped reserves, December 31, 2008			
2009			
Proved reserves			
Beginning balance	2,193	671	2,304
Revisions of previous estimates	781	(84)	767
Extensions, discoveries and other additions	8,381	3,414	8,950
Sales of reserves in place	(2)	(16)	(5)
Purchases of reserves in place	1,726	1,611	1,995
Production	(658)	(326)	(712)
Net proved reserves at December 31, 2009	12,421	5,270	13,299
Proved developed reserves, December 31, 2009	5,231	2,293	5,613
Proved undeveloped reserves, December 31, 2009	7,190	2,977	7,686
2010			
Proved reserves			
Beginning balance	12,421	5,270	13,299
Revisions of previous estimates	2,235	1,897	2,552
Extensions, discoveries and other additions	22,445	12,172	24,473
Sales of reserves in place	(122)	(5)	(123)

Purchases of reserves in place	1,363	696	1,479
Production	(1,792)	(651)	(1,900)
Net proved reserves at December 31, 2010	36,550	19,379	39,780
Proved developed reserves, December 31, 2010	15,650	8,208	17,018
Proved undeveloped reserves, December 31, 2010	20,900	11,171	22,762

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

Purchases of Reserves in Place

Of the total 1,479 MBoe of reserves purchased in 2010, 715 MBoe were from the properties acquired in Roosevelt County, Montana in November 2010 and 764 MBoe were from the properties acquired in Richland County, Montana in December 2010.

Of the total 1,995 MBoe of reserves purchased in 2009, 1,511 MBoe were from the Kerogen Acquisition Properties and 484 MBoe were from the Fidelity Acquisition Properties. The Company did not purchase reserves in place in 2008.

Extensions, Discoveries and Other Additions

In 2010, the Company had a total of 24,473 MBoe of additions. An estimated 8,122 MBoe of extensions and discoveries were associated with new wells, which were producing at December 31, 2010, with approximately 99% of these reserves from wells producing in the Bakken or Three Forks formations. An additional 16,351 MBoe of proved undeveloped reserves were added across all three of the Company s Williston Basin project areas associated with the Company s 2010 operated and non-operated drilling program, with 100% of these proved undeveloped reserves in the Bakken or Three Forks formations.

In 2009, the Company had a total of 8,950 MBoe of additions. An estimated 1,508 MBoe of extensions and discoveries were associated with new wells, which were producing at December 31, 2009, with approximately 95% of these reserves from wells producing in the Bakken or Three Forks formations. An additional 7,442 MBoe of proved undeveloped reserves were added across all three of the Company s Williston Basin project areas associated with the Company s 2009 operated and non-operated drilling program, with 100% of these proved undeveloped reserves in the Bakken or Three Forks formations.

In 2008, the Company had a total of 137 MBoe of additions. An estimated 127 MBoe resulted from the Company s 2008 Bakken drilling program in the East Nesson project area.

Sales of Reserves in Place

The Company traded interests in three non-operated properties as part of the Richland County, Montana acquisition in December 2010. These properties produce from the Red River formation and had remaining reserves of 123 MBoe.

In 2009, the Company sold a portion its interests in non-core oil and gas producing properties located in the Barnett shale in Texas, which had minimal impact on the Company s proved reserves. The Company had no divestitures for the year ended December 31, 2008.

Revisions of Previous Estimates

In 2010, the Company had net positive revisions of 2,552 MBoe. Approximately 29% of these revisions were due to the increase in oil prices from 2009 to 2010. The unweighted arithmetic average first-day-of-the-month prices for the 12 months prior were $79.40/Bbl for the year ended December 31, 2010 as compared to $61.04/Bbl for the year ended December 31, 2009. An estimated 29% of the increase was due to higher working interests in proved wells. The remaining 42% of these revisions were due to other changes, including the estimate of recoverable hydrocarbons from proved wells.

In 2009, the Company had net positive revisions of 767 MBoe, primarily due to the increase in oil prices. The unweighted arithmetic average first-day-of-the-month prices for the 12 months prior was $61.04/Bbl for the year ended December 31, 2009 as compared to the market price for oil of $44.60/Bbl used for the December 31, 2008 reserves.

