

Rosetta Resources Inc.
Form 10-K
February 24, 2014
Table of Contents

Index to Financial Statements

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, 2013**

OR

.. **Transition Report Pursuant To Section 13 Or 15(d) of the Securities Exchange Act of 1934
Commission File Number: 000-51801**

ROSETTA RESOURCES INC.

(Exact name of registrant as specified in its charter)

Delaware
(State or other jurisdiction of
incorporation or organization)

43-2083519
(I.R.S. Employer
Identification No.)

1111 Bagby Street, Suite 1600, Houston, TX
(Address of principal executive offices)

77002
(Zip Code)

Registrant's telephone number, including area code: (713) 335-4000

Securities Registered Pursuant to Section 12(b) of the Act:

Common Stock, \$.001 Par Value
(Title of Class)

The Nasdaq Stock Market LLC (Nasdaq Global Select Market)
(Name of Exchange on which registered)

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 No

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

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

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

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

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

Large accelerated filer

Accelerated filer

Edgar Filing: Rosetta Resources Inc. - Form 10-K

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 Exchange Act). Yes No

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 28, 2013 was approximately \$2.6 billion based on the closing price of \$42.52 per share on the Nasdaq Global Select Market.

The number of shares of the registrant's Common Stock, \$0.001 par value per share, outstanding as of February 7, 2014 was 61,344,077, which excludes unvested restricted stock.

Documents Incorporated By Reference

Portions of the definitive proxy statement relating to the 2014 annual meeting of stockholders to be filed with the Securities and Exchange Commission are incorporated by reference in answer to Part III of this Form 10-K.

Table of Contents

Index to Financial Statements

Table of Contents

	Page
Part I	
<u>Items 1 and 2. Business and Properties</u>	5
<u>Item 1A. Risk Factors</u>	16
<u>Item 1B. Unresolved Staff Comments</u>	28
<u>Item 3. Legal Proceedings</u>	28
<u>Item 4. Mine Safety Disclosures</u>	28
Part II	
<u>Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities</u>	29
<u>Item 6. Selected Financial Data</u>	31
<u>Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations</u>	31
<u>Item 7A. Quantitative and Qualitative Disclosures about Market Risk</u>	47
<u>Item 8. Financial Statements and Supplementary Data</u>	49
<u>Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure</u>	88
<u>Item 9A. Controls and Procedures</u>	88
<u>Item 9B. Other Information</u>	88
Part III	
<u>Item 10. Directors, Executive Officers and Corporate Governance</u>	89
<u>Item 11. Executive Compensation</u>	89
<u>Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters</u>	89
<u>Item 13. Certain Relationships and Related Transactions, and Director Independence</u>	89
<u>Item 14. Principal Accountant Fees and Services</u>	89
Part IV	
<u>Item 15. Exhibits and Financial Statement Schedules</u>	90

Table of Contents

Index to Financial Statements

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This report includes forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended (the Securities Act), and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). All statements other than statements of historical fact included in this report are forward-looking statements, including without limitation all statements regarding future plans, business objectives, strategies, expected future financial position or performance, expected future operational position or performance, budgets and projected costs, future competitive position, or goals and/or projections of management for future operations. In some cases, you can identify a forward-looking statement by terminology such as may, will, could, should, would, expect, plan, project, intend, anticipate, believe, estimate, potential, pursue, target or continue, the negative of such terms or variations thereon, or other comparable terminology.

The forward-looking statements contained in this report reflect certain estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions, operating trends, and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. As such, management's assumptions about future events may prove to be inaccurate. For a more detailed description of the risks and uncertainties involved, see Item 1A. Risk Factors in Part I of this report. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events, changes in circumstances or otherwise. These cautionary statements qualify all forward-looking statements attributable to us, or persons acting on our behalf. Management cautions all readers that the forward-looking statements contained in this report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or that the events and circumstances they describe will occur. Factors that could cause actual results to differ materially from those anticipated or implied in the forward-looking statements herein include, but are not limited to:

our ability to maintain leasehold positions that require exploration and development activities and material capital expenditures;

unexpected difficulties in integrating our operations as a result of any significant acquisitions;

the supply and demand for oil, natural gas liquids (NGLs) and natural gas;

changes in the price of oil, NGLs and natural gas;

general economic conditions, either internationally, nationally or in jurisdictions where we conduct business;

conditions in the energy and financial markets;

our ability to obtain credit and/or capital in desired amounts and/or on favorable terms;

the ability and willingness of our current or potential counterparties or vendors to enter into transactions with us and/or to fulfill their obligations to us;

failure of our joint interest partners to fund any or all of their portion of any capital program and/or lease operating expenses;

failure of joint interest partners to pay us our share of revenue;

the occurrence of property acquisitions or divestitures;

reserve levels;

inflation;

competition in the oil and natural gas industry;

the availability and cost of relevant raw materials, equipment, goods, services and personnel;

changes or advances in technology;

Table of Contents

Index to Financial Statements

potential reserve revisions;

the availability and cost, as well as limitations and constraints on infrastructure required, to gather, transport, process and market oil, NGLs and natural gas;

performance of contracted markets, and companies contracted to provide transportation, processing and trucking of oil, NGLs and natural gas;

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

drilling, completion, production and facility risks;

exploration risks;

legislative initiatives and regulatory changes potentially adversely impacting our business and industry, including, but not limited to, changes in national healthcare, cap and trade, hydraulic fracturing, state and federal corporate income taxes, retroactive royalty or production tax regimes, environmental regulations and environmental risks and liability under federal, state and local environmental laws and regulations;

effects of the application of applicable laws and regulations, including changes in such regulations or the interpretation thereof;

present and possible future claims, litigation and enforcement actions;

lease termination due to lack of activity or other disputes with mineral lease and royalty owners, whether regarding calculation and payment of royalties or otherwise;

the weather, including the occurrence of any adverse weather conditions and/or natural disasters affecting our business;

factors that could impact the cost, extent and pace of executing our capital program, including but not limited to, access to oilfield services, access to water for hydraulic fracture stimulations and permitting delays, unavailability of required permits, lease suspensions, drilling, exploration and production moratoriums and other legislative, executive or judicial actions by federal, state and local authorities, as well as actions by private citizens, environmental groups or other interested persons;

sabotage, terrorism and border issues, including encounters with illegal aliens and drug smugglers; and

any other factors that impact or could impact the exploration and development of oil, NGL or natural gas resources, including but not limited to the geology of a resource, the total amount and costs to develop recoverable reserves, legal title, regulatory, natural gas administration, marketing and operational factors relating to the extraction of oil, NGLs and natural gas.

For a listing of oil and natural gas terms used in this report, see [Glossary of Oil and Natural Gas Terms](#) at the end of this report.

Table of Contents

Index to Financial Statements

Part I

Items 1 and 2. Business and Properties

General

We are an independent exploration and production company engaged in the acquisition and development of onshore energy resources in the United States of America. Our operations are located in the Eagle Ford shale in South Texas and in the Permian Basin in West Texas. Our headquarters are located in Houston, Texas and we have field offices throughout South and West Texas.

Rosetta Resources Inc. (together with its consolidated subsidiaries, we, our, us, the Company, Rosetta or like terms) was incorporated in Delaware in June 2005. We have grown our property base by developing and exploring our acreage, purchasing new undeveloped leases, acquiring oil and natural gas producing properties and drilling prospects from third parties and strategically divesting certain assets that were more gas-based. We operate in one geographic operating segment. See Item 8. Financial Statements and Supplementary Data, Note 15 Operating Segments.

Our Strategy

Our strategy is to increase shareholder value by delivering sustainable growth from unconventional onshore domestic basins through sound stewardship, wise capital resource management, taking advantage of business cycles and emerging trends and minimizing liabilities through governmental compliance and protecting the environment. Below is a discussion of the key elements of our strategy.

Leverage high-grade asset base. Our extensive inventory of investment opportunities in the Eagle Ford area, which is a major source of our production and reserves, provides higher economic returns than areas in which we have sold assets during the last few years. With our entry into the Permian Basin, we have increased our portfolio of long-lived, oil-rich resource projects that will further drive our long-term growth and sustainability. Additionally, we are developing this new core area through both vertical and horizontal applications to further enhance the value of this large resource.

Successfully execute our business plan. We have increased our total production and diversified our production base to include a greater mix of crude oil and NGLs. In addition, we manage all elements of our cost structure, including drilling and operating costs, as well as overhead costs. We strive to minimize our drilling and operating costs by concentrating our activities within existing and new unconventional resource play areas where we can achieve efficiencies through economies of scale. As part of our strategy to minimize costs, we have taken aggressive steps to ensure access to transportation and processing facilities in our operating areas where midstream services are in high demand and infrastructure is under construction.

Test future growth opportunities. Our strategy involves evaluating previously untested Eagle Ford acreage and continued testing of optimal Eagle Ford and Permian well spacing. In this regard, we intend to maintain, further develop and apply the technological expertise that helped us establish a major production base in the Eagle Ford area. We use advanced geological and geophysical technologies, detailed petrophysical analyses, advanced reservoir engineering and sophisticated drilling, completion and stimulation techniques to grow our reserves, production and project inventory. We intend to increase our operational footprint in the Eagle Ford and Permian areas, as well as evaluate new areas within the United States characterized by a significant presence of resource potential that can be

exploited utilizing our technological expertise.

Maintain Financial Strength and Flexibility. As of December 31, 2013, we had no borrowings outstanding and \$800.0 million available for borrowing under our Amended and Restated Senior Revolving Credit Facility (the Credit Facility). We expect internally generated cash flows and cash on hand, supplemented by borrowings under our Credit Facility, to provide financial flexibility to further develop our assets in the next few

Table of Contents

Index to Financial Statements

years. We intend to continue to actively manage our exposure to commodity price risk in the marketing of our oil, NGL and natural gas production. As of December 31, 2013, we have entered into a series of commodity derivative contracts through 2016 as part of this strategy.

Our Operating Area and Other Plays

We own producing and non-producing oil and natural gas properties in proven or prospective basins that are primarily located in the Eagle Ford shale in South Texas and in the Permian Basin in West Texas.

As of December 31, 2013, we owned approximately 65,000 net acres in South Texas and 55,000 net acres in West Texas. Our production in South Texas comes primarily from the Eagle Ford area, which averaged 47.6 MBoe per day in 2013, an increase of 33% from the prior year. With our entrance into the Permian Basin in West Texas in 2013, our production has increased sequentially quarter over quarter, with fourth quarter and full year 2013 production averaging 3.5 MBoe and 1.8 MBoe per day, respectively.

The Eagle Ford area has become our largest producing area where we hold approximately 63,000 net acres, with 50,000 net acres located in the liquids-rich area of the play. Our 2013 activities were focused on five areas of the Eagle Ford, including the Gates Ranch, Karnes Trough, Dimmit County, northern LaSalle County and Briscoe Ranch areas. We drilled 111 gross wells and completed 79 gross wells in the Eagle Ford area in 2013. For 2013, the Eagle Ford area provided approximately 96% of our total production. In addition, approximately 62% of our production mix from the Eagle Ford area in 2013 was attributable to crude oil, condensate and NGLs, compared to 60% in 2012.

As part of our ongoing initiative to pursue new growth opportunities, we acquired producing and undeveloped oil and natural gas interests in the Permian Basin in Gaines and Reeves Counties, Texas (the Permian Acquisition) in the second quarter of 2013. The Permian Acquisition added roughly 40,000 net acres in the Wolfbone play in Reeves County in the Delaware Basin and 13,000 net acres in Gaines County in the Midland Basin. We drilled 39 gross operated wells and completed 32 gross operated wells in the Permian area in 2013. For 2013, production from the Permian area provided approximately 4% of our total production. In addition, approximately 86% of our production mix from the Permian area in 2013 was attributable to crude oil and NGLs.

In 2012, we concluded our exploratory drilling program in the Southern Alberta Basin in Northwest Montana. Of the seven horizontal wells that were drilled in 2012 and 2011, five were completed. Based on results that were not economic, we suspended all capital activity for exploration in the area. Our Southern Alberta Basin leases and lease options began expiring in January 2014.

In the last four years, we have become a significant producer in the liquids-rich window of the Eagle Ford region and have established an inventory of lower-risk, higher-return drilling opportunities that offer more predictable and long-term production, reserve growth and a more valuable commodity mix. With our entry into the Permian Basin, we have increased our portfolio of long-lived, oil-rich resource projects that will further drive our long-term growth and sustainability. We will continue to consider investments in the Eagle Ford shale region, Permian Basin and other unconventional resource basins that offer a viable inventory of projects, including resource-based exploration projects and producing property acquisitions in early development stages.

Acquisition and Divestiture Activities

Edgar Filing: Rosetta Resources Inc. - Form 10-K

In 2013, we purchased producing and undeveloped oil and natural gas interests in the Permian Basin in Gaines and Reeves Counties, Texas for \$768 million, subject to customary purchase price adjustments. This acquisition provides for growth potential in a new core area with both vertical and horizontal opportunities. We also acquired the remaining 10% working interest in certain producing wells for a portion of our leases in the Gates Ranch area located in the Eagle Ford shale for \$128 million.

Table of Contents**Index to Financial Statements**

As part of our strategic decision to focus on the Eagle Ford area and to explore prospective basins, we divested certain gas-based assets that we believed did not offer the same investment opportunities or rates of return as our unconventional resources. The divestitures of these properties were not material to our operations but affect the comparability of our results between periods. In 2012, we closed the sale of our Lobo assets and a portion of our Olmos assets located in South Texas for \$95 million. In 2011, we divested our assets located in the DJ Basin in Colorado and the Sacramento Basin in California for \$255 million. These divestitures were all subject to post-closing adjustments. See Item 8. Financial Statements and Supplementary Data, Note 4 Property and Equipment.

Title to Properties

Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions as well as mortgage liens on at least 80% of our proved reserves in accordance with our Credit Facility. We do not believe that any of these burdens materially interfere with our use of the properties in the operation of our business.

We believe that we generally have satisfactory title to or rights in all of our producing properties in accordance with standards generally accepted in the oil and natural gas industry. As is customary in the oil and natural gas industry, we make minimal investigation of title at the time we acquire undeveloped properties. We make title investigations and receive title opinions of local counsel only before we commence drilling operations. We believe that we have satisfactory title to all of our other assets. Although title to our properties is subject to encumbrances in certain cases, we believe that none of these burdens will materially detract from the value of our properties or from our interest therein or will materially interfere with our use in the operation of our business.

Crude Oil, NGL and Natural Gas Operations***Production by Operating Area***

The following tables present certain information with respect to our production data for the periods presented:

	Year Ended December 31, 2013			
	Oil (MBbls) (1)	NGLs (MBbls)	Natural Gas (MMcf)	Equivalents (MBoe) (2)
Eagle Ford	4,469	6,317	39,561	17,379
Permian	508	69	548	669
Other	22	12	234	73
Total	4,999	6,398	40,343	18,121

	Year Ended December 31, 2012			
	Oil (MBbls) (1)	NGLs (MBbls)	Natural Gas (MMcf)	Equivalents (MBoe) (2)

Edgar Filing: Rosetta Resources Inc. - Form 10-K

Eagle Ford	3,445	4,391	31,717	13,122
South Texas	12	81	2,110	444
Other	40		26	45
Total	3,497	4,472	33,853	13,611

7

Table of Contents**Index to Financial Statements**

	Year Ended December 31, 2011			
	Oil (MBbls) (1)	NGLs (MBbls)	Natural Gas (MMcf)	Equivalents (MBoe) (2)
Eagle Ford	1,747	2,396	22,057	7,824
South Texas	43	247	6,968	1,448
California	44		3,440	617
Rockies	10		862	153
Gulf Coast	19		62	29
Other Onshore			4	1
Total	1,863	2,643	33,393	10,072

- (1) Includes crude oil and condensate. For the years ended December 31, 2013, 2012, and 2011 approximately 52%, 68% and 88%, respectively, of our oil production consisted of condensate, which we define as oil with an API gravity higher than 55 degrees.
- (2) Oil equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of natural gas to 1.0 Bbl of oil or NGLs.

For additional information regarding our oil, NGL and natural gas production, production prices and production costs, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Proved Reserves

There are a number of uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control, such as reservoir performance, commodity pricing, and expected recovery rates associated with infill drilling. Therefore, the reserve information in this report represents only estimates. Reserve 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 available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of oil, NGLs and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent that we acquire additional properties containing proved reserves or conduct successful exploration and development activities, or both, our proved reserves will decline as reserves are produced.

As of December 31, 2013, we had an estimated 279 MMBoe of proved reserves, of which 32% was proved developed. Based on the twelve-month first-day-of-the-month historical average prices for 2013, as adjusted for basis and quality differentials, for West Texas Intermediate oil of \$93.42 per Bbl and Henry Hub natural gas of \$3.67 per MMBtu, our reserves had an estimated standardized measure of discounted future net cash flows of \$2.3 billion as of December 31, 2013.

Table of Contents**Index to Financial Statements**

The following table sets forth, by operating area, a summary of our estimated net proved reserve information as of December 31, 2013:

	Developed				Undeveloped				Percent of	
	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	Total (MMBoe)	Reserves
Eagle Ford	17.9	30.4	211.7	83.6	30.7	64.7	444.2	169.4	253.0	91%
Permian	4.6	1.1	5.2	6.6	13.2	3.1	15.1	18.8	25.4	9%
Other			0.4	0.1					0.1	0%
Total	22.5	31.5	217.3	90.3	43.9	67.8	459.3	188.2	278.5	100%

- (1) These estimates are based upon a reserve report prepared using internally developed reserve estimates and criteria in compliance with the Securities and Exchange Commission (SEC) guidelines and audited by Netherland, Sewell & Associates, Inc. (NSAI), independent petroleum engineers. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates and Item 8. Financial Statements and Supplementary Data Supplemental Oil and Gas Disclosures. NSAI's report is attached as Exhibit 99.1 to this Form 10-K.
- (2) The reserve volumes and values were determined under the method prescribed by the SEC, which requires the use of an average price, calculated as the twelve-month first-day-of-the-month historical average price for the twelve-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.
- (3) Includes crude oil and condensate. As of December 31, 2013, approximately 65%, of our proved oil reserves consisted of condensate.

All of our proved undeveloped reserves at December 31, 2013 are scheduled for development within five years from the date first recorded as a proved undeveloped reserve.

In 2013, we added 70.6 MMBoe of proved reserves in the Eagle Ford area by drilling and completing 79 successful wells and adding 106 proved undeveloped locations. The significant addition of proved reserves primarily resulted from the completion of 33 producing wells and the addition of 42 proved undeveloped locations in the Gates Ranch area. We also added proved reserves at Adele Dubose (eight proved producing), Briscoe Ranch (eight proved producing and 51 proved undeveloped), Lasseter & Eppright (two proved developed and six proved undeveloped), and Light Ranch (one proved developed). We spent approximately \$212 million for the development of 24 MMBoe of proved undeveloped reserves from 33 wells in the Gates Ranch area.

We initially delineated the Gates Ranch area by drilling 17 delineation wells from late 2009 through 2010. Initial development of the Gates Ranch area utilized approximately 100-acre well spacing to prove that there was a continuous accumulation of hydrocarbons in this area and to gather production data to determine the correct well spacing for future development. In 2012 and 2013, we adjusted our well spacing to approximately 55 acres.

Technology Used to Establish Proved Reserves

We are employing technologies that have been demonstrated to provide consistent results capable of repetition. The technologies and economic data being used in the estimation of our proved reserves include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps, seismic data, production data and well test data. The estimated reserves of wells with sufficient production history are estimated using appropriate decline curves. Estimated reserves of producing wells with limited production history and for undeveloped locations are estimated using performance data from analogous wells in the area. These wells are considered analogous based on production performance from the same formation and with similar completion techniques. Geologic data from well logs, core analysis and seismic data is used to assess reservoir continuity more than one location away from production.

Table of Contents

Index to Financial Statements

Internal Control

The preparation of our reserve estimates is in accordance with our prescribed internal control procedures that include verification of input data into a reserve forecasting and economic software, as well as management review. Internal controls include but are not limited to the following:

Internal reserve estimates are prepared under the supervision and guidance of the Corporate Reserves Manager.

The internal reserve estimates by well and by area are reviewed by the Vice President of Corporate Reserves and Technical Services. A variance by well to the previous year-end reserve report and quarter-end reserve estimate is used as a tool in this process.

The discussion of any material reserve variances among the internal reservoir engineers, the Corporate Reserves Manager, and the Vice President of Corporate Reserves and Technical Services to ensure the best estimate of remaining reserves.

The review of internal reserve estimates by senior management and the Audit Committee of our Board of Directors prior to publication.

The Company's primary reserves estimator is Mark D. Petrichuk, Vice President of Corporate Reserves and Technical Services. Mr. Petrichuk has over 36 years of experience in the petroleum industry spent almost entirely in the evaluation of reserves and income attributable to oil and natural gas properties. He holds a Bachelor of Science in Mechanical Engineering from Texas A&M University. He is a licensed Professional Engineer in the State of Texas and is a member of the Society of Petroleum Engineers. The Vice President of Corporate Reserves and Technical Services maintains oversight and compliance responsibility for the internal reserve estimate process and provides appropriate data to the independent third party engineers for the annual audit of our year-end reserves.

Qualifications of Third Party Engineers

The reserves estimates shown herein have been independently audited by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under the Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for auditing the estimates set forth in the NSAI audit incorporated herein are Mr. Danny Simmons and Mr. David Nice. Mr. Simmons has been a practicing consulting petroleum engineer at NSAI since 1976. Mr. Simmons is a Registered Professional Engineer in the State of Texas (License No. 45270) and has more than 35 years of practical experience in petroleum engineering, with over 35 years of experience in the estimation and evaluation of reserves. He graduated from the University of Tennessee in 1973 with a Bachelor of Science Degree in Mechanical Engineering. Mr. Nice has been a practicing consulting petroleum geologist at NSAI since 1998. Mr. Nice is a Licensed Professional Geoscientist in the State of Texas, Geology (License No. 346) and has over 28 years of practical experience in petroleum geosciences, with over 15 years of experience in the estimation and evaluation of reserves. He graduated from the University of Wyoming in 1982 with a

Edgar Filing: Rosetta Resources Inc. - Form 10-K

Bachelor of Science Degree in Geology and in 1985 with a Master of Science Degree in Geology. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations, as well as applying SEC and other industry reserves definitions and guidelines.

Table of Contents**Index to Financial Statements****Capital Expenditures**

The following table summarizes information regarding our development and exploration capital expenditures for the years ended December 31, 2013, 2012, and 2011:

	Year Ended December 31,		
	2013	2012	2011
	(In thousands)		
Drilling, completions and facilities	\$ 834,492	\$ 613,343	\$ 452,304
Leasehold	10,268	18,753	10,605
Acquisitions	952,642		
Delay rentals	294	1,089	1,144
Geological and geophysical/seismic	3,521	1,269	2,638
Exploration overhead	7,155	6,041	7,049
Capitalized interest	28,298	3,757	5,511
Other corporate	15,464	8,731	296
Total capital expenditures	\$ 1,852,134	\$ 652,983	\$ 479,547

Productive Wells and Acreage

The following table sets forth our interest in undeveloped acreage, developed acreage and productive wells in which we own a working interest as of December 31, 2013. Gross represents the total number of acres or wells in which we own a working interest. Net represents our proportionate working interest resulting from our ownership in the gross acres or wells. Productive wells are wells in which we have a working interest and that are capable of producing oil, NGLs and natural gas.

	Undeveloped Acres		Developed Acres		Productive Wells (2)				
					Gross		Net		
	Gross	Net	Gross	Net	Oil	Natural Gas	Oil	Natural Gas	
Eagle									
Ford	44,529	43,147	20,960	19,625	30	177	22	127	
Permian	69,606	42,509	18,778	12,514	116		64		
Other									
(1)	182,418	160,067	14,277	8,496	7	47	4	32	
Total	296,553	245,723	54,015	40,635	153	224	90	159	

(1)

Other primarily includes acreage related to our new venture opportunities outside of the Eagle Ford and Permian areas, acreage in the Rockies area in which we still hold interests, and acreage and productive wells outside of the Eagle Ford area in South Texas. Other acreage excludes approximately 228,000 net undeveloped acres under exploration option in the Southern Alberta Basin which began to expire in January 2014.

(2) Of our productive wells listed above, there were no multiple completions.

The following table shows our interest in undeveloped acreage as of December 31, 2013 that is subject to expiration in 2014, 2015, and 2016 and thereafter, to the extent that we do not commence or continue drilling operations upon such acreage:

2014		2015		2016		Thereafter	
Gross	Net	Gross	Net	Gross	Net	Gross	Net
117,655	87,463	71,844	66,802	45,965	35,560	61,089	55,898

Table of Contents**Index to Financial Statements****Drilling Activity**

The following table sets forth the number of gross exploratory and gross development wells that we drilled or in which we participated during the last three fiscal years. The number of wells drilled refers to the number of wells completed at any time during the respective fiscal year. Productive wells are either producing wells or wells capable of production.

	Gross Wells					
	Exploratory			Development		
	Productive	Dry	Total	Productive	Dry	Total
2013	1.0		1.0	163.0	1.0	164.0
2012	6.0		6.0	91.0		91.0
2011	5.0		5.0	59.0		59.0

The following table sets forth the number of net exploratory and net development wells that we drilled based on our proportionate working interest in such wells during the last three fiscal years.

	Net Wells					
	Exploratory			Development		
	Productive	Dry	Total	Productive	Dry	Total
2013	0.5		0.5	150.1	1.0	151.1
2012	6.0		6.0	76.6		76.6
2011	5.0		5.0	47.9		47.9

At December 31, 2013, we had 77 gross and 76 net wells that were in the process of being drilled or awaiting results from completion. Of these wells, 63 gross wells were located in the Eagle Ford area where we own an average 100% working interest. In the Permian Basin, 14 gross wells were in the process of being drilled or awaiting completion as of December 31, 2013, and we own 93% of the working interests in these wells.

Marketing

We market the oil, NGL and natural gas production from properties that we operate for both our account and the accounts of other working interest owners in our properties. We sell our production to a variety of purchasers under contracts with daily, monthly, seasonal, annual or multi-year terms, all at market prices. Our oil production is delivered to contracted third parties who load it onto truck transports on the lease or gather, stabilize if necessary, and re-deliver the oil via pipeline at a truck loading and downstream pipeline loading terminal. We sell our oil production under contracts utilizing the daily settlement price of the New York Mercantile Exchange (NYMEX) prompt month futures contract for West Texas Intermediate crude oil and, where appropriate, the Louisiana Light Sweet crude oil location differential thereto, or utilizing regional crude oil or condensate postings. All prices are adjusted for location, quality and, where applicable, gravity differentials. Our NGLs that are extracted from our produced natural gas during processing are generally purchased by the processors and priced based on the monthly average of the daily prices of NGLs at Mont Belvieu. Our natural gas is transported and sold under contract at a negotiated price, the majority of

which is based on the Houston Ship Channel and Tennessee Gas Pipeline Zone 0 indices, adjusted for transportation or market conditions.

Major Customers

In 2013, two customers, Shell Trading (US) Company and Enterprise Products Operating LLC, accounted for approximately 23% and 21%, respectively, of our consolidated revenue, excluding the effects of derivative instruments.

In 2012, four customers, Enterprise Products Operating LLC, Shell Trading (US) Company, Exxon Mobil Corporation and Calpine Energy Services, accounted for approximately 21%, 21%, 13% and 12%, respectively, of our consolidated revenue, excluding the effects of derivative instruments.

Table of Contents

Index to Financial Statements

In 2011, four customers, Shell Trading (US) Company, Calpine Energy Services, Regency Gas Services, LLC, and Exxon Mobil Corporation, accounted for approximately 25%, 24%, 17% and 10%, respectively, of our consolidated revenue, excluding the effects of derivative instruments.

No other customers accounted for more than 10% of our consolidated revenue, excluding the effects of derivative instruments, for the years ended December 31, 2013, 2012 and 2011. The loss of any one of these customers would not have a material adverse effect on our operations as management believes other purchasers are available in our areas of operations.

Competition

The oil and natural gas industry is highly competitive and we compete with a substantial number of other companies that have greater resources than we do. Many of these companies explore, develop, produce and market oil, NGLs and natural gas, carry on refining operations and market the resulting products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and natural gas properties, securing sufficient capacity from processing and/or refining facilities for our NGL production, and obtaining purchasers and transporters of the oil, NGLs and natural gas we produce. There is also competition between producers of oil, NGLs and natural gas with other companies producing alternative energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by federal, state and local governments. It is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such legislation and regulations may, however, substantially increase the costs of exploring for, developing, producing or marketing oil, NGLs and natural gas and may prevent or delay the commencement or continuation of a given operation. The effect of these risks cannot be accurately predicted.

Seasonal Nature of Business

Generally, the demand for oil, NGLs and natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or abnormally hot summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other oil and natural gas operations in certain areas. These seasonal anomalies can increase competition for equipment, supplies and personnel.

