Rosetta Resources Inc.
Form 10-K
February 24, 2015

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, 2014

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	The Nasdaq Stock Market LLC (Nasdaq Global Select Market)
(Title of Class)	(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 x 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 x

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of 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. x

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

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2014 was approximately $3.4 billion based on the closing price of $54.85 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 6, 2015 was 61,569,296, which excludes unvested restricted stock.

Documents Incorporated By Reference

Portions of the definitive proxy statement relating to the 2015 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.

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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," "foreca
"potential," "pursue," "target" or "continue," the negative of such terms or variations thereon, or other comparable terminology. Unless the context clearly indicates otherwise, references in this report to "Rosetta," "the Company," "we," "our," "us" or like terms refer to Rosetta Resources Inc. and its subsidiaries.

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 or deflation;
- 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;
- 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;

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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;
electronic, cyber or physical security breaches; 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.

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. 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, NGL and natural gas producing properties and drilling prospects from third parties and strategically divesting certain assets produced primarily from dry gas reservoirs. We operate in one geographic operating segment. See Item 8. "Financial Statements and Supplementary Data, Note 15 – Operating Segments."

As discussed in other parts of this report, the success of our business depends in large part on the price we receive for our oil, NGL and natural gas production and on the demand for oil, NGL and natural gas. During recent months, deteriorating commodity prices have brought significant and immediate changes affecting our industry and our company. The current economic environment and the recent decline in commodity prices is causing us (and other oil and gas companies) to significantly reduce overall current activity levels and spending, but our long term strategy remains intact.

Our Long-term 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. We recognize that there are industry cycles, such as the current commodity price downturn, that will impact our ability to fully execute this strategy in the near term. However, we believe our strategy is fundamentally sound, and we are currently focused on maintaining financial strength and flexibility; executing our business plan; leveraging our core asset base; and testing growth opportunities. Below is a discussion of the key elements of our strategy.

Maintain financial strength and flexibility. We operate nearly all of our estimated proved reserves, which allows us to more effectively manage expenses, control the timing of capital expenditures and provide flexibility to adjust our capital program to prudently manage our resources. We expect internally generated cash flows and cash on hand to provide financial flexibility to fund our operations. In addition, we may supplement our operating cash flow through borrowings under our Amended and Restated Senior Revolving Credit Facility (the "Credit Facility") and may consider accessing the capital markets. As of December 31, 2014, we had $200 million outstanding and $600 million available for borrowing under our Credit Facility. 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, 2014, we had entered into a series of financial commodity derivative contracts through 2016 as part of this strategy. These notional financial instruments, such as swaps and costless collars, have the effect of hedging our exposure to commodity price fluctuations. The notional volumes hedged equate to a substantial portion of our 2015 projected equivalent production and a portion of our 2016 projected equivalent production.

Successfully execute our business plan. We have increased our total production and diversified our production base to include a more balanced commodity mix. In addition, we manage all elements of our cost structure, including drilling and operating costs and general and administrative 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, we have taken aggressive steps to ensure access to transportation and processing facilities in our operating areas where infrastructure and midstream services are in high demand. See Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations for further discussion of our firm oil and natural gas transportation and processing commitments. In the current commodity price environment, we are intensifying our focus on managing our cost structure to improve cash margins.

Leverage core asset base. Our inventory of investment opportunities in the Eagle Ford area, which is a major source of our production and reserves, provides projects with higher economic returns. With the addition of our Permian Basin assets, we have increased our portfolio of long-lived, oil-rich horizontal resource projects that will further drive our long-term growth and sustainability. We recognize that the value of our project inventory is sensitive to commodity prices. In the current price environment, we are reducing capital spending to a level that delivers our targets while preserving the value of our inventory for a commodity price recovery.

Test future growth opportunities. Our strategy involves the disciplined delineation of our Delaware Basin potential and the testing of optimal Permian horizontal well spacing. In South Texas, we identify opportunities to expand recoveries from our current Eagle Ford assets. When commodity prices recover, we plan to test drilling both upper and lower Eagle Ford wells in a staggered pattern pilot program that will access new resource if successful. 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 prudently manage our operational footprint in the Eagle Ford and Permian areas. Over the long term, as industry market conditions dictate, we may evaluate new areas within the United States characterized by a significant presence of resource potential that can be exploited utilizing our technological expertise.

Our Operating Area and Other Plays

We own producing and non-producing oil, NGL 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, 2014, we owned approximately 64,000 net acres in South Texas and 57,000 net acres in West Texas. Our production in South Texas comes primarily from the Eagle Ford area, which averaged 59.3 MBoe per day in 2014, an increase of 25 percent from the prior year. Since initiating operations in the Permian Basin in 2013, our production in this area has increased to 7.9 MBoe per day in the fourth quarter of 2014, more than double from the fourth quarter of 2013, and full year 2014 production averaged 6.3 MBoe per day, compared to full year 2013 production of 1.8 MBoe per day.

