Oasis Petroleum Inc.
Form 10-K
March 01, 2013
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2012

OR

¨ **TRANSITION REPORT 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:

Common Stock, par value $0.01 per share	**New York Stock Exchange**
(Title of Class)	**(Name of 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 x No ¨

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

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 x No ¨

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

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

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

Large accelerated filer	x	Accelerated filer	¨
Non-accelerated filer	¨ (do not check if a smaller reporting company)	Smaller reporting company	¨

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

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: $2,251,698,496

Number of shares of registrant s common stock outstanding as of February 22, 2013: 93,602,754

Documents Incorporated By Reference:

Portions of the registrant s definitive proxy statement for its 2013 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2012, are incorporated by reference into Part III of this report for the year ended December 31, 2012.

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OASIS PETROLEUM INC.

FORM 10-K

FOR THE YEAR ENDED DECEMBER 31, 2012

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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 and similar expressions are intended to identify for statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements about:

- our business strategy;
- estimated future net reserves and present value thereof;
- technology;
- cash flows and liquidity;
- our financial strategy, budget, projections, execution of business plan and operating results;
- oil and natural gas realized prices;
- timing and amount of future production of oil and natural gas;
- availability of drilling, completion and production equipment and materials;
- availability of qualified personnel;
- owning and operating a services company;
- the amount, nature and timing of capital expenditures;
- availability and terms of capital;
- property acquisitions;

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

drilling and completion of wells;

infrastructure for salt water disposal;

gathering, transportation and marketing of oil and natural gas, both in the Williston Basin and other regions in the United States;

general economic conditions;

operating environment, including inclement weather conditions;

competition in the oil and natural gas industry;

effectiveness of risk management activities;

environmental liabilities;

counterparty credit risk;

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

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

uncertainty regarding future operating results; and

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

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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.

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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 acquisition and development of unconventional oil and natural gas resources in the Montana and North Dakota regions of the Williston Basin. As of December 31, 2012, we have accumulated 335,383 net leasehold acres in the Williston Basin. We are currently exploiting significant resource potential from the Bakken and Three Forks formations, which are present across a substantial portion of our acreage. 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 Williston Basin experience. In 2012, we completed and placed on production 117 gross operated wells in the Williston Basin. We have built our Williston Basin leasehold acreage position primarily through acquisitions and development in our three primary project areas: West Williston, East Nesson and Sanish.

DeGolyer and MacNaughton, our independent reserve engineers, estimated our net proved reserves to be 143.3 MMBoe as of December 31, 2012, of which 49% were classified as proved developed and of which 89% were oil. The following table presents summary data for each of our primary project areas as of December 31, 2012:

				Estimated net proved		2012 Average
		Productive Bakken and Three Forks Wells		reserves as of December 31, 2012		daily production
Project area	**Net acreage**	**Gross**	**Net**	**MMBoe**	**% Developed**	**Boe/d**
West Williston	208,062	204	128.8	94.6	47	15,263
East Nesson	118,943	145	67.5	41.4	47	4,936
Sanish	8,378	257	19.9	7.3	83	2,270
Total	335,383	606	216.2	143.3	49	22,469

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 (OP LLC), our predecessor, 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. We completed our initial public offering (IPO) in June 2010. In connection with our IPO and related corporate reorganization, we acquired all of the outstanding membership interests in OP LLC in exchange for shares of our common stock. Oasis Petroleum North America LLC (OPNA) conducts our exploration and production activities and owns our proved and unproved oil and natural gas properties. In 2011, we formed Oasis Well Services LLC (OWS), which provides well services to OPNA, and Oasis Petroleum Marketing LLC (OPM), which provides marketing services to OPNA.

Our business strategy

Our goal is to enhance value by investing capital to build reserves, production and cash flows at attractive rates of return through the following strategies:

- ***Develop our Williston Basin leasehold position.*** We intend to continue to drill and develop our acreage position to maximize the value of our resource potential. During 2012, we completed and brought on production 117 gross (95.8 net) operated Bakken and Three Forks wells in the Williston Basin. As of December 31, 2012, we had 21 gross operated wells waiting on completion and 11 gross operated wells drilling in the Bakken and Three Forks formations. Our 2013 drilling plan contemplates completing approximately 128 gross (92.5 net) operated wells in our project areas. We believe we have the ability to increase or decrease the number of wells drilled during 2013 based on market conditions and program results.

Focus on operational and cost efficiencies. Our management team is focused on continuous improvement of our operations 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 provide 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 oil, gas and water fluid handling facilities and infrastructure and reducing the time and cost of rig mobilization. In addition, OWS is expected to continue to provide capital savings and decrease our operated well capital costs going forward.