Government Regulation

The oil and natural gas industry is subject to extensive laws that are subject to change. These laws have a significant impact on oil and natural gas exploration, production and marketing activities and increase the cost of doing business, and consequently, affect profitability. Some of the legislation and regulation affecting the oil and natural gas industry carry significant penalties for failure to comply and could result in a shut-down of operations. While there can be no assurance that we will not incur fines, penalties or other sanctions, we believe we are currently in material compliance with the applicable federal, state and local laws. Because enactment of new laws affecting the oil and natural gas industry is common and because existing laws are often amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws. We do not expect that any of these laws would affect us in a materially different manner than any other similarly sized oil and natural gas company operating in the U.S. The following are

significant types of legislation affecting our business.

Exploration and Production Regulation

Oil, NGL and natural gas production is regulated under a wide range of federal, state and local statutes, rules, orders and regulations, including laws related to the location, drilling and casing of wells; well production

Table of Contents**Index to Financial Statements**

limitations; spill prevention plans; surface use and restoration; platform, facility and equipment removal; the calculation and disbursement of royalties; the plugging and abandonment of wells; bonding; permits for drilling operations; and production, severance and ad valorem taxes. Oil and natural gas companies can encounter delays in drilling from the permitting process and requirements. Our operations are subject to regulations governing operation restrictions and conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells and prevention of flaring or venting of natural gas. The conservation laws have the effect of limiting the amount of oil, NGLs and natural gas we can produce from our wells and limit the number of wells or the locations at which we can drill.

Environmental Regulation

Our operations are subject to extensive environmental, health and safety regulation by federal, state and local agencies. These requirements govern the handling, generation, storage and management of hazardous substances, including how these substances are released or discharged into the air, water, surface and subsurface. These laws and regulations often require permits and approvals from various agencies before we can commence or modify our operations or facilities and on occasion (especially on federally-managed land) require the preparation of an environmental impact assessment or study (which can result in the imposition of various conditions and mitigation measures) prior to or in connection with obtaining such permits. In connection with releases of hydrocarbons or hazardous substances into the environment, we may be responsible for the costs of remediation even if we did not cause the release or were not otherwise at fault, under applicable laws. These costs can be substantial and we evaluate them regularly as part of our environmental and asset retirement programs. Failure to comply with applicable laws, permits or regulations can result in project or operational delays, civil or in some cases criminal fines and penalties and remedial obligations.

Climate Change. Current and future regulatory initiatives directed at climate change may increase our operating costs and may, in the future, reduce the demand for some of our produced materials. Such initiatives may contain a cap and trade approach to greenhouse gas regulation, which would require companies to hold sufficient emission allowances to cover their greenhouse gas emissions. Over time, the total number of allowances would be reduced or expire, thereby relying on market-based incentives to allocate investment in emission reductions across the economy. As the number of available allowances declines, the cost would presumably increase. While the current prospect for such climate change legislation by the current U.S. Congress appears to be low, several states, excluding Texas, have adopted, or are in the process of adopting greenhouse gas reporting or cap-and-trade programs. Therefore, while the outcome of the federal and state legislative processes is currently uncertain, if such an approach were adopted (either by domestic legislation, international treaty obligation or domestic regulation), we would expect our operating costs to increase as we buy additional allowances or embark on emission reduction programs.

Even without further federal legislation, the U.S. Environmental Protection Agency (EPA) has begun to regulate greenhouse gas emissions. In 2009 and 2010, the EPA promulgated new greenhouse gas reporting rules, requiring certain petroleum and natural gas facilities and facilities that emit more than 25,000 tons per year of carbon dioxide equivalents (CO₂e) to prepare and file annual emission reports. These rules, which are currently in effect and to which some of our facilities are subject, may require some data reporting in 2014 for our facilities if they emitted more than 25,000 tons of CO₂e in 2013, with annual reporting thereafter. Our emissions in 2011 and 2012 were below the 25,000 tons of CO₂e threshold and we were not required to report our greenhouse gas emissions to EPA. In addition, on May 13, 2010, the EPA issued a new tailoring rule, which imposes additional permitting requirements on certain stationary sources emitting over 75,000 tons per year of CO₂e. This rule does not currently affect our operations but may as our operations grow. As a result of these regulatory initiatives, our operating costs may increase due to

compliance with these programs, although we are not situated differently in this respect from our competitors in the industry.

Ground Water Impact due to Hydraulic Fracturing. Various federal and state initiatives are underway to regulate, or further investigate, the environmental impacts of hydraulic fracturing, a practice that involves the

Table of Contents**Index to Financial Statements**

pressurized injection of water, chemicals and other substances into rock formation to stimulate production of oil, NGLs and natural gas. The U.S. Congress has considered legislation to amend the federal Safe Drinking Water Act (SDWA) to subject hydraulic fracturing operations to regulation under the SDWA 's Underground Injection Control Program and to require the disclosure of chemicals used in the hydraulic fracturing process. Any such legislation could make it easier for third parties opposed to hydraulic fracturing to initiate legal proceedings against us. In addition, the federal government is currently undertaking several studies of hydraulic fracturing 's potential impacts. The Secretary of Energy Advisory Board published their ninety-day report that included a number of recommendations. On December 21, 2012, the EPA published an update on its ongoing national study currently underway to better understand any potential impacts of hydraulic fracturing on drinking water resources. A report that compiles the results of various research projects is expected during 2014. The EPA has developed draft permitting guidance under the SDWA where the EPA is the permitting authority for hydraulic fracturing activities that use diesel fuels in fracturing fluids. In addition, on October 21, 2011, the EPA announced its intention to propose regulations by 2014 under the federal Clean Water Act to regulate waste water discharges from hydraulic fracturing and other natural gas production. Further, on May 24, 2013, the federal Bureau of Land Management published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian lands that replaces a prior draft of proposed rulemaking issued by the agency in May 2012. The revised proposed rule would continue to require public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface. While we are in material compliance with applicable environmental laws and regulations and do not use diesel fuels as one of our hydraulic fracturing fluid components, the increased legislation, regulation or enforcement of hydraulic fracturing operations at the federal level could lead to operational delays, increased operating costs and additional regulatory burdens for our business.

Furthermore, a number of states, local governments and regulatory commissions, excluding Texas, or any of the areas in which we currently operate, have adopted, or are evaluating the adoption of, legislation or regulations that could impose more stringent permitting, disclosure, well construction, water usage and wastewater disposal requirements on hydraulic fracturing operations. Because we already participate in public disclosure on the FracFocus.com internet site, we do not anticipate experiencing a material adverse effect from disclosure requirements. The outcome for other proposed state, regional and local regulations is uncertain, but potential increased legislation, regulation or enforcement of hydraulic fracturing at the state, regional or local level could reduce our drilling activity or increase our operating costs.

Air Emissions from Oil and Natural Gas Operations. On August 16, 2012 the EPA published final rules that extend New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPs) to certain exploration and production operations. The first compliance date was October 15, 2012 with a phase-in of some of the requirements over the next two years. The final rule requires the use of reduced emission completions or green completions on all hydraulically-fractured gas wells constructed or refractured after January 1, 2015. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. In response to some of these challenges, the EPA amended the rule to extend compliance dates for certain storage vessels on August 2, 2013, and may issue additional revised rules in response to additional requests in the future. Only a portion of these new rules appear to affect our operations at this time by requiring new air emissions controls, equipment modification, maintenance, monitoring, recordkeeping and reporting. Although these new requirements will increase our operating and capital expenditures and it is possible that the EPA will adopt further regulation that could further increase our operating and capital expenditures, we do not currently expect such existing and new regulations will have a material adverse impact on our operations or financial results.

Derivative Legislation

The Dodd-Frank Act establishes federal oversight and regulation of the over-the-counter derivatives market. The legislation was signed into law in 2010 and requires the Commodities Futures Trading Commission

Table of Contents

Index to Financial Statements

(the CFTC), the SEC and other regulators to promulgate regulations implementing the new legislation. Among other things, the Dodd-Frank Act and the regulations promulgated under the Dodd-Frank Act impose requirements relating to reporting and recordkeeping, position limits, margin and capital, and mandatory trading and clearing. While many of the regulations are already in effect, the implementation process is still ongoing, and we cannot yet predict the ultimate effect of the regulations on our business. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through restrictions on the types of collateral we are required to post), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks, reduce our ability to monetize or restructure existing derivative contracts, and increase our exposure to less creditworthy counterparties.

Insurance Matters

As is common in the oil and natural gas industry, we are not fully insured against all risks associated with our business either because such insurance is unavailable or because premium costs are considered uneconomic. A material loss not fully covered by insurance could have an adverse effect on our financial position, results of operations or cash flows. We maintain insurance at industry customary levels to limit our financial exposure in the event of a substantial environmental claim resulting from sudden, unanticipated and accidental discharges of certain prohibited substances into the environment. Such insurance might not cover the complete amount of such a claim and would not cover fines or penalties for a violation of an environmental law.

Filings of Reserve Estimates with Other Agencies

We annually file estimates of our oil, NGL and natural gas reserves with the U.S. Department of Energy (DOE) for those properties which we operate. During 2013, we filed estimates of our oil, NGL and natural gas reserves as of December 31, 2012 with the DOE, which differed by five percent or less from the reserve data presented in the Annual Report on Form 10-K for the year ended December 31, 2012. For information concerning proved reserves, refer to Item 8. Financial Statements and Supplementary Data Supplemental Oil and Gas Disclosures.

Employees

As of February 7, 2014, we had 252 full time employees. We also contract for the services of consultants involved in land, regulatory, accounting, financial, legal and other disciplines, as needed. None of our employees are represented by labor unions or covered by any collective bargaining agreement. We believe that our relations with our employees are satisfactory.

Available Information

Through our website, <http://www.rosettaresources.com>, you can access, free of charge, our filings with the SEC, including our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, our proxy statements, our Code of Business Conduct and Ethics, Nominating and Corporate Governance Committee Charter, Audit Committee Charter, and Compensation Committee Charter. You may also read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Room 1580, 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. In addition, the SEC maintains a website that contains reports, proxy and information statements and other information that is filed electronically with the SEC. The website can be accessed at

<http://www.sec.gov>.

Item 1A. Risk Factors

Oil, NGL and natural gas prices are volatile, and a decline in these prices would significantly affect our financial results and impede our growth. Additionally, our results are subject to commodity price fluctuations related to seasonal and market conditions and reservoir and production risks.

Table of Contents

Index to Financial Statements

Our revenue, profitability and cash flow depend substantially upon the prices of and demand for oil, NGLs and natural gas. The markets for these commodities are volatile, and even relatively modest drops in prices can significantly affect our financial results and impede our growth. Prices for oil, NGLs and natural gas fluctuate widely in response to a variety of factors beyond our control, such as:

domestic and foreign supply of oil, NGLs and natural gas;

price and quantity of foreign imports of oil, NGLs and natural gas;

actions of the Organization of Petroleum Exporting Countries and state-controlled oil companies relating to oil price and production controls;

restrictions on exportation of our oil, NGLs and natural gas;

consumer demand;

the impact of energy conservation efforts;

regional price differentials and quality differentials of oil, NGLs and natural gas;

domestic and foreign governmental regulations, actions and taxes;

political conditions in or affecting other oil producing and natural gas producing countries, including current conflicts outside of the U.S.;

the availability of refining capacity;

weather conditions and natural disasters;

technological advances affecting oil, NGL and natural gas production and consumption;

overall U.S. and global economic conditions;

price and availability of alternative fuels;

seasonal variations in oil, NGL and natural gas prices;

variations in levels of production; and

the completion of large domestic or international exploration and production projects.

Further, oil, NGL and natural gas prices do not necessarily fluctuate in direct relation to each other. Our revenue, profitability, and cash flow depend upon the prices of, supply and demand for oil, NGLs and natural gas, and a drop in prices can significantly affect our financial results and impede our growth. In particular, declines in commodity prices may:

negatively impact the value of our reserves, because declines in oil, NGL and natural gas prices would reduce the value and amount of oil, NGLs and natural gas that we can produce economically;

reduce the amount of cash flow available for capital expenditures, repayment of indebtedness and other corporate purposes; and

result in a decrease in the borrowing base under our Credit Facility or otherwise limit our ability to borrow money or raise additional capital.

Adverse economic and capital market conditions may significantly affect our ability to meet liquidity needs, access to capital and cost of capital.

Concerns over inflation, the stability of sovereign debt levels, volatility and declines in the prices of securities and the bankruptcy, failure, collapse or sale of financial institutions have led to diminished expectations of the U.S. and foreign economies. These factors, combined with increased levels of unemployment and diminished liquidity and credit availability, prompted an unprecedented level of intervention by the U.S. federal government and other governments.

Table of Contents

Index to Financial Statements

If the economic recovery in the U.S. or other large economies is slow or prolonged, our ability to access the capital markets may be restricted at a time when we desire, or need, to raise capital. In addition, volatility and disruption in the financial and credit markets may adversely affect the financial condition of lenders in our Credit Facility and/or the ability or willingness of other lenders to participate in our Credit Facility. These market conditions may adversely affect our liquidity by limiting our ability to access our Credit Facility.

Potential deterioration in the credit markets, combined with a decline in commodity prices, may impact our capital expenditure level and also our counterparty risk.

While we seek to fund our capital expenditures primarily through cash flows from operating activities, we have in the past also drawn on unused capacity under our Credit Facility for capital expenditures. Borrowings under our Credit Facility are subject to the maintenance of a borrowing base, which is subject to semi-annual review and other adjustments. In the event that our borrowing base is reduced, outstanding borrowings in excess of the revised borrowing base will be due and payable immediately and we may not have the financial resources to make the mandatory prepayments. If our ability to borrow under our Credit Facility is impacted, we may be required to reduce our capital expenditures, which may in turn adversely affect our ability to carry out our business plan. Furthermore, if we lack the resources to dedicate sufficient capital expenditures to our existing oil and natural gas leases, we may be unable to produce adequate quantities of oil and natural gas to retain these leases and they may expire due to a lack of production. The loss of leases could have a material adverse effect on our results of operations.

Development and exploration drilling activities do not ensure reserve replacement and thus our ability to generate revenue.

Development and exploration drilling and strategic acquisitions are the main methods of replacing reserves. However, development and exploration drilling operations may not result in any increases in reserves for various reasons. Our future oil, NGL and natural gas production depends on our success in finding or acquiring additional reserves. If we fail to replace reserves through drilling or acquisitions, our level of production and cash flows will be affected adversely. In general, production from oil and natural gas properties declines as reserves are depleted, with the rate of decline dependent on reservoir characteristics. Our total proved reserves decline as reserves are produced. Our ability to make the necessary capital investment to maintain or expand our asset base of oil, NGL and natural gas reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves.

The terms of our agreements governing our indebtedness contain a number of operating and financial covenants. If we are unable to comply with these covenants, the repayment of our indebtedness may be accelerated.

We are subject to a number of covenants in our Credit Facility and in the indentures governing our Senior Notes (the 9.500% Senior Notes, 5.625% Senior Notes and 5.875% Senior Notes are collectively referred to as our Senior Notes) that impose restrictions on us, including our ability to incur indebtedness and liens, make loans and investments, make capital expenditures, sell assets, engage in mergers, consolidations and acquisitions, enter into transactions with affiliates, enter into sale and leaseback transactions and pay dividends on our common stock. We are also required by the terms of our Credit Facility to comply with financial covenants. A more detailed description of our Credit Facility and the indentures governing our Senior Notes is included in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources and the footnotes to the audited Consolidated Financial Statements included elsewhere in this Form 10-K.

A breach of any of the covenants imposed on us by the agreements governing our indebtedness, including the financial covenants in our Credit Facility, could result in a default under such indebtedness. In the event of a

Table of Contents

Index to Financial Statements

default, the lenders under our Credit Facility could terminate their commitments to us, and they could accelerate the repayment of all of our indebtedness. In such case, we may not have sufficient funds to pay the total amount of accelerated obligations, and our lenders could proceed against the collateral securing the facilities, which is substantially all of our assets. Any acceleration in the repayment of our indebtedness or related foreclosure could adversely affect our business.

Our exploration and development activities may not be commercially successful.

Exploration and development activities involve numerous risks, including the risk that no commercially productive quantities of oil, NGLs and natural gas will be discovered. In addition, the future cost and timing of drilling, completing and producing wells is often uncertain. Furthermore, drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors, including:

reductions in oil, NGL and natural gas prices;

unexpected drilling conditions;

pressure or irregularities in formations;

disruptions to production from producing wells related to hydraulic fracturing operations in nearby wells;

interference between producing wells, as a result of, among other things, spacing between wells;

equipment failures, including corrosion of aging equipment, systems failures and extended downtime, or accidents;

unavailability or high cost of drilling rigs, equipment or labor;

lost or damaged oilfield development and services tools;

limitations in midstream infrastructure or the lack of markets for oil, NGLs and natural gas;

unavailability or high cost of processing and transportation;

human error;

community unrest;

sabotage, terrorism and border issues, including encounters with illegal aliens and drug smugglers;

adverse weather conditions, including severe droughts resulting in new restrictions on water usage;

environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases;

compliance with environmental and other governmental regulations;

possible federal, state, regional and municipal regulatory moratoriums on new permits, delays in securing new permits, changes to existing permitting requirements without grandfathering of existing permits and possible prohibition and limitations with regard to certain completion activities; and

increases in severance taxes.

Our decisions to purchase, explore, develop and exploit prospects or properties depend, in part, on data obtained through geological and geophysical analyses, production data and engineering studies, the results of which are uncertain. Even when used and properly interpreted, 3-D seismic data and visualization techniques only assist geoscientists in identifying potentially productive hydrocarbon traps and geohazards. They do not allow the interpreter to know conclusively if hydrocarbons are present or economic. In addition, the use of 3-D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies. Because of these factors, we could incur losses as a result of exploratory drilling expenditures. Poor results from exploration activities could have a material adverse effect on our future financial position, results of operations and cash flows.

Table of Contents**Index to Financial Statements**

Numerous uncertainties are inherent in our estimates of oil, NGL and natural gas reserves and our estimated reserve quantities, and our present value calculations may not be accurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the estimated quantities and present value of our reserves.

Estimates of proved oil, NGL and natural gas reserves and the future net cash flows attributable to those reserves are prepared by our engineers and audited by independent petroleum engineers and geologists. There are numerous uncertainties inherent in estimating quantities of proved oil, NGL and natural gas reserves and cash flows attributable to such reserves, including factors beyond our engineers' control. Reserve engineering is a subjective process of estimating underground accumulations of oil, NGLs and natural gas that cannot be measured in an exact manner. The accuracy of an estimate of quantities of reserves, or of cash flows attributable to such reserves, is a function of the available data, assumptions regarding future oil, NGL and natural gas prices, expenditures for future development and exploration activities, engineering and geological interpretation and judgment. Additionally, reserves and future cash flows may be subject to material downward or upward revisions based upon production history, development and exploration activities and prices of oil, NGLs and natural gas. In addition, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. The present value of future net revenues from our proved reserves referred to in this report is not necessarily the actual current market value of our estimated oil, NGL and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on an average price, calculated as the twelve-month first-day-of-the-month historical average price for the twelve-month period prior to the end of the reporting period, and costs as of the date of the estimate. Our reserves as of December 31, 2013 were based on the trailing twelve-month first-day-of-the-month historical unweighted averages of West Texas Intermediate oil prices, adjusted for basis and quality differentials, of \$93.42 per Bbl and Henry Hub natural gas prices, adjusted for basis and quality differentials, of \$3.67 per MMBtu. Actual future prices and costs fluctuate over time and may differ materially from those used in the present value estimate.

The timing of both the production and expenses from the development and production of oil and natural gas properties will affect both the timing of actual future net cash flows from our proved reserves and their present value. In addition, the 10% discount factor that we use to calculate the standardized measure of future net cash flows for reporting purposes in accordance with the SEC's rules may not necessarily be the most appropriate discount factor. The effective interest rate at various times and the risks associated with our business or the oil and natural gas industry, in general, will affect the appropriateness of the 10% discount factor in arriving at the standardized measure of future net cash flows.

Downward revisions of reserves or lower oil and natural gas prices could result in impairments of our oil and natural gas properties.

Under the full cost method, we are subject to quarterly calculations of a ceiling, or limitation, on the amount of our oil and natural gas properties that can be capitalized on our balance sheet. If the net capitalized costs of our oil and natural gas properties exceed the cost ceiling, we are subject to a ceiling test write-down of our estimated net reserves to the extent of such excess. If required, a write-down would reduce earnings and impact stockholders' equity in the period of occurrence and result in lower amortization expense in future periods. The discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgment. The current ceiling calculation utilizes a trailing twelve-month first-day-of-the-month historical unweighted average price and does not allow us to re-evaluate the calculation subsequent to the end of the period if prices increase. It also dictates that costs in effect as of the last day of the quarter are held constant. The risk that we

will be required to write down the carrying value of oil and natural gas properties increases when oil and natural gas prices are depressed or volatile. In addition, a write-down of proved oil and natural gas properties may occur if we experience substantial downward adjustments to our estimated proved reserves. It is possible that we may recognize revisions to our proved reserves in the future. Write-downs recorded in one period will not be reversed in a subsequent period even though higher oil and natural gas prices may have increased the ceiling applicable in the subsequent period.

Table of Contents

Index to Financial Statements

We have not recorded any write-downs or impairments for the years ended December 31, 2013, 2012 or 2011. Due to the volatility of commodity prices, however, should oil and natural gas prices decline in the future, it is possible that write-downs could occur. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates for further information.

A widening of the condensate and crude oil price differential, which is currently at a discount, could negatively impact our revenue and the value of our reserves.

A significant portion of our crude oil production (approximately 52% in 2013) and our proved oil reserves (approximately 65% as of December 31, 2013) consists of condensate. Condensate is common in our Eagle Ford assets and typically requires stabilization to reduce vapor pressure, currently possesses a lower refining value, and may subject us to a higher discounted price as a result of its higher API gravity. Currently, condensate is priced at a discount compared to lower API gravity crude oil as a result of several factors, including high levels of condensate production, limited condensate refining capacity and limited means of exporting or transporting condensate volumes to areas with high demand. A significant decrease in the value of condensate could have a material, negative effect on our business, financial position, results of operations, cash flows and future growth, as well as a negative impact on the value of our oil reserves and the value and volumes of oil that we can economically produce.

Changes in governmental laws, regulations, and rules could materially affect our business, results of operations, cash flows, financial position and future growth.

Our activities are subject to federal, state, regional and local laws and regulations. Some of the laws, regulations and rules contain provisions for significant fines and penalties for non-compliance. Changes in laws and regulations could affect our costs of operations, production levels, royalty obligations, price levels, environmental requirements, and other aspects of our business, including our general profitability. We are unable to predict changes to existing laws and regulations. For example, the EPA has recently focused on public concerns about the risk of water contamination and public health problems from drilling and hydraulic fracturing activities. On August 16, 2012, the EPA published final rules that extend NSPS and NESHAPs to certain exploration and production operations. This renewed focus could lead to additional federal and state regulations affecting the oil and natural gas industry. New regulations or changes to existing laws and regulations could materially affect our business, results of operations, cash flows, financial position and future growth.

Our business requires a staff with technical expertise, specialized knowledge and training and a high degree of management experience.

Our success is largely dependent upon our ability to attract and retain personnel with the skills and experience required for our business. An inability to sufficiently staff our operations or the loss of the services of one or more members of our senior management or of numerous employees with technical skills could have a negative effect on our business, financial position, results of operations, cash flows and future growth.

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

Market conditions, the unavailability of satisfactory oil, NGL and natural gas processing and transportation to available markets or the remote location of certain of our drilling operations may hinder our access to markets or delay our production. The availability of a ready market for our various products depends on a number of factors, including

the demand for and supply of oil, NGLs and natural gas and the proximity of reserves to pipelines, terminals and trucking, railroad and/or barge transportation and processing facilities. Our ability to market our production also depends in substantial part on the availability and capacity of gathering systems, pipelines, terminals, other means of transportation and processing facilities. We may be required to shut in wells or delay production for lack of a market or because of inadequacy or unavailability of gathering systems,

Table of Contents

Index to Financial Statements

pipelines, or other means of transportation or processing facilities. The transportation of our production may be interrupted under the terms of our interruptible or short-term transportation agreements due to capacity constraints on the applicable system. The transportation of our production may also be interrupted under the terms of our firm long-term transportation, terminal and processing agreements due to operational upset, third party force majeure or other events beyond our control. Further, any disruption of third-party facilities due to maintenance, repairs, debottlenecking, expansion projects, weather or other interruptions of service could negatively impact our ability to market and deliver our products. Our concentration of operations in the Eagle Ford and Permian Basin areas increases these risks and their potential impact upon us. If we experience any interruptions to the transportation and/or processing of our products, we may be unable to realize revenue from our wells until our production can be tied to a pipeline or gathering system, transported by truck, rail and/or barge, or processed, as applicable, into the particular products. This can result in considerable delays from the initial discovery of a reservoir to the actual production of the oil, NGLs and natural gas and ultimate realization of revenues.

Competition in the oil and natural gas industry is intense, and many of our competitors have resources that are greater than ours.

We operate in a highly competitive environment for acquiring prospects and productive properties, marketing oil, NGLs and natural gas and securing equipment and trained personnel. Our competitors include major and large independent oil and natural gas companies that possess financial, technical and personnel resources substantially greater than our resources. Those companies may be able to develop and acquire more prospects and productive properties at a lower cost and more quickly than our financial or personnel resources permit. Our ability to acquire additional prospects and discover reserves in the future will depend on our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. Larger competitors may be better able to withstand sustained periods of unsuccessful drilling and absorb the burden of changes in laws and regulations more easily than we can, which would adversely affect our competitive position. 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.

Our strategy as an onshore unconventional resource player has resulted in operations concentrated in one geographic area and increases our exposure to many of the risks enumerated herein.

Currently, our operations are highly concentrated in the Eagle Ford area. As our largest producing area, this play provided approximately 93% of our total revenue for 2013, excluding the impact of derivative instruments, and it represents approximately 91% of our estimated total proved reserves as of December 31, 2013. This concentration increases the potential impact that many of the risks stated herein may have upon our ability to perform. For example, we have greater exposure to regulatory actions impacting Texas, natural disasters in the geographic area, competition for equipment, services and materials available in the area and access to infrastructure and markets.

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

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. If the level of exploration and production increases in the future, the demand for and costs of oilfield services could rise, while the quality of these services may decline. If the unavailability or high cost of drilling rigs,

equipment, supplies or qualified personnel were particularly severe in the Eagle Ford area, we could be materially and adversely affected because our operations and properties are concentrated in this area.

Table of Contents

Index to Financial Statements

Operating hazards, natural disasters or other interruptions of our operations could result in potential liabilities, which may not be fully covered by our insurance.

The oil and natural gas business involves certain operating hazards such as:

well blowouts;

cratering;

explosions;

uncontrollable flows of oil, natural gas or well fluids;

fires;

hurricanes, tropical storms and flooding;

pollution;

releases of toxic gas; and

surface spillage and surface or ground water contamination from petroleum constituents or hydraulic fracturing chemical additives.

Any of these operating hazards could cause serious injuries, fatalities or property damage, which could expose us to liabilities. The payment of any of these liabilities could reduce, or even eliminate, the funds available for exploration, development, and acquisition or could result in a loss of our properties. We are not fully insured against all risks, including development and completion risks that are generally not recoverable from third parties or insurance. In addition, our insurance policies provide limited coverage for losses or liabilities relating to sudden and accidental pollution, but not for other types of pollution. Our insurance might be inadequate to cover our liabilities. Our energy package is written on reasonably standard terms and conditions that are generally available to the exploration and production industry. The insurance market in general and the energy insurance market in particular have been difficult markets over the past several years. Insurance costs could increase in the future as the insurance industry adjusts to difficult exposures and we may decrease coverage and retain more risk to mitigate future cost increases. If we incur substantial liability and the damages are not covered by insurance or are in excess of policy limits, or if we incur a liability for a risk at a time when we do not have liability insurance, then our business, financial position, results of operations and cash flows could be materially adversely affected.

Our current insurance policies provide some coverage for losses arising out of our hydraulic fracturing operations. However, these policies may not cover fines, penalties or costs and expenses related to government-mandated clean-up activities, and total losses related to a spill, contamination or blowout during completion operations could exceed our per occurrence or aggregate policy limits. Furthermore, our current insurance policies do not provide coverage for ground water contamination due to any migration if not discoverable within a certain period, from fractured areas or from leaking associated with inadequate casing or cementing or defective and/or inadequate pipe and/or casing in the vertical sections of any of our shale wells that traverse aquifers in the locations of our producing properties. Any losses due to hydraulic fracturing that are not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

Regulation and competition of hydraulic fracturing services could impede our ability to develop our shale plays.

Hydraulic fracturing activities are required for all of our wells on our shale producing properties. Our shale properties are dependent on our ability to hydraulically fracture the producing formations. Commonly referred to as fracking, hydraulic fracturing is an integral part of the well completion process for all of our shale properties, including all of our exploration and development activities related to these properties.