The Eagle Ford area is 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 2014 activities were focused on four areas of the Eagle Ford, including the Gates Ranch, Central Dimmit County, northern LaSalle County and Briscoe Ranch areas. We drilled 94 gross wells and completed 95 gross wells in the Eagle Ford area in 2014. For 2014, the Eagle Ford area provided approximately 90 percent of our total production. In addition, approximately 62 percent of our production mix from the Eagle Ford area in 2014 was attributable to crude oil, condensate and NGLs, which is consistent with our 2013 production mix from this area.

As part of our long-term strategy to pursue new growth opportunities, we acquired producing and undeveloped oil, NGL and natural gas interests in the Permian Basin in Reeves and Gaines Counties, Texas in both 2014 and 2013 (the “2014 Permian Acquisition” and “2013 Permian Acquisition”). Our operations in the Permian Basin are primarily focused in Reeves County in the southern Delaware Basin where we have added project inventory in multiple benches in the Wolfcamp and 3rd Bone Spring. Currently, we hold 47,000 net acres in the Delaware Basin and approximately 10,000 net acres in the Midland Basin. We drilled 46 gross operated wells and completed 36 gross operated wells in the Permian area in 2014. For 2014, production from the Permian area provided approximately 10 percent of our total production. In addition, approximately 88 percent of our production mix from the Permian area in 2014 was attributable to crude oil and NGLs, as compared to 86 percent in 2013.

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 five 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 balanced 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. Under current market conditions, we may postpone making capital investments in certain assets, such as our Gaines and Encinal properties where we hold approximately 10,000 and 13,000 net acres, respectively. The lack of investment in these comparatively lower-return properties would result in the expiration of these leases over time.

Acquisition and Divestiture Activities

In 2014, we purchased additional Delaware Basin assets for total cash consideration of $83.8 million. These assets included 13 gross producing wells, of which 11 are operated by us.

In 2013, we purchased producing and undeveloped oil, NGL and natural gas interests in the Permian Basin in Gaines and Reeves Counties, Texas for total cash consideration of $825.2 million. We also acquired the remaining 10% working interest in certain producing wells for a portion of our leases in the Gates Ranch area for $128.1 million.

As part of our strategic decision to focus on the Eagle Ford area and 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, prior to customary purchase price adjustments. These divestitures were 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, 2014			
	Oil (MBbls) (1)	NGLs (MBbls)	Natural Gas (MMcf)	Equivalents (MBoe) (2)
Eagle Ford	5,237	8,111	49,883	21,662
Permian	1,709	296	1,708	2,290
Other	9	1	25	14
Total	6,955	8,408	51,616	23,966

	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)
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

(1) Includes crude oil and condensate. For the years ended December 31, 2014, 2013, and 2012 approximately 50%, 52% and 68%, 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, NGLs 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, 2014, we had an estimated 282 MMBoe of proved reserves, of which 49% was proved developed. Based on the twelve-month first-day-of-the-month historical average prices for 2014, as adjusted for basis and quality differentials, for West Texas Intermediate oil of $91.48 per Bbl and Henry Hub natural gas of $4.35 per MMBtu, our reserves had an estimated standardized measure of discounted future net cash flows of $2.6 billion as of December 31, 2014.

The following table sets forth, by operating area, a summary of our estimated net proved reserve information as of December 31, 2014:

	Estimated Proved Reserves at December 31, 2014 (1)(2)									
	Developed				Undeveloped					Percent of
	Oil (MMBbls)(3)	NGLs (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	Oil (MMBbls)(3)	NGLs (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	Total (MMBoe)	Total Reserves
Eagle Ford	25.7	51.1	325.3	131.0	19.8	48.7	304.2	119.2	250.2	89 %
Permian	5.3	1.1	6.0	7.4	17.1	3.7	19.3	24.0	31.4	11 %
Other	—	—	0.3	0.1	—	—	—	—	0.1	0 %
Total	31.0	52.2	331.6	138.5	36.9	52.4	323.5	143.2	281.7	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, 2014, approximately 58% of our proved oil reserves consisted of condensate.

In 2014, we added 24.3 MMBoe of net proved reserves through extensions, discoveries and additions. We added 19.5 MMBoe in the Eagle Ford primarily through our development of 64 gross wells in the Gates Ranch area and 40 gross wells in other Eagle Ford fields. In the Permian Basin, we added 4.8 MMBoe primarily through our development of 50 gross wells. Our 2014 Permian Acquisition also contributed 1.6 MMBoe from 13 gross producing wells.

We spent approximately $403.4 million in 2014 to convert 60.6 MMBoe of proved undeveloped reserves to proved developed reserves. Under our current development schedule, all of our proved undeveloped reserves at December 31, 2014 are scheduled for development within five years from the date first recorded as a proved undeveloped reserve.

Technology Used to Establish Proved Reserves

We employ technologies that have been demonstrated to provide consistent results capable of repetition. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps, seismic data, production data and well testing 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 the use of 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.