Adopt and employ leading drilling and completion techniques. Our team is focused on enhancing our drilling and completion techniques to maximize overall well economics. 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 drilling longer laterals and more tightly spacing fracturing stimulation stages. We continuously evaluate our internal drilling and completion results and monitor the results of other operators to improve our operating practices. This continued evolution may 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, 2012, we had no borrowings and $2.2 million of outstanding letters of credit under our revolving credit facility and $737.1 million of liquidity available, including $239.3 million in cash and short-term investments and $497.8 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. We also 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. As of December 31, 2012, our 335,383 net leasehold acres in the Williston Basin were highly prospective in the Bakken and Three Forks formations and 89% of our 143.3 MMBoe estimated net proved reserves in this area were comprised of oil. We increased our operated drill blocks by 37 through acreage additions and trades during 2012. In addition, we have 264,595 net acres held-by-production as of December 31, 2012. We believe our acreage is one of the largest concentrated leasehold positions that is prospective in the Bakken and Three Forks formations, and much of our acreage is in areas of significant drilling activity by other exploration and production companies. We expect that the scale and concentration of our acreage will enable us to reduce our drilling and completion costs and improve operational efficiency as we transition to full development mode throughout 2013.

Large, multi-year project inventory. We believe we have a large inventory of potential drilling locations that we have not yet drilled, a majority of which is operated by us. We plan to complete 128 gross (92.5 net) operated wells in the Williston Basin in 2013.

Management team with proven operating and acquisition skills. Our senior management team has extensive expertise in the oil and gas industry. 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 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, our technical team possesses substantial expertise in horizontal drilling techniques and managing and acquiring large development programs and also has prior experience in the Williston Basin.

Incentivized management team. As of December 31, 2012, our executive officers owned approximately 5% of our outstanding 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 64% of our gross drilling locations, or 91% of our net drilling locations. As of December 31, 2012, 93% of our estimated net proved reserves were attributable to properties that we expect to operate. Approximately 89% of our 2013 drilling and completion capital expenditure budget is related to operated wells. As of December 31, 2012, our average working interest in our operated and non-operated identified drilling locations was 69% and 12%, 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. We are also better able to control infrastructure investment to drive down operating costs and increase gas production and oil price realizations.

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Our operations

Estimated net proved reserves

The table below summarizes our estimated net proved reserves and related PV-10 at December 31, 2012, 2011 and 2010 for each of our project areas 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, 2012, 2011 and 2010 in accordance with the rules and regulations of the Securities and Exchange Commission (SEC) applicable to companies involved in oil and natural gas producing activities. Our estimated net proved reserves were determined using the preceding twelve months unweighted arithmetic average of the first-day-of-the-month prices and do not include probable or possible reserves. The information in the following table does not give any effect to or reflect our commodity derivatives. For a definition of proved reserves under the SEC rules, please see the Glossary of oil and natural gas terms included at the end of this report. For more information regarding our independent reserve engineers, please see Independent petroleum engineers below.

	At December 31, 2012		At December 31, 2011		At December 31, 2010	
Project area	Proved reserves (MMBoe)	PV-10(1) (in millions)	Proved reserves (MMBoe)	PV-10(1) (in millions)	Proved reserves (MMBoe)	PV-10(1) (in millions)
Williston Basin:						
West Williston	94.6	$ 2,066.6	51.6	$ 1,242.6	22.9	$ 380.0
East Nesson	41.4	975.6	21.1	479.1	9.6	160.7
Sanish	7.3	202.1	6.0	182.0	7.2	156.4
Total Williston Basin	143.3	3,244.3	78.7	1,903.7	39.7	697.1
Other(2)					0.1	0.7
Total	143.3	$ 3,244.3	78.7	$ 1,903.7	39.8	$ 697.8

(1) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable financial measure under accounting principles generally accepted in the United States of America (GAAP), because it does not include the effect of income taxes on discounted future net cash flows. 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. See Reconciliation of PV-10 to Standardized Measure below.

(2) Represents data relating to our properties in the Barnett shale, which we sold in November 2011.

Estimated net proved reserves at December 31, 2012 were 143.3 MMBoe, an 82% increase from estimated net proved reserves of 78.7 MMBoe at December 31, 2011 primarily as a result of our 2012 drilling program and well completions. Our proved developed reserves increased 34.2 MMBoe, or 95%, to 70.0 MMBoe for the year ended December 31, 2012 from 35.8 MMBoe for the year ended December 31, 2011, primarily due to our 2012 drilling program, including the completion of 117 gross (95.8 net) operated wells. Our proved undeveloped reserves increased to 73.3 MMBoe for the year ended December 31, 2012 from 42.9 MMBoe for the year ended December 31, 2011 primarily due to our 2012 drilling program.