Table of Contents

Index to Financial Statements

The fracking process involves pumping fluid at high pressure into underground shale formations through steel pipe that is perforated at the location of the hydrocarbons. The composition of the fluid is generally 99% water and sand or a ceramic material called proppant and less than 1% of highly diluted chemical additives, many of which are commonly found in household items. The high pressure creates small fractures that allow the oil and natural gas to flow into the well bore for collection at the surface. While the majority of the proppant remains wedged underground to prop open the fractures, a percentage of the water and additives flows back from hydraulic fracturing operations. These fluids are then either recycled onsite or must be transported to and disposed of at sites that are approved and permitted by applicable regulatory authorities.

The practice of hydraulic fracturing formations to stimulate production of oil, NGLs and natural gas has come under increased scrutiny by the environmental community. Various federal, state and local initiatives are underway to regulate, or further investigate, the environmental impacts of hydraulic fracturing. For example, in 2011, Texas has adopted regulations requiring certain hydraulic fracturing disclosures. Although hydraulic fracturing has been largely exempt from the federal Safe Drinking Water Act since 2005, bills have been considered in Congress that would repeal this exemption. In addition, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a number of federal agencies are analyzing environmental issues associated with hydraulic fracturing. For example, the EPA has commenced a multi-year study of the potential environmental impacts of hydraulic fracturing, the results of which are anticipated to be available in 2014. Further, on May 24, 2013, the federal Bureau of Land Management published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian lands that replaces a prior draft of proposed rulemaking issued by the agency in May 2012. The revised proposed rule would continue to require public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface.

On August 16, 2012 the EPA published final rules that extend New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPs) to certain exploration and production operations. The first compliance date was October 15, 2012 with a phase-in of some of the requirements over the next two years. The final rule requires the use of reduced emission completions or green completions on all hydraulically fractured natural gas wells constructed or refractured after January 1, 2015. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. In response to some of these challenges, The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. In response to some of these challenges, the EPA amended the rule to extend compliance dates for certain storage vessels on August 2, 2013, and it may issue additional revised rules in response to additional requests in the future. Only a portion of these new rules affect our operations at this time by requiring new air emissions controls, equipment modification, maintenance, monitoring, recordkeeping and reporting. Although these new requirements will increase our operating and capital expenditures and it is possible that the EPA will adopt further regulation that could further increase our operating and capital expenditures, we do not currently expect such existing and new regulations will have a material adverse impact on our operations or financial results.

The adoption of any future federal, state or local laws or regulations imposing additional permitting, disclosure or regulatory obligations related to, or otherwise restricting or increasing costs regarding the use of, hydraulic fracturing could make it more difficult to conduct drilling activity. As a result, such additional regulations could affect the volume of hydrocarbons we recover, and could increase the cycle times and costs to receive permits, delay or possibly preclude receipt of permits in certain areas, impact water usage and waste water disposal and require air emissions,

water usage and chemical additives disclosures. Such regulations could result in increased compliance costs or additional operating restrictions and, if the use of hydraulic fracturing is limited or prohibited, could lead to our inability to access existing and new oil, NGL and natural gas reserves in the future.

Table of Contents

Index to Financial Statements

Our industry is experiencing a growing emphasis on the exploitation and development of shale resource plays which are dependent on hydraulic fracturing for economically successful development. We engage third-party contractors to provide hydraulic fracturing services and related services, equipment and supplies. The availability or high cost of high pressure pumping services (or hydraulic fracturing services), chemicals, proppant, water, and related services and equipment could limit our ability to execute our exploration and development plans on a timely basis and within our budget. Hydraulic fracturing in shale plays requires high pressure pumping service crews. A shortage of service crews or proppant, chemicals or water could materially and adversely affect our operations and the timeliness of executing our development plans within our budget.

Hydraulic fracturing operations can result in air emissions, surface spillage and surface or ground water contamination, or ground water contamination by reason of well design and/or construction, and a blowout during completion operations when hydraulic services are being provided could result in personal injury or death and loss or damage to property. Additionally, pre-existing or concurrent non-Company spillage, contamination or property damage could result in litigation, government fines and penalties or remediation or restoration obligations, and damages.

Environmental matters and costs can be significant.

The oil and natural gas business is subject to various federal, state, and local laws and regulations relating to the discharge of materials into, and protection of, the environment. Such laws and regulations may impose liability on us for pollution clean-up, remediation, restoration and other liabilities arising from or related to our operations. Any noncompliance with these laws and regulations could subject us to material administrative, civil or criminal penalties or other liabilities. Additionally, our compliance with these laws may, from time to time, result in increased costs to our operations or decreased production. We also may be liable for environmental damages caused by the previous owners or operators of properties we have purchased or are currently operating. The cost of future compliance is uncertain and is subject to various factors, including future changes to laws and regulations. We have no assurance that future changes in or additions to the environmental laws and regulations will not have a significant impact on our business, results of operations, cash flows, financial condition and future growth.

Possible regulations related to global warming and climate change could have an adverse effect on our operations and the demand for oil, NGLs and natural gas.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases, may be contributing to the warming of the Earth's atmosphere. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of refined oil products and natural gas, are examples of greenhouse gases. In recent years, the U.S. Congress has considered climate-related legislation to reduce emissions of greenhouse gases. In addition, at least 20 states have developed measures to regulate emissions of greenhouse gases, primarily through the planned development of greenhouse gas emissions inventories and/or regional greenhouse gas cap and trade programs. The EPA has adopted regulations requiring reporting of greenhouse gas emissions from certain facilities and is considering additional regulation of greenhouse gases as air pollutants under the existing federal Clean Air Act. In November 2010, the EPA adopted rules expanding the industries subject to greenhouse gas reporting to include certain petroleum and natural gas facilities. These rules required data collection beginning in 2011 and reporting beginning in 2012, with annual reporting thereafter if emissions exceed 25,000 tons per year of CO₂e. Although our emissions did not exceed this threshold in 2011 or 2012, and our 2013 emissions data collection is in progress, some of our facilities may be subject to these rules in the future. Passage of climate change legislation or other regulatory initiatives by Congress or various states, or the adoption of other regulations by the EPA or analogous state agencies,

such as the Texas Commission of Environmental Quality (TCEQ), that regulate or restrict emissions of greenhouse gases (including methane or carbon dioxide) in areas in which we conduct business could have an adverse effect on our operations and the demand for oil, NGLs and natural gas.

Table of Contents

Index to Financial Statements

Our property acquisition strategy could fail or present unanticipated problems for our business in the future, which could adversely affect our ability to make property acquisitions and/or realize anticipated benefits of those acquisitions.

Our growth strategy includes acquiring oil and natural gas properties. We may not be able to identify suitable acquisition opportunities or finance and complete any particular acquisition successfully. Furthermore, acquisitions involve a number of risks and challenges, including:

diversion of management's attention;

ability or impediments to conducting thorough due diligence activities;

potential lack of operating experience in the geographic market where the acquired properties are located;

an increase in our expenses and working capital requirements;

the validity of our assumptions about reserves, future production, revenues, capital expenditures and operating costs, including synergies;

a decrease in our liquidity by using a significant portion of our available cash or borrowing capacity under our Credit Facility to finance acquisitions;

a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;

the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;

the incurrence of other significant charges, such as impairment of oil and natural gas properties, asset devaluation or restructuring charges; and

the inability to transition and integrate successfully or timely the businesses and/or assets we acquire.

Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses, environmental compliance review and seismic and other information, the results of which are often inconclusive and subject to various interpretations.

Also, our reviews of acquired properties are inherently incomplete because it generally is not feasible to perform an in-depth review of the individual properties involved in each acquisition given time constraints imposed by sellers. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to fully access their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken.

Derivative transactions may limit our potential revenue or result in financial losses which would reduce our income.

We have entered into oil, NGL and natural gas price derivative contracts with respect to a portion of our expected production through 2016. These derivative contracts may limit our potential revenue if oil, NGL and natural gas prices were to rise over the price established by the contract. Such transactions may expose us to the risk of loss in certain circumstances, including instances in which our production is less than expected, there is a widening of price differentials between delivery points for our production and the delivery point assumed in the derivative contract, or the counterparties to our derivative contracts fail to perform under the contracts. Our current derivative instruments are with counterparties that are lenders under our Credit Facility. A default by any of our counterparties could negatively impact our financial performance.

Table of Contents

Index to Financial Statements

The adoption of the Dodd-Frank Act 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, resulting in our operations becoming more volatile and our cash flows less predictable.

Congress has adopted the Dodd-Frank Act, a comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market. The legislation was signed into law by President Obama in 2010 and requires the CFTC, the SEC and other regulators to promulgate regulations implementing the new legislation. While many of the regulations are already in effect, the implementation process is still ongoing, and we cannot yet predict the ultimate effect of the regulations on our business.

The Dodd-Frank Act expanded the types of entities that are required to register with the CFTC and the SEC as a result of their activities in the derivatives markets or otherwise become specifically qualified to enter into derivatives contracts. We will be required to assess our activities in the derivatives markets, and to monitor such activities on an ongoing basis, to identify any potential change in our regulatory status.

CFTC reporting and recordkeeping requirements are currently effective and could significantly increase operating costs and expose us to penalties for non-compliance. These additional recordkeeping and reporting requirements may require additional compliance resources and may also have a negative effect on market liquidity, which could negatively impact commodity prices and our ability to hedge our commercial price risk.

The CFTC has also issued regulations to set position limits for certain futures, options, and swap contracts in the major energy markets. A United States District Court vacated and remanded the position limits rules to the CFTC in September 2012. On November 5, 2013, the CFTC proposed new rulemaking on position limits. It is uncertain at this time whether, when, and to what extent the CFTC's position limits rules will become final and effective.

The new regulations may also require us to comply with certain margin requirements for our over-the-counter derivative contracts with certain regulated entities, which could adversely affect our liquidity and ability to use derivatives to hedge our risks; however, the proposed margin rules are not yet final and therefore the application of those provisions to us is uncertain at this time. The financial reform legislation may also require our counterparties to spin off some of their derivatives activities to a separate entity, which entity may not be as creditworthy as the current counterparty.

The new legislation also requires that certain derivative instruments be centrally cleared and executed through an exchange or other approved trading platform, which may result in increased costs in the form of additional margin requirements imposed by clearing organizations. On December 13, 2012, the CFTC published final rules regarding mandatory clearing of certain interest rate swaps and index credit default swaps and setting compliance dates for different categories of market participants, the last of which was September 9, 2013. Mandatory trading on designated contract markets or swap execution facilities of certain interest rate swaps and index credit default swaps will begin in February 2014. The CFTC has not yet proposed any rules requiring the clearing of any other classes of swaps, including physical commodity swaps. Although there may be an exception to the mandatory exchange trading and clearing requirement that applies to our trading activities, we must obtain approval from our Board of Directors and make certain filings in order to rely on this exception. In addition, mandatory clearing requirements applicable to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for our commercial hedging program.

Rules promulgated under the Dodd-Frank Act further defined forward contracts as well as instances where forwards may become swaps. Because guidance regarding forwards is still developing, it is possible that some arrangements that previously qualified as forwards or energy service contracts may fall within the regulatory category of swaps. In addition, the CFTC's rules applicable to trade options may further impose burdens on our ability to conduct our traditional hedging operations.

Table of Contents

Index to Financial Statements

The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through restrictions on the types of collateral we are required to post), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks, 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. Finally, if we fail to comply with applicable laws, rules or regulations, we may be subject to fines, cease-and-desist orders, civil and criminal penalties or other sanctions.

The impairment of financial institutions or counterparty credit default could adversely affect us.

Our commodity derivative transactions expose us to credit risk in the event of default by our counterparties. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us. We may have significant exposure to our derivative counterparties and the value of our derivative positions may provide a significant amount of cash flow. In addition, if any lender under our Credit Facility is unable to fund its commitment, our liquidity may be reduced by an amount up to the aggregate amount of such lender's commitment under our Credit Facility. Currently, no single lender in our Credit Facility has commitments representing more than 11% of our total commitments. However, if banks continue to consolidate, we may experience a more concentrated credit risk.

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

Among the changes contained in the President's Fiscal Year 2014 budget proposal, as released by the White House, is the elimination of certain U.S. federal income tax deductions and credits currently available to oil and natural gas exploration and production companies. Such proposed 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 U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Recently, members of the U.S. Congress have considered, and in some cases proposed, similar changes to the existing federal income tax laws that affect oil and natural gas exploration and production companies. It is unclear, however, whether any such changes will be enacted or, if enacted, how soon such changes would be effective. The passage of any legislation as a result of the budget proposal or any other similar change in U.S. federal income tax law could eliminate or defer certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could negatively affect our financial condition, results of operations and cash flows.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

See Part II, Item 8, Note 11-Commitments and Contingencies of this Form 10-K, which is incorporated in this item by reference.

Item 4. Mine Safety Disclosures

Not applicable.

Table of ContentsIndex to Financial Statements**Part II****Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities**
Trading Market

Our common stock is listed on The NASDAQ Global Select Market® under the symbol ROSE. The following table sets forth the high and low sale prices of our common stock for the periods indicated:

	2013			2012	
	High	Low		High	Low
January 1 - March 31	\$ 54.61	\$ 44.50	January 1 - March 31	\$ 54.43	\$ 43.59
April 1 - June 30	50.10	40.83	April 1 - June 30	51.35	32.37
July 1 - September 30	55.15	42.04	July 1 - September 30	49.96	35.68
October 1 - December 31	65.30	45.26	October 1 - December 31	51.78	41.65

The number of shareholders of record on February 7, 2014 was approximately 226. However, we believe that we have a significantly greater number of beneficial shareholders since a substantial number of our common shares are held of record by brokers or dealers for the benefit of their customers.

We have not paid a cash dividend on our common stock and currently intend to retain earnings to fund the growth and development of our business. Any future change in our policy will be made at the discretion of our board of directors in light of our financial condition, capital requirements, earnings prospects and limitations imposed by our lenders or by any of our investors, as well as other factors the board of directors may deem relevant. The declaration and payment of dividends is restricted by our Credit Facility and the indenture governing our Senior Notes. Future agreements may also restrict our ability to pay dividends.

The following table sets forth certain information with respect to repurchases of our common stock during the three months ended December 31, 2013:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Maximum Number (or Approximate Dollar Value) of Shares that May yet Be Purchased Under the Plans or Programs	
			Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value) of Shares that May yet Be Purchased Under the Plans or Programs
October 1 - October 31	598	\$ 55.07		
November 1 - November 30	2,140	57.90		

December 1 - December 31	2,467		47.92
Total	5,205	\$	52.84

- (1) All of the shares were surrendered by our employees and certain of our directors to pay tax withholding upon the vesting of restricted stock awards. We do not have a publicly announced program to repurchase shares of common stock.

Issuance of Unregistered Securities

None.

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 or the Securities Exchange Act, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

Table of Contents**Index to Financial Statements**

The following common stock performance graph shows the performance of our common stock through December 31, 2013. As required by applicable rules of the SEC, the performance graph shown below was prepared based on the following assumptions:

a \$100 investment was made in our common stock at the closing trade price of \$7.08 per share on December 31, 2008, and \$100 was invested in each of the Standard & Poor's 500 Index (S&P 500) and the Standard & Poor's MidCap 400 Oil & Gas Exploration & Production Index (S&P 400 E&P) at the closing trade price on December 31, 2008; and

all dividends are reinvested for each measurement period.

The S&P 400 E&P Index is widely recognized in our industry and includes a representative group of independent peer companies (weighted by market capital) that are engaged in comparable exploration, development and production operations.

Total Return Among Rosetta Resources Inc., the S&P 500 Index and the S&P 400 E&P Index

	12/31/2008	12/31/2009	12/31/2010	12/31/2011	12/31/2012	12/31/2013
ROSE	\$ 100.00	\$ 281.36	\$ 531.64	\$ 614.41	\$ 640.11	\$ 678.53
S&P 500	100.00	126.45	145.49	148.55	172.31	228.10
S&P 400 E&P	100.00	178.15	255.12	209.33	182.72	269.02

Table of Contents**Index to Financial Statements****Item 6. Selected Financial Data**

The following selected financial data should be read in connection with Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and the audited Consolidated Financial Statements and related notes included elsewhere in this Form 10-K.

	Year Ended December 31,				
	2013	2012	2011	2010	2009 (1)
	(In thousands, except per share data)				
Operating Data:					
Total revenues	\$ 814,018	\$ 613,499	\$ 446,200	\$ 308,430	\$ 293,951
Net income (loss)	199,352	159,295	100,546	19,046	(219,176)
Net Income (loss) per share:					
Basic	\$ 3.40	\$ 3.03	\$ 1.93	\$ 0.37	\$ (4.30)
Diluted	3.39	3.01	1.91	0.37	(4.30)
Cash dividends declared and paid per common share:					
	\$	\$	\$	\$	\$
Balance Sheet Data (At the end of the period):					
Total assets	\$ 3,276,618	\$ 1,415,416	\$ 1,065,345	\$ 989,440	\$ 872,042
Long-term debt	1,500,000	410,000	230,000	350,000	288,742
Total other long-term liabilities	154,157	17,570	14,949	28,275	31,261
Stockholders' equity	1,348,334	803,999	632,836	528,816	493,095

(1) Includes a \$379.5 million non-cash, pre-tax impairment charge for 2009.

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

The following discussion addresses material changes in our results of operations for the year ended December 31, 2013 compared to the year ended December 31, 2012 and material changes in our financial condition since December 31, 2012.

Results for full-year 2013 include the following:

production of 18.1 MMBoe compared to 13.6 MMBoe for the year ended December 31, 2012;

150 gross (149 net) operated wells drilled compared to 85 gross (82 net) operated wells drilled for the year ended December 31, 2012; and

net income of \$199 million, or \$3.39 per diluted share, compared to \$159 million, or \$3.01 per diluted share, for the year ended December 31, 2012.

Our principal operating and business strategy is focused on the acquisition, development and production of oil, NGLs and natural gas from unconventional resource plays. Our operations are primarily located in the Eagle Ford area in South Texas and the Delaware Basin in West Texas, two of the most active unconventional resource plays in the United States. During the first quarter of 2013, we entered into a purchase and sale agreement with Comstock Oil & Gas, LP to acquire producing and undeveloped assets covering 87,373 gross (53,306 net) acres in the oil-rich areas of the Permian Basin. The Permian Acquisition closed on May 14, 2013, with an effective date of January 1, 2013, for total consideration of \$825.2 million, which includes the \$768 million purchase price and \$57.2 million in customary closing adjustments. The Permian Acquisition added roughly 40,000 net acres in the Wolfbone play in Reeves County in the Delaware Basin and 13,000 net acres in Gaines County in the Midland Basin. As of December 31, 2013, we estimate 698 gross (454 net) horizontal drilling locations with potential in multiple horizons including the upper Wolfcamp, lower Wolfcamp and 3rd Bone Springs. We have

Table of Contents

Index to Financial Statements

also identified 1,619 gross (725 net) vertical drilling locations assuming 20-acre spacing. Additionally, both Rosetta and the industry are actively participating in horizontal well applications in the Delaware Basin to further enhance the value of this large resource.

During the second quarter of 2013, we also acquired for total consideration of \$128.1 million the remaining 10% working interest in 46 gross producing wells and the leasehold associated with 170 future gross drilling locations in the Gates Ranch area of the Eagle Ford Shale. The net production associated with this acquisition was approximately 1,800 Boe per day at closing on June 5, 2013. We now own a 100% working interest in the entire Gates Ranch leasehold. On December 30, 2013, Rosetta entered into a definitive agreement with several private parties to acquire Delaware Basin assets for a purchase price of \$85 million. The acquisition covers 5,078 net acres (14,985 gross) located in Reeves County. These assets include 13 gross producing wells, of which 11 are operated. We estimate the addition of 49 net (145 gross) future horizontal upper Wolfcamp drilling locations to expand our capital project inventory. This transaction is expected to close on or about February 28, 2014, subject to customary closing conditions.

In the last four years, we have become a significant producer in the liquids-rich window of the Eagle Ford region and have established an inventory of lower-risk, higher-return drilling opportunities that offer more predictable and long-term production, reserve growth and a more valuable commodity mix. With our entry into the Permian Basin and bolt-on activity, we have increased our portfolio of long-lived, oil-rich resource projects that will further drive our long-term growth and sustainability. We will continue to consider investments in the Eagle Ford shale region, Permian Basin and other unconventional resource basins that offer a viable inventory of projects, including resource-based exploration projects and producing property acquisitions in early development stages.

Our current operations in the Eagle Ford shale are primarily focused in five areas. Our original discovery in 2009 is located in the 26,230-acre Gates Ranch leasehold in Webb County. We are also active in the Karnes Trough area, the Briscoe Ranch leasehold and Central Dimmit County, where our positions were delineated in 2010, 2011 and 2012, respectively. Earlier in 2013, we delineated the Tom Hanks lease in northern LaSalle County with an Eagle Ford discovery well completed in June 2013. Overall, as of December 31, 2013 we hold 63,000 net acres in the region, with approximately 50,000 acres located in the liquids producing portions of the play.

The development of our assets in the Eagle Ford, which averaged approximately 47,600 Boe per day in 2013, an increase of 33% from 2012, has led to substantial growth for the Company, while shifting our portfolio toward higher-valued crude oil and NGL production. During 2013, we recorded a 34% increase in daily total equivalent production, with total liquids production growth of 43%. Approximately 63% of our total production during 2013 was attributable to crude oil and NGLs and 44% of our total liquids production was attributable to oil. This compares to 59% of our production being attributable to crude oil and NGLs and 44% of our total liquids production being attributable to oil in 2012. The Eagle Ford area accounted for approximately 96% of our total production in 2013. In addition, approximately 62% of the production from the Eagle Ford area in 2013 was from crude oil, condensate and NGLs.

At December 31, 2013, our total estimated proved reserves were 279 MMBoe compared to 201 MMBoe at the prior year-end, representing an increase of 39%. Of our total reserves, approximately 60% were liquids and 32% were classified as proved developed. We replaced 528% of production from all sources, including net reserve additions from drilling activity, price revisions, proved acquisitions and performance revisions. Finding and development costs, excluding proved acquisitions, totaled approximately \$12 per Boe to organically replace 402% of production.

Edgar Filing: Rosetta Resources Inc. - Form 10-K

We drilled 150 gross operated wells and completed 113 gross wells during 2013. Of those totals, 111 were drilled and 79 were completed in the Eagle Ford area. In the Delaware Basin, 37 gross vertical wells were drilled and 30 gross vertical wells were completed. We also drilled two gross horizontal well and completed two

Table of Contents

Index to Financial Statements

gross horizontal wells in this basin in 2013. As of December 31, 2013, we had completed a total of 205 gross wells in the Eagle Ford shale since entering the play. During 2013, we continued to record strong sequential growth in Eagle Ford volumes, averaging a record 48,065 Boe per day in the fourth quarter, a 9% increase from the same period in 2012. To handle our increased production, we have secured multiple options for transportation and processing capacity with commitments in place to meet total planned production levels through 2014, and we are evaluating adding more firm capacity in our operating areas.

Our 2014 capital program is expected to total \$1.1 billion. The 2014 budget is based on a four to five-rig Eagle Ford program with plans to drill and complete roughly 90 – 95 gross wells. Approximately half of the completions will be located in the Gates Ranch area with the remainder in other areas in the liquids-rich window of the play, including Briscoe Ranch, Tom Hanks, and Central Dimmit County. The budget also includes a six-rig Permian program, including four rigs dedicated to horizontal drilling and two rigs allocated to vertical wells. We plan to drill and complete approximately 50 – 55 gross operated wells in the oil-rich Delaware Basin, about half of which will be horizontal wells. Approximately \$735 million, or 67% of our 2014 capital program, will be spent on development activities in the liquids-rich window of the Eagle Ford shale in South Texas. Approximately \$265 million, or 24%, will be spent on activities in the Delaware Basin in West Texas. In addition, the 2014 budget allocates approximately \$100 million for other capital items, including evaluation of new venture opportunities, capitalized interest and other corporate capital.

While our unconventional resource strategy has proven to be successful, we recognize that there are risks inherent to our industry that could impact our ability to meet future goals. Although we cannot completely control all external factors that could affect our operating environment, our business model takes into account the threats that could impede achievement of our stated growth objectives and the building of our asset base. We have diversified our production base to include a greater mix of crude oil and NGLs, which continue to be priced at more favorable levels than natural gas. Because our production is highly concentrated in the Eagle Ford and Permian Basin areas, we have taken various steps to provide access to necessary services and infrastructure. We believe that our 2014 capital program can be executed using a combination of internally generated cash flows, cash on hand, and borrowings under our Credit Facility. We continuously monitor our liquidity to respond to changing market conditions, commodity prices and service costs. If our internal funds are insufficient to meet projected funding requirements, we would consider curtailing capital spending or accessing the capital markets.

Availability under our Credit Facility is restricted to a borrowing base, which is subject to review and adjustment on a semi-annual basis and other interim adjustments, including adjustments based on hedging arrangements and asset divestitures. The amount of the borrowing base is dependent on a number of factors, including our level of reserves, as well as the pricing outlook at the time of the redetermination. As of December 31, 2013, our borrowing base and committed amount under our Credit Facility was \$800 million. As of February 24, 2014, we had no borrowings outstanding with \$800 million available for borrowing under our Credit Facility.

Financial Highlights

Our consolidated financial statements reflect total revenue of \$814.0 million (net of derivative losses of \$7.1 million) based on total volumes of 18.1 MMBoe for 2013.

Significant transactions which affect the comparability of our financial results between periods include the acquisitions of our Permian Basin assets and Gates Ranch leasehold in 2013, the divestiture of our Lobo assets and a portion of our Olmos assets in 2012, and the divestitures of our Sacramento Basin and DJ Basin assets in 2011.

Table of Contents**Index to Financial Statements****Results of Operations**

The following table summarizes the components of our revenues for the periods indicated, as well as each period's production volumes and average realized prices:

	Year Ended December 31,		
	2013	2012	2011
(In thousands, except per unit amounts)			
Revenues:			
Oil sales	\$ 475,119	\$ 318,782	\$ 156,284
NGL sales	198,966	160,461	125,301
Natural gas sales	147,028	93,711	163,382
Derivative instruments	(7,095)	40,545	1,233
Total revenues	\$ 814,018	\$ 613,499	\$ 446,200
Production:			
Oil (MBbls)	4,999	3,497	1,863
NGLs (MBbls)	6,398	4,472	2,643
Natural Gas (MMcf)	40,343	33,853	33,393
Total equivalents (MBoe)	18,121	13,611	10,072
Average sales price:			
Oil, excluding derivatives (per Bbl)	\$ 95.04	\$ 91.16	\$ 85.04
Oil, including realized derivatives (per Bbl)	93.74	89.66	83.89
NGL, excluding derivatives (per Bbl)	31.10	35.88	51.26
NGL, including realized derivatives (per Bbl)	32.83	37.84	47.41
Natural gas, excluding derivatives (per Mcf)	3.64	2.77	4.00
Natural gas, including realized derivatives (per Mcf)	3.76	3.28	4.89
Revenue, excluding derivatives (per Boe)	45.31	42.09	42.45
Revenue, including realized derivatives (per Boe)	45.82	43.63	44.18

Revenues

Our revenue is derived from the sale of our oil, NGL and natural gas production, and includes the effects of our commodity derivative contracts. Our revenue may vary significantly from period to period as a result of changes in commodity prices, volumes of production sold and the impact of our commodity derivative instruments.

Excluding the effects of derivative instruments, revenue for 2013, 2012 and 2011 was \$821.1 million, \$573.0 million and \$427.5 million, respectively, and year-over-year growth in 2013 and 2012 was attributable to increased oil and NGL production and higher average realized oil and natural gas prices. Excluding the effects of derivative instruments, revenue attributable to oil and NGL sales in 2013, 2012 and 2011 was approximately 82%, 84% and 69%, respectively, of total revenue.

Oil sales. Oil sales, excluding derivative instruments, of \$475.1 million, \$318.8 million and \$158.4 million for 2013, 2012 and 2011, respectively, increased year-over-year due to higher oil production and higher realized prices. The

increase in oil production in 2013 was primarily attributable to our acquired Permian assets as well as higher production in both 2013 and 2012 at our Gates Ranch, Klotzman and Reilly wells in the Eagle Ford area, whose combined total oil production in 2013, 2012 and 2011 was 10.0 MBbls per day, 8.7 MBbls per day and 4.6 MBbls per day, respectively.

For 2013 and 2012, realized oil derivative losses of \$6.5 million and \$5.2 million, respectively, are reported as a component of Derivative instruments within Revenues. For 2011, a realized oil derivative loss of \$2.1 million is reported as a component of Oil sales within Revenues and reflects the effect of oil hedging activities on oil revenues.

Table of Contents

Index to Financial Statements

NGL sales. NGL sales, excluding derivative instruments, of \$199.0 million, \$160.5 million and \$135.5 million for 2013, 2012 and 2011, respectively, increased year-over-year due to higher NGL production, partially offset by lower realized prices. The increase in both periods due to higher NGL production was primarily attributable to our Gates Ranch wells in the Eagle Ford area, whose total NGL production in 2013, 2012 and 2011 was 14.7 MBbls per day, 10.7 MBbls per day and 6.5 MBbls per day, respectively.

For 2013 and 2012, realized NGL derivative gains of \$11.1 million and \$8.7 million, respectively, are reported as a component of Derivative instruments within Revenues. For 2011, a realized NGL derivative loss of \$10.2 million is reported as a component of NGL sales within Revenues and reflects the effect of NGL hedging activities on NGL revenues.