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 quarterly review of internal reserve estimates by senior management and an annual review by 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 37 years of experience in the petroleum industry spent almost entirely in the evaluation of reserves and income attributable to oil, NGL 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 reserve 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 41 years of practical experience in petroleum engineering, with over 38 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 29 years of practical experience in petroleum geosciences, with over 16 years of experience in the estimation and evaluation of reserves. He graduated from the University of Wyoming in 1982 with a 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.

Capital Expenditures

The following table summarizes information regarding our development and exploration capital expenditures for the years ended December 31, 2014, 2013, and 2012:

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
Drilling, completions and facilities	$1,149,246	$834,492	$613,343
Leasehold	18,436	10,268	18,753
Acquisitions	83,850	952,642	—
Delay rentals	22	294	1,089
Geological and geophysical/seismic	2,328	3,521	1,269
Exploration overhead	7,259	7,155	6,041
Capitalized interest	32,272	28,298	3,757
Other corporate	9,461	15,464	8,731
Total capital expenditures	$1,302,874	$1,852,134	$652,983

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, 2014. "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 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	37,338	35,773	27,840	26,886	45	267	31	191
Permian	71,738	40,474	23,218	16,890	178	—	100	—
Other (1)	118,544	101,259	12,628	6,692	2	23	1	18
Total	227,620	177,506	63,686	50,468	225	290	132	209

(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.

(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, 2014 that is subject to expiration in 2015, 2016, 2017 and thereafter, to the extent that we do not commence or continue drilling operations upon such acreage:

2015		2016		2017		Thereafter (1)	
Gross	Net	Gross	Net	Gross	Net	Gross	Net
43,965	30,636	63,037	45,403	58,548	54,618	62,070	46,849

(1) Includes acreage subject to continued drilling obligations

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
2014	8.0	—	8.0	149.0	-	149.0
2013	1.0	—	1.0	163.0	1.0	164.0
2012	6.0	—	6.0	91.0	—	91.0

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
2014	3.7	—	3.7	136.2	-	136.2
2013	0.5	—	0.5	150.1	1.0	151.1
2012	6.0	—	6.0	76.6	—	76.6

At December 31, 2014, we had 80 gross and 79 net wells that were in the process of being drilled or awaiting completion. Of these wells, 57 gross wells were located in the Eagle Ford area where we own a 100% working interest. In the Permian Basin, 23 gross wells were in the process of being drilled or awaiting completion as of December 31, 2014, and we own 95% 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 Light Louisiana Sweet and Midland 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, Tennessee Gas Pipeline Zone 0 and West Texas Waha indices, adjusted for transportation or market conditions.

Major Customers

In 2014, two customers, Shell Trading (US) Company and ETC Texas Pipeline Ltd., accounted for approximately 31% and 14%, respectively, of our consolidated revenue, excluding the effects of derivative instruments.

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.

No other customers accounted for more than 10% of our consolidated revenue, excluding the effects of derivative instruments, for the years ended December 31, 2014, 2013 and 2012. 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, NGL 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 fluctuates seasonally. 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, NGL 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 non-compliance and could result in the shut-down of operations, and we cannot guarantee that we will not incur fines, penalties or other sanctions. In addition, the enactment of new laws affecting the oil and natural gas industry is common and existing laws are often amended or reinterpreted. However, we do not expect that any of these laws would have a material effect on our operations or financial results. 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 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 response to findings that emissions of greenhouse gases (“GHG”) present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the Clean Air Act, including regulations that establish Prevention of Significant Deterioration (“PSD”) pre-construction and Title V operating permit requirements for certain large stationary sources. This rule does not currently affect our operations but may do so in the future as our operations grow. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain onshore oil and natural gas facilities. These rules, which are currently in effect and to which some of our facilities are subject, required data reporting in 2014 for our facilities that emitted more than 25,000 tons of CO2e in 2013, with annual reporting thereafter.

Hydraulic Fracturing. We routinely use hydraulic fracturing techniques in our drilling and completion programs. The process involves the injection of water, sand and chemical additives under pressure into targeted subsurface formations to stimulate oil and gas production. The process is typically regulated by state oil and gas commissions or environmental agencies, but the EPA and other agencies have asserted regulatory authority over the process. For example, the EPA issued an Advanced Notice of Proposed Rulemaking that seeks public input on its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing; the EPA also announced its intent to propose regulations under the Clean Water Act (the “CWA”) to govern wastewater discharges from hydraulic fracturing operations. These or similar rules could require modifications to our operations or result in significant costs, including capital expenditures and operating costs, or production delays to ensure compliance. At the same time, a number of studies evaluating the environmental impacts of hydraulic fracturing have been initiated by the EPA and other federal agencies. These studies, depending on their results, could spur further federal initiatives to regulate hydraulic fracturing.

Furthermore, a number of states, local governments and regulatory commissions, including Texas, 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. 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, 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.

Hazardous Substances and Waste Handling. The Comprehensive Environmental Response, Compensation and Liability Act (“CERCLA”) and analogous state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and persons that transported or disposed or arranged for the transport or disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

The Resource Conservation and Recovery Act ("RCRA") and analogous state laws regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Exploration and production wastes are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our operating expenses, which could have a material adverse effect on our results of operations or financial position. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

Water Discharges. The CWA and analogous state laws and regulations impose restrictions and controls on the discharge of pollutants, including produced waters and other oil and gas wastes, into regulated waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or state. Spill prevent, control and countermeasure plan requirements require appropriate containment berms and similar structures to help prevent the contamination of certain waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges.