Table of Contents

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

In 2008, the Company had net negative revisions of 1,684 MBoe. An estimated 461 MBoe reduction resulted from poor drilling results in the conventional Madison formation, including proved undeveloped locations offsetting the Madison formation drilling results. The remaining net 1,223 MBoe reduction is primarily related to the decrease in oil price, including 461 MBoe of proved undeveloped reserves at December 31, 2007, which did not have a positive PV-10 at the lower oil prices and were removed from the December 31, 2008 reserves. The index price for oil at December 31, 2008 decreased to $44.60/Bbl from $96.00/Bbl at December 31, 2007.

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

The Standardized Measure represents the present value of estimated future cash flows from proved oil and natural gas reserves, less future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows. Production costs do not include depreciation, depletion and amortization of capitalized acquisition, exploration and development costs.

Our estimated proved reserves and related future net revenues and Standardized Measure were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic average first-day-of-the-month prices for the prior 12 months were $79.40/Bbl for oil and $4.38/MMBtu for natural gas for the year ended December 31, 2010 and $61.04/Bbl for oil and $3.87/MMBtu for natural gas for the year ended December 31, 2009. The index prices were $44.60/Bbl for oil and $5.63/MMBtu for natural gas at December 31, 2008. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. The impact of the adoption of the FASB s authoritative guidance on the SEC oil and gas reserve estimation final rule on our consolidated financial statements is not practicable to estimate due to the operational and technical challenges associated with calculating a cumulative effect of adoption by preparing reserve reports under both the old and new rules.

The following table sets forth the Standardized Measure of discounted future net cash flows from projected production of the Company s oil and natural gas reserves at December 31, 2010, 2009 and 2008.

	At Year Ended December 31,		
	2010	2009	2008
	(In thousands)		
Future cash inflows	$ 2,620,530	$ 664,480	$ 85,678
Future production costs	(696,890)	(258,137)	(54,885)
Future development costs	(362,328)	(120,212)	(3,708)
Future income tax expense(1)	(495,788)		
Future net cash flows	1,065,524	286,131	27,085
10% annual discount for estimated timing of cash flows	(579,789)	(152,601)	(9,355)
Standardized measure of discounted future net cash flows	$ 485,735	$ 133,530	$ 17,730

(1) Does not include the effect of income taxes on discounted future net cash flows for the years ended December 31, 2009 and 2008 because as of December 31, 2009 and 2008, the Company was a limited liability company not subject to entity-level taxation. Accordingly, no provision for federal or state corporate income taxes was provided because taxable income was passed through to the Company s equity holders.

Table of Contents

Oasis Petroleum Inc.

Notes to Consolidated Financial Statements (Continued)

The following table sets forth the changes in the Standardized Measure of discounted future net cash flows applicable to proved oil and natural gas reserves for the periods presented.

	2010	2009 (In thousands)	2008
January 1,	$ 133,530	$ 17,730	$ 121,807
Net changes in prices and production costs	126,089	11,423	(48,986)
Net changes in future development costs	(9,767)	1,998	210
Sales of oil and natural gas, net	(100,577)	(25,254)	(24,662)
Extensions	426,824	71,333	2,648
Discoveries			
Purchases of reserves in place	26,919	36,809	
Sales of reserves in place	(1,720)	(108)	
Revisions of previous quantity estimates	55,149	7,700	(48,260)
Previously estimated development costs incurred	32,729		746
Accretion of discount	13,353	3,352	12,181
Net change in income taxes	(212,085)		
Changes in timing and other	(4,709)	8,547	2,046
December 31,	$ 485,735	$ 133,530	$ 17,730

18. Quarterly Financial Data Unaudited

The Company s results of operations by quarter for the years ended December 31, 2010 and 2009 are as follows:

	For the Year Ended December 31, 2010:			
	First Quarter	Second Quarter(1) (In thousands)	Third Quarter	Fourth Quarter
Revenues	$ 20,068	$ 26,734	$ 32,978	$ 49,147
Operating income (loss)	(2,479)	648	10,831	12,993
Net income (loss)	$ (3,231)	$ (26,350)	$ (1,701)	$ 1,587