Natural gas sales. Natural gas sales, excluding derivative instruments, of \$147.0 million, \$93.7 million and \$133.6 million for 2013, 2012 and 2011, respectively, increased year-over-year in 2013 and decreased year-over-year in 2012. The increase in 2013 from 2012 was due to higher natural gas production and higher realized prices. The decrease in 2012 from 2011 was due to lower realized prices, partially offset by higher natural gas production. The increase in natural gas production in 2013 and 2012 was primarily attributable to our Gates Ranch wells in the Eagle Ford area, whose total natural gas production in 2013, 2012 and 2011 was 93.5 MMcf per day, 77.8 MMcf per day and 56.0 MMcf per day, respectively.

For 2013 and 2012, realized natural gas derivative gains of \$4.7 million and \$17.4 million, respectively, are reported as a component of Derivative instruments within Revenues. For 2011, a realized natural gas derivative gain of \$29.8 million is reported as a component of Natural gas sales within Revenues and reflects the effect of natural gas hedging activities on natural gas revenues.

Derivative Instruments. Derivative instruments includes (i) unrealized derivative gains and losses due to changes in fair value of our commodity derivative contracts, (ii) unrealized derivative gains and losses due to the reclassification of commodity hedging gains and losses from Accumulated other comprehensive income, and (iii) realized derivative gains and losses attributable to cash settlements associated with our commodity derivative contracts.

In 2013, Derivative instruments included (i) an unrealized derivative loss of \$16.3 million due to changes in fair value of our commodity derivative contracts, (ii) the reclassification of an unrealized derivative loss of \$0.1 million from Accumulated other comprehensive income, and (iii) a realized derivative gain of \$9.3 million from cash settlements.

In 2012, Derivative instruments included (i) an unrealized derivative gain of \$17.0 million due to changes in fair value of our commodity derivative contracts, (ii) the reclassification of an unrealized derivative gain of \$2.7 million from Accumulated other comprehensive income, and (iii) a realized derivative gain of \$20.9 million from cash settlements.

In 2011, Derivative instruments included (i) an unrealized derivative gain of \$1.2 million due to changes in fair value of our crude oil basis and NYMEX roll swaps, (ii) the reclassification of a realized derivative gain of \$6.4 million from Accumulated other comprehensive income associated with hedge accounting, and (iii) a realized derivative gain of \$11.0 million associated with the 2011 termination of derivatives used to hedge production from our divested DJ Basin and Sacramento Basin properties.

Table of Contents**Index to Financial Statements****Operating Expenses**

The following table summarizes our production costs and operating expenses for the periods indicated:

	Year Ended December 31,		
	2013	2012	2011
	(In thousands, except per unit amounts)		
Direct lease operating expense	\$ 45,155	\$ 32,874	\$ 27,326
Insurance expense	1,015	985	902
Workover expense	7,166	1,279	594
Lease operating expense (Production costs)	\$ 53,336	\$ 35,138	\$ 28,822
Treating and transportation	71,338	51,826	22,316
Taxes, other than income (1)	31,075	24,013	18,151
Depreciation, depletion and amortization (DD&A)	218,571	154,223	123,244
Reserve for commercial disputes	20,450		
General and administrative costs	73,043	68,731	75,256
Costs and expenses (per Boe of production)			
Lease operating expense (Production costs)	\$ 2.94	\$ 2.58	\$ 2.86
Treating and transportation	3.94	3.81	2.22
Taxes, other than income (1)	1.71	1.76	1.80
Depreciation, depletion and amortization (DD&A)	12.06	11.33	12.24
General and administrative costs	4.03	5.05	7.47
General and administrative costs, excluding stock-based compensation	3.42	3.69	4.59

(1) Beginning in 2013, production taxes and ad valorem taxes are included as a component of Taxes, other than income. Prior year amounts have been reclassified to conform to the current presentation.

Lease Operating Expense. Lease operating expense increased in 2013 from 2012 on a per unit basis primarily due to the Permian Acquisition which contributed \$14.1 million (or \$0.78 per Boe) of the overall increase, inclusive of \$5.1 million (or \$0.28 per Boe) of well workover costs. Lease operating expense on a per unit basis in the Eagle Ford area decreased in 2013 primarily due to an increase in production, which more than offset the operating costs of higher volumes. Lease operating expense decreased on a per unit basis in 2012 from 2011 primarily due to our divestiture of higher-cost dry gas properties and an increase in lower-cost Eagle Ford production.

Treating and Transportation. Treating and transportation expense increased year-over-year as a result of increased daily production of 33% and 67% in 2013 and 2012, respectively, in the Eagle Ford area, as well as higher unit costs required to transport incremental production from the area. In addition, we accrued deficiency fees of \$7.8 million and \$5.2 million in 2013 and 2012, respectively, related to shortfalls in delivering the minimum volumes required under our transportation and processing agreements during 2013 and 2012.

Taxes, other than income. Taxes, other than income include production taxes and ad valorem taxes. Production taxes are based on revenues generated from production, and ad valorem taxes are based on the valuation of the underlying assets. The year-over-year increase in 2013 was primarily due to a \$4.2 million increase in production taxes resulting

from a 33% increase in production and a \$2.9 million increase in ad valorem taxes primarily due to higher assessments on our Eagle Ford assets. The increase in 2012 from 2011 was primarily due to a \$4.7 million increase in production taxes resulting from a 35% increase in production and a \$1.2 million increase in ad valorem taxes primarily associated with our Gates Ranch assets.

Table of Contents

Index to Financial Statements

Depreciation, Depletion, and Amortization. DD&A expense increased year-over-year in 2013 due to a 34% increase in daily production from 2012 and an increased DD&A rate due to the inclusion of higher-cost Permian reserves in our depletion pool. In 2012, DD&A expense increased year-over-year due to a 35% increase in daily production from 2011, partially offset by a lower DD&A rate driven by significant additions of proved reserves, primarily in the Gates Ranch area.

Reserve for commercial disputes. In 2013, we recorded a reserve of \$20.5 million related to two commercial disputes, one of which was settled in the fourth quarter of 2013 and the other which is expected to be settled in the first quarter of 2014. See Part II. Item 8. Financial Statements and Supplementary Data, Note 11 Commitments and Contingencies.

General and Administrative Costs. General and administrative costs, net of capitalized exploration and development overhead of \$7.2 million, increased \$4.3 million in 2013 from 2012. The increase in 2013 was primarily related to a \$7.4 million increase in salaries, wages and bonuses due to higher headcount, a \$3.4 million increase in consultant costs related to acquisition activities and various internal projects and a \$1.3 million increase in rent expense related to our new office location, partially offset by a \$7.6 million decrease in stock-based compensation expense driven by our performance share units and a \$0.2 million decrease in other administrative costs.

In 2012, General and administrative costs, net of capitalized exploration and development overhead costs of \$6.0 million, decreased \$6.5 million from 2011. The decrease in 2012 was primarily related to a \$10.5 million decrease in stock-based compensation expense driven by our performance share units, partially offset by a \$2.2 million increase in rent expense related to our new office location and a \$1.8 million increase in other administrative costs.

Total Other Expense

Total other expense, which includes Interest expense, net of interest capitalized; Interest income; and Other expense (income), net, increased \$11.9 million in 2013 from 2012 primarily due to the issuance of our 5.625% Senior Notes and 5.875% Senior Notes in 2013, which resulted in higher interest expense partially offset by an increase in capitalized interest.

Total other expense increased \$2.2 million in 2012 from 2011 primarily due to increased borrowings under our Credit Facility.

Provision for Income Taxes

Our 2013 income tax expense was \$110.6 million. For the year ended December 31, 2013, our effective tax rate was 35.7% compared to an effective tax rate of 37.6% for the year ended December 31, 2012 and 35.7% for the year ended December 31, 2011. The provision for income taxes differs from the tax computed at the federal statutory income tax rate primarily due to the effects of state taxes and the deductibility of certain incentive compensation.

The Company provides for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in the financial statements in accordance with authoritative guidance for accounting for income taxes. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in determining when these events may occur and whether recovery of an asset is more likely than not. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax

assets will not be realized. As of December 31, 2013, we had a net deferred tax liability of \$108.4 million, compared to a net deferred tax liability of \$9.8 million at December 31, 2012.

Table of Contents

Index to Financial Statements

In connection with our asset divestitures in 2012 and 2011, we concluded that it was more likely than not that the net operating losses (NOLs) and other deferred tax assets in those states impacted by our divestitures would not be realized. Therefore, valuation allowances were established for these items as well as state NOLs in other jurisdictions in which we previously operated but had since divested of operating assets. Annually, changes in our valuation allowance are made to reflect revised estimates of the utilization of state deferred tax assets. We will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods.

Liquidity and Capital Resources

Our sources of liquidity and capital are our operating cash flow, cash on hand and our Credit Facility, which can be accessed as needed to supplement operating cash flow.

Operating Cash Flow. Our cash flows depend on many factors, including the price of oil, NGLs and natural gas and the success of our development and exploration activities. We actively manage our exposure to commodity price fluctuations by executing derivative transactions to hedge 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 commodity prices. The effects of these derivative transactions on our oil, NGL and natural gas sales are discussed above under Results of Operations Revenues. The majority of our capital expenditures is discretionary and could be curtailed if our cash flows materially decline from expected levels. Economic conditions and lower commodity prices could adversely affect our cash flow and liquidity. We will continue to monitor our cash flow and liquidity and, if appropriate, we may consider adjusting our capital expenditure program or accessing the capital markets.

Senior Secured Revolving Credit Facility. As of December 31, 2013, we had no borrowings outstanding with \$800 million of available borrowing capacity under the Credit Facility. Amounts outstanding under the Credit Facility bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 1.50% to 2.50% and mature in April 2018. Additionally, we can borrow under the Credit Facility at the Alternative Base Rate (ABR) which is typically based upon the Prime Rate in effect on such day plus a margin of 0.5% to 1.5% depending on our utilization percentage. The weighted average borrowing rate for the year ended December 31, 2013 under the Credit Facility was 3.22%, inclusive of interest and commitment fees. Borrowings under the Credit Facility are collateralized by liens and security interests on substantially all of our assets, including a mortgage lien on oil and natural gas properties having at least 80% of the pre-tax SEC PV-10 proved reserve value, a guaranty by all of our domestic subsidiaries, and a pledge of 100% of the membership and limited partnership interests of our domestic subsidiaries. Collateralized amounts under the mortgages are subject to semi-annual reviews based on updated reserve information. We are also subject to certain financial covenants, including the requirement to maintain a minimum current ratio of consolidated current assets, including the unused amount of available borrowing capacity, to consolidated current liabilities, excluding certain non-cash obligations, of not less than 1.0 to 1.0 as of the end of each fiscal quarter. The terms of the credit agreement also require the maintenance of a maximum leverage ratio of total debt to earnings before interest expense, income taxes and noncash items, such as depreciation, depletion, amortization and impairment, of not greater than 4.0 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended, measured quarterly after giving pro forma effect to acquisitions and divestitures. At December 31, 2013, our current ratio was 4.4 and our leverage ratio was 2.5. In addition, we are subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. We were in compliance with all covenants at December 31, 2013.

Second Lien Term Loan. Our amended and restated term loan (the Restated Term Loan) of \$20.0 million was prepaid in full on August 31, 2012. Outstanding fixed-rate borrowings under the Restated Term Loan bore interest at 13.75% and would have matured on October 2, 2012. The loan was collateralized by second priority liens on substantially all of our assets and upon prepayment, the second priority liens were released. In connection with the prepayment of the Restated Term Loan, \$0.2 million of prepayment fees were incurred and have been reflected as a component of interest expense.

Table of Contents**Index to Financial Statements**

9.500% Senior Notes. On April 15, 2010, we issued and sold \$200.0 million in aggregate principal amount of 9.500% Senior Notes due 2018 in a private offering. Interest is payable on the 9.500% Senior Notes semi-annually on April 15 and October 15. The 9.500% Senior Notes were issued under an indenture (the 9.500% Senior Notes Indenture) with Wells Fargo Bank, National Association, as trustee. Under the indenture, we have the option to redeem the notes on or after April 15, 2014 at a price of \$104.75. Provisions of the 9.500% Senior Notes Indenture limit our ability to, among other things, incur additional indebtedness; pay dividends on capital stock or purchase, repurchase, redeem, defease or retire capital stock or subordinated indebtedness; make investments; incur liens; create any consensual restriction on the ability of our restricted subsidiaries to pay dividends, make loans or transfer property to us; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. The 9.500% Senior Notes Indenture also contains customary events of default. At December 31, 2013, we were in compliance with the terms and provisions as contained within the 9.500% Senior Notes Indenture. On September 21, 2010, we exchanged all of the privately placed 9.500% Senior Notes for registered 9.500% Senior Notes which contain terms substantially identical to the terms of the privately placed notes.

5.625% Senior Notes. On May 2, 2013, we completed our public offering of \$700.0 million in aggregate principal amount of 5.625% Senior Notes due 2021. Interest is payable on the 5.625% Senior Notes semi-annually on May 1 and November 1. The 5.625% Senior Notes were issued under an indenture (the Base Indenture), as supplemented by a first supplemental indenture with Wells Fargo Bank, National Association, as trustee, which contains covenants and events of default substantially similar to those in the 9.500% Senior Notes Indenture. At December 31, 2013, we were in compliance with the terms and provisions as contained in our indenture. Net proceeds from the debt offering were used to fund a portion of the consideration for the Permian Acquisition.

5.875% Senior Notes. On November 15, 2013, we completed our public offering of \$600 million aggregate principal amount of 5.875% Senior Notes due 2022. Interest is payable on the 5.875% Senior Notes semi-annually on June 1 and December 1. The 5.875% Senior Notes were issued under the Base Indenture, as supplemented by a second supplemental indenture with Wells Fargo Bank, National Association, as trustee, which contains covenants and events of default substantially similar to those in the 9.500% Senior Notes Indenture. At December 31, 2013, we were in compliance with the terms and provisions as contained in our indenture. Net proceeds from the debt offering were used to repay all of the borrowings outstanding under our Credit Facility and for general corporate purposes.

Total Indebtedness. As of December 31, 2013 and 2012, we had total outstanding indebtedness of \$1.5 billion and \$410 million, respectively, and for the years ended December 31, 2013 and 2012, our weighted average borrowing rate was 5.99% and 7.18%, respectively.

Working Capital

Our working capital fluctuates primarily as a result of changes in commodity pricing and production volumes, capital spending to fund our exploratory and development initiatives and the impact of our outstanding derivative instruments. At December 31, 2013, we had a working capital surplus of \$85.8 million, and at December 31, 2012, we had a working capital deficit of \$21.3 million. We believe we have adequate availability under our Credit Facility and liquidity available to meet our working capital requirements.

Cash Flows

	Year Ended December 31,		
	2013	2012	2011
	(In thousands)		
Cash flows provided by operating activities	\$ 591,009	\$ 370,630	\$ 299,537
Cash flows used in investing activities	(1,829,288)	(533,641)	(190,363)
Cash flows provided by (used in) financing activities	1,395,277	152,747	(103,758)
Net increase (decrease) in cash and cash equivalents	\$ 156,998	\$ (10,264)	\$ 5,416

Table of Contents

Index to Financial Statements

Operating Activities. Net cash provided by operating activities in 2013 reflects higher operating income as a result of increased overall production and higher realized pricing of oil and NGLs. Net cash provided by operating activities in 2012 and 2011 reflects higher operating income as a result of increased liquids production and an expansion of our production base to include a greater mix of crude oil and NGLs.

Investing Activities. Net cash used in investing activities in 2013 reflects acquisitions of oil and natural gas properties of \$956.9 million and additions to oil and natural gas assets of \$871.1 million. These capital expenditures were used to drill 150 gross wells, the majority of which were located in the Eagle Ford area.

Net cash used in investing activities in 2012 reflects additions to oil and natural gas assets of \$622.2 million. These capital expenditures were used to drill 85 gross wells, the majority of which were located in the Eagle Ford area. Additions to oil and natural gas assets were partially offset by net asset divestiture proceeds of \$88.5 million from the divestiture of our Lobo assets and a portion of our Olmos assets in 2012.

Net cash used in investing activities in 2011 reflects additions to oil and natural gas assets of \$433.0 million. These capital expenditures were used to drill 64 gross wells, the majority of which were located in the Eagle Ford area. Additions to oil and natural gas assets were partially offset by net asset divestiture proceeds of \$242.6 million primarily from the divestitures of our Sacramento Basin assets in California and our DJ Basin assets in Colorado in 2011.

Financing Activities. Net cash provided by financing activities in 2013 primarily reflects the issuance of the \$700 million 5.625% Senior Notes and \$600 million 5.875% Senior Notes, \$329.0 million in proceeds from the issuance of common stock, excess tax benefit from share-based awards of \$6.7 million and proceeds from stock options exercised of \$5.0 million, partially offset by net payments of \$210.0 million under the Credit Facility, \$28.3 million in deferred loan fees and treasury stock purchases of \$7.1 million.

Net cash provided by financing activities in 2012 primarily reflects net borrowings of \$180.0 million under the Credit Facility, partially offset by the prepayment of \$20.0 million of indebtedness under the Restated Term Loan and treasury stock purchases of \$6.2 million.

Net cash used in financing activities in 2011 reflects payments of \$100.0 million under the Credit Facility, treasury stock purchases of \$4.4 million and payments of \$3.2 million in deferred loan fees, partially offset by proceeds from exercised stock options of \$3.8 million.

Commodity Price Risk and Related Derivative Activities

The energy markets have historically been very volatile and oil, NGL and natural gas prices will be subject to wide fluctuations in the future. To mitigate our exposure to changes in commodity prices, management hedges oil, NGL and natural gas prices from time to time, primarily through the use of certain derivative instruments, including fixed price swaps, basis swaps, NYMEX roll swaps, costless collars and put options. Although not risk-free, we believe these activities will reduce our exposure to commodity price fluctuations and thereby enable us to achieve a more predictable cash flow. Consistent with this policy, we have entered into a series of oil, NGL and natural gas fixed price swaps and costless collars for each year through 2016. Our fixed price swap and costless collar agreements require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a notional quantity of oil, NGLs and natural gas, as applicable, without the exchange of underlying volumes. The notional amounts of these financial instruments were based on a portion of our expected production upon

inception of the derivative instruments.

As of December 31, 2013, our derivative instruments are with counterparties who are lenders under our Credit Facility. This practice allows us to satisfy any need for any margin obligation resulting from an adverse change in the fair market value of the derivative contracts with the collateral securing our Credit Facility, thus eliminating the need for independent collateral postings. As of December 31, 2013, we had no deposits for collateral in regard to our commodity derivative instruments.

Table of Contents**Index to Financial Statements*****Capital Expenditures and Requirements***

Our capital expenditures for the year ended December 31, 2013 were \$1.9 billion, including capitalized interest of \$28.3 million and capitalized internal costs directly identified with acquisition, and exploration and development activities of \$7.2 million. We have plans to execute a capital program in 2014 of \$1.1 billion that will be funded from a combination of internally generated cash flows, cash on hand, and borrowings under our Credit Facility.

Commitments and Contingencies

As is common within the oil and natural gas industry, we have entered into various commitments and operating agreements related to the exploration and development of and production from proved oil and natural gas properties. It is our belief that such commitments will be met without a material adverse effect on our financial position, results of operations or cash flows.

Contractual Obligations. At December 31, 2013, the aggregate amounts of our contractually obligated payment commitments for the next five years and thereafter were as follows:

	Total	Payments Due By Period			
		2014	2015 to 2016	2017 to 2018	Thereafter
		(In thousands)			
Senior secured revolving line of credit	\$	\$	\$	\$	\$
Senior notes	1,500,000			200,000	1,300,000
Operating leases	55,515	19,148	8,868	7,676	19,823
Interest payments on long-term debt					
(1)	680,033	96,625	193,258	177,630	212,520
Drilling rig commitments	25,062	19,762	5,300		
Completion service agreements	16,226	14,806	1,420		
Firm transportation and processing	269,958	34,486	68,157	63,227	104,088
Total contractual obligations	\$ 2,546,794	\$ 184,827	\$ 277,003	\$ 448,533	\$ 1,636,431

(1) Future interest payments were calculated based on interest rates, commitment fees and amounts outstanding at December 31, 2013.

Asset Retirement Obligations. At December 31, 2013, we had total liabilities of \$13.1 million related to asset retirement obligations (ARO) that are excluded from the table above. Of the total ARO, the current portion of \$3.9 million at December 31, 2013 was included in Accrued liabilities on the Consolidated Balance Sheet. The long-term portion of ARO of \$9.2 million at December 31, 2013 was included in Other long-term liabilities on the Consolidated Balance Sheet. Due to the nature of these obligations, we cannot determine precisely when the payments will be made to settle these obligations. See Item 8. Financial Statements and Supplementary Data, Note 9 Asset Retirement Obligations.

Firm Oil and Natural Gas Transportation and Processing Commitments. We have commitments for the transportation and processing of our production in the Eagle Ford area and have an aggregate minimum commitment to deliver 6.1 MMBbls of oil by the end of 2017 and 367 million MMBtu of natural gas by the end of 2023. We are required to make periodic deficiency payments for any shortfalls in delivering the minimum volumes under these commitments. Currently, we have insufficient production to meet all of these contractual commitments. As we develop additional reserves in the Eagle Ford area, we anticipate exceeding our current minimum volume commitments and we therefore intend to enter into additional transportation and processing commitments in the future. These future transportation and processing commitments could expose us to additional volume deficiency payments as we further develop our Eagle Ford assets. See Items 1 and 2, *Business and Properties* for a description of our production and proved reserves and Item 8. *Financial Statements and Supplementary Data, Note 11 Commitments and Contingencies.*

Table of Contents

Index to Financial Statements

Contingencies. We are party to various legal and regulatory proceedings and commercial disputes arising in the normal course of business. The ultimate outcome of each of these matters cannot be absolutely determined, and in the event of a negative outcome as to any proceeding, the liability we may ultimately incur with respect to such proceeding may be in excess of amounts currently accrued, if any. After considering our available insurance and, to the extent applicable, that of third parties, and the performance of contractual defense and indemnity rights and obligations, where applicable, we do not believe any such matters will have a material adverse effect on our financial position, results of operations or cash flows.

As noted in Note 11 Commitments and Contingencies included in Part II. Item 8. Financial Statements and Supplementary Data of this Form 10-K, we recorded a reserve of \$20.5 million related to two commercial disputes, one of which was settled in the fourth quarter of 2013, and the other which is expected to be settled in the first quarter of 2014.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the U.S. The preparation of these financial statements requires us to make estimates and assumptions about future events and apply judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and the related disclosure of contingent assets and liabilities and proved oil, NGL and natural gas reserves. 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 financial statements. Below, we have provided expanded discussion of our more significant accounting policies, estimates and judgments for our financial statements. We believe these accounting policies reflect the more significant estimates and assumptions used in preparation of the financial statements.

We also describe the most significant estimates and assumptions we make in applying these policies. See Item 8.

Financial Statements and Supplementary Data, Note 2 Summary of Significant Accounting Policies, for a discussion of additional accounting policies and estimates made by management.

Business Combinations

Accounting for business combinations requires that the various assets acquired and liabilities assumed in a business combination be recorded at their respective fair values. The most significant estimates to us typically relate to the value assigned to future recoverable oil and gas reserves and unproved properties. Deferred taxes are recorded for any differences between the fair value and tax basis of assets acquired and liabilities assumed. To the extent the purchase price plus the liabilities assumed (including deferred income taxes recorded in connection with the transaction) exceeds the fair value of the net assets acquired, we are required to record the excess as goodwill. As the fair value of assets acquired and liabilities assumed is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain. The value assigned to recoverable oil and gas reserves is subject to the full cost ceiling limitation, and the value assigned to unproved properties is assessed at least annually to ascertain whether impairment has occurred.

Proved Oil, NGL and Natural Gas Reserves

The engineering estimates of proved oil, NGL and natural gas reserves directly impact financial accounting estimates, including DD&A expense and the full cost ceiling limitation. Proved oil, NGL and natural gas reserves are the estimated quantities of oil, NGL and natural gas reserves that geological and engineering data

Table of Contents**Index to Financial Statements**

demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under period-end economic and operating conditions. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. Accordingly, our reserve estimates are developed internally and subsequently provided to NSAI, which performs a year-end reserve report audit. The data for a given reservoir may change substantially over time as a result of numerous factors including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Changes in oil, NGL and natural gas prices, operating and future development costs and expected performance from a given reservoir also will result in revisions to the amount of our estimated proved reserves. The estimate of proved oil and natural gas reserves primarily impacts oil and natural gas property amounts in the Consolidated Balance Sheet and the DD&A amounts in the Consolidated Statement of Operations. For more information regarding reserve estimation, including historical reserve revisions, refer to Item 8. Financial Statements and Supplementary Data Supplemental Oil and Gas Disclosures.

Full Cost Accounting Method

We use the full cost method to account for our oil and natural gas activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized and accumulated into a cost center (the amortization base), whether or not the activities to which they apply are successful. This includes any internal costs that are directly related to acquisition, exploration and development activities but does not include any costs associated with production and general corporate activities, which are expensed in the period incurred. The capitalized costs of our oil and natural gas properties, plus an estimate of our future development and abandonment costs, are amortized on a unit-of-production method based on our estimate of reserves. Unevaluated costs are excluded from the full cost pool and are periodically considered for impairment. Upon evaluation or impairment, these costs are transferred to the full cost pool and amortized. Proceeds received from disposals are credited against accumulated cost except when the sale represents a significant disposal of reserves, in which case a gain or loss is calculated and recognized. The application of the full cost method generally results in higher capitalized costs and higher depletion rates compared to its alternative, the successful efforts method.

Depreciation, Depletion and Amortization

The quantities of estimated proved oil, NGL and natural gas reserves are a significant component of our calculation of depletion expense and revisions in such estimates may alter the rate of future depletion expense. Holding all other factors constant, if reserves are revised upward, earnings would increase due to lower depletion expense. Likewise, if reserves are revised downward, earnings would decrease due to higher depletion expense or a ceiling test write-down. A five percent positive revision to proved reserves would decrease our depletion rate by approximately \$0.62 per Boe while a five percent negative revision to proved reserves would increase our depletion rate by approximately \$0.70 per Boe. This estimated impact is based on current data at December 31, 2013, and actual events could result in different adjustments to depletion expense.

Costs Withheld From Amortization

Costs associated with unevaluated properties are excluded from our amortization base until we have evaluated the properties. The costs associated with unevaluated leasehold acreage, wells currently drilling, suspended wells and capitalized interest are initially excluded from our amortization base. Leasehold costs are either transferred to our amortization base with the costs of drilling a well on the lease or are assessed quarterly for possible impairment. In addition, a portion of incurred (if not previously included in the amortization base) and future estimated development

costs associated with major development projects may be temporarily excluded from amortization due to the size and complexity of the resource play. Incurred and estimated future development costs are allocated between completed and future work. Any costs withheld from the amortization base are subsequently included in the amortization base upon the earlier of when proved reserves are recorded or impairment is indicated.

Table of Contents**Index to Financial Statements**

Our decision to withhold costs from amortization and the timing of the transfer of those costs into the amortization base involve a significant amount of judgment and may be subject to changes over time based on several factors, including our drilling plans, remaining lease terms, availability of capital, project economics and results of drilling on adjacent acreage. At December 31, 2013, our full cost pool had approximately \$755.4 million of costs excluded from the amortization base.

Future Development and Abandonment Costs

Future development costs include the estimated costs to obtain access to proved and undeveloped reserves such as drilling and completion costs and the cost of the installation of production equipment. Such costs are included in the calculation of DD&A expense. Future abandonment costs include costs to plug and abandon wells, dismantle and relocate or dispose of our production platforms, gathering systems and related structures, and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon the property's geographic location, type of production structure, well depth, currently available procedures and ongoing consultations with construction and engineering consultants and the operator of any of our non-operated properties. Estimating these costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and future abandonment costs on an annual basis.

We record a liability for the discounted fair value of an asset retirement obligation in the period in which it is incurred in accordance with authoritative asset retirement obligation guidance. We capitalize the corresponding cost as part of the carrying amount of the related long-lived asset. The liability is accreted each period, and the capitalized cost is depreciated over the useful life of the related asset. Holding all other factors constant, if our estimates of future abandonment and future development costs are revised upward, earnings would decrease due to higher DD&A expense. Likewise, if these estimates are revised downward, earnings would increase due to lower DD&A expense.