The Oil Pollution Act ("OPA") is the primary federal law for oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of certain onshore facilities near or crossing waterways must develop and maintain facility response contingency plans and maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters.

Noncompliance with the CWA or the OPA may result in substantial administrative, civil and criminal penalties, as well as injunctive obligations.

We own or lease, and have in the past owned or leased, onshore properties that for many years have been used for or associated with the exploration and production of natural gas and oil. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us on or under other locations where such wastes have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of wastes was not under our control. These properties and the wastes disposed on them may be subject to CERCLA, CWA, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators), or to perform remedial plugging or closure operations to prevent future contamination.

Endangered and Threatened Species. The federal Endangered Species Act (“ESA”) was established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species’ habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We may conduct operations on oil and natural gas leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species that potentially could be listed as threatened or endangered may exist. The U.S. Fish and Wildlife Service (“FWS”) may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions and may materially delay or prohibit land access for oil and natural gas development. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the FWS is required to make a determination on the listing of more than 250 species as endangered or threatened under the ESA by the end of the agency’s 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could have a material adverse impact on the value of our leases.

Employee Health and Safety. The Occupational Safety and Health Act (“OSHA”) and comparable state statutes regulate the protection of the health and safety of workers. The OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations and provision of such information to employees. Other OSHA standards regulate specific worker safety aspects of our operations. Failure to comply with OSHA requirements can lead to the imposition of penalties.

Derivative Legislation

The Dodd-Frank Act was signed into law in 2010 and amended the Commodity Exchange Act. This law regulates derivative and commodity transactions, which include certain instruments used in our risk management activities. The Dodd-Frank Act requires the Commodities Futures Trading Commission (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, 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

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 levels we believe to be customary in the industry 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 2014, we filed gross estimates of our operated oil, NGL and natural gas reserves as of December 31, 2013 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, 2013. For information concerning proved reserves, refer to Item 8. “Financial Statements and Supplementary Data – Supplemental Oil and Gas Disclosures.”

Employees

As of February 6, 2015, we had 318 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 Exchange Act, 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.

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. In particular, declines in or depressed 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;
- result in a decrease in the borrowing base under our Credit Facility due to a reduction in reserves or otherwise limit our ability to borrow money or raise additional capital; and
- negatively impact our ability to comply with the financial covenants under our Credit Facility, potentially resulting in a default under that indebtedness.

Further, oil, NGL and natural gas prices do not necessarily fluctuate in direct relation to each other, and prices 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.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil, NGL and natural gas price movements with any certainty. A further or extended decline in commodity prices will likely materially and adversely affect our future business, financial condition and results of operations.

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, and volatility in the prices of securities 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 in recent years.

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.

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. Our borrowing base is dependent on a number of factors, including our level of reserves, which may be adversely impacted by depressed or declining commodity prices. 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 investment. The loss of leases could have a material adverse effect on our cash flows and 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, NGL 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 5.625% Senior Notes due 2021, 5.875% Senior Notes due 2022 and 5.875% Senior Notes due 2024 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 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, such as the recent decline in commodity 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;
- disputes regarding leases;
- disputes with mineral interest, surface or royalty owners and access constraints or limitations on surface use on or near our operating areas;
- 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.

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, 2014 were based on the trailing twelve-month first-day-of-the-month historical unweighted averages of West Texas Intermediate oil prices of $91.48 per Bbl, adjusted for basis and quality differentials, and Henry Hub natural gas prices of $4.35 per MMBtu, adjusted for basis and quality differentials. 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, NGL 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, NGL 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, NGL and natural gas properties that can be capitalized on our balance sheet. If the net capitalized costs of our oil, NGL 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, NGL and natural gas properties increases when oil and natural gas prices are depressed or volatile. In addition, a write-down of proved oil, NGL 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.

We did not record any write-downs or impairments for the years ended December 31, 2014, 2013 or 2012. Given the recent decline in commodity prices, should oil and natural gas prices remain depressed or further decline, it is likely that write-downs will 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 difference between condensate and crude oil prices could negatively impact our revenue and the value of our reserves.

A significant portion of our oil production (approximately 50% in 2014) and our proved oil reserves (approximately 58% as of December 31, 2014) is condensate. Condensate is common in our Eagle Ford assets and is priced unfavorably versus crude oil as a result of its higher API gravity. A significant widening of this differential 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 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, 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, including the current decline in oil, NGL and natural gas prices, or transportation impediments may hinder our access to oil, NGL and natural gas markets, delay our production and expose us to additional deficiency payments under our long-term transportation and processing agreements.

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, 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. In addition, if the prices of oil, NGLs and natural gas decline further, the amount of oil, NGLs and natural gas that we can produce economically may decline. As a result, we may be unable to satisfy our commitments under our long-term transportation and processing agreements, which may expose us to additional volume deficiency payments.