	For the Year Ended December 31, 2009:			
	First Quarter	Second Quarter (In thousands)	Third Quarter	Fourth Quarter

Revenues	$ 3,216	$ 6,036	$ 11,046	$ 17,457
Operating loss	(6,091)	(1,536)	(329)	(1,599)
Net loss	$ (5,512)	$ (5,883)	$ (171)	$ (3,643)

(1) In connection with the closing of the Company s IPO, it merged into a corporation and became subject to federal and state entity-level taxation. At June 30, 2010, the Company recorded an estimated net deferred tax expense of $29.2 million to recognize a deferred tax liability for the initial book and tax basis differences. See Note 11.

Table of Contents

Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

None.

Item 9A. *Controls and Procedures*

Material Weakness in Internal Control over Financial Reporting. Prior to the completion of our IPO, we were a private company with limited accounting personnel to adequately execute our accounting processes and other supervisory resources with which to address our internal control over financial reporting. As such, we have not maintained an effective control environment in that the design and execution of our controls have not consistently resulted in effective review and supervision by individuals with financial reporting oversight roles. The lack of adequate staffing levels resulted in insufficient time spent on review and approval of certain information used to prepare our financial statements. We concluded that these control deficiencies constitute a material weakness in our control environment. A material weakness is a control deficiency, or a combination of control deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis. The control deficiencies described below, at varying degrees of severity, contributed to the material weakness in the control environment.

In 2007, we did not maintain effective controls to ensure that correct working interests were used in our calculations of asset retirement obligations and depreciation, depletion and amortization expense. In 2008, the lack of effective controls over the accuracy of working interests and the accurate clearing of asset retirement obligations resulted in the misstatement of our proved property impairment expense. In 2009, we did not maintain effective controls over the accuracy of key spreadsheets used in our computations of unproved property impairment expense. For the first quarter of 2010, we did not maintain adequate controls over changes to our depreciation, depletion and amortization rate calculations. For each of these periods, effective controls were not adequately designed or consistently operating to ensure that key computations were properly reviewed before the amounts were recorded in our accounting records. The above identified control deficiencies resulted in audit adjustments to our consolidated financial statements for the period from February 26, 2007 (inception) through December 31, 2007, the years ended December 31, 2008 and 2009 and for the three months ended March 31, 2010. In each case, the adjustments were made prior to the issuance of such financial statements and did not result in a restatement. These control deficiencies contributed to the material weakness in the control environment described above.

Remediation Activites. Although remediation efforts are still in progress, management has taken steps to address the causes of the adjustments by putting into place new accounting processes and control procedures. Management created a centralized source for working interests and implemented controls to ensure that working interests used in reserve report information and accounting computations are reconciled to the centralized source of working interests. In addition, we have hired additional accounting and financial reporting staff since our IPO, implemented additional analysis and reconciliation procedures and increased the levels of review and approval. Additionally, we have begun taking steps to comprehensively document and analyze our system of internal control over financial reporting in preparation for our first management report on internal control over financial reporting required in connection with our annual report for the year ended December 31, 2011.

Due to the recent implementation of these changes to our control environment, management continues to evaluate the design and effectiveness of these control changes in conjunction with its ongoing evaluation, review, formalization and testing of our internal control environment over the remainder of 2011. We will not complete our review until after this Annual Report on Form 10-K is filed. We cannot predict the outcome of our review at this time. During the course of the review, we may identify additional control deficiencies, which could give rise to additional significant deficiencies and other material weaknesses.

Evaluation of Disclosure Controls and Procedures. As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as

Table of Contents

of December 31, 2010. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. In light of the previously identified material weakness described above, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were not effective at the reasonable assurance level as of December 31, 2010. Notwithstanding the existence of the material weakness, management concluded that the financial statements and other financial information included in this Annual Report on Form 10-K presents fairly, in all material respects, the financial condition, results of operations and cash flows for all periods presented.