Full Cost Ceiling Limitation

Under the full cost method, we are subject to quarterly calculations of a ceiling or limitation on the amount of costs associated with our oil and natural gas properties that can be capitalized on our balance sheet. This ceiling limits such capitalized costs to the present value of estimated future cash flows from proved oil and natural gas reserves reduced by future operating expenses, development expenditures, abandonment costs (net of salvage values) to the extent not included in oil and natural gas properties pursuant to authoritative guidance, and estimated future income taxes thereon. If net capitalized costs exceed the applicable cost center ceiling, we are subject to a ceiling test write-down to the extent of such excess. If required, such write-down would reduce earnings and stockholders' equity in the period of occurrence and result in lower DD&A expense in future periods. The discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. The current ceiling calculation utilizes a trailing twelve-month first-day-of-the-month historical unweighted average price. The costs in effect as of the last day of the quarter or annual period are held constant. Given the fluctuation of oil, NGL and natural gas prices, it is reasonably possible that the estimated discounted future net cash flows from our proved reserves will change in the near term. If oil, NGL and natural gas prices decline, or if we have downward revisions to our estimated proved reserves, it is possible that write-downs of our oil and natural gas properties could occur in the future. For more information regarding the full cost ceiling limitation, refer to Item 8.

Financial Statements and Supplementary Data, Note 2 – Summary of Significant Accounting Policies.

Derivative Transactions and Activities

We enter into derivative transactions to hedge against changes in oil, NGL and natural gas prices primarily through the use of fixed price swaps and costless collars. We have entered into a series of derivative transactions to hedge a portion of our expected oil, NGL and natural gas production through 2016.

Table of Contents**Index to Financial Statements**

These transactions are recorded in our financial statements in accordance with authoritative guidance for accounting for derivative instruments and hedging activities. Although not risk-free, we believe these agreements reduce our exposure to commodity price fluctuations and thereby enable us to achieve a more predictable cash flow. We do not enter into derivative agreements for trading or other speculative purposes.

In accordance with authoritative guidance, all derivative instruments, unless designated as normal purchase and normal sale, are recorded on the balance sheet at fair market value. Effective January 1, 2012, we elected to de-designate all of our commodity contracts that were previously designated as cash flow hedges as of December 31, 2011 and elected to discontinue hedge accounting prospectively. Accumulated other comprehensive income included \$2.6 million (\$1.6 million after tax) of unrealized gains, representing the mark-to-market value of our cash flow hedges as of December 31, 2011. As a result of discontinuing hedge accounting, the mark-to-market values included in Accumulated other comprehensive income as of the de-designation date were frozen and were reclassified into earnings as the underlying hedged transactions affected earnings. With the election to de-designate hedging instruments, all of our derivative instruments continue to be recorded at fair value with unrealized gains and losses recognized immediately in earnings within Revenues Derivative instruments on our Consolidated Statement of Operations, rather than in Accumulated other comprehensive income. These mark-to-market adjustments will produce a degree of earnings volatility that can be significant from period to period, but such adjustments will have no cash flow impact relative to changes in market prices. The cash flow impact occurred upon settlement of the underlying contract.

Fair Value Measurements

Authoritative guidance on fair value measurements defines fair value, establishes a framework for measuring fair value and stipulates the related disclosure requirements. Our financial assets and liabilities are measured at fair value on a recurring basis. Our non-financial assets and liabilities, such as asset retirement obligations and other property and equipment, are recognized at fair value on a non-recurring basis but at least annually. For our non-financial assets and liabilities, we are required to disclose information that enables users of our financial statements to assess the inputs used to develop these measurements. Changes in fair value associated with both financial and non-financial assets and liabilities are recorded in our Consolidated Statement of Operations. See Item 8. Financial Statements and Supplementary Data, Note 7 Fair Value Measurements.

Stock-Based Compensation

We account for stock-based compensation in accordance with applicable authoritative guidance. Stock-based compensation expense for restricted stock is estimated at the grant date based on the award's fair value, which is equal to the average high and low common stock price on the date of grant. Such fair value is recognized as expense over the requisite service period. Stock-based compensation expense for options is estimated at the grant date based on the award's fair value as calculated using an option-pricing model. During the years ended December 31, 2013, 2012 and 2011, no options were granted to our employees, officers or directors, and all options granted prior to 2011 have vested. Compensation expense was recognized ratably over the requisite service period.

Stock-based compensation expense for performance share units (PSUs) is measured and adjusted quarterly until settlement occurs, based on Company performance, quarter-end closing common stock prices and the anticipated vesting percentage. Compensation expense for performance-based awards is recognized when it is probable that performance conditions will be achieved and such awards are expected to vest. The Compensation Committee of the Board of Directors retains discretion beyond the stated performance metrics to ensure it has the ability to reward a

focus on behaviors that improves total shareholder return over the long-term and promote various corporate goals. The Compensation Committee has not adopted a policy that all compensation must be deductible for federal income tax purposes, and therefore we may make payments that are not fully deductible if we believe they are necessary to achieve corporate objectives and protect shareholder interests. See Item 8. Financial Statements and Supplementary Data, Note 12 Stock-Based Compensation and Employee Benefits.

Table of Contents

Index to Financial Statements

Revenue Recognition

Oil, NGL and natural gas revenue from our interests in producing wells is recognized upon delivery and passage of title, using the sales method for gas imbalances, net of any royalty interests in the produced product in accordance with the particular contractual provisions of the lease. If our sales of production volumes for a well exceed our portion of the estimated remaining recoverable reserves of the well, a liability is recorded. We record our share of revenues based on sales volumes and contracted sales prices, adjusted for basis and quality differentials. In addition, oil, NGL and natural gas volumes sold are not significantly different from our share of production.

Income Taxes

We recognize deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in our financial statements. These deferred tax assets and liabilities are measured using the 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, respectively. 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.

Accruals for deferred tax assets and liabilities are subject to a considerable amount of judgment by management and are reviewed and adjusted routinely based on changes in facts and circumstances. Material changes in these accruals may occur in the future based on future taxable income, changes in legislation and feasible tax planning strategies. We routinely assess our deferred tax assets and reduce such assets by a valuation allowance if we deem it is more likely than not that some portion or all of the deferred tax assets 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.

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. See Item 8. Financial Statements and Supplementary Data, Note 13 – Income Taxes.

Recent Accounting Developments

The following recently issued accounting development has been applied for the current period.

Comprehensive Income. In June 2011, the Financial Accounting Standards Board (FASB) issued authoritative guidance to increase the prominence of items reported in other comprehensive income. This guidance requires an entity to present components of other comprehensive income either in a single continuous statement or in two separate but consecutive statements of net income and comprehensive income. In February 2013, the FASB further clarified this guidance relating to the presentation of reclassification adjustments stating that an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income. The Company adopted the provisions of the initial guidance effective

January 1, 2012 and the provisions of the February 2013 amendment effective January 1, 2013. See the Consolidated Statement of Comprehensive Income, Note 6 Commodity Derivative Contracts and Note 12 Stock-Based Compensation and Employee Benefits.

Table of Contents

Index to Financial Statements

Off-Balance Sheet Arrangements

At December 31, 2013, we did not have any off-balance sheet arrangements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil, NGL and natural gas prices. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonable possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Commodity Price Risk and Related Derivative Activities.

Commodity Price Risk. Our major market risk exposure is in the pricing of our oil, NGL and natural gas production. Realized pricing is primarily driven by the prevailing price for crude oil and spot market prices applicable to our NGL and natural gas production. Pricing for oil, NGL and natural gas production fluctuates due to market conditions and cannot be accurately predicted. Accordingly, we use certain derivative instruments, including fixed price swaps and costless collars. Although not risk-free, we believe these activities will reduce commodity price fluctuations and thereby enable us to achieve a more predictable cash flow.

Our fixed price swap agreements are used to fix the sales price for our anticipated future oil, NGL and natural gas production. Upon settlement, we receive a fixed price for the hedged commodity and pay our counterparty a floating market price, as defined in each instrument. These instruments are settled monthly. When the floating price exceeds the fixed price for a contract month, we pay our counterparty. When the fixed price exceeds the floating price, our counterparty is required to make a payment to us. Should the market for this instrument become attractive, we have the ability to enter into additional fixed price swaps for a portion of our anticipated future oil, NGL and natural gas production.

Our costless collar agreements are used to fix the variability in sales price within a floor price and ceiling price for our anticipated future oil and natural gas production. These instruments are settled monthly when required as defined in each instrument. When the floating market price exceeds the ceiling price, we pay our counterparty. When the floor price exceeds the floating market price, our counterparty is required to make payment to us. If the floating market price is within the floor and ceiling prices, no payments are required by either us or the counterparties. Should the market for this instrument become attractive, we have the ability to enter into costless collar agreements for a portion of our anticipated future NGL production, as well as add additional costless collar swaps for a portion of our anticipated future oil and natural gas production.

As of December 31, 2013, we had open crude oil derivative contracts in a net liability position with a fair value of \$2.2 million. A 10% increase in crude oil prices would reduce the fair value by approximately \$59.3 million, while a 10% decrease in crude oil prices would increase the fair value by approximately \$58.1 million. The effects of these derivative transactions on our revenues are discussed above under Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Revenues.

As of December 31, 2013, we had open NGL derivative contracts in a net asset position with a fair value of \$2.7 million. A 10% increase in NGL prices would reduce the fair value by approximately \$17.9 million, while a 10% decrease in NGL prices would increase the fair value by approximately \$17.9 million. The effects of these derivative transactions on our revenues are discussed above under Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Revenues.

Table of Contents

Index to Financial Statements

As of December 31, 2013, we had open natural gas derivative contracts in a net asset position with a fair value of \$3.9 million. A 10% increase in natural gas prices would reduce the fair value by approximately \$18.0 million, while a 10% decrease in natural gas prices would increase the fair value by approximately \$18.7 million. The effects of these derivative transactions on our revenues are discussed above under Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Revenues.

These fair value changes assume volatility based on prevailing market parameters at December 31, 2013.

These transactions may expose us to the risk of loss in certain circumstances, including instances in which our production is less than expected, there is a widening of price differentials between delivery points for our production and the delivery point assumed in the derivative arrangement, or in the event of nonperformance under the contracts by the counterparties to our derivative agreements.

As of December 31, 2013, our derivative instruments are with counterparties who are lenders under our Credit Facility. This practice allows us to satisfy any need for margin obligations resulting from an adverse change in the fair market value of the derivative contracts with the collateral securing our Credit Facility, thus eliminating the need for independent collateral postings. As of December 31, 2013, we had no deposits for collateral regarding commodity derivative instruments. Our derivative instrument assets and liabilities relate to commodity hedges that represent the difference between hedged prices and future market prices on hedged volumes of the commodities as of December 31, 2013. Our third-party provider evaluated nonperformance risk using the current credit default swap values or bond spreads for both the counterparties and us. We recorded a downward adjustment to the fair value of our derivative instruments in the amount of \$0.3 million as of December 31, 2013. We currently do not know of any circumstances that would limit access to our Credit Facility or require a change in our debt or hedging structure.

We entered into oil, NGL and natural gas derivative contracts with respect to a portion of our anticipated production through 2016. These derivative contracts may limit our potential revenue if oil, NGL and natural gas prices were to exceed the price established by the contract. As of December 31, 2013, 100% of our crude oil derivative transactions represented hedged prices of crude oil at West Texas Intermediate on the NYMEX; 100% of our total NGL derivative transactions represented hedged prices of NGLs at Mont Belvieu; and 61% of our natural gas derivative transactions represented hedged prices of natural gas at Houston Ship Channel, 33% at Tennessee, zone 0 and the remaining 6% at Henry Hub.

We use a third-party provider to determine the valuation of our derivative instruments and compare the fair values derived from the third-party provider with values provided by our counterparties. We mark-to-market the fair values of our derivative instruments on a quarterly basis and 100% of our derivative assets and liabilities are considered Level 3 instruments.

Table of Contents

Index to Financial Statements

Item 8. Financial Statements and Supplementary Data
Index to Financial Statements

	Page
<u>Report of Independent Registered Public Accounting Firm</u>	50
<u>Consolidated Balance Sheet as of December 31, 2013 and 2012</u>	51
<u>Consolidated Statement of Operations for the years ended December 31, 2013, 2012, and 2011</u>	52
<u>Consolidated Statement of Comprehensive Income for the years ended December 31, 2013, 2012, and 2011</u>	53
<u>Consolidated Statement of Cash Flows for the years ended December 31, 2013, 2012, and 2011</u>	54
<u>Consolidated Statement of Stockholders' Equity for the years ended December 31, 2013, 2012, and 2011</u>	55
<u>Notes to Consolidated Financial Statements</u>	56

Table of Contents

Index to Financial Statements

Report of Independent Registered Public Accounting Firm

To the Board of Directors

And Stockholders of Rosetta Resources Inc.:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Rosetta Resources Inc. and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company’s management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management’s Report on Internal Control over Financial Reporting appearing under Item 9A – Controls and Procedures. Our responsibility is to express opinions on these financial statements and on the Company’s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Notes 2 and 6 to the financial statements, the Company discontinued hedge accounting effective January 1, 2012.

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

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

deteriorate.

/s/ PricewaterhouseCoopers LLP

Houston, Texas

February 24, 2014

Table of Contents**Index to Financial Statements****Item 8. Financial Statements and Supplementary Data****Rosetta Resources Inc.****Consolidated Balance Sheet****(In thousands, except par value and share amounts)**

	December 31,	
	2013	2012
Assets		
Current assets:		
Cash and cash equivalents	\$ 193,784	\$ 36,786
Accounts receivable	122,677	103,828
Derivative instruments	4,307	14,437
Prepaid expenses	9,860	5,742
Deferred income taxes	27,976	311
Other current assets	1,284	1,456
Total current assets	359,888	162,560
Oil and natural gas properties using the full cost method of accounting:		
Proved properties	3,951,397	2,829,431
Unproved/unevaluated properties, not subject to amortization	755,438	95,540
Gathering systems and compressor stations	168,730	104,978
Other fixed assets	26,362	16,346
	4,901,927	3,046,295
Accumulated depreciation, depletion and amortization, including impairment	(2,020,879)	(1,808,190)
Total property and equipment, net	2,881,048	1,238,105
Other assets:		
Debt issuance costs	25,602	7,699
Derivative instruments	5,458	6,790
Other long-term assets	4,622	262
Total other assets	35,682	14,751
Total assets	\$ 3,276,618	\$ 1,415,416
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable and accrued liabilities	\$ 190,950	\$ 122,210
Royalties and other payables	78,264	61,637

Derivative instruments	4,913	
Total current liabilities	274,127	183,847
Long-term liabilities:		
Derivative instruments	433	563
Long-term debt	1,500,000	410,000
Deferred income taxes	136,407	10,086
Other long-term liabilities	17,317	6,921
Total liabilities	\$ 1,928,284	\$ 611,417
Commitments and contingencies (Note 11)		
Stockholders' equity:		
Preferred stock, \$0.001 par value; authorized 5,000,000 shares; no shares issued in 2013 or 2012		
Common stock, \$0.001 par value; authorized 150,000,000 shares; issued 62,032,162 shares and 53,145,853 shares at December 31, 2013 and 2012, respectively	61	53
Additional paid-in capital	1,182,672	830,539
Treasury stock, at cost; 724,755 shares and 581,717 shares at December 31, 2013 and 2012, respectively	(24,592)	(17,479)
Accumulated other comprehensive loss	(108)	(63)
Retained earnings (Accumulated deficit)	190,301	(9,051)
Total stockholders' equity	1,348,334	803,999
Total liabilities and stockholders' equity	\$ 3,276,618	\$ 1,415,416

See accompanying notes to the consolidated financial statements.

Table of Contents**Index to Financial Statements****Rosetta Resources Inc.****Consolidated Statement of Operations****(In thousands, except per share amounts)**

	Year Ended December 31,		
	2013	2012	2011
Revenues:			
Oil sales	\$ 475,119	\$ 318,782	\$ 156,284
NGL sales	198,966	160,461	125,301
Natural gas sales	147,028	93,711	163,382
Derivative instruments	(7,095)	40,545	1,233
Total revenues	814,018	613,499	446,200
Operating costs and expenses:			
Lease operating expense	53,336	35,138	28,822
Treating and transportation	71,338	51,826	22,316
Taxes, other than income	31,075	24,013	18,151
Depreciation, depletion and amortization	218,571	154,223	123,244
Reserve for commercial disputes	20,450		
General and administrative costs	73,043	68,731	75,256
Total operating costs and expenses	467,813	333,931	267,789
Operating income	346,205	279,568	178,411
Other expense (income):			
Interest expense, net of interest capitalized	35,957	24,316	21,291
Interest income	(2)	(7)	(42)
Other expense, net	314	60	903
Total other expense	36,269	24,369	22,152
Income before provision for income taxes	309,936	255,199	156,259
Income tax expense	110,584	95,904	55,713
Net income	\$ 199,352	\$ 159,295	\$ 100,546
Earnings per share:			
Basic	\$ 3.40	\$ 3.03	\$ 1.93
Diluted	\$ 3.39	\$ 3.01	\$ 1.91

Weighted average shares outstanding:

Edgar Filing: Rosetta Resources Inc. - Form 10-K

Basic	58,571	52,496	51,996
Diluted	58,830	52,887	52,616

See accompanying notes to the consolidated financial statements.

Table of ContentsIndex to Financial Statements**Rosetta Resources Inc.****Consolidated Statement of Comprehensive Income****(In thousands)**

	Year Ended December 31,		
	2013	2012	2011
Net income	\$ 199,352	\$ 159,295	\$ 100,546
Other comprehensive (loss) income:			
Change in fair value of hedging instruments			2,033
Reclassification of (gain) on settled hedging instruments, net of income tax benefit of \$5,770 for the year ended December 31, 2011			(11,660)
Amortization of accumulated other comprehensive gain (loss) related to de-designated hedges, net of income taxes of (\$37) and \$968 for the year ended December 31, 2013 and 2012, respectively	63	(1,695)	
Postretirement medical benefits prior service cost, net of income tax benefit of \$61 for the year ended December 31, 2013	(108)		
Other comprehensive loss	(45)	(1,695)	(9,627)
Comprehensive income	\$ 199,307	\$ 157,600	\$ 90,919

See accompanying notes to the consolidated financial statements.

Table of Contents**Index to Financial Statements****Rosetta Resources Inc.****Consolidated Statement of Cash Flows****(In thousands)**

	Year Ended December 31,		
	2013	2012	2011
Cash flows from operating activities:			
Net income	\$ 199,352	\$ 159,295	\$ 100,546
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	218,571	154,223	123,244
Deferred income taxes	100,876	95,904	56,170
Amortization of deferred loan fees recorded as interest expense	8,421	2,856	2,248
Stock-based compensation expense	10,979	18,539	29,010
Loss (gain) due to change in fair value of derivative instruments	16,345	(19,662)	(12,124)
Change in operating assets and liabilities:			
Accounts receivable	(18,849)	(26,454)	(41,215)
Prepaid expenses	21	(2,780)	(226)
Other current assets	172	680	287
Long-term assets	(108)	650	(450)
Accounts payable and accrued liabilities	37,370	(19,997)	765
Royalties and other payables	16,627	10,948	37,409
Other long-term liabilities	3,413	(3,572)	(8,863)
Income taxes	(2,181)		
Derivative instruments			12,736
Net cash provided by operating activities	591,009	370,630	299,537
Cash flows from investing activities:			
Acquisitions of oil and gas assets	(956,892)		
Additions to oil and gas assets	(871,092)	(622,168)	(432,951)
Disposals of oil and gas assets	(1,304)	88,527	242,588
Net cash used in investing activities	(1,829,288)	(533,641)	(190,363)
Cash flows from financing activities:			
Borrowings on Credit Facility	670,000	290,000	
Payments on Credit Facility	(880,000)	(110,000)	(100,000)
Repayments on Restated Term Loan		(20,000)	
Issuance of Senior Notes	1,300,000		
Proceeds from issuance of common stock	329,008		
Deferred loan fees	(28,280)	(1,980)	(3,150)

Edgar Filing: Rosetta Resources Inc. - Form 10-K

Proceeds from stock options exercised	4,981	910	3,792
Purchases of treasury stock	(7,113)	(6,183)	(4,400)
Excess tax benefit from share-based awards	6,681		
Net cash provided by (used in) financing activities	1,395,277	152,747	(103,758)
Net increase (decrease) in cash	156,998	(10,264)	5,416
Cash and cash equivalents, beginning of year	36,786	47,050	41,634
Cash and cash equivalents, end of year	\$ 193,784	\$ 36,786	\$ 47,050
Supplemental disclosures:			
Cash paid for interest expense, net of capitalized interest	\$ 24,824	\$ 20,834	\$ 19,044
Cash paid (received) for income taxes	\$ 2,941	\$ (105)	\$ (405)
Supplemental non-cash disclosures:			
Capital expenditures included in Accounts payable and accrued liabilities	\$ 118,725	\$ 88,844	\$ 57,546

See accompanying notes to the consolidated financial statements.

Table of ContentsIndex to Financial Statements

Rosetta Resources Inc.

Consolidated Statement of Stockholders Equity

(In thousands, except share amounts)

	Common Stock			Treasury Stock		Accumulated Other Comprehensive (Loss)/Income	Retained Earnings / Accumulated Deficit	Total Stockholders Equity
	Shares	Amount	Additional Paid-In Capital	Shares	Amount			
Balance at December 31, 2010	52,031,004	\$ 52	\$ 793,293	343,093	\$ (6,896)	\$ 11,259	\$ (268,892)	\$ 528,816
Stock options exercised	230,741		3,792					3,792
Treasury stock employee tax payment				107,080	(4,400)			(4,400)
Stock-based compensation			13,709					13,709
Vesting of restricted stock	368,738							
Net income							100,546	100,546
Other comprehensive loss						(9,627)		(9,627)
Balance at December 31, 2011	52,630,483	\$ 52	\$ 810,794	450,173	\$ (11,296)	\$ 1,632	\$ (168,346)	\$ 632,836
Stock options exercised	69,862	1	910					911
Treasury stock employee tax payment				131,544	(6,183)			(6,183)
Stock-based compensation			18,835					18,835
Vesting of restricted stock	445,508							
Net income							159,295	159,295
Other comprehensive loss						(1,695)		(1,695)

Edgar Filing: Rosetta Resources Inc. - Form 10-K

Balance at December 31, 2012	53,145,853	\$ 53	\$ 830,539	581,717	\$(17,479)	\$ (63)	\$ (9,051)	\$ 803,999
Stock options exercised	379,145		4,981					4,981
Treasury stock employee tax payment				143,038	(7,113)			(7,113)
Stock-based compensation			11,471					11,471
Issuance of common stock	8,050,000	8	329,000					329,008
Vesting of restricted stock	457,164							
Excess tax benefit from share-based awards			6,681					6,681
Net income							199,352	199,352
Other comprehensive loss							(45)	(45)
Balance at December 31, 2013	62,032,162	\$ 61	\$ 1,182,672	724,755	\$(24,592)	\$ (108)	\$ 190,301	\$ 1,348,334

See accompanying notes to the consolidated financial statements.

Table of Contents

Index to Financial Statements

Rosetta Resources Inc.

Notes to Consolidated Financial Statements

(1) Organization and Operations of the Company

Nature of Operations. Rosetta Resources Inc. (together with its consolidated subsidiaries, the Company) is an independent exploration and production company engaged in the acquisition and development of onshore energy resources in the United States of America. The Company's operations are located in the Eagle Ford shale in South Texas and the Permian Basin in West Texas.

In preparing these financial statements, events occurring after December 31, 2013 through the release of these financial statements were evaluated by the Company to ensure that subsequent events meeting the criteria for recognition and/or disclosure in this report have been included.

Certain reclassifications of prior year balances have been made to conform with current year classifications. These reclassifications have no impact on net income.

(2) Summary of Significant Accounting Policies

Use of Estimates in Preparation of Financial Statements

The preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expense during the reporting period. 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. The Company evaluates its estimates and assumptions on a regular basis. The Company bases its 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 the Company's financial statements. The most significant estimates with regard to these financial statements relate to the provision for income taxes including uncertain tax positions, the outcome of pending litigation and environmental costs, stock-based compensation, valuation of derivative instruments, future development and abandonment costs, estimates related to certain oil, NGL and natural gas revenues and operating expenses, determination of the fair value of assets acquired and liabilities assumed and recording of goodwill and deferred taxes, if any, in connection with business combinations, and the estimates of proved oil, NGL and natural gas reserve quantities that are used to calculate depletion and impairment of proved oil and natural gas properties.

Cash and Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

With respect to the current market environment for liquidity and access to credit, the Company, through banks participating in its credit facility, has invested available cash in interest and non-interest bearing demand deposit accounts in those participating banks and in money market accounts and funds whose investments are limited to U.S. Government securities, securities backed by the U.S. Government, or securities of U.S. Government agencies. The Company has followed this policy and believes this is an appropriate approach for the investment of Company funds.

Table of Contents

Index to Financial Statements

Allowance for Doubtful Accounts

The Company regularly reviews all aged accounts receivables for collectability and establishes an allowance as necessary for individual customer balances. As of December 31, 2013 and 2012, the Company had no allowance for doubtful accounts.

Oil and Natural Gas Properties

The Company follows the full cost method of accounting whereby all costs incurred in acquiring, exploring and developing properties, including salaries, benefits and other internal costs directly attributable to these activities, are capitalized when incurred into cost centers that are established on a country-by-country basis. Such costs are amortized on a unit-of-production basis over reserves in the cost center in which they are produced, subject to a limitation that the capitalized costs not exceed the value of those reserves. In some cases, however, certain significant costs, such as those associated with unevaluated properties and significant development projects, are deferred separately without amortization until the specific property to which they relate is found to be either productive or nonproductive, at which time those deferred costs and any reserves attributable to the property are included in the computation of amortization in the cost center. All costs incurred in oil and natural gas producing activities are regarded as integral to the acquisition, discovery and development of reserves that ultimately result from the efforts as a whole, and are thus associated with the Company's reserves. The Company capitalizes internal costs directly identified with acquisition, exploration and development activities. The Company capitalized \$7.2 million, \$6.0 million and \$7.0 million of internal costs for the years ended December 31, 2013, 2012 and 2011, respectively. Unevaluated costs are excluded from the full cost pool and are periodically evaluated for impairment. Upon evaluation or impairment, costs associated with productive properties are transferred to the full cost pool and amortized. Gains or losses on the sale of oil and natural gas properties are generally reflected in the full cost pool, unless a significant portion of the pool or reserves is sold causing a significant change in the relationship between capitalized costs and proved reserves, in which case a gain or loss is calculated and recognized in the Consolidated Statement of Operations.

The Company assesses the impairment for oil and natural gas properties quarterly using a ceiling test to determine if impairment is necessary. This ceiling limits capitalized costs to the present value of estimated future cash flows from proved oil and natural gas reserves reduced by future operating expenses, development expenditures, abandonment costs (net of salvage values) to the extent not included in oil and natural gas properties pursuant to authoritative guidance, and estimated future income taxes thereon.

A ceiling test write-down is a charge to earnings and cannot be reinstated even if the cost ceiling increases at a subsequent reporting date. If required, a write-down would reduce earnings and impact shareholders' equity in the period of occurrence and result in lower DD&A expense in the future.

Other Fixed Assets

Other fixed assets primarily include computer hardware and software, office leasehold, and furniture and fixtures, which are recorded at cost and depreciated on a straight-line basis over useful lives of five to seven years. Repair and maintenance costs are charged to expense as incurred while renewals and betterments are capitalized as additions to the related assets in the period incurred. Gains or losses from the disposal of other fixed assets are recorded in the period incurred. The net book value of other fixed assets that are retired or sold is charged to accumulated depreciation and the difference is recognized as a gain or loss in the Consolidated Statement of Operations in the period the

retirement or sale transpires.

Future Development and Abandonment Costs

Future development costs include costs incurred to obtain access to proved reserves, such as drilling costs and the installation of production equipment, and such costs are included in the calculation of DD&A expense. Future abandonment costs include costs to plug and abandon wells, dismantle and relocate or dispose of our production platforms, gathering systems and related structures and restoration costs of land and seabed. The

Table of Contents

Index to Financial Statements

Company develops estimates of these costs for each of its properties based upon their geographic location, type of production structure, well depth, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. The Company reviews its assumptions and estimates of future development and future abandonment costs on an annual basis.

The Company provides for future abandonment costs in accordance with authoritative guidance regarding the accounting for asset retirement obligations. A liability is recorded for the fair value of an asset retirement obligation in the period in which it is incurred and the corresponding cost is capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset.

Capitalized Interest

The Company capitalizes interest on capital invested in projects related to unevaluated properties and significant development projects. As proved reserves are established or impairment determined, the related capitalized interest is included in costs subject to amortization. The Company capitalized interest of \$28.3 million, \$3.8 million, and \$5.5 million in 2013, 2012 and 2011, respectively.

Fair Value of Financial Instruments

Authoritative guidance on fair value measurements defines fair value, establishes a framework for measuring fair value and stipulates the related disclosure requirements. The Company's financial assets and liabilities are measured at fair value on a recurring basis and non-financial assets and liabilities, such as asset retirement obligations and other property and equipment, are recognized at fair value on a non-recurring basis but at least annually. For non-financial assets and liabilities, the Company is required to disclose information that enables users to assess the inputs used to develop these measurements. Changes in fair value associated with both financial and non-financial assets and liabilities are recorded in the Consolidated Statement of Operations. See Note 7 Fair Value Measurements.

Concentrations of Credit Risk

Financial instruments which potentially subject the Company to concentrations of credit risk consist primarily of cash, accounts receivable and derivative instruments. The Company's accounts receivable and derivative instruments are concentrated among entities engaged in the energy industry within the U.S. and financial institutions, respectively. The Company periodically assesses the financial condition of these entities and institutions and considers any possible credit risk to be minimal.