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 commodity price volatility, depressed commodity prices and 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 two geographic areas, with the majority of operations in the Eagle Ford area, and increases our exposure to many of the risks enumerated herein, including a lack of diversification with respect to mineral interest, surface and/or royalty owners.

Currently, the majority of our assets and operations are in the Eagle Ford area, which provided approximately 85% of our total revenue for 2014, excluding the impact of derivative instruments, and it represents approximately 89% of our estimated total proved reserves as of December 31, 2014. 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.

In addition, because our operations are highly concentrated geographically, we contract with a limited number of mineral interest, surface and/or royalty owners. From time to time, disagreements with such interest owners may arise with respect to interpretations of agreements relating to our and their rights. Failure to satisfy our obligations under these agreements may adversely affect our rights under such agreements. To the extent these agreements relate to material properties, the loss of rights under such agreements could materially and adversely affect us.

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 increase, 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 or Permian areas, we could be materially and adversely affected because our operations and properties are concentrated in these areas.

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.

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 completion 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 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. Hydraulic fracturing involves pumping a mixture of water, sand and chemicals at high pressure into underground shale formations through steel pipe that is perforated at the location of the hydrocarbons. The high pressure creates small fractures that allow the oil, NGLs 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 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 2015.

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 amended the rule to extend compliance dates for certain storage vessels, and it may issue additional revised rules in response to additional requests in the future.

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.

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.

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.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component for deep shale oil, NGL and natural gas development during both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners for use in our operations. According to the Lower Colorado River Authority, from 2011 to 2013, Texas experienced some of the lowest inflows of water in recorded history. As a result of this severe drought, some local water districts have begun restricting the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supply. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce our reserves, which could have an adverse effect on our financial condition, results of operations and cash flows.

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, including oil and natural gas production facilities, and has adopted regulations imposing permitting requirements on certain large stationary sources. The EPA also is considering additional regulation of greenhouse gases, including regulations targeting methane emissions from the oil and natural gas sector. Passage of climate change legislation or additional regulatory initiatives by federal and state governments that regulate or restrict emissions of greenhouse gases (including methane or carbon dioxide) could have an adverse effect on our operations and the demand for oil, NGLs and natural gas.

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.

Although we have entered into hedges equating to a substantial portion of our 2015 projected equivalent production and a portion of our 2016 projected equivalent production, we may still be adversely affected by continuing and prolonged declines in the price of oil, NGLs and natural gas.

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 and costless collars. Consistent with this policy, as of December 31, 2014, we have entered into a series of oil, NGL and natural gas fixed price swaps and costless collars for each year through 2016. However, to the extent that the price of oil remains at current levels or declines further, volumes of production that exceed the notional hedge volumes will be exposed to price volatility, and we may not be able to enter into additional hedges at the same level as our current hedges, either of which may materially and adversely affect our future business, financial condition and results of operations.

The implementation 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.

The Dodd-Frank Act is 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.

In its rulemaking under the Dodd-Frank Act, the CFTC is finalizing its regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents, although certain bona fide hedging transactions would be exempt from these position limits provided that various conditions are satisfied. Once finalized, the position limits rule and its companion rule on aggregation may have an impact on our ability to hedge our exposure to certain enumerated commodities.

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. The CFTC has implemented final rules regarding mandatory clearing of certain interest rate swaps and index credit default swaps. Mandatory trading on designated contract markets or swap execution facilities of certain interest rate swaps and index credit default swaps also began in February 2014. The CFTC has not yet proposed any rules requiring the clearing of any other classes of swaps, including physical commodity swaps. As the CFTC further designates swap contracts as required to be cleared and traded on a trading facility, the utility of the end-user exception will become even more important. Our ability to rely on the end-user exception may change the profitability of our trades or the efficiency of our hedging.

Rules promulgated under the Dodd-Frank Act further defined forward contracts as well as instances where forwards may become swaps. Because the CFTC is still in the process of interpreting its regulations, it is possible that some of the derivative and commodity contracts used in our business may be treated differently in the future. For example, the CFTC may further revise its definitions for spots, forwards, forwards with volumetric optionality, trade options, full requirements contracts and certain other contracts that may combine the elements of physical commodity trades and cash settlement, netting and book-outs. If these contracts were classified as swaps, the costs of entering into these contracts will likely increase.

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.

In addition to the Dodd-Frank Act, the European Union and other foreign regulators have adopted and are implementing local reforms generally comparable with the reforms under the Dodd-Frank Act. Implementation and enforcement of these regulatory provisions may reduce our ability to hedge our market risks with non-U.S. counterparties and may make our transactions involving cross-border swaps more expensive and burdensome. Additionally, the lack of regulatory equivalency across jurisdictions may increase compliance costs and make it more difficult to satisfy our regulatory obligations.