Changes in Internal Control over Financial Reporting. As described above, there were changes in our system of internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act) that occurred during the three months ended December 31, 2010 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

This Annual Report on Form 10-K does not include a report of management s assessment regarding internal control over financial reporting or an attestation of the Company s independent registered public accounting firm due to a transition period established by SEC rules for newly public companies. A report of management s assessment regarding internal control over financial reporting and an attestation on the effectiveness of our internal control over financial reporting by our independent registered public accounting firm are not required until we file our annual report for the year ended December 31, 2011.

Item 9B. *Other Information*

None.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2011 Annual Meeting of Stockholders.

Item 11. *Executive Compensation*

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2011 Annual Meeting of Stockholders.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2011 Annual Meeting of Stockholders.

Item 13. *Certain Relationships and Related Transactions and Director Independence*

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2011 Annual Meeting of Stockholders.

Item 14. ***Principal Accountant Fees and Services***

Pursuant to General Instruction 6 to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2011 Annual Meeting of Stockholders.

Table of Contents

PART IV

Item 15. *Exhibits, Financial Statement Schedules*

a. The following documents are filed as a part of this Annual Report on Form 10-K or incorporated herein by reference:

(1) Financial Statements:

See Item 8. Financial Statements and Supplementary Data.

(2) Financial Statement Schedules:

None.

(3) Exhibits:

The following documents are included as exhibits to this report:

Exhibit No.	Description of Exhibit
2.1	Asset Purchase Agreement, dated July 24, 2010, by and among Oasis Petroleum North America LLC, Luff Exploration Company and the other parties thereto (filed as Exhibit 2.1 to the Company s Current Report on Form 8-K on December 16, 2010, and incorporated herein by reference).
3.1	Amended and Restated Certificate of Incorporation of Oasis Petroleum Inc. (filed as Exhibit 3.1 to the Company s Current Report on Form 8-K on June 24, 2010, and incorporated herein by reference).
3.2	Amended and Restated Bylaws of Oasis Petroleum Inc. (filed as Exhibit 3.2 to the Company s Current Report on Form 8-K on June 24, 2010, and incorporated herein by reference).
4.1	Specimen Common Stock Certificate (filed as Exhibit 4.1 to the Company s Registration Statement on Form S-1/A on May 19, 2010, and incorporated herein by reference).
4.2	Indenture dated as of February 2, 2011 among the Company and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Company s Current Report on Form 8-K on February 2, 2011, and incorporated herein by reference).
4.3	Supplemental Indenture dated as of February 2, 2011 among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to the Company s Current Report on Form 8-K on February 2, 2011, and incorporated herein by reference).
4.4	Registration Rights Agreement dated as of February 2, 2011 among the Company, the Guarantors and J.P. Morgan Securities LLC, as representative of the several initial purchasers (filed as Exhibit 4.3 to the Company s Current Report on Form 8-K on February 2, 2011, and incorporated herein by reference).
10.1	Contribution Agreement, dated June 15, 2010, by and among Oasis Petroleum Inc., Oasis Petroleum LLC, OAS Holding Company LLC, OAS Mergerco LLC and EnCap Energy Capital Fund VI, L.P. (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on June 22, 2010, and incorporated herein by reference).
10.2	

	Registration Rights Agreement dated as of June 22, 2010 by and between Oasis Petroleum Inc. and OAS Holding Company LLC (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on June 24, 2010, and incorporated herein by reference).
10.3	Business Opportunities Agreement dated as of June 22, 2010 by and among Oasis Petroleum Inc., EnCap Investments L.P., Douglas E. Swanson, Jr. and Robert L. Zorich (filed as Exhibit 10.2 to the Company s Current Report on Form 8-K on June 24, 2010, and incorporated herein by reference).
10.4	Services Agreement dated as of June 22, 2010 by and between Oasis Petroleum Inc. and Oasis Petroleum Management LLC (filed as Exhibit 10.3 to the Company s Current Report on Form 8-K on June 24, 2010, and incorporated herein by reference).