Estimated net proved reserves at December 31, 2011 were 78.7 MMBoe, a 98% increase from estimated net proved reserves of 39.8 MMBoe at December 31, 2010. Our 2011 estimated net proved reserves increased 38.9 MMBoe over our 2010 estimated net proved reserves due to acquisitions, our drilling program and higher oil price assumptions at December 31, 2011. Our commodity price assumption for oil increased \$16.83/Bbl to \$96.23/Bbl for the year ended December 31, 2011 from \$79.40/Bbl for the year ended December 31, 2010. Our proved developed producing reserves increased 18.8 MMBoe, or 111%, to 35.8 MMBoe for the year ended December 31, 2011 from 17.0 MMBoe for the year ended December 31, 2010, primarily due to our drilling program completing 63 gross (49.2 net) operated wells. Our proved undeveloped reserves increased to 42.9 MMBoe for the year ended December 31, 2011 from 22.8 MMBoe for the year ended December 31, 2010 due to our drilling program, significant regional drilling activity, higher commodity price assumptions and higher overall estimated ultimate recoveries using recent drilling and completion techniques.

The following table sets forth more information regarding our estimated net proved reserves at December 31, 2012, 2011 and 2010:

	At December 31,		
	2012	2011	2010
Reserves Data(1):			
Estimated proved reserves:			
Oil (MMBbls)	128.1	69.1	36.6
Natural gas (Bcf)	91.5	57.9	19.4
Total estimated proved reserves (MMBoe)	143.3	78.7	39.8
Percent oil	89%	88%	92%

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	At December 31, 2012	2011	2010
Reserves Data(1):			
Estimated proved developed reserves:			
Oil (MMBbls)	62.6	31.8	15.7
Natural gas (Bcf)	44.7	24.5	8.2
Total estimated proved developed reserves (MMBoe)	70.0	35.8	17.0
Percent proved developed	49%	46%	43%
Estimated proved undeveloped reserves:			
Oil (MMBbls)	65.5	37.3	20.9
Natural gas (Bcf)	46.8	33.4	11.2
Total estimated proved undeveloped reserves (MMBoe)	73.3	42.9	22.8
PV-10 (in millions)(2)	$ 3,244.3	$ 1,903.7	$ 697.8
Standardized Measure (in millions)(3)	$ 2,259.9	$ 1,319.5	$ 485.7

(1) Our estimated net 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 twelve months were $94.68/Bbl for oil and $2.75/MMBtu for natural gas, $96.23/Bbl for oil and $4.12/MMBtu for natural gas, and $79.40/Bbl for oil and $4.38/MMBtu for natural gas for the years ended December 31, 2012, 2011 and 2010, respectively. 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. 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. See Reconciliation of PV-10 to Standardized Measure below.

(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.

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 represent 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, 2012, 2011 and 2010:

	December 31, 2012	2011 (In millions)	2010
PV-10	$ 3,244.3	$ 1,903.7	$ 697.8
Present value of future income taxes discounted at 10%	984.4	584.2	212.1
Standardized Measure of discounted future net cash flows	$ 2,259.9	$ 1,319.5	$ 485.7

The PV-10 of our estimated net proved reserves at December 31, 2012 was $3,244.3 million, a 70% increase from PV-10 of $1,903.7 million at December 31, 2011. This increase was mainly due to an increase in reserves and a reduction in costs, partially offset by lower commodity price assumptions year over year.

Estimated future net revenues

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, 2012, 2011 and 2010:

	At December 31,		
(In millions)	**2012**	**2011**	**2010**
Future net revenues	$ 7,077.4	$ 4,034.9	$ 1,561.3
Present value of future net revenues:			
Before income tax (PV-10)	3,244.3	1,903.7	697.8
After income tax (Standardized Measure)	2,259.9	1,319.5	485.7
Benchmark oil price ($/Bbl)(1)	$ 94.68	$ 96.23	$ 79.40

(1) Our estimated net 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 twelve months were $94.68/Bbl for oil and $2.75/MMBtu for natural gas, $96.23/Bbl for oil and $4.12/MMBtu for natural gas, and $79.40/Bbl for oil and $4.38/MMBtu for natural gas for the years ended December 31, 2012, 2011 and 2010, respectively. 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.