Finally, under the Dodd-Frank Act, the CFTC is also directed generally to prevent price manipulation and fraud in physical commodities markets traded in interstate commerce, including physical energy and other commodities, as well as financial instruments, such as futures, options and swaps. Pursuant to the Dodd-Frank Act, the CFTC has adopted additional anti-market manipulation, anti-fraud and disruptive trading practices regulations that prohibit, among other things, fraud and price manipulation in the physical commodities, futures, options and swaps markets. Accordingly, the CFTC and the self-regulatory organizations (“SROs”), such as commodity futures exchanges, are continuing to develop their respective enforcement authorities and compliance priorities under the Dodd-Frank Act. Given the novelty of the regulations under the Dodd-Frank Act, it is difficult to predict how these new enforcement priorities of the CFTC and the SROs will impact our business. Should we violate the Commodity Exchange Act, as amended, the regulations promulgated by the CFTC, and any rules adopted by the SROs thereunder, we could be subject to CFTC enforcement action and material penalties and 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 have significant exposure to our derivative counterparties where approximately 86% of our derivative fair value is derived from two counterparties as of December 31, 2014. Given current market conditions, 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 2016 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 relating to oil and natural gas production; 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, these or 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 postpone 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 business, financial condition, results of operations and cash flows.

Cyber-attacks targeting our computer and telecommunications systems and infrastructure used by the oil and gas industry may materially impact our business and operations.

Computers and telecommunication systems are used to conduct our exploration, development and production activities and have become an integral part of our business. We use these systems to analyze and store financial and operating data and to communicate within our company and with outside business partners. Cyber-attacks could compromise our computer and telecommunications systems and result in disruptions to our business operations, the loss or corruption of our data and proprietary information and communications interruptions. In addition, computers control oil and gas distribution systems globally and are necessary to deliver our production to market. A cyber-attack impacting these distribution systems, or the networks and infrastructure on which they rely, could damage critical production, distribution and/or storage assets, delay or prevent delivery to markets and make it difficult or impossible to accurately account for production and settle transactions. Our systems and procedures for protecting against such attacks and mitigating such risks may prove to be insufficient and such attacks could have an adverse impact on our business and operations.

Item 1B. Unresolved Staff Comments
None.

Item 3. Legal Proceedings
We are party to various legal and regulatory proceedings arising in the ordinary 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, management does not believe any such matters will have a material adverse effect on our financial position, results of operations or cash flows.

Item 4. Mine Safety Disclosures
Not applicable.

Part II

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

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:

2014			2013		
	High	Low		High	Low
January 1 - March 31	$49.61	$39.33	January 1 - March 31	$54.61	$44.50
April 1 - June 30	55.45	43.10	April 1 - June 30	50.10	40.83
July 1 - September 30	55.36	43.17	July 1 - September 30	55.15	42.04
October 1 - December 31	45.86	16.67	October 1 - December 31	65.30	45.26

The number of shareholders of record on February 6, 2015 was approximately 273. 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, 2014:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May yet Be Purchased Under the Plans or Programs
October 1 - October 31	757	$ 44.51	—	—
November 1 - November 30	826	36.09	—	—
December 1 - December 31	1,725	24.83	—	—
Total	3,308	$ 32.15	—	—

(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.

Securities Authorized for Issuance under Equity Compensation Plans

See “Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters” for information regarding shares of common stock authorized for issuance under our long-term incentive plans.

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 Exchange Act, except to the extent that the Company specifically incorporates it by reference into such filing.

The following common stock performance graph shows the performance of our common stock through December 31, 2014. 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 $19.92 per share on December 31, 2009, 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, 2009; 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

	12/31/2009	12/31/2010	12/31/2011	12/31/2012	12/31/2013	12/31/2014
ROSE	$ 100.00	$ 188.96	$ 218.37	$ 227.51	$ 241.16	$ 112.00
S&P 500	100.00	115.06	117.48	136.27	180.39	205.07
S&P 400 E&P	100.00	143.21	117.50	102.57	151.01	97.67

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,				
	2014	2013	2012	2011	2010
	(In thousands, except per share data)				
Operating Data:					
Total revenues	$1,304,679	$814,018	$613,499	$446,200	$308,430
Net income	313,562	199,352	159,295	100,546	19,046
Net Income per share:					
Basic	$5.10	$3.40	$3.03	$1.93	$0.37
Diluted	5.09	3.39	3.01	1.91	0.37
Cash dividends declared and paid per common share:	$—	$—	$—	$—	$—
Balance Sheet Data (At the end of the period):					
Total assets	$4,250,667	$3,276,618	$1,415,416	$1,065,345	$989,440
Long-term debt	2,000,000	1,500,000	410,000	230,000	350,000
Total other long-term liabilities	230,784	154,157	17,570	14,949	28,275
Stockholders' equity	1,669,113	1,348,334	803,999	632,836	528,816

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, 2014, compared to the year ended December 31, 2013 and material changes in our financial condition since December 31, 2013.

Results for the year ended December 31, 2014 include the following:

- production of 65.7 MBoe per day compared to 49.6 MBoe per day for the year ended December 31, 2013;
- 140 gross (138 net) operated wells drilled compared to 150 gross (149 net) operated wells drilled for the year ended December 31, 2013; and
- net income of $314 million, or $5.09 per diluted share, compared to $199 million, or $3.39 per diluted share, for the year ended December 31, 2013.