Debt Issuance Costs

Costs incurred in connection with the Company's Credit Facility, Restated Term Loan and Senior Notes (each as hereinafter defined in Note 10 Debt and Credit Agreements) are recorded on the Company's Consolidated Balance Sheet as Debt issuance costs. Such costs are amortized to interest expense over the term of the related debt using the effective interest method.

Derivative Instruments and Activities

The Company utilizes various types of derivative instruments to manage commodity price risk, including fixed price swaps and costless collars. The Company does not enter into derivative agreements for trading or other speculative purposes and the fair value of derivative contracts is presented on a net basis where the right of

Table of Contents

Index to Financial Statements

offset is provided for in the counterparty agreements. Effective January 1, 2012, the Company elected to de-designate all of its commodity derivative contracts that had previously been designated as cash flow hedges as of December 31, 2011 and elected to discontinue hedge accounting prospectively. See Note 6 Commodity Derivative Contracts for a more detailed discussion of derivative activities.

Environmental

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 that 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 cost can be reasonably estimated. There were no significant environmental liabilities as of December 31, 2013 or 2012.

Stock-Based Compensation

Stock-based compensation cost for restricted stock is estimated at the grant date based on the award's fair value, which is equal to the average high and low common stock price on the date of grant. Such fair value is recognized as expense over the requisite service period. Stock-based compensation cost for options is estimated at the grant date based on the award's fair value as calculated using an option-pricing model. During the years ended December 31, 2013, 2012 and 2011, no options were granted to the Company's employees, officers or directors and all options granted prior to 2011 have vested. Compensation expense was recognized ratably over the requisite service period.

Stock-based compensation expense for performance share units (PSUs) is measured and adjusted quarterly until settlement occurs, based on Company performance, quarter-end closing common stock prices and the anticipated vesting percentage. Compensation expense for performance-based awards is recognized when it is probable that performance conditions will be achieved and such awards are expected to vest. The Compensation Committee of the Board of Directors retains discretion beyond the stated performance metrics to ensure it has the ability to reward a focus on behaviors that improve total shareholder return over the long-term and promote various corporate goals. The Compensation Committee has not adopted a policy that all compensation must be deductible for federal income tax purposes, and therefore the Company may make payments that are not fully deductible if it believes such payments are necessary to achieve corporate objectives and protect shareholder interests. See Note 12 Stock-Based Compensation and Employee Benefits.

Any excess tax benefit arising from the Company's stock-based compensation plans is recognized as a credit to additional paid-in capital when realized and is calculated as the amount by which the tax effect of the tax deduction received exceeds the deferred tax asset associated with recorded stock-based compensation expense. Current authoritative guidance requires that cash flows resulting from tax deductions in excess of recorded compensation expense are recognized as financing activities.

Preferred Stock

The Company is authorized to issue 5,000,000 shares of preferred stock with preferences and rights as determined by the Company's Board of Directors. As of December 31, 2013 and 2012, there were no shares of preferred stock outstanding.

Treasury Stock

The Company repurchases shares that are surrendered by employees and certain directors to pay tax withholding upon the vesting of restricted stock awards. These repurchases are not part of a publicly announced program to repurchase shares of the Company's common stock, nor does the Company have a publicly announced program to repurchase shares of common stock. Treasury stock purchases are recorded at cost.

Table of Contents

Index to Financial Statements

Revenue Recognition

Oil, NGL and natural gas revenue from our interests in producing wells is recognized upon delivery and passage of title, using the sales method for gas imbalances, net of any royalty interests or other profit interests in the produced product. Under the sales method, if our gas imbalance (amount of production sold in excess of amount entitled) exceeds our portion of the estimated remaining recoverable reserves of the well, a liability is recorded. No receivables are recorded for those wells on which we have taken less than our ownership share of production, unless the amount taken by other parties exceeds the estimate of their remaining reserves. There were no significant gas imbalances at December 31, 2013 or 2012.

Income Taxes

The Company uses the liability method of accounting for income taxes. Under this method, deferred income taxes are provided to reflect the tax consequences in future years of differences between the financial statement and tax basis of assets and liabilities. Income taxes are provided based on earnings reported for tax return purposes in addition to a provision for deferred income taxes and are measured using enacted tax rates and laws that will be in effect when the differences are expected to reverse. 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.

Authoritative guidance for accounting for uncertainty in income taxes requires that the Company recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not support 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.

Recent Accounting Developments

The following recently issued accounting development has been applied for the current period.

Comprehensive Income. In June 2011, the Financial Accounting Standards Board (FASB) issued authoritative guidance to increase the prominence of items reported in other comprehensive income. This guidance requires an entity to present components of other comprehensive income either in a single continuous statement or in two separate but consecutive statements of net income and comprehensive income. In February 2013, the FASB further clarified this guidance relating to the presentation of reclassification adjustments stating that an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income. The Company adopted the provisions of the initial guidance effective January 1, 2012 and the provisions of the February 2013 amendment effective January 1, 2013. See the Consolidated Statement of Comprehensive Income, Note 6 Commodity Derivative Contracts and Note 12 Stock-Based Compensation and Employee Benefits.

(3) Accounts Receivable

Accounts receivable consists of the following:

	December 31,	
	2013	2012
	(In thousands)	
Oil, NGL and natural gas sales	\$ 96,576	\$ 84,533
State severance tax refunds	19,157	16,269
Joint interest billings	4,696	3,026
Other	2,248	
Total	\$ 122,677	\$ 103,828

Table of Contents**Index to Financial Statements**

There are no balances in accounts receivable that are considered to be uncollectible and an allowance was unnecessary as of December 31, 2013 and 2012.

(4) Property and Equipment

The Company's total property and equipment consists of the following:

	December 31,	
	2013	2012
	(In thousands)	
Proved properties	\$ 3,951,397	\$ 2,829,431
Unproved/unevaluated properties	755,438	95,540
Gathering systems and compressor stations	168,730	104,978
Other fixed assets	26,362	16,346
Total	4,901,927	3,046,295
Less: Accumulated depreciation, depletion and amortization	(2,020,879)	(1,808,190)
Total property and equipment, net	\$ 2,881,048	\$ 1,238,105

Acquisitions

Permian Basin Acquisition. On March 14, 2013, the Company entered into a purchase and sale agreement with Comstock Oil & Gas, LP (Comstock) to purchase producing and undeveloped oil and natural gas interests in the Permian Basin in Gaines and Reeves Counties, Texas for \$768 million, subject to customary closing adjustments, including adjustments based upon title and environmental due diligence (the Permian Acquisition). The Company completed the Permian Acquisition on May 14, 2013 (the Permian Acquisition Date), with an effective date of January 1, 2013, for total cash consideration of \$825.2 million. The Permian Acquisition was financed with the proceeds from the Company's issuance of the 5.625% Senior Notes, as described in Note 10 Debt and Credit Agreements, and the common stock offering described in Note 14 Equity. In connection with the Permian Acquisition and related financings, the Company incurred total transaction costs of approximately \$31.0 million, including (i) \$5.6 million of commitment fees and related expenses associated with a bridge credit facility (Bridge Credit Facility), which were recorded as Interest expense since the Company did not borrow under the Bridge Credit Facility, (ii) \$10.0 million of debt issuance costs paid in connection with the issuance of the 5.625% Senior Notes, which were deferred and are being amortized over the term of these senior notes, (iii) \$13.1 million of equity issuance costs and related expenses associated with the common stock offering, which were reflected as a reduction of equity proceeds, and (iv) \$2.3 million of consulting, investment, advisory, legal and other acquisition-related fees, which were expensed and are included in General and administrative costs.

Gates Ranch Acquisition. In the second quarter of 2013, the Company acquired the remaining 10% working interest in certain producing wells in certain leases of its Gates Ranch leasehold located in the Eagle Ford shale (the Gates Acquisition) in Webb County for total cash consideration of approximately \$128.1 million. The transaction closed on June 5, 2013 (the Gates Acquisition Date) and was financed with borrowings under the Company's Credit Facility, as

described in Note 10 Debt and Credit Agreements. As of the Gates Acquisition Date, the Company now owns 100% working interest in the entire Gates Ranch leasehold.

Both of the above transactions were accounted for under the acquisition method of accounting, whereby the purchase price was allocated to the assets acquired and liabilities assumed based on their estimated fair values, with any excess of the purchase price over the estimated fair value of the identifiable net assets acquired recorded as goodwill (or shortfall of purchase price versus net fair value recorded as bargain purchase). Based on the purchase price allocation for these acquisitions, no goodwill or bargain purchase was recognized. The combined

Table of ContentsIndex to Financial Statements

cash consideration paid for these transactions and the assets and liabilities recognized at the respective acquisition dates are shown in the table below.

	Total Purchase Price Allocation
	(in thousands)
Cash consideration	\$ 953,242
Fair value of assets acquired:	
Other fixed assets	\$ 600
Oil and natural gas properties	
Proved properties	290,273
Unproved/unevaluated properties	663,300
Total assets acquired	\$ 954,173
Fair value of liabilities assumed:	
Asset retirement obligations	\$ 931
Net assets acquired	\$ 953,242

The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties included estimates of: (i) reserves, including risk adjustments for probable and possible reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices; (v) future cash flows; and (vi) a market-based weighted average cost of capital rate. These inputs required significant judgments and estimates by the Company's management at the time of the valuation and are the most sensitive and subject to change.

The results of operations attributable to the Permian Basin assets and the acquired Gates Ranch working interests were included in the Company's Consolidated Statement of Operations beginning on May 14, 2013 (Permian Acquisition) and June 5, 2013 (Gates Acquisition), respectively. Revenues of \$68.4 million and net income of \$47.4 million from these acquired assets were generated in the year ended December 31, 2013, and are included in the Consolidated Statement of Operations for the year ended December 31, 2013.

The following unaudited pro forma information shows the pro forma effects of the acquisitions, the issuance of the 5.625% Senior Notes, the issuance of common stock in the equity offering and the use of proceeds from the debt and equity offerings. The unaudited pro forma information assumes the transactions and related financings occurred on January 1, 2012. The pro forma results of operations have been prepared by adjusting the Company's historical results to include the historical results of the acquired assets based on information provided by the seller, the Company's knowledge of the acquired properties and the impact of the Company's preliminary purchase price allocation. The Company believes the assumptions used provide a reasonable basis for reflecting the pro forma significant effects directly attributable to the acquisitions and associated financings. The pro forma results of operations do not include any cost savings or other synergies that may result from the Permian

Table of Contents**Index to Financial Statements**

Acquisition or any estimated costs that have been or will be incurred by the Company to integrate the Permian assets. The pro forma information does not purport to represent what the Company's results of operations would have been if such transactions had occurred on January 1, 2012.

	Year Ended December 31,	
	2013	2012
	(In thousands, except per share and share data)	
Total revenues	\$ 846,560	\$ 671,780
Net income	191,478	151,144
Earnings per share:		
Basic	\$ 3.13	\$ 2.50
Diluted	\$ 3.12	\$ 2.48
Weighted average shares outstanding:		
Basic	61,081	60,546
Diluted	61,339	60,937

Divestitures

On February 15, 2012, the Company entered into an agreement to sell its Lobo assets and a portion of its Olmos assets for \$95.0 million, subject to customary post-closing adjustments and the receipt of appropriate consents for assignment. During the third quarter of 2012, the Company closed on the sale of the final portion of the properties. Proceeds from the closing of the divestiture were recorded as adjustments to the full cost pool, with no gain or loss recognized.

In February 2011, the Company executed purchase and sale agreements for the divestitures of its Sacramento Basin assets in California and its DJ Basin assets in Colorado for \$200.0 million and \$55.0 million, respectively. These asset divestitures were effective as of January 1, 2011 and were subject to post-closing purchase price adjustments. Proceeds from the divestitures were recorded as adjustments to the full cost pool, with no gain or loss recognized.

Additional Disclosures about Property and Equipment

Included in the Company's oil and natural gas properties are asset retirement costs of \$22.2 million and \$15.1 million as of December 31, 2013 and 2012, respectively, including additions of \$2.7 million and \$4.7 million for the years ended December 31, 2013 and 2012, respectively.

Pursuant to full cost accounting rules, the Company must perform a ceiling test each quarter on its proved oil and natural gas assets within each separate cost center. All of the Company's costs are included in one cost center because all of the Company's operations are located in the United States. The Company's ceiling test was calculated using trailing twelve-month, unweighted-average first-day-of-the-month prices for oil and natural gas as of December 31, 2013, which were based on a West Texas Intermediate oil price of \$93.42 per Bbl and a Henry Hub natural gas price of \$3.67 per MMBtu (adjusted for basis and quality differentials), respectively. Utilizing these prices, the calculated ceiling amount exceeded the net capitalized cost of oil and natural gas properties at December 31, 2013 and as a result, no write-down was recorded.

The Company did not record any write-downs or impairments for the years ended December 31, 2013, 2012 and 2011. Effective January 1, 2012, the Company elected to de-designate all of its commodity contracts that had previously been designated as cash flow hedges as of December 31, 2011 and elected to discontinue hedge accounting prospectively. As a result, there is no future impact to the calculated ceiling value due to cash flow hedges, and there was no potential impairment absent the effects of hedging in 2011.

Table of Contents**Index to Financial Statements**

Capitalized costs excluded from DD&A as of December 31, 2013 and 2012, all of which are located onshore in the U.S., are as follows by the year in which such costs were incurred:

	Total	December 31, 2013			Prior
		2013	2012	2011	
		(In thousands)			
Development costs	\$ 129,812	\$ 129,812	\$	\$	\$
Exploration costs	15,459	8,445	7,014		
Acquisition cost of undeveloped acreage	584,137	565,330	4,485	5,170	9,152
Capitalized interest	26,030	22,718	1,471	480	1,361
Total capitalized costs excluded from DD&A	\$ 755,438	\$ 726,305	\$ 12,970	\$ 5,650	\$ 10,513

	Total	December 31, 2012			Prior
		2012	2011	2010	
		(In thousands)			
Development costs	\$ 29,857	\$ 29,857	\$	\$	\$
Exploration costs	16,180	16,180			
Acquisition cost of undeveloped acreage	42,186	15,297	6,672	16,920	3,297
Capitalized interest	7,317	3,309	2,064	1,481	463
Total capitalized costs excluded from DD&A	\$ 95,540	\$ 64,643	\$ 8,736	\$ 18,401	\$ 3,760

It is anticipated that development costs of \$129.8 million will be included in oil and natural gas properties subject to amortization within one year. With respect to the remaining capitalized costs excluded from DD&A of \$625.6 million, it is anticipated that these costs will be included in oil and natural gas properties subject to amortization within five years.

Gathering systems and compressor stations. The gross book value of the Company's gathering systems and compressor stations was \$168.7 million and \$105.0 million at December 31, 2013 and 2012, respectively, and is being depreciated on a straight-line basis over 15 years. Accumulated depreciation related to these assets at December 31, 2013 and 2012 was \$13.7 million and \$5.7 million, respectively. Depreciation expense associated with the gathering systems and compressor stations for the years ended December 31, 2013, 2012, and 2011 was \$7.9 million, \$4.0 million, and \$2.3 million, respectively. In connection with divestitures in 2011, the Company sold certain of these assets primarily located in the Sacramento Basin in California with no gain or loss recognized.

Other fixed assets. Other fixed assets at December 31, 2013 and 2012 of \$26.4 million and \$16.3 million, respectively, consisted primarily of office leasehold, furniture and fixtures and computer hardware and software. Accumulated depreciation associated with Other fixed assets at December 31, 2013 and 2012 was \$2.9 million and \$5.1 million, respectively. For the years ended December 31, 2013, 2012 and 2011, depreciation expense for Other fixed assets was \$3.4 million, \$1.4 million and \$2.6 million, respectively.

(5) Debt Issuance Costs

As of December 31, 2013 and 2012, debt issuance costs, net were \$25.6 million and \$7.7 million, respectively. Total amortization expense for such costs was \$8.4 million, \$2.9 million and \$2.2 million for the years ended December 31, 2013, 2012 and 2011, respectively.

(6) Commodity Derivative Contracts

The Company is exposed to various market risks, including volatility in oil, NGL and natural gas prices, which are managed through derivative instruments. The level of derivative activity utilized depends on market

Table of Contents**Index to Financial Statements**

conditions, operating strategies and available derivative prices. The Company utilizes various types of derivative instruments to manage commodity price risk, including fixed price swaps and costless collars. Forward contracts on various commodities are entered into to manage the price risk associated with forecasted sales of the Company's oil, NGL and natural gas production.

At December 31, 2013, the following derivative contracts were outstanding with associated notional volumes and average underlying prices that represent hedged prices of commodities at various market locations:

Product	Settlement Period	Derivative Instrument	Notional Daily Volume (Bbls)	Total Notional Volume (Bbls)	Average Floor/Fixed Price per Bbl	Average Ceiling Prices per Bbl
Crude oil	2014	Costless Collar	3,000	1,095,000	\$ 83.33	\$ 109.63
Crude oil	2014	Swap	6,000	2,190,000	93.13	
Crude oil	2015	Swap	10,000	3,650,000	88.58	
Crude oil	2016	Swap	1,000	366,000	84.40	
				7,301,000		

Product	Settlement Period	Derivative Instrument	Notional Daily Volume (Bbls)	Total Notional Volume (Bbls)	Average Fixed Prices per Bbl
NGL-Ethane	2014	Swap	4,500	1,642,500	\$ 13.21
NGL-Propane	2014	Swap	2,785	1,016,525	44.71
NGL-Isobutane	2014	Swap	930	339,450	61.26
NGL-Normal Butane	2014	Swap	875	319,375	60.29
NGL-Pentanes Plus	2014	Swap	910	332,150	84.97
NGL-Ethane	2015	Swap	2,500	912,500	11.59
NGL-Propane	2015	Swap	1,250	456,250	43.26
NGL-Isobutane	2015	Swap	450	164,250	53.76
NGL-Normal Butane	2015	Swap	400	146,000	53.76
				5,329,000	

Product	Settlement Period	Derivative Instrument	Notional Daily Volume (MMBtu)	Total Notional Volume (MMBtu)	Average Floor/Fixed Prices per MMBtu	Average Ceiling Prices per MMBtu
Natural gas	2014	Costless Collar	50,000	18,250,000	\$ 3.60	\$ 4.94
Natural gas	2015	Costless Collar	50,000	18,250,000	3.60	5.04
Natural gas	2014	Swap	30,000	10,950,000	4.07	

Edgar Filing: Rosetta Resources Inc. - Form 10-K

Natural gas	2015	Swap	40,000	14,600,000	4.18
Natural gas	2016	Swap	10,000	3,660,000	4.03
				65,710,000	

The Company's derivative instruments are with counterparties who are lenders under the Company's Credit Facility. This practice allows the Company to satisfy any need for margin obligations resulting from an adverse change in the fair market value of its derivative contracts with the collateral securing its Credit Facility, thus eliminating the need for independent collateral postings. The Company's ability to continue satisfying any applicable margin requirements in this manner may be subject to change as described in Items 1 and 2. Business and Properties Government Regulation. As of December 31, 2013, the Company had no deposits for collateral regarding commodity derivative positions.

Table of Contents**Index to Financial Statements*****Discontinuance of Hedge Accounting***

Effective January 1, 2012, the Company elected to de-designate all commodity contracts previously designated as cash flow hedges as of December 31, 2011, and elected to discontinue hedge accounting prospectively. Accumulated other comprehensive income included \$2.6 million (\$1.6 million after tax) of unrealized net gains, representing the mark-to-market value of the Company's cash flow hedges as of December 31, 2011. As a result of discontinuing hedge accounting, the mark-to-market values included in Accumulated other comprehensive income as of the de-designation date were frozen and were reclassified into earnings as the underlying hedged transactions affected earnings. For the years ended December 31, 2013 and 2012, the Company reclassified unrealized net losses of \$0.1 million and unrealized net gains of \$2.7 million, respectively, into earnings from Accumulated other comprehensive income. As of December 31, 2013, all frozen mark-to-market values included in Accumulated other comprehensive have been reclassified into earnings.

With the election to de-designate hedging instruments, all of the Company's derivative instruments continue to be recorded at fair value with unrealized gains and losses recognized immediately in earnings rather than in Accumulated other comprehensive income. These mark-to-market adjustments produce a degree of earnings volatility that can be significant from period to period, but such adjustments had no cash flow impact in the current period. The cash flow impact occurs upon settlement of the underlying contract.

Additional Disclosures about Derivative Instruments

Authoritative derivative guidance requires companies to recognize all derivative instruments as either assets or liabilities at fair value in the Company's financial statements. The following table sets forth information on the location and amounts of the Company's derivative instrument fair values in the Consolidated Balance Sheet as of December 31, 2013 and 2012, respectively:

Commodity derivative contracts	Location on Consolidated Balance Sheet		Asset (Liability) Fair Value	
			December 31, 2013	December 31, 2012
(in thousands)				
Oil	Derivative instruments	current assets	\$ 1,299	\$ 564
Oil	Derivative instruments	non-current assets	2,117	3,329
Oil	Derivative instruments	current liabilities	(5,629)	
NGL	Derivative instruments	current assets	2,834	8,361
NGL	Derivative instruments	non-current assets	(129)	3,534
NGL	Derivative instruments	current liabilities	461	
NGL	Derivative instruments	non-current liabilities	(433)	(563)
Natural gas	Derivative instruments	current assets	174	5,512
Natural gas	Derivative instruments	non-current assets	3,470	(73)
Natural gas	Derivative instruments	current liabilities	255	
Total derivative fair value, net, not designated as hedging instruments			\$ 4,419	\$ 20,664

Table of Contents**Index to Financial Statements**

The following table sets forth information on the location and amounts of derivative gains and losses in the Consolidated Statement of Operations for the years ended December 31, 2013, 2012 and 2011, respectively:

Location on Consolidated Statement of Operations	Description of Gain (Loss)	December 31,		
		2013	2012	2011
			(in thousands)	
Oil sales	Loss reclassified from Accumulated OCI	\$	\$	\$ (2,149)
NGL sales	Loss reclassified from Accumulated OCI			(10,190)
Natural gas sales	Gain reclassified from Accumulated OCI			18,751
Natural gas sales (1)	Gain recognized in income			11,018
Derivative instruments	Gain recognized in income	9,250	20,883	
	Realized gain recognized in income	\$ 9,250	\$ 20,883	\$ 17,430
Derivative instruments (2)	(Loss) gain recognized in income due to changes in fair value	\$ (16,245)	\$ 16,999	\$ 1,233
Derivative instruments	(Loss) gain reclassified from Accumulated OCI	(100)	2,663	
	Unrealized (loss) gain recognized in income	\$ (16,345)	\$ 19,662	\$ 1,233
	Total commodity derivative (loss) gain recognized in income	\$ (7,095)	\$ 40,545	\$ 18,663

(1) For 2011, the amount represents the realized gains associated with the 2011 termination of derivatives used to hedge production from the Company's divested DJ Basin and Sacramento Basin properties.

(2) For 2011, the amount represents the unrealized gain associated with the change in fair value of the Company's crude oil basis and NYMEX roll swaps.

As a result of the Company's election to de-designate all commodity contracts that were previously designated as cash flow hedges as of December 31, 2011 and to discontinue hedge accounting prospectively, the Company recognized no gain or loss in Accumulated other comprehensive income for the years ended December 31, 2013 and 2012. The Company recognized unrealized losses of \$2.0 million in Accumulated other comprehensive income for the year ended December 31, 2011.

(7) Fair Value Measurements

The Company's financial assets and liabilities are measured at fair value on a recurring basis. The Company measures its non-financial assets and liabilities, such as asset retirement obligations and other property and equipment, at fair value on a non-recurring basis. For non-financial assets and liabilities, the Company is required to disclose information that enables users of its financial statements to assess the inputs used to develop these measurements. As none of the Company's non-financial assets and liabilities were impaired during the year ended December 31, 2013, and because the Company had no other material assets or liabilities reported at fair value on a non-recurring basis, no additional disclosures are provided as of December 31, 2013.

Table of ContentsIndex to Financial Statements

As defined in the FASB's guidance, fair value is the amount 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 (an exit price). To estimate fair value, the Company utilizes market data and 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 FASB's guidance establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy are as follows:

Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2 inputs are quoted prices for similar assets and liabilities in active markets or inputs that are observable for the asset or liability, either directly or indirectly through market corroboration, for substantially the full term of the financial instrument.

Level 3 inputs are measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources.

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 along with their placement within the fair value hierarchy levels. The Company determines the appropriate level for each financial asset and liability on a quarterly basis and recognizes any transfers at the end of the reporting period.

The following table sets 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 as of December 31, 2013 and 2012.

	Fair value as of December 31, 2013				Total
	Level 1	Level 2	Level 3	Netting (1)	
	(In thousands)				
Assets:					
Money market funds	\$	\$ 1,035	\$	\$	\$ 1,035
Commodity derivative contracts			21,675	(11,910)	9,765
Liabilities:					
Commodity derivative contracts			(17,256)	11,910	(5,346)
Total fair value	\$	\$ 1,035	\$ 4,419	\$	\$ 5,454

	Fair value as of December 31, 2012				Total
	Level 1	Level 2	Level 3	Netting (1)	
(In thousands)					
Assets:					
Money market funds	\$	\$ 1,035	\$	\$	\$ 1,035
Commodity derivative contracts			44,036	(22,809)	21,227
Liabilities:					
Commodity derivative contracts			(23,372)	22,809	(563)
Total fair value	\$	\$ 1,035	\$ 20,664	\$	\$ 21,699

- (1) Represents the impact of netting commodity derivative assets and liabilities with counterparties where the Company has the contractual right and intends to net settle. No margin or collateral balances are deposited with counterparties and as such, gross amounts are offset to determine the net amounts presented in the Consolidated Balance Sheet.

Table of Contents**Index to Financial Statements**

The Company's Level 3 instruments include commodity derivative contracts for which fair value is determined by a third-party provider. Although the Company compares the fair values derived from the third-party provider with its counterparties, the Company does not currently have sufficient corroborating market evidence to support classifying these contracts as Level 2 instruments and does not have access to the specific valuation models or certain inputs used by its third-party provider or counterparties. Therefore, these commodity derivative contracts are classified as Level 3 instruments.

The following table presents a range of the unobservable inputs provided by our third-party provider utilized in the fair value measurements of the Company's assets and liabilities classified as Level 3 instruments as of December 31, 2013 (in thousands):

Level 3 Instrument	Asset (Liability)	Valuation Technique	Unobservable Input	Range		Weighted
				Minimum	Maximum	Average
Oil swaps	(5,297)	Discounted cash flow	Forward price curve-swaps	\$ 91.67	\$ 98.52	\$ 95.58
Oil swaps	2,117	Discounted cash flow	Forward price curve-swaps	81.93	90.90	87.61
Oil costless collars	967	Option model	Forward price curve-costless collar option value	(1.39)	3.62	0.88
NGL swaps	5,764	Discounted cash flow	Forward price curve-swaps	0.27	1.40	0.58
NGL swaps	(3,031)	Discounted cash flow	Forward price curve-swaps	0.28	2.13	0.97
Natural gas swaps	1,984	Discounted cash flow	Forward price curve-swaps	3.86	4.40	4.04
Natural gas swaps	(100)	Discounted cash flow	Forward price curve-swaps	3.95	4.34	4.08
Natural gas costless collars	2,015	Option model	Forward price curve-costless collar option value	(0.26)	0.31	0.06
Total	\$ 4,419					

The determination of derivative fair values by the third-party provider incorporates a credit adjustment for nonperformance risk, including the credit standing of the counterparties involved, and the impact of the Company's nonperformance risk on its liabilities. The Company recorded a downward adjustment to the fair value of its derivative instruments in the amount of \$0.3 million as of December 31, 2013.

The significant unobservable inputs for Level 3 derivative contracts include forward price curves and option values. Significant increases (decreases) in the quoted forward prices for commodities and option values generally lead to corresponding decreases (increases) in the fair value measurement of the Company's oil, NGL and natural gas derivative contracts.

Table of Contents**Index to Financial Statements**

The tables below present reconciliations of financial assets and liabilities classified as Level 3 in the fair value hierarchy during the indicated periods.

	Derivative Asset Money Market Funds		
	(Liability)	Asset (Liability)	Total
		(In thousands)	
Balance at December 31, 2011	\$ 3,665	\$ 1,035	\$ 4,700
Total Gains or (Losses) (Realized or Unrealized):			
Included in Earnings	37,882		37,882
Included in Other Comprehensive Income			
Purchases, Issuances and Settlements			
Settlements	(20,883)		(20,883)
Purchases			
Transfers in and out of Level 3 (1)		(1,035)	(1,035)
Balance at December 31, 2012	\$ 20,664	\$	\$ 20,664
Total Gains or (Losses) (Realized or Unrealized):			
Included in Earnings	(6,995)		(6,995)
Included in Other Comprehensive Income			
Purchases, Issuances and Settlements			
Settlements	(9,250)		(9,250)
Purchases			
Transfers in and out of Level 3			
Balance at December 31, 2013	\$ 4,419	\$	\$ 4,419

(1) The value related to the money market funds was transferred from Level 3 to Level 2 in 2012 as a result of the Company's ability to obtain independent market-corroborated data.