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, 2012, 2011 and 2010 are based on costs in effect at December 31 of each year and the twelve-month unweighted arithmetic average of the first-day-of-the-month price for January through December of such year, 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.

Proved undeveloped reserves

At December 31, 2012, we had approximately 73.3 MMBoe of proved undeveloped reserves as compared to 42.9 MMBoe at December 31, 2011.

The following table summarizes the changes in our proved undeveloped reserves during 2012 (in MBoe):

At December 31, 2011	42,876
Extensions, discoveries and other additions	57,322
Purchases of minerals in place	812
Sales of minerals in place	
Revisions of previous estimates	(1,223)
Conversion to proved developed reserves	(26,493)
At December 31, 2012	73,294

During 2012, we spent a total of $642.7 million related to the development of proved undeveloped reserves, $90.0 million of which was spent on proved undeveloped reserves that still remain proved undeveloped at year-end. The remaining $552.7 million resulted in the conversion of 26,493MBoe of proved undeveloped reserves, or 62% of our proved undeveloped reserves balance at the beginning of 2012, to proved developed reserves. We added 57,322 MBoe of proved undeveloped reserves across all three of our project areas as a result of our 2012 operated and non-operated drilling program.

In 2012, we also had a net negative revision of 1,223 MBoe, or 2.9 % of our December 31, 2011 proved undeveloped reserves balance. The primary causes for these revisions were negative well performances partially offset by working interest increases in the proved undeveloped locations. Within portions of the West Williston and East Nesson project areas, actual well results underperformed relative to the proved undeveloped forecasts prepared in 2011. The proved undeveloped forecasts in these areas have been adjusted to reflect these well performances in the 2012 reserve report. The working interest increases arose from acreage trades, non-participation by other interest owners and additional mineral leasing in the reserve locations. Operating costs and realized prices had an immaterial impact on the proved undeveloped reserves balance.

All of our proved undeveloped reserves as of December 31, 2012 are expected to be developed within five years of their initial booking.

Independent petroleum engineers

Our estimated net proved reserves and related future net revenues, PV-10 and Standardized Measure at December 31, 2012, 2011 and 2010 are based on reports prepared by DeGolyer and MacNaughton, our independent reserve engineers, by the use of appropriate geologic, petroleum engineering and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled *Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)* 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.

Technology used to establish proved reserves

In accordance with rules and regulations of the SEC applicable to companies involved in oil and natural gas producing activities, 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 means deterministically, the quantities of oil and/or natural gas are much more likely to be achieved than not, and probabilistically, there should be at least a 90% probability of recovering volumes equal to or exceeding 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 using reliable technology. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

In order to establish reasonable certainty with respect to our estimated net proved reserves, DeGolyer and MacNaughton employed technologies including, but not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available down hole 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. 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 areas 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 employ DeGolyer and MacNaughton as the independent reserves evaluator for 100% of our reserves base. We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with the independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished for the reserves estimation process. Brett Newton, Senior Vice President of Asset Management, is the technical person primarily responsible for overseeing our reserves evaluation process. He has over 20 years of industry experience with positions of increasing responsibility in engineering and management. He holds both a Bachelor of Science degree and Master of Science degree in petroleum engineering. Mr. Newton reports directly to our Chief Operating Officer.

Throughout each fiscal year, our technical team meets with the independent reserve engineers to review properties and discuss evaluation methods and assumptions used in the proved reserves estimates, in accordance with our prescribed internal control procedures. Our internal controls over the reserves estimation process include verification of input data into our reserves evaluation software as well as management review, such as, but not limited to the following:

Comparison of historical expenses from the lease operating statements and workover authorizations for expenditure to the operating costs input in our reserves database;

Review of working interest and net revenue interest in our reserves database against our well system;

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Review of realized prices and differentials from index prices from the well profitability report as compared to the differentials used in our reserves database;

Review of updated capital costs prepared by our operations team;

Review of internal reserve estimates by well and by area by our internal reservoir engineers;

Discussion of material reserve variances among our internal reservoir engineers and our Senior Vice President of Asset Management;

Review of a preliminary copy of the reserve report by our Chief Operating Officer with representatives from our independent reserve engineers and internal technical staff; and

Review of our reserves estimation process by our Audit Committee 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, 2011 and 2012, demand for oil and natural 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 our oil and natural gas production, 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 Operations.