Exhibit No.	Description of Exhibit
10.5	Services Agreement dated as of June 22, 2010 by and between Oasis Petroleum Inc. and OAS Holding Company LLC (filed as Exhibit 10.4 to the Company s Current Report on Form 8-K on June 24, 2010, and incorporated herein by reference).
10.6	First Amendment to Amended and Restated Credit Agreement and Consent dated as of June 3, 2010 by and among Oasis Petroleum North America LLC, as borrower, Oasis Petroleum LLC and Oasis Petroleum Inc., as guarantors, BNP Paribas, as Administrative Agent, and the lenders party thereto (filed as Exhibit 10.5 to the Company s Current Report on Form 8-K on June 24, 2010, and incorporated herein by reference).
10.7	Second Amendment to Amended and Restated Credit Agreement dated as of August 11, 2010, among Oasis Petroleum North America LLC, as borrower, Oasis Petroleum LLC and Oasis Petroleum Inc., as guarantors, BNP Paribas, as Administrative Agent, and the lenders party thereto (filed as Exhibit 10.18 to the Company s Quarterly Report on Form 10-Q on August 13, 2010, and incorporated herein by reference).
10.8	Third Amendment to Amended and Restated Credit Agreement and Limited Waiver, dated as of January 21, 2011, among Oasis Petroleum North America LLC, as borrower, Oasis Petroleum LLC and Oasis Petroleum Inc., as guarantors, BNP Paribas, as administrative agent, and the lenders party thereto (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on January 24, 2011, and incorporated herein by reference).
10.9**	Employment Agreement dated as of June 18, 2010 between Oasis Petroleum Inc. and Thomas B. Nusz (filed as Exhibit 10.6 to the Company s Current Report on Form 8-K on June 24, 2010, and incorporated herein by reference).
10.10**	Employment Agreement dated as of June 18, 2010 between Oasis Petroleum Inc. and Taylor L. Reid (filed as Exhibit 10.7 to the Company s Current Report on Form 8-K on June 24, 2010, and incorporated herein by reference).
10.11**	Long-Term Incentive Plan of Oasis Petroleum Inc. (filed as Exhibit 10.6 to the Company s Registration Statement on Form S-1/A on May 19, 2010, and incorporated herein by reference).
10.12(a)**	Form of Indemnification Agreement between Oasis Petroleum Inc. and each of the directors and executive officers thereof.
10.13**	Executive Change in Control and Severance Benefit Plan of Oasis Petroleum Inc. (filed as Exhibit 10.8 to the Company s Registration Statement on Form S-1/A on May 19, 2010, and incorporated herein by reference).
10.14**	2010 Annual Incentive Compensation Plan of Oasis Petroleum Inc. (filed as Exhibit 10.9 to the Company s Registration Statement on Form S-1/A on May 19, 2010, and incorporated herein by reference).
10.15**	Form of Notice of Grant of Restricted Stock (filed as Exhibit 10.10 to the Company s Registration Statement on Form S-1/A on May 19, 2010, and incorporated herein by reference).
10.16**	Form of Restricted Stock Agreement (filed as Exhibit 10.11 to the Company s Registration Statement on Form S-1/A on May 19, 2010, and incorporated herein by reference).
10.17**	Form of Notice of Grant of Restricted Stock Unit (filed as Exhibit 10.12 to the Company s Registration Statement on Form S-1/A on May 19, 2010, and incorporated herein by reference).
10.18**	Form of Notice of Grant of Restricted Stock Unit Designated as a Performance Share Unit (filed as Exhibit 10.13 to the Company s Registration Statement on Form S-1/A on May 19, 2010, and incorporated herein by reference).
10.19**	Form of Restricted Stock Unit Agreement (filed as Exhibit 10.14 to the Company s Registration Statement on Form S-1/A on May 19, 2010, and incorporated herein by reference).

10.20	Purchase and Sale Agreement, dated November 5, 2010, by and among Oasis Petroleum North America LLC, Zenergy Onshore Properties, LLC, Zenergy Operating Company, LLC, Zeneco, Inc. and Garden Isle Investments, LLC (filed as Exhibit 10.4 to the Company s Quarterly Report on Form 10-Q/A on December 16, 2010, and incorporated herein by reference).