Fair Value of Other Financial Instruments

All of the Company's other financial instruments (excluding derivatives) are presented on the balance sheet at carrying value. As of December 31, 2013, the carrying value of cash and cash equivalents (excluding money market funds), other current assets and current liabilities reported in the Consolidated Balance Sheet approximate fair value because of their short-term nature, and all such financial instruments are considered Level 1 instruments.

The Company's debt consists of publicly traded Senior Notes (defined below) and borrowings under the Credit Facility (defined below). The fair values of the Company's Senior Notes are based upon unadjusted quoted market prices and are considered Level 1 instruments. The Company's borrowings under the Credit Facility approximate fair value as the

interest rates are variable and reflective of current market rates, and are therefore considered a Level 1 instrument. As of December 31, 2013 and 2012, the estimated fair value of total debt was \$1.5 billion and \$432.5 million, respectively.

Table of Contents**Index to Financial Statements****(8) Accounts Payable, Accrued Liabilities, Royalties and Other Payables**

The Company's accrued liabilities consist of the following:

	December 31,	
	2013	2012
	(In thousands)	
Accrued capital costs	\$ 93,725	\$ 88,844
Accounts payable	29,682	1,874
Accrued reserve for commercial disputes	20,000	
Accrued payroll and employee incentive expense	10,516	10,436
Accrued lease operating expense	12,064	9,605
Accrued interest	15,025	4,582
Asset retirement obligation	3,930	2,440
Other	6,008	4,429
Total Accounts payable and accrued liabilities	\$ 190,950	\$ 122,210

At December 31, 2013, Royalties and other payables of \$78.3 million includes \$47.0 million of royalty revenues payable to landowners, \$14.1 million of accrued transportation costs and \$17.2 million of other operating liabilities.

(9) Asset Retirement Obligations

The following table provides a rollforward of the Company's asset retirement obligations (ARO). Liabilities incurred during the period include additions to obligations and obligations incurred from acquisitions. Liabilities settled during the period include settlement payments for obligations as well as obligations that were assumed by the purchasers of divested properties. Activity related to the Company's ARO is as follows:

	For the Year Ended December 31,		
	2013	2012	2011
	(In thousands)		
ARO at the beginning of the period	\$ 8,400	\$ 14,313	\$ 27,934
Liabilities incurred during period	1,795	866	2,096
Liabilities settled during period	(1,566)	(8,538)	(20,395)
Revision of previous estimate	3,850	935	3,454
Accretion expense	578	824	1,224
ARO at the end of the period	\$ 13,057	\$ 8,400	\$ 14,313

As of December 31, 2013 and 2012, the current portion of ARO of \$3.9 million and \$2.4 million, respectively, was included in Accrued liabilities on the Consolidated Balance Sheet. The long-term portion of ARO of \$9.2 million and \$6.0 million as of December 31, 2013 and 2012, respectively, was included in Other long-term liabilities on the

Consolidated Balance Sheet. The increase in ARO in 2013 was primarily due to the assumption of obligations to plug and abandon wells acquired in Reeves County, as well as the acceleration of the abandonment of certain non-core assets. In 2012 and 2011, ARO obligations related to divested properties were assumed by the purchasers and resulted in a reduction of the obligation during those periods.

Table of ContentsIndex to Financial Statements**(10) Debt and Credit Agreements**

The Company's long-term debt consists of the following:

	December 31,	
	2013	2012
	(In thousands)	
Credit Facility	\$	\$ 210,000
9.500% Senior Notes due 2018	200,000	
5.625% Senior Notes due 2021	700,000	
5.875% Senior Notes due 2022	600,000	200,000
Total debt	\$ 1,500,000	\$ 410,000

Senior Secured Revolving Credit Facility. As of December 31, 2013, the Company had no borrowings outstanding with \$800.0 million of available borrowing capacity under its Credit Facility. Amounts outstanding under the Credit Facility bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 1.50% to 2.50% and mature in April 2018. Additionally, the Company can borrow under the Credit Facility at the Alternative Base Rate (ABR) which is typically based upon the Prime Rate in effect on such day plus a margin of 0.5% to 1.5% depending on the Company's utilization percentage. The weighted average borrowing rate for the year ended December 31, 2013 under the Credit Facility was 3.22%, inclusive of interest and commitment fees. Borrowings under the Credit Facility are collateralized by liens and security interests on substantially all of the Company's assets, including a mortgage lien on oil and natural gas properties having at least 80% of the pre-tax SEC PV-10 proved reserve value, a guaranty by all of the Company's domestic subsidiaries and a pledge of 100% of the membership and limited partnership interests of the Company's domestic subsidiaries. Collateralized amounts under the mortgages are subject to semi-annual reviews based on updated reserve information. The Company is also subject to certain financial covenants, including the requirement to maintain a minimum current ratio of consolidated current assets, including the unused amount of available borrowing capacity, to consolidated current liabilities, excluding certain non-cash obligations, of not less than 1.0 to 1.0 as of the end of each fiscal quarter. The terms of the credit agreement also require the maintenance of a maximum leverage ratio of total debt to earnings before interest expense, income taxes and noncash items, such as depreciation, depletion, amortization and impairment, of not greater than 4.0 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended, measured quarterly after giving pro forma effect to acquisitions and divestitures. At December 31, 2013, the Company's current ratio was 4.4 and leverage ratio was 2.5. In addition, the Company is subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties.

9.500% Senior Notes. On April 15, 2010, the Company issued and sold \$200.0 million in aggregate principal amount of 9.500% Senior Notes due 2018 in a private offering. Interest is payable on the 9.500% Senior Notes semi-annually on April 15 and October 15. The 9.500% Senior Notes were issued under an indenture (the "9.500% Senior Notes Indenture") with Wells Fargo Bank, National Association, as trustee. Under the indenture, the Company has the option to redeem the notes on or after April 15, 2014 at a price of \$104.75. Provisions of the 9.500% Senior Notes Indenture limit the Company's ability to, among other things, incur additional indebtedness; pay dividends on capital stock or purchase, repurchase, redeem, defease or retire capital stock or subordinated indebtedness; make investments; incur liens; create any consensual restriction on the ability of the Company's restricted subsidiaries to pay dividends, make

loans or transfer property to the Company; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. The 9.500% Senior Notes Indenture also contains customary events of default. On September 21, 2010, the Company exchanged all of the privately placed 9.500% Senior Notes for registered 9.500% Senior Notes which contain terms substantially identical to the terms of the privately placed notes.

5.625% Senior Notes. On May 2, 2013, the Company completed its public offering of \$700.0 million in aggregate principal amount of 5.625% Senior Notes due 2021. Interest is payable on the 5.625% Senior Notes semi-annually on May 1 and November 1. The 5.625% Senior Notes were issued under an indenture (the Base

Table of Contents**Index to Financial Statements**

Indenture), as supplemented by a first supplemental indenture with Wells Fargo Bank, National Association, as trustee, which contains covenants and events of default substantially similar to those in the 9.500% Senior Notes Indenture.

5.875% Senior Notes. On November 15, 2013, the Company completed its public offering of \$600 million aggregate principal amount of 5.875% Senior Notes due 2022. Interest is payable on the 5.875% Senior Notes semi-annually on June 1 and December 1. The 5.875% Senior Notes were issued under the Base Indenture, as supplemented by a second supplemental indenture with Wells Fargo Bank, National Association, as trustee, which contains covenants and events of default substantially similar to those in the 9.500% Senior Notes Indenture.

Second Lien Term Loan. The Company's amended and restated term loan (the Restated Term Loan) of \$20.0 million was prepaid in full on August 31, 2012. Outstanding fixed-rate borrowings under the Restated Term Loan bore interest at 13.75% and would have matured on October 2, 2012. The loan was collateralized by second priority liens on substantially all of the Company's assets and upon prepayment, the second priority liens were released. In connection with the prepayment of the Restated Term Loan, \$0.2 million of prepayment fees were incurred and have been reflected as a component of interest expense.

Total Indebtedness. As of December 31, 2013, the Company had total outstanding borrowings of \$1.5 billion, and for the year ended December 31, 2013 the Company's weighted average borrowing rate was 5.99%. The Company does not have any debt that matures within the five years ending December 31, 2018 other than the 9.500% Senior Notes that become due in 2018.

(11) Commitments and Contingencies

Firm Oil and Natural Gas Transportation and Processing Commitments. The Company has commitments for the transportation and processing of its production in the Eagle Ford area and has an aggregate minimum commitment to deliver 6.1 MMBbls of oil by the end of 2017 and 367 million MMBtus of natural gas by the end of 2023. The Company is required to make periodic deficiency payments for any shortfalls in delivering the minimum volumes under these commitments. Currently, the Company has insufficient production to meet all of these contractual commitments. As the Company develops additional reserves in the Eagle Ford area, it anticipates exceeding its current minimum volume commitments and therefore intends to enter into additional transportation and processing commitments in the future. These future transportation and processing commitments could expose the Company to volume deficiency payments as it further develops its Eagle Ford assets. As of December 31, 2013, the Company has accrued deficiency fees of \$7.8 million and expects to continue to accrue deficiency fees under its commitments. Future obligations under firm oil and natural gas transportation and processing agreements as of December 31, 2013 are as follows:

	December 31, 2013
	(In thousands)
2014	34,486
2015	34,313
2016	33,844
2017	33,388
2018	29,839

Thereafter		104,088
Total future obligations	\$	269,958

Drilling Rig and Completion Services Commitments. Drilling rig and completion services commitments represent obligations with certain contractors to execute the Company's Eagle Ford and Permian Basin drilling programs, and payments under these commitments are accounted for as capital additions to oil and natural gas

Table of Contents**Index to Financial Statements**

properties. As of December 31, 2013, the Company had two outstanding drilling rig commitments with a term greater than one year that will expire in 2015, and minimum contractual commitments due in the next twelve months are \$19.8 million. As of December 31, 2013, the Company's minimum contractual commitments due in the next twelve months for completion services agreements for the stimulation, cementing and delivery of drilling fluids were \$14.8 million.

Lease Obligations and Other Commitments. The Company has operating leases for office space and other property and equipment. The Company incurred rental expense of \$7.3 million, \$5.7 million and \$3.4 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Future minimum annual rental commitments under non-cancelable leases at December 31, 2013 were as follows:

	December 31, 2013
	(In thousands)
2014	\$ 19,148
2015	5,132
2016	3,736
2017	3,804
2018	3,872
Thereafter	19,823
	\$ 55,515

Contingencies. The Company is party to various legal and regulatory proceedings and commercial disputes arising in the normal course of business. The ultimate outcome of each of these matters cannot be absolutely determined, and in the event of a negative outcome as to any proceeding, the liability the Company may ultimately incur with respect to any such proceeding may be in excess of amounts currently accrued, if any. After considering the Company's available insurance and, to the extent applicable, that of third parties, and the performance of contractual defense and indemnity rights and obligations, where applicable, the Company does not believe any such matter will have a material adverse effect on its financial position, results of operations or cash flows.

Commercial Disputes. In the fourth quarter of 2013, the Company recorded a reserve of \$20.5 million related to two commercial disputes, which is included in Reserve for commercial disputes in the Consolidated Statement of Operations for the year ended December 31, 2013. One commercial dispute was settled in the fourth quarter of 2013, and the other is expected to be settled in the first quarter of 2014.

(12) Stock-Based Compensation and Employee Benefits

Stock-based compensation expense includes the expense associated with restricted stock granted to employees and directors and the expense associated with the Performance Share Units (PSUs) granted to management. As of the indicated dates, stock-based compensation expense consisted of the following:

	Year Ended December 31,		
	2013	2012	2011
	(in thousands)		
Total stock-based compensation expense	\$ 11,471	\$ 18,835	\$ 29,676
Capitalized in oil and gas properties	(492)	(296)	(666)
Net stock-based compensation expense	\$ 10,979	\$ 18,539	\$ 29,010

Table of Contents

Index to Financial Statements

For the years ended December 31, 2013, 2012 and 2011, the Company had an associated tax benefit of \$3.0 million, \$2.8 million and \$10.6 million, respectively, related to stock-based compensation.

Long-Term Incentive Plans

In July 2005, the Board of Directors adopted the Rosetta 2005 Long-Term Incentive Plan (the "2005 Plan") under which stock was granted to employees, officers and directors of the Company. The 2005 Plan allowed for the granting of stock awards, stock options, restricted stock, restricted stock units, stock appreciation rights, performance awards and other incentive awards. As approved by the shareholders in 2008, the 2005 Plan allowed for a maximum of 4,950,000 shares to be granted, plus any shares that became available under the 2005 Plan for any reason other than exercise, such as shares traded for related tax withholding liabilities. The 2005 Plan was replaced by the 2013 Long-Term Incentive Plan (the "2013 Plan") by vote of the Company's shareholders in May 2013. No new grants are to be made from the 2005 Plan, although the Company will settle awards, options and PSUs made under the 2005 Plan as they vest.

The 2013 Plan allows for the granting of stock options, stock awards, restricted stock, restricted stock units, stock appreciation rights, performance awards, and other incentive awards to employees, non-employee directors and other service providers who are in a position to make a significant contribution to the success of the Company. The maximum number of shares available for grant under the 2013 Plan is 3,600,000 shares, with any shares from the 2005 Plan that are forfeited, cancelled or expire added to the shares authorized for issuance under the 2013 Plan. Shares may not be returned to the 2013 Plan for reissuance that are tendered in payment of an option exercise price, or that are withheld to satisfy tax obligations. The maximum number of shares of common stock available for the grant of awards under the 2013 Plan to any one participant is (i) 500,000 shares during the fiscal year in which the participant begins work for Rosetta and (ii) 300,000 shares during each fiscal year thereafter.

Stock Options

Prior to 2010, the Company granted stock options under the Plan, which generally expire ten years from the date of grant. The exercise price of the option could not be less than the fair market value per share of the Company's common stock on the grant date and the majority of options vested over a three-year period. During the years ended December 31, 2013, 2012 and 2011, no options were granted to employees, officers or directors of the Company and all options granted prior to 2011 under the Plan have vested. Compensation expense was recognized ratably over the requisite service period.

Table of Contents**Index to Financial Statements**

The following table summarizes information related to outstanding and exercisable options held by the Company's employees and directors at December 31, 2013:

	Shares	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term (In years)	Aggregate Intrinsic Value (In thousands) (1)
Outstanding at December 31, 2011	580,513	\$ 13.48		
Granted				
Exercised	(69,862)	13.21		
Forfeited				
Outstanding at December 31, 2012	510,651	\$ 13.52		
Granted				
Exercised	(379,145)	13.08		
Forfeited				
Outstanding at December 31, 2013	131,506	\$ 14.79		
Options vested and exercisable at December 31, 2013	131,506	\$ 14.79	3.91	\$ 4,302

(1) The intrinsic value of a stock option is the amount by which the current market value or the market value upon exercise of the underlying stock, at the indicated date, exceeds the exercise price of the option.

Stock-based compensation expense recorded for stock option awards for the years ended December 31, 2012 and 2011 was less than \$0.1 million and \$0.4 million, respectively. As of December 31, 2013, the Company has no unrecognized expense because all outstanding stock options have vested.

The total intrinsic value of options exercised during the years ended December 31, 2013, 2012 and 2011 was \$13.4 million, \$2.3 million and \$7.1 million, respectively.

Restricted Stock

The Company has granted restricted stock to employees and directors under the Plan. The majority of the Company's restricted stock grants 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. The Company has assumed an annual forfeiture rate of 10% for these awards based on the Company's

history for this type of award to various employee groups.

The following table summarizes information related to restricted stock held by the Company's employees and directors at December 31, 2013:

	Shares	Weighted Average Grant Date Fair Value
Non-vested shares outstanding at December 31, 2011	542,222	\$ 23.43
Granted	267,377	47.33
Lapse of restrictions	(445,508)	25.82
Forfeited	(34,977)	41.07
Non-vested shares outstanding at December 31, 2012	329,114	\$ 37.76
Granted	584,184	49.18
Lapse of restrictions	(457,164)	43.60
Forfeited	(81,285)	44.59
Non-vested shares outstanding at December 31, 2013	374,849	\$ 46.94

Table of Contents**Index to Financial Statements**

The fair value of awards vested for the year ended December 31, 2013 was \$22.7 million. Stock-based compensation expense recorded for restricted stock awards for the years ended December 31, 2013, 2012 and 2011 was \$6.7 million, \$7.4 million and \$4.9 million, respectively. Unrecognized expense as of December 31, 2013 for all outstanding restricted stock awards was \$9.7 million and will be recognized over a weighted average period of 1.74 years.

Performance Share Units

The Company's Compensation Committee of the Board of Directors agreed to allocate a portion of the long-term incentive grants to executives as PSUs. The PSUs are payable, at the Company's option, either in shares of common stock or as a cash payment equivalent to the fair market value of a share of common stock at settlement based on the achievement of performance metrics or market conditions at the end of a three-year performance period. The number of shares vested or equivalent cash payment can range from 0% to 200% of the targeted amount as determined by the Compensation Committee. None of these PSUs have voting rights and they may be vested solely at the discretion of the Board of Directors. Any PSUs not vested by the Board at the end of a performance period will expire.

As discussed in Note 2, stock-based compensation expense for PSUs is measured and adjusted quarterly until settlement occurs, based on Company performance, quarter-end closing common stock prices and the Board's anticipated vesting percentage. For the years ended December 31, 2013, 2012 and 2011, the Company recognized \$4.7 million, \$11.4 million and \$23.7 million, respectively, of stock-based compensation expense associated with PSUs.

The following table is a summary of PSU awards for the year ended December 31, 2013 assuming a 100% payout of the targeted amount:

	PSUs
Unvested PSUs at December 31, 2012	284,307
Granted	82,192
Vested	(152,319)
Forfeited	(46,595)
Unvested PSUs at December 31, 2013	167,585

On December 31, 2013, the three-year performance period ended for the 2011 PSUs, and in the first quarter of 2014, the Company vested the 2011 PSUs at 150% of the targeted amount, or a total of 75,275 units, in common stock. Stock-based compensation expense associated with the 2011 PSUs was recognized over the three-year performance period, and as of December 31, 2013, the Company had accrued \$3.7 million as a component of Additional paid-in capital.

On December 31, 2012, the three-year performance period ended for the 2010 PSUs and in the first quarter of 2013, the Company vested the 2010 PSUs at 175% of the targeted amount, or a total of 268,469 units, in common stock. Stock-based compensation expense associated with the 2010 PSUs was recognized over the three-year performance period, and as of December 31, 2012, the Company had accrued \$12.2 million as a component of Additional paid-in capital.

As of December 31, 2013, there were 118,379 unvested PSUs associated with the 2012 and 2013 grants. These awards are accounted for as equity-classified awards and are included as a component of Additional paid-in capital. Based on the Company's closing common stock price of \$48.04 at December 31, 2013, and assuming that the Board elects the maximum available payout of 200% for unvested 2012 and 2013 PSUs, unrecognized stock-based compensation expense related to these awards is approximately \$9.1 million and would be recognized over the remaining respective performance periods. The Company's total stock-based compensation expense will be measured and adjusted quarterly until settlement occurs, based on the Company's performance, quarter-end closing common stock prices and the Board's anticipated vesting percentage.

Table of Contents**Index to Financial Statements****(13) Income Taxes**

The Company's income tax expense (benefit) consists of the following:

	Year Ended December 31,		
	2013	2012	2011
	(In thousands)		
Current:			
Federal	\$ 5,332	\$	\$
State	4,376		(457)
	9,708		(457)
Deferred:			
Federal	99,768	92,001	52,327
State	1,108	3,903	3,843
	100,876	95,904	56,170
Total income tax expense	\$ 110,584	\$ 95,904	\$ 55,713

The differences between income taxes computed using the statutory federal income tax rate and that shown in the Consolidated Statement of Operations are summarized as follows:

	Year Ended December 31,					
	2013		2012		2011	
	(In thousands)	(%)	(In thousands)	(%)	(In thousands)	(%)
US statutory rate	\$ 108,477	35.0%	\$ 89,320	35.0%	\$ 54,691	35.0%
State income tax, net of federal benefit	3,538	1.1%	1,846	0.7%	3,348	2.2%
Non-deductible permanent items	1,137	0.4%	4,197	1.6%	677	0.4%
Valuation allowance	(15)	(0.0%)	954	0.4%	(2,262)	(1.4%)
Other, net	(2,553)	(0.8%)	(413)	(0.1%)	(741)	(0.5%)
Total tax expense	\$ 110,584	35.7%	\$ 95,904	37.6%	\$ 55,713	35.7%

The effective tax rate in all periods is the result of earnings in various domestic tax jurisdictions that apply to a broad range of income tax rates. The provision for income taxes differs from the tax computed at the federal statutory income tax rate primarily due to the impact of state income taxes and the deductibility of certain incentive compensation. Future effective tax rates could be adversely affected if unfavorable changes in tax laws and regulations occur, or if the Company experiences future adverse determinations by taxing authorities.

The components of deferred tax assets and liabilities are as follows:

	December 31,	
	2013	2012
	(In thousands)	
Deferred income tax assets:		
Net operating loss carryforwards	\$ 119,794	\$ 194,259
Stock-based compensation	2,001	3,223
Other	13,737	4,083
Gross deferred income tax assets	\$ 135,532	\$ 201,565
Valuation allowance	(5,235)	(5,250)
Net deferred income tax assets	\$ 130,297	\$ 196,315
Deferred income tax liabilities:		
Oil and gas properties basis differences	(237,220)	(198,734)
Derivative financial instruments	(1,508)	(7,356)
Deferred income tax liability	\$ (238,728)	\$ (206,090)
Net deferred income tax liability	\$ (108,431)	\$ (9,775)

Table of Contents**Index to Financial Statements**

As of December 31, 2013, the total net operating loss (NOL) carryforward consists of \$347.0 million of federal NOL carryforwards, which expire between 2029 and 2032, and \$105.1 million of state NOL carryforwards, which expire primarily between 2014 and 2032. The tax benefits of carryforwards are recorded as an asset to the extent that management assesses the utilization of such carryforwards to be more likely than not. When the future utilization of some portion of the carryforward is determined not to be more likely than not, a valuation allowance is provided to reduce the recorded tax benefits from such assets. Management believes that the Company's taxable temporary differences and future taxable income will more likely than not be sufficient to utilize all of its federal tax carryforwards prior to their expiration.

However, in connection with the asset divestitures in 2010, 2011 and 2012, the Company concluded that it is more likely than not that the NOLs and other deferred tax assets for the states impacted by these divestitures will not be realized. Therefore, valuation allowances were established for these items as well as state NOLs in jurisdictions in which the Company previously operated but has since divested of its operating assets. Annually, changes in the Company's valuation allowance are made to reflect revised estimates of the utilization of state deferred tax assets. The Company will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods.

The rollforward of our deferred tax asset valuation allowance is as follows:

	Year Ended December 31,		
	2013	2012	2011
	(in thousands)		
Balance at the beginning of the year	\$ 5,250	\$ 4,296	\$ 6,558
Change to provision for income taxes	(15)	954	(2,262)
Balance at the end of the year	\$ 5,235	\$ 5,250	\$ 4,296

Pursuant to authoritative guidance, the Company's \$119.8 million deferred tax asset related to NOL carryforwards is net of \$7.0 million of unrealized excess tax benefits related to \$20.0 million of stock-based compensation which will be recognized in Additional paid-in capital upon utilization of the Company's NOL carryforward.

Accounting for uncertainty in income taxes prescribes a recognition threshold and measurement methodology for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. As of December 31, 2013, the Company had no unrecognized tax benefits. The Company files income tax returns in the U.S. and in various state jurisdictions. With few exceptions, the Company is subject to U.S. federal, state and local income tax examinations by tax authorities for tax periods 2005 and forward.

Estimated interest and penalties related to potential underpayment on any unrecognized tax benefits are classified as a component of tax expense in the Consolidated Statement of Operations. The Company has not recorded any interest or penalties associated with unrecognized tax benefits.

(14) Equity

Earnings per Share. Basic earnings per share (EPS) is calculated by dividing income (the numerator) by the weighted-average number of shares of common stock (excluding unvested restricted stock awards) outstanding during the period (the denominator). Diluted EPS incorporates the dilutive impact of outstanding stock options and unvested restricted stock awards using the treasury stock method.

Table of Contents**Index to Financial Statements**

The following is a calculation of basic and diluted weighted average shares outstanding:

	Year Ended December 31,		
	2013	2012	2011
	(In thousands)		
Basic weighted average number of shares outstanding	58,571	52,496	51,996
Dilution effect of stock option and restricted shares at the end of the period	259	391	620
Diluted weighted average number of shares outstanding	58,830	52,887	52,616
Anti-dilutive stock awards and shares	2	1	4

Common Stock Offering. On April 23, 2013, the Company completed its public offering of 7,000,000 shares of common stock at a price to the public of \$42.50 per share for net proceeds of approximately \$286.3 million (\$40.80 per share, net of underwriting discounts and commissions), including offering expenses and reimbursements by the underwriters of certain expenses incurred in connection with the offering. The Company also received net proceeds of approximately \$43.0 million in connection with the underwriters' full exercise of their over-allotment option to purchase 1,050,000 additional shares of common stock, which closed on April 29, 2013.

(15) Operating Segments

The Company has one reportable segment, oil and natural gas exploration and production, as determined in accordance with authoritative guidance regarding disclosure about segments of an enterprise and related information. All of the Company's costs are included in one cost pool because all of the Company's operations are located in the United States.

Geographic Area Information

Geographic revenue information below is based on the physical location of the assets at the end of each period. Certain amounts in prior periods have been reclassified to conform to the current presentation.

	Year Ended December 31,		
	2013 (1)	2012 (1)	2011 (1)
	(In thousands)		
Oil, NGL, and Natural Gas Revenue			
Eagle Ford	\$ 764,251	\$ 561,143	\$ 354,741
Permian	52,603		
Other (2)	4,259	11,811	72,796
Total	\$ 821,113	\$ 572,954	\$ 427,537

- (1) Excludes the effects of derivative losses of \$7.1 million and gains of \$40.5 million and \$18.7 million, respectively, for the years ended December 31, 2013, 2012 and 2011.
- (2) The decline in revenues from 2011 to 2013 was due to the Company's asset divestitures and suspension of capital programs in areas that produced primarily from dry gas reservoirs. See Note 4 Property and Equipment.

Major Customers

In 2013, two customers, Shell Trading (US) Company and Enterprise Products Operating LLC, accounted for approximately 23% and 21%, respectively, of the Company's consolidated revenue, excluding the effects of derivative instruments.

Table of Contents

Index to Financial Statements

In 2012, four customers, Enterprise Products Operating LLC, Shell Trading (US) Company, Exxon Mobil Corporation and Calpine Energy Services, accounted for approximately 21%, 21%, 13% and 12%, respectively, of the Company's consolidated revenue, excluding the effects of derivative instruments.

In 2011, four customers, Shell Trading (US) Company, Calpine Energy Services, Regency Gas Services, LLC, and Exxon Mobil Corporation, accounted for approximately 25%, 24%, 17% and 10%, respectively, of the Company's consolidated revenue, excluding the effects of derivative instruments.

No other customers accounted for more than 10% of the Company's consolidated revenue, excluding the effects of derivative instruments, for the years ended December 31, 2013, 2012 and 2011. The loss of any one of these customers would not have a material adverse effect on the Company's operations as management believes other purchasers are available in the Company's areas of operations.

(16) Guarantor Subsidiaries

The Company's Senior Notes are guaranteed by its wholly owned subsidiaries. Rosetta Resources Inc., as the parent company, has no independent assets or operations. The guarantees are full and unconditional and joint and several. In addition, there are no restrictions on the ability of the Company to obtain funds from its subsidiaries by dividend or loan. Finally, none of the Company's subsidiaries has restricted assets that exceed 25% of net assets as of December 31, 2013, which may not be transferred to the Company in the form of loans, advances or cash dividends by the subsidiaries without the consent of a third party.

Supplemental Oil and Gas Disclosures

(Unaudited)

The following disclosures for the Company are made in accordance with authoritative guidance regarding disclosures about oil and natural gas producing activities. Users of this information should be aware that the process of estimating quantities of proved, proved developed and proved undeveloped crude oil, NGL and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reported reserve estimates represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

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

Proved developed reserves are proved reserves that can be expected to be recovered (a) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared

with the cost of a new well or (b) through installed extraction equipment and infrastructure operational at the time of the reserve estimate if the extraction is by means not involving a well.

Table of Contents

Index to Financial Statements

Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Estimates of proved developed and proved undeveloped reserves as of December 31, 2013 are based on estimates made by the Company's engineers and audited by the Company's independent engineers, Netherland, Sewell & Associates, Inc. (NSAI). The Company's primary reserves estimator is the Company's Vice President of Corporate Reserves and Technical Services, who has over 36 years of experience in the petroleum industry spent almost entirely in the evaluation of reserves and income attributable to oil and natural gas properties. He holds a Bachelor of Science in Mechanical Engineering from Texas A&M University. He is a licensed Professional Engineer in the State of Texas and is a member of the Society of Petroleum Engineers. The Company makes representations to the independent engineers that it has provided all relevant operating data and documents, and in turn the Company reviews these reserve reports provided by the independent engineers to ensure completeness and accuracy. NSAI performs petroleum engineering consulting services under the Texas Board of Professional Engineers. NSAI's President and Chief Operating Officer is a licensed professional engineer with more than 35 years of experience, and the engineer and geologist charged with the Company's audit are both licensed professionals with more than 50 years of experience combined.