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.

Rosetta is a significant producer in the liquids-rich window of the Eagle Ford region, and we have established an inventory of high-return drilling opportunities that offer predictable and long-term production, reserve growth and a more balanced commodity mix. Our Permian Basin assets and bolt-on activity further expand our portfolio of long-lived, oil-rich resource projects that will drive our long-term growth and sustainability. During the first quarter of

2014, we acquired additional Delaware Basin assets from several private parties for total cash consideration of $83.8 million. The acquisition covered 5,034 net acres located in Reeves County. The acquired assets included 13 gross producing wells (11 operated) and added future horizontal drilling locations to expand our capital project inventory. We continually monitor market conditions in our cyclical industry and adjust our investment decisions accordingly. Over the long-term, we may consider investments in the Eagle Ford shale region and in the Permian Basin that offer a viable inventory of projects, including resource-based exploration projects and producing property acquisitions in early development stages.

Our development operations in the Eagle Ford shale are focused in several 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 Briscoe Ranch lease in Dimmit County, and we have three leases located in the Central Dimmit County area and the Tom Hanks lease in northern LaSalle County, where our positions were delineated in 2011, 2012 and 2013, respectively. In addition, we evaluated several operated pilot wells testing the Upper Eagle Ford before announcing plans for staggered Upper and Lower Eagle Ford development in Briscoe Ranch, northern Gates Ranch and Lasseter and Eppright leases. Overall, we hold 63,000 net acres in the region with approximately 50,000 acres located in the liquids-producing portions of the play. Our delineation operations in the Permian are focused in Reeves County in the Delaware Basin where we are testing benches in the Wolfcamp and 3rd Bone Spring. Currently, we hold 47,000 net acres in the Delaware Basin and approximately 10,000 net exploratory acres in the Midland Basin. The current operating environment for the oil and gas industry is challenging as commodity prices remain depressed. In November 2014, we announced our decision to forgo further capital investments in our Eagle Ford dry gas assets, which represent a small percentage of our current inventory of well locations.

The ongoing development of our assets in South Texas, which averaged approximately 59.4 MBoe per day in 2014, an increase of 24 percent from 2013, has contributed to record liquids volumes for the Company. Production from the Permian averaged approximately 6.3 MBoe per day in 2014, an increase of 242 percent from 2013, reflecting our successful delineation activity and higher crude oil mix. For 2014, our commodity mix was 29 percent crude oil, 35 percent NGLs and 36 percent natural gas. The Eagle Ford area accounted for approximately 90 percent of our total production for 2014. In addition, crude oil and NGLs represented approximately 62 percent of our production from the Eagle Ford area and 88 percent of our production from the Permian.

At December 31, 2014, our total estimated proved reserves were 282 MMBoe compared to 279 MMBoe at the prior year end. Of our total reserves, approximately 61 percent were liquids and 49 percent were classified as proved developed. We replaced 113 percent of production from all sources, including net reserve additions from drilling activities, performance and price revisions, and acquisitions.

We drilled 140 gross operated wells and completed 131 gross operated wells during 2014. Of these totals, 94 wells were drilled and 95 completed in the Eagle Ford area. In the Delaware Basin, we drilled 46 gross operated wells, including 31 horizontal and 15 vertical wells. A total of 36 gross operated wells were successfully completed, 17 of which were horizontal wells. As of December 31, 2014, we had completed a total of 300 gross wells in the Eagle Ford shale since entering the play in 2009. Since initiating our Permian operations in August 2013, we have completed 19 horizontal wells.

During 2014, total annual daily equivalent production reached a record 65.7 MBoe per day, an increase of 32 percent from 2013. For the same period, total daily crude oil production was 19 MBbls per day, an increase of 39 percent from the same period in 2013. To handle our increased production, we have multiple options for transportation and processing capacity with firm commitments and other arrangements in place to meet total planned production levels through 2016.

We enter 2015 in an uncertain and challenging commodity price environment. Reflective of our plans to maintain financial discipline and operate within cash flow, our 2015-2016 capital program contemplates expenditures of up to $350 million per year. Approximately 47 percent of our 2015 capital program will be spent on higher return development activities in the Eagle Ford shale in South Texas, including central facilities. In addition, approximately 41 percent of the 2015 capital program will be spent on activities to hold and delineate our leases in the Delaware Basin in West Texas. We expect to allocate the remaining 12 percent for other capital items, including capitalized interest and corporate capital.

While our unconventional resource strategy has proven to be successful, we recognize 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 may impede achievement of our stated growth objectives and the building of our asset base. We have a diversified production base which includes a balanced mix of crude oil, NGLs and natural gas. Because our production is highly concentrated geographically, we have taken various steps to provide access to necessary services and infrastructure. We believe our 2015 capital program can be executed from internally generated cash flows, borrowings under our Credit Facility, access to capital markets and cash on hand. We continuously monitor our liquidity to respond to changing market conditions, commodity prices and service costs.