Table of Contents

Exhibit No.	Description of Exhibit
10.21	Purchase Agreement dated as of January 28, 2011 among the Company, the Guarantors and J.P. Morgan Securities LLC, as representative of the several initial purchasers (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on February 2, 2011, and incorporated herein by reference).
21.1(a)	List of Subsidiaries of Oasis Petroleum Inc.
23.1(a)	Consent of PricewaterhouseCoopers LLP.
23.2(a)	Consent of W.D. Von Gonten & Co.
23.3(a)	Consent of DeGolyer and MacNaughton.
31.1(a)	Sarbanes-Oxley Section 302 certification of Principal Executive Officer.
31.2(a)	Sarbanes-Oxley Section 302 certification of Principal Financial Officer.
32.1(b)	Sarbanes-Oxley Section 906 certification of Principal Executive Officer.
32.2(b)	Sarbanes-Oxley Section 906 certification of Principal Financial Officer.
99.1(a)	Report of DeGolyer and MacNaughton.

(a) Filed herewith.

(b) Furnished herewith.

** Management contract or compensatory plan or arrangement.

Table of Contents

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, on March 10, 2011.

OASIS PETROLEUM INC.

By:
/s/ Thomas B. Nusz
Thomas B. Nusz
Chairman of the Board, President and
Chief Executive Officer

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 capacity and on the dates indicated:

Signature	Title	Date
/s/ Thomas B. Nusz Thomas B. Nusz	Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)	March 10, 2011
/s/ Taylor L. Reid Taylor L. Reid	Director, Executive Vice President and Chief Operating Officer	March 10, 2011
/s/ Roy W. Mace Roy W. Mace	Senior Vice President and Chief Accounting Officer (Principal Financial Officer and Principal Accounting Officer)	March 10, 2011
/s/ Douglas E. Swanson, Jr. Douglas E. Swanson, Jr.	Director	March 10, 2011
/s/ Robert L. Zorich Robert L. Zorich	Director	March 10, 2011
/s/ William Cassidy William Cassidy	Director	March 10, 2011
/s/ Ted Collins, Jr. Ted Collins, Jr.	Director	March 10, 2011
/s/ Michael McShane	Director	March 10, 2011

Michael McShane

Table of Contents

GLOSSARY OF OIL AND NATURAL GAS TERMS

The terms defined in this section are used throughout this Annual Report on Form 10-K:

Bbl. One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or natural gas liquids.

Bcf. One billion cubic feet of natural gas.

Boe. Barrels of oil equivalent, with 6,000 cubic feet of natural gas being equivalent to one barrel of oil.

British thermal unit. The heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Basin. A large natural depression on the earth s surface in which sediments generally brought by water accumulate.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Developed reserves. Reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods or for which the cost of required equipment is relatively minor when compared to the cost of a new well.

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

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Economically producible. A resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

Environmental assessment. An environmental assessment, a study that can be required pursuant to federal law to assess the potential direct, indirect and cumulative impacts of a project.

Exploratory well. A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

Formation. A layer of rock which has distinct characteristics that differ from nearby rock.

Horizontal drilling. A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

Infill wells. Wells drilled into the same pool as known producing wells so that oil or natural gas does not have to travel as far through the formation.

MBbl. One thousand barrels of crude oil, condensate or natural gas liquids.

MBoe. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet of natural gas.

MMBbl. One million barrels of crude oil, condensate or natural gas liquids.

MMBoe. One million barrels of oil equivalent.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

NYMEX. The New York Mercantile Exchange.

Net acres. The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

PV-10. When used with respect to oil and natural gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the Commission.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

Proved developed reserves. Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved reserves.

Under SEC rules for fiscal years ending on or after December 31, 2009, proved reserves are defined as:

Those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data. 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. Where direct observation from well penetrations has defined a highest known oil, HKO, elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. 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 (i) 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 (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Under SEC rules for fiscal years ending prior to December 31, 2009, proved reserves are defined as:

The estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based. Estimates of proved reserves do not include the following: (A) Oil that may become available from known reservoirs but is classified separately as indicated additional reserves; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

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

Reasonable certainty. A high degree of confidence.

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

Reserves. Estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible as of a given date by application of development prospects to known accumulations.

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

Spacing. The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

Unit. The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

Wellbore. The hole drilled by the bit that is equipped for oil or gas production on a completed well. Also called well or borehole.

Working interest. The right granted to the lessee of a property to explore for and to produce and own oil, gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.