The preparation of the Company's reserve estimates are completed in accordance with the Company's prescribed internal control procedures, which include verification of input data into a reserve forecasting and economic evaluation software, as well as management review. The technical persons responsible for preparing the reserve estimates meet the required standards regarding qualifications and objectivity. Additionally, the Company engages qualified, independent reservoir engineers to audit the internally generated reserve report in accordance with all SEC reserve estimation guidelines.

A twelve-month first-day-of-the-month historical average price as of December 31, 2013, 2012 and 2011 was used for future sales of oil and natural gas. Future operating costs, production and ad valorem taxes and capital costs were based on current costs as of each year end, with no escalation. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. Reserve data represent estimates only and should not be construed as being exact. Moreover, the standardized measure should not be construed as the current market value of proved oil, NGL and natural gas reserves or the costs that would be incurred to obtain equivalent reserves. A market value determination would include many additional factors including (a) anticipated future changes in oil, NGL and natural gas prices, production and development costs, (b) an allowance for return on investment, (c) the value of additional reserves, not considered proved at present, which may be recovered as a result of further exploration and development activities, and (d) other business risk.

Table of Contents**Index to Financial Statements****Capitalized Costs Relating to Oil, NGL and Gas Producing Activities**

The following table sets forth the capitalized costs relating to the Company's oil, NGL and natural gas producing activities at December 31, 2013, 2012 and 2011:

	2013	2012	2011
	(In thousands)		
Proved properties	\$ 3,951,397	\$ 2,829,431	\$ 2,297,312
Unproved properties	755,438	95,540	141,016
Total	4,706,835	2,924,971	2,438,328
Less: Accumulated depletion	(2,003,893)	(1,797,203)	(1,649,403)
Net capitalized costs	\$ 2,702,942	\$ 1,127,768	\$ 788,925

Net capitalized costs include asset retirement costs of \$22.2 million, \$15.1 million and \$18.0 million as of December 31, 2013, 2012 and 2011, respectively.

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

The following table sets forth costs incurred related to the Company's oil, NGL and natural gas producing activities for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31,		
	2013	2012	2011
	(In thousands)		
Acquisition costs			
Proved	\$ 290,273	\$	\$
Unproved	672,634	18,753	10,605
Subtotal	962,907	18,753	10,605
Exploration costs	534,881	93,542	98,781
Development costs	338,882	531,957	369,865
Total	\$ 1,836,670	\$ 644,252	\$ 479,251

Results of Operations for Oil, NGL and Natural Gas Producing Activities

	Year Ended December 31,		
	2013 (1)	2012 (1)	2011 (1)

	(In thousands)		
Oil, NGL and natural gas producing revenues	\$ 821,113	\$ 572,954	\$ 427,537
Production costs	155,749	110,977	69,289
Depreciation, depletion and amortization	218,571	154,223	123,244
Income before income taxes	446,793	307,754	235,004
Income tax provision	159,505	115,716	83,896
Results of operations	\$ 287,288	\$ 192,038	\$ 151,108

- (1) Excludes the effects of derivative losses of \$7.1 million, and gains of \$40.5 million and \$18.7 million, respectively, for the years ended December 31, 2013, 2012 and 2011.

Table of Contents**Index to Financial Statements**

The results of operations for oil, NGL and natural gas producing activities exclude other income and expenses, interest charges and general and administrative expenses. Sales are based on market prices.

Net Proved and Proved Developed Reserve Summary

The following table provides a rollforward of the total proved reserves (all within the United States) for the years ended December 31, 2013, 2012 and 2011, respectively, as well as proved developed and proved undeveloped reserves at the end of each respective year.

	Oil (MBbls) (1)	Natural gas liquids (MBbls)	Natural gas (MMcf)	Equivalents (MBoe)
Net proved reserves at December 31, 2010	12,401	19,326	288,927	79,819
Revisions of previous estimates (2)	4,839	7,192	60,712	22,212
Purchases in place				
Extensions, discoveries and other additions (3)	21,027	26,344	210,292	82,420
Sales in place	(34)		(80,582)	(13,464)
Production	(1,863)	(2,643)	(33,393)	(10,072)
Net proved reserves at December 31, 2011	36,370	50,219	445,956	160,915
Revisions of previous estimates (4)	(4,947)	4,923	(10,107)	(1,709)
Purchases in place	70	104	744	298
Extensions, discoveries and other additions (5)	16,737	22,440	158,788	65,641
Sales in place	(309)	(1,641)	(52,075)	(10,629)
Production	(3,497)	(4,472)	(33,853)	(13,611)
Net proved reserves at December 31, 2012	44,424	71,573	509,453	200,905
Revisions of previous estimates (6)	(8,945)	(65)	(9,580)	(10,606)
Purchases in place (7)	10,972	5,857	36,523	22,916
Extensions, discoveries and other additions (8)	25,010	28,342	180,570	83,447
Sales in place				
Production	(4,999)	(6,398)	(40,343)	(18,121)
Net proved reserves at December 31, 2013	66,462	99,309	676,623	278,541
Proved Developed Reserves				
December 31, 2010	3,687	6,471	183,954	40,817

Edgar Filing: Rosetta Resources Inc. - Form 10-K

December 31, 2011	11,766	16,635	177,278	57,947
December 31, 2012	19,321	25,068	178,214	74,092
December 31, 2013	22,560	31,542	217,328	90,324
Proved Undeveloped Reserves				
December 31, 2010	8,714	12,855	104,973	39,002
December 31, 2011	24,604	33,584	268,678	102,968
December 31, 2012	25,103	46,505	331,239	126,813
December 31, 2013	43,902	67,767	459,295	188,217

- (1) Includes crude oil and condensate. As of December 31, 2013, 2012, 2011 and 2010, approximately 65%, 92%, 97%, and 95%, respectively, of our proved oil reserves consisted of condensate, which the Company defines as oil with an API gravity higher than 55 degrees.
- (2) Upward revision of 22,212 MBoe resulting from positive performance revisions primarily due to an increase in the estimated ultimate recovery of hydrocarbons on 35 Gates Ranch wells. Twenty-two of these Gates Ranch wells have greater than 12 months of production history and some of these wells have been

Table of Contents**Index to Financial Statements**

- producing for over two years. The decline profiles on wells with significant production history indicate that the estimated ultimate recovery is much more likely to increase or remain constant than to decline.
- (3) The Company added 82,420 MBoe in the Eagle Ford area by drilling and completing 13 wells and adding 91 proved undeveloped locations.
 - (4) The downward revision of 1,709 MBoe was primarily due to two factors in the Eagle Ford area. The first factor was a downward oil revision of 4,947 MBbls, partially offset by an upward NGL revision of 4,923 MBbls, which was due to condensate stabilization that is required before transportation of condensate to the market. The stabilization process separates NGLs from the Company's oil production which resulted in a reclassification of some of the Company's reserves from oil to NGLs. The second factor was a downward natural gas revision of 10,107 MMcf, which was due largely to a decrease in the twelve-month first-day-of-the-month historical average commodity price for natural gas from \$4.12 per MMBtu in 2011 to \$2.76 per MMBtu in 2012 and an increase in treating and transportation costs.
 - (5) The Company added 65,641 MBoe primarily in the Eagle Ford area by drilling and completing 37 wells and adding 54 proved undeveloped locations.
 - (6) The downward revision of 10,606 MBoe is primarily due to lower than expected condensate yields from the Company's 2013 completions in the north central portion of Gates Ranch.
 - (7) The Company added 22,916 MBoe primarily due to the Permian Acquisition.
 - (8) The Company added 83,447 MBoe, of which 70,626 MBoe and 12,821 MBoe was from the Eagle Ford and Permian Basin areas, respectively. In the Eagle Ford area, the Company added reserves through the drilling and completion of 79 wells and the addition of 106 proved undeveloped locations. In the Permian Basin area, the Company added reserves through the drilling and completion of 30 wells and the addition of 84 proved undeveloped locations.

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

The following information has been developed utilizing procedures prescribed by authoritative guidance and based on oil, NGL and natural gas reserves and production volumes estimated by internal reserves engineers and audited by independent petroleum engineers. This information may be useful for certain comparison purposes but should not be solely relied upon in evaluating the Company or its performance. In accordance with SEC requirements, the estimated discounted future net revenues from proved reserves are generally based on average first-day-of-the-month oil and natural gas prices in effect for the prior twelve months in 2013, 2012 and 2011 and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower than the average prices and costs as of the date of the estimate. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the current value of the Company's oil and natural gas assets.

The future cash flows presented below are based on sales prices, cost rates and statutory income tax rates in existence as of the date of the projections. It is expected that material revisions to some estimates of oil, NGL and natural gas reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used. Income tax expense has been computed using expected future tax rates and giving effect to tax deductions and credits available, under current laws, and which relate to oil and natural gas producing activities.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves and varying price and cost assumptions considered more representative of a range of possible economic conditions that

may be anticipated.

Table of Contents**Index to Financial Statements**

The following table sets forth the standardized measure of discounted future net cash flows from projected production of the Company's reserves for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31, 2013		
	Proved Developed	Proved Undeveloped (In millions)	Total
Future cash inflows	\$ 3,826	\$ 7,770	\$ 11,596
Future production costs	(1,224)	(2,188)	(3,412)
Future development costs	(20)	(1,990)	(2,010)
Future income taxes	(641)	(892)	(1,533)
Future net cash flows	1,941	2,700	4,641
Discount to present value at 10% annual rate	(982)	(1,365)	(2,347)
Standardized measure of discounted future net cash flows relating to proved oil, NGL and natural gas reserves	\$ 959	\$ 1,335	\$ 2,294

	Year Ended December 31, 2012		
	Proved Developed	Proved Undeveloped (In millions)	Total
Future cash inflows	\$ 3,239	\$ 5,013	\$ 8,252
Future production costs	(854)	(1,227)	(2,081)
Future development costs	(8)	(1,110)	(1,118)
Future income taxes	(652)	(733)	(1,385)
Future net cash flows	1,725	1,943	3,668
Discount to present value at 10% annual rate	(859)	(968)	(1,827)
Standardized measure of discounted future net cash flows relating to proved oil, NGL and natural gas reserves	\$ 866	\$ 975	\$ 1,841

	Year Ended December 31, 2011		
	Proved Developed	Proved Undeveloped (In millions)	Total
Future cash inflows	\$ 2,527	\$ 4,765	\$ 7,292
Future production costs	(542)	(816)	(1,358)
Future development costs	(18)	(990)	(1,008)

Edgar Filing: Rosetta Resources Inc. - Form 10-K

Future income taxes	(584)	(878)	(1,462)
Future net cash flows	1,383	2,081	3,464
Discount to present value at 10% annual rate	(702)	(1,056)	(1,758)
Standardized measure of discounted future net cash flows relating to proved oil, NGL and natural gas reserves	\$ 681	\$ 1,025	\$ 1,706

Table of Contents**Index to Financial Statements****Changes in Standardized Measure of Discounted Future Net Cash Flows**

The following table sets forth the changes in the standardized measure of discounted future net cash flows for the years ended December 31, 2013, 2012 and 2011:

	Year ended December 31		
	2013	2012	2011
	(in millions)		
Standardized measure beginning of year	\$ 1,841	\$ 1,706	\$ 697
Sales and transfers of crude oil, NGLs and natural gas produced, net of production costs	(665)	(462)	(358)
Revisions to estimates of proved reserves:			
Net changes in prices and production costs	(268)	(591)	39
Extensions, discoveries, additions and improved recovery, net of related costs	849	814	1,117
Development costs incurred	275	220	370
Changes in estimated future development costs	86	54	(26)
Revisions of previous quantity estimates	(127)	(12)	357
Accretion of discount	244	229	143
Net change in income taxes	(113)	(17)	(549)
Purchases of reserve in place	216	6	
Sales of reserves in place		(104)	(79)
Changes in timing and other	(44)	(2)	(5)
Standardized measure end of year	\$ 2,294	\$ 1,841	\$ 1,706

Quarterly Selected Financial Data**(Unaudited)**

Summaries of the Company's results of operations by quarter for the years ended 2013 and 2012 are as follows:

	2013			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share data)			
Revenues	\$ 178,120	\$ 236,520	\$ 194,568	\$ 204,810
Operating income	86,305	131,703	72,306	55,891
Net income	53,480	75,352	41,025	29,495
Basic earnings per share	1.01	1.28	0.67	0.48
Diluted earnings per share	1.01	1.27	0.67	0.48

	2012			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share data)			
Revenues	\$ 114,458	\$ 197,981	\$ 122,752	\$ 178,308
Operating income	40,541	127,111	33,442	78,474
Net income	22,297	76,969	17,689	42,340
Basic earnings per share	0.43	1.47	0.34	0.81
Diluted earnings per share	0.42	1.46	0.33	0.80

Table of Contents

Index to Financial Statements

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

None

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of 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 Securities Exchange Act of 1934, as amended (Exchange Act), as of December 31, 2013. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2013, our disclosure controls and procedures were effective in providing reasonable assurance that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control Over Financial Reporting

Management, including our Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Management conducted an assessment as of December 31, 2013 of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control - Integrated Framework* (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2013, based on criteria in *Internal Control - Integrated Framework* issued by the COSO.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report, which is included in Item 8. Financial Statements and Supplementary Data of this Annual Report on Form 10-K.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the quarter ended December 31, 2013 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

Table of Contents

Index to Financial Statements

Part III

Item 10. Directors, Executive Officers and Corporate Governance

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2014 annual meeting under the headings Security Ownership of Directors and Executive Officers, Company Nominees for Director, Section 16(a) Beneficial Ownership Reporting Compliance, and Corporate Governance and Committees of the Board.

Item 11. Executive Compensation

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2014 annual meeting under the headings Executive Compensation, Information Concerning the Board of Directors, and Compensation Committee Report.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

This information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2014 annual meeting under the headings Security Ownership of Certain Beneficial Owners and Management and Securities Authorized for Issuance Under Equity Compensation Plans.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2014 annual meeting under the heading Certain Transactions and Corporate Governance and Committees of the Board.

Item 14. Principal Accountant Fees and Services

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2014 annual meeting under the heading Audit and Non-Audit Fees Summary.

Table of Contents

Index to Financial Statements

Part IV

Item 15. Exhibits and Financial Statement Schedules

a. The following documents are filed as a part of this report or incorporated herein by reference:

(1) Our audited Consolidated Financial Statements are provided in Item 8. Financial Statements and Supplementary Data in this Annual Report on Form 10-K.

(2) Financial Statement Schedules:

All schedules are omitted for the reason that they are not required or the information is otherwise supplied in Item 8. Financial Statements and Supplementary Data in this Annual Report on Form 10-K.

(3) Exhibits: The following documents are included as exhibits to this report:

Exhibit Number	Description
3.1	Certificate of Incorporation (incorporated herein by reference to Exhibit 3.1 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
3.2	Amended and Restated Bylaws (incorporated herein by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed on December 6, 2012 (Registration No. 000-51801)).
4.1	Registration Rights Agreement (incorporated herein by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
4.2	Indenture, dated April 15, 2010, among the Company, the Subsidiary Guarantors parties thereto and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K filed on April 19, 2010 (Registration No. 000-51801)).
4.3	Form of the 9.500% Senior Notes due 2018 (incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K filed on April 19, 2010 (Registration No. 000-51801)).
4.4	Indenture, dated as of May 2, 2013, between Rosetta Resources Inc., as issuer, and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K filed on May 2, 2013 (Registration

No. 000-51801)).

- 4.5 First Supplemental Indenture, dated as of May 2, 2013, among Rosetta Resources Inc., as issuer, the Subsidiary Guarantors named therein, as guarantors, and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K filed on May 2, 2013 (Registration No. 000-51801)).
- 4.6 Second Supplemental Indenture, dated as of November 15, 2013, among Rosetta Resources Inc., as issuer, the Subsidiary Guarantors named therein, as guarantors, and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K filed on November 15, 2013 (Registration No. 000-51801)).
- 10.9 Amended and Restated 2005 Long-Term Incentive Plan, effective January 1, 2011 (incorporated herein by reference to Exhibit 10.9 to the Company's Annual Report on Form 10-K filed on February 25, 2011 (Registration No. 000-51801)).

Table of Contents**Index to Financial Statements**

Exhibit Number	Description
10.10	Form of Option Grant Agreement (incorporated herein by reference to Exhibit 10.10 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.11	Form of Restricted Stock Agreement (incorporated herein by reference to Exhibit 10.11 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.12	Form of Bonus Restricted Stock Agreement (incorporated herein by reference to Exhibit 10.12 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.18	Amended and Restated Senior Revolving Credit Agreement (incorporated herein by reference to Exhibit 10.18 to the Company's Current Report on Form 8-K filed on April 15, 2009 (Registration No. 000-51801)).
10.20	Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.20 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.24	First Amendment to Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.24 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.26	Deposit Account Control Agreement (incorporated herein by reference to Exhibit 10.26 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.36	Indemnification Agreement with Directors and Officers (incorporated herein by reference to Exhibit 10.36 to the Company's Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.39	2005 Long-Term Incentive Plan Performance Share Unit Award Agreement (incorporated herein by reference to Exhibit 10.18 to the Company's Annual Report on Form 10-K filed on February 26, 2013 (Registration No. 000-51801)).
10.41	Executive Employee Severance Plan (incorporated herein by reference to Exhibit 10.41 to the Company's Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.44	First Amendment dated October 22, 2009 to Amended and Restated Senior Revolving Credit Agreement (incorporated herein by reference to Exhibit 10.44 to the Company's Quarterly Report on Form 10-Q filed on November 6, 2009 (Registration No. 000-51801)).
10.46	Second Amendment to Amended and Restated Senior Revolving Credit Agreement, effective as of April 5, 2010, among Rosetta Resources Inc., as borrower, BNP Paribas, as administrative agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed on May 10, 2010 (Registration No. 000-51801)).

10.48

Third Amendment to Amended and Restated Senior Revolving Credit Agreement, effective as of December 2, 2010, among Rosetta Resources Inc., as borrower, BNP Paribas, as administrative agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.48 to the Company's Annual Report on Form 10-K filed on February 25, 2011 (Registration No. 000-51801)).

Table of Contents

Index to Financial Statements

Exhibit Number	Description
10.50	Fourth Amendment to Amended and Restated Senior Revolving Credit Agreement, effective as of May 10, 2011, among Rosetta Resources Inc., as borrower, BNP Paribas, as administrative agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K filed on May 16, 2011 (Registration No. 000-51801)).
10.51	Fifth Amendment to Amended and Restated Senior Revolving Credit Agreement, effective as of April 25, 2012, among Rosetta Resources Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders signatory thereto (incorporated herein by reference to Exhibit 10.51 to the Company's Current Report on Form 8-K filed on April 30, 2012 (Registration No. 000-51801)).
10.52	Sixth Amendment to Amended and Restated Senior Revolving Credit Agreement, effective as of April 12, 2013, among Rosetta Resources Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders signatory thereto (incorporated herein by reference to Exhibit 10.52 to the Company's Current Report on Form 8-K filed on April 15, 2013 (Registration No. 000-51801)).
10.53	Seventh Amendment to Amended and Restated Senior Revolving Credit Agreement, effective as of July 30, 2013, among Rosetta Resources Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders signatory thereto (incorporated herein by reference to Exhibit 10.53 to the Company's Current Report on Form 10-Q filed on November 6, 2013 (Registration No. 000-51801)).
10.54	2013 Long-Term Incentive Plan (incorporated by reference to Appendix A to the Company's Definitive Proxy Statement on Schedule 14A filed on March 27, 2013).
10.55 *	Executive Employee Change of Control Plan.
21.1*	Subsidiaries of the registrant
23.1*	Consent of PricewaterhouseCoopers LLP
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of Periodic Financial Reports by James E. Craddock in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Periodic Financial Reports by John E. Hagale in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification of Periodic Financial Reports by James E. Craddock and John E. Hagale in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002 and 18 U.S.C. Section 1350
99.1*	Report of Netherland, Sewell & Associates, Inc.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document

101.LAB* XBRL Label Linkbase Document
101.PRE* XBRL Presentation Linkbase Document

* Filed herewith
Management contract or compensatory plan or arrangement required to be filed as an exhibit hereto.

Table of ContentsIndex to Financial Statements**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 February 24, 2014.

ROSETTA RESOURCES INC.

By: /s/ James E. Craddock
James E. Craddock, Chairman of the
Board,

Chief Executive Officer and President

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/ JAMES E. CRADDOCK James E. Craddock	Chairman of the Board, Chief Executive Officer and President (Principal Executive Officer)	February 24, 2014
/s/ JOHN E. HAGALE John E. Hagale	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 24, 2014
/s/ DON O. MCCORMACK Don O. McCormack	Senior Vice President, Treasurer and Chief Accounting Officer (Principal Accounting Officer)	February 24, 2014
/s/ PHILIP L. FREDERICKSON Philip L. Frederickson	Lead Director	February 24, 2014
/s/ MATTHEW D. FITZGERALD Matthew D. Fitzgerald	Director	February 24, 2014
/s/ CARIN S. KNICKEL Carin S. Knickel	Director	February 24, 2014

Edgar Filing: Rosetta Resources Inc. - Form 10-K

/s/ HOLLI C. LADHANI Director February 24, 2014

Holli C. Ladhani

/s/ DONALD D. PATTESON, JR. Director February 24, 2014

Donald D. Patteson, Jr.

/s/ JERRY R. SCHUYLER Director February 24, 2014

Jerry R. Schuyler

Table of Contents

Index to Financial Statements

Glossary of Oil and Natural Gas Terms

We are in the business of exploring for and producing oil, NGLs and natural gas. Oil, NGL and natural gas exploration is a specialized industry. Many of the terms used to describe our business are unique to the oil and natural gas industry. The following is a description of the meanings of some of the oil and natural gas industry terms used in this report.

3-D Seismic. (Three-Dimensional Seismic Data) Geophysical data that depicts the subsurface strata in three dimensions. 3-D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than two-dimensional seismic data.

Analogous reservoir. Analogous reservoirs, as used in resource assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, analogous reservoir refers to a reservoir that shares all of the following characteristics with the reservoir of interest: (i) the same geological formation (but not necessarily in pressure communication with the reservoir of interest; (ii) the same environment of deposition; (iii) similar geologic structure; and (iv) the same drive mechanism.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, of oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of natural gas.

Boe. One barrel of oil equivalent determined using the ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids.

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Condensate. We define condensate as oil with an API gravity higher than 55 degrees.

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

Deterministic estimate. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering or economic data) in the reserves calculation is used in the reserves estimation procedure.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Developed oil, NGL and natural gas reserves. Developed oil, NGL and natural gas reserves are reserves of any category that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the related equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Development project. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

Table of Contents

Index to Financial Statements

Development well. A well drilled within the proved boundaries of an oil or natural gas reservoir with the intention of completing the 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 exceeds production expenses and taxes.

Dry hole costs. Costs incurred in drilling a well, assuming a well is not successful, including plugging and abandonment costs.

Economically producible. The term economically producible, as it relates to a resource, means a resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and natural gas producing activities.

Estimated ultimate recovery. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

Exploitation. Optimizing oil, NGL and natural gas production from producing properties or establishing additional reserves in producing areas through additional drilling or the application of new technology.

Exploratory well. A well drilled to find and produce oil, NGL or natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil, NGLs or natural gas in another reservoir or to extend a known reservoir.

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

Finding and development costs. Capital costs incurred in the acquisition, exploration, development and revisions of proved oil, NGL and natural gas reserves divided by proved reserve additions.

Fracking or fracture stimulation technology. The technique of improving a well's production or injection rates by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand, ceramics or other material may also be injected into the formation to keep the channel open, so that fluids or natural gases may more easily flow through the formation.

Gas. Natural gas.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Horizontal drilling. A drilling operation in which a portion of the well is drilled horizontally within a productive or potentially productive formation. This operation usually yields a well that has the ability to produce higher volumes than a vertical well drilled in the same formation.

Hydraulic Fracturing. See Fracking or fracture stimulation technology above.

Infill well. A well drilled between known producing wells to better exploit the reservoir.

Injection well or injection. A well which is used to place liquids or natural gases into the producing zone during secondary/tertiary recovery operations to assist in maintaining reservoir pressure and enhancing recoveries from the field.

Table of Contents

Index to Financial Statements

Lease operating expenses. The expenses of lifting oil, NGLs or natural gas from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs, workover, insurance and other expenses incidental to production, but excluding lease acquisition or drilling or completion expenses.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

MBoe. One thousand barrels of crude oil equivalent, determined using the ratio of six Mcf of natural gas to one barrel of oil, condensate or NGLs.

Mcf. One thousand cubic feet of natural gas.

MMBbls. One million barrels of oil or other liquid hydrocarbons.

MMSBoe. One million barrels of crude oil equivalent, determined using the ratio of six Mcf of natural gas to one barrel of oil, condensate or NGLs.

MMBtu. One million British Thermal Units.

MMcf. One million cubic feet of natural gas.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or wells, as the case may be.

NGL. Natural gas liquid. Hydrocarbons which can be extracted from wet natural gas and become liquid under various combinations of increasing pressure and lower temperature. NGLs consist primarily of ethane, propane, butane and natural gasolines.

Nonoperated working interests. The working interest or fraction thereof in a lease or unit, the owner of which is without operating rights by reason of an operating agreement.

NYMEX. New York Mercantile Exchange.

Oil. Crude oil and condensate.

Operated working interests. Where the working interests for a property are co-owned, and where more than one party elects to participate in the development of a lease or unit, there is an operator designated for full control of all operations within the limits of the operating agreement for the development and production of the wells on the co-owned interests. The working interests of the operating party become the operated working interests.

PV-10 or present value of estimated future net revenues. An estimate of the present value of the estimated future net revenues from proved oil, NGL and natural gas reserves at a date indicated after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of federal income taxes. The estimated future net revenues are discounted at an annual rate of 10%, in accordance with the Securities and Exchange Commission's practice, to determine their present value. The present value is shown to indicate the effect of time on the value of the revenue stream and should not be construed as being the fair market value of the properties. Estimates of future net revenues are made using oil and natural gas prices and operating costs at the date

indicated and held constant for the life of the reserves.

Probabilistic estimate. The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

Table of Contents

Index to Financial Statements

Productive well. A well that is producing or is capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities.

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

Proved oil, NGL and natural gas reserves or Proved reserves. Proved oil, NGL and natural gas reserves are those quantities of oil, NGL and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulation 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 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 all of the following: (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, NGL and natural 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 as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil 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 twelve-month first day of the month historical average price during the twelve-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.

Proved undeveloped reserves. Proved undeveloped oil, NGL and natural gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive

formation. Estimates for proved undeveloped reserves will not be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Proved reserve additions. The sum of additions to proved reserves from extensions, discoveries, improved recovery, acquisitions and revisions of previous estimates.

Table of Contents

Index to Financial Statements

Reasonable certainty. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical and geochemical), engineering and economic data are made to estimated ultimate recovery with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease.

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.

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.

Reserves. Reserves are estimated remaining quantities of oil, NGLs and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil, NGLs and natural gas or related substances to market and all permits and financing required to implement the project.

Reserve additions. Changes in proved reserves due to revisions of previous estimates, extensions, discoveries, improved recovery and other additions and purchases of reserves in-place.

Reserve life index. This index is calculated by dividing year-end reserves by the average production during the past year to estimate the number of years of remaining production.

Reserve replacement cost. This metric provides an assessment of the cost of adding reserves that is ultimately included in depreciation, depletion and amortization expense. The metric is calculated by dividing capital costs incurred in the current year to add proved reserves (excluding other or corporate capital expenditures) by the sum of current year reserve extensions, discoveries and other additions, reserve revisions of previous estimates and reserve purchases in place.

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

Resources. Resources are quantities of oil, NGLs and natural gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable and another portion may be considered unrecoverable. Resources include both discovered and undiscovered accumulations.

Secondary recovery. An artificial method or process used to restore or increase production from a reservoir after the primary production by the natural producing mechanism and reservoir pressure has experienced partial depletion. Natural gas injection and waterflooding are examples of this technique.

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.

Trap. A configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not escape.

Unconventional resource. A term used in the oil and natural gas industry to refer to a play in which the targeted reservoirs generally fall into one of four categories: (1) tight sands, (2) coal beds, (3) gas shales, or

Table of Contents

Index to Financial Statements

(4) oil shales. These reservoirs tend to cover large areas and lack the readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require fracture stimulation treatments or other special recovery processes in order to produce economic flow rates.

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

Undeveloped oil, NGL and natural gas reserves or Undeveloped reserves. Undeveloped oil, NGL and natural gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

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

Workover. The repair or stimulation of an existing production well for the purpose of restoring, prolonging or enhancing the production of hydrocarbons.

/d. Per day when used with volumetric units or dollars.