	Year Ended December 31,		
	2012	**2011**	**2010**
Net production volumes:			
Oil (MBbls)	7,533	3,732	1,792
Natural gas (MMcf)	4,146	1,092	651
Oil equivalents (MBoe)	8,224	3,914	1,900
Average daily production (Boe/d)	22,469	10,724	5,206
Average sales prices:			
Oil, without realized derivatives (per Bbl)	$ 85.22	$ 86.18	$ 69.60
Oil, with realized derivatives (per Bbl)(1)	86.09	85.15	69.53
Natural gas (per Mcf)(2)	6.52	8.02	6.52
Costs and expenses (per Boe of production):			
Lease operating expenses(3)	$ 6.68	$ 8.36	$ 7.43
Marketing, transportation and gathering expenses	1.13	0.34	0.24
Production taxes	7.66	8.65	7.25
Depreciation, depletion and amortization	25.14	19.16	19.91
General and administrative expenses	6.95	7.52	10.39
Stock-based compensation expenses(4)			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) Natural gas prices include the value for natural gas and natural gas liquids.
(3) For the years ended December 31, 2011 and 2010, lease operating expenses exclude marketing, transportation and gathering expenses to conform such amounts to current year classifications.
(4) During 2010, we recorded $8.7 million in stock-based compensation expense associated with Class C common unit interests (C Units) and discretionary stock awards granted. Stock-based compensation expense related to the amortization of restricted stock and performance share units is included in general and administrative expenses on the Consolidated Statement of Operations. See Note 9 to our audited consolidated financial statements.

Net production volumes for the year ended December 31, 2012 were 8,224 MBoe, a 110% increase from net production of 3,914 MBoe for the year ended December 31, 2011. Our net production volumes increased 4,310 MBoe over 2011 due to a successful operated and non-operated drilling and completion program. Average oil sales prices, without realized derivatives, decreased by $0.96/Bbl, or 1%, to an average of $85.22/Bbl for the year ended December 31, 2012 as compared to the year ended December 31, 2011. Giving effect to our derivative transactions in both periods, our oil sales prices increased $0.94/Bbl to $86.09/Bbl for the year ended December 31, 2012 from $85.15/Bbl for the year ended December 31, 2011.

Net production volumes for the year ended December 31, 2011 were 3,914 MBoe, a 106% increase from net production of 1,900 MBoe for the year ended December 31, 2010. Our net production volumes increased 2,014 MBoe over 2010 due to a successful operated and non-operated drilling and completion program. Average oil sales prices, without realized derivatives, increased by $16.58/Bbl, or 24%, to an average of $86.18/Bbl for the year ended December 31, 2011 as compared to the year ended December 31, 2010. Giving effect to our derivative transactions in both periods, our oil sales prices increased $15.62/Bbl to $85.15/Bbl for the year ended December 31, 2011 from $69.53/Bbl for the year ended December 31, 2010.

The following table sets forth information regarding our average daily production for the years ended December 31, 2012 and 2011:

	Average daily production for the years ended December 31,								
	2012			2011			2010		
	Bbls	Mcf	Boe	Bbls	Mcf	Boe	Bbls	Mcf	Boe
Williston Basin:									
West Williston	13,904	8,152	15,263	6,426	1,278	6,639	1,976	564	2,070
East Nesson	4,586	2,106	4,936	2,333	430	2,404	1,607	215	1,643
Sanish	2,091	1,070	2,270	1,467	750	1,592	1,325	561	1,419
Total Williston Basin	20,581	11,328	22,469	10,226	2,458	10,635	4,908	1,340	5,132
Other(1)					533	89		444	74
Total	20,581	11,328	22,469	10,226	2,991	10,724	4,908	1,784	5,206

(1) Represents data relating to our properties in the Barnett shale, which we sold in November 2011.

Productive wells

The following table presents the total gross and net productive wells by project area as of December 31, 2012:

	Total wells		Bakken and Three Forks	
Project area	Gross	Net	Gross	Net
West Williston	311	176.2	204	128.8
East Nesson	145	67.5	145	67.5
Sanish	257	19.9	257	19.9
Total	713	263.6	606	216.2

All of our productive wells are oil wells. Gross wells are the number of wells, operated and non-operated, in which we own a working interest and net wells are the total of our working interests owned in gross wells.

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, 2012 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	
Project area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
West Williston	211,701	154,711	73,003	53,351	284,704	208,062
East Nesson	104,969	72,605	66,993	46,338	171,962	118,943
Sanish	41,373	8,373	160	5	41,533	8,378
Total	358,043	235,689	140,156	99,694	498,199	335,383

We have increased our acreage that is held-by-production to approximately 265 thousand net acres at December 31, 2012 from 184 thousand net acres at December 31, 2011.

Undeveloped acreage