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, 2014, our borrowing base and committed amounts under the Credit Facility were $950 million and $800 million, respectively. As of February 6, 2015, we had $200 million of borrowings outstanding with $600 million available for borrowing under the Credit Facility. To improve flexibility in the current depressed commodity price environment, we recently amended our Credit Facility as discussed in greater detail elsewhere in this Form 10-K. The amendment, among other things, modified our financial covenant requirements by replacing our debt to EBITDA leverage ratio with two additional covenants, a senior secured leverage ratio, where secured debt to EBITDA cannot be greater than 2.5 to 1.0, and an interest coverage ratio, where EBITDA to gross interest expense cannot be less than 2.5 to 1.0.

On May 5, 2014, we redeemed our 9.500% Senior Notes with borrowings under the Credit Facility for a total payment of $210.6 million, which includes the principal amount, a call premium and accrued and unpaid interest. On May 29, 2014, we completed our public offering of $500.0 million in aggregate principal amount of 5.875% Senior Notes due 2024. Interest is payable on the 5.875% Senior Notes due 2024 semi-annually on June 1 and December 1.

Financial Highlights

Our consolidated financial statements reflect total revenue of $1.3 billion, including derivative gains of $293.8 million, based on total volumes of 24.0 MMBoe for 2014.

Significant transactions which affect the comparability of our financial results between periods include the acquisition of Permian Basin assets in 2014, the acquisitions of Permian Basin assets and Gates Ranch leasehold in 2013 and the divestiture of our Lobo assets and a portion of our Olmos assets in 2012.

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,		
	2014	2013	2012
	(In thousands, except per unit amounts)		
Revenues:			
Oil sales	$574,552	$475,119	$318,782
NGL sales	222,682	198,966	160,461
Natural gas sales	213,609	147,028	93,711
Derivative instruments	293,836	(7,095)	40,545
Total revenues	$1,304,679	$814,018	$613,499
Production:			
Oil (MBbls)	6,955	4,999	3,497
NGLs (MBbls)	8,408	6,398	4,472
Natural gas (MMcf)	51,616	40,343	33,853
Total equivalents (MBoe)	23,966	18,121	13,611
Average daily production:			
Oil (MBbls/d)	19.1	13.7	9.6
NGLs (MBbls/d)	23.0	17.5	12.2
Natural gas (MMcf/d)	141.4	110.5	92.5
Total equivalents (MBoe/d)	65.7	49.6	37.2
Average sales price:			
Oil, excluding derivatives (per Bbl)	$82.61	$95.04	$91.16
Oil, including realized derivatives (per Bbl)	83.10	93.74	89.66
NGL, excluding derivatives (per Bbl)	26.48	31.10	35.88
NGL, including realized derivatives (per Bbl)	27.78	32.83	37.84
Natural gas, excluding derivatives (per Mcf)	4.14	3.64	2.77
Natural gas, including realized derivatives (per Mcf)	4.09	3.76	3.28

Revenue, excluding derivatives (per Boe)	42.18	45.31	42.09
Revenue, including realized derivatives (per Boe)	42.66	45.82	43.63

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 2014, 2013 and 2012 was $1.0 billion, $821.1 million and $573.0 million, respectively, and year-over-year growth in 2014 and 2013 was primarily attributable to increased overall production in addition to higher realized natural gas prices in 2014 and higher realized oil and natural gas prices in 2013. Excluding the effects of derivative instruments, revenue attributable to oil and NGL sales in 2014, 2013 and 2012 was approximately 79%, 82% and 84%, respectively, of total revenue.

Oil sales. Oil sales, excluding derivative instruments, of $574.5 million, $475.1 million and $318.8 million for 2014, 2013 and 2012, respectively, increased year-over-year due to higher oil production, partially offset by lower realized prices in 2014 and 2012. The increase in oil production in 2014 was primarily attributable to our Permian assets, whose total oil production in 2014 and 2013 was 4.7 MBbls per day and 1.4 MBbls per day, respectively. The increase in oil production in 2013 was primarily attributable to our acquired Permian assets as well as higher production at our Gates Ranch, Klotzman and Reilly wells in the Eagle Ford area.

Realized oil derivative gains of $3.4 million and losses of $6.5 million and $5.2 million for 2014, 2013 and 2012, respectively, are reported as a component of Derivative instruments within Revenues.

NGL sales. NGL sales, excluding derivative instruments, of $222.7 million, $199.0 million and $160.5 million for 2014, 2013 and 2012, respectively, increased year-over-year due to higher NGL production, partially offset by lower realized prices. The increase in both periods was primarily attributable to increased NGL production from our Gates Ranch wells in the Eagle Ford area, whose total NGL production in 2014, 2013 and 2012 was 18.1 MBbls per day, 14.7 MBbls per day and 10.7 MBbls per day, respectively.

Realized NGL derivative gains of $10.9 million, $11.1 million and $8.7 million for 2014, 2013 and 2012, respectively, are reported as a component of Derivative instruments within Revenues.

Natural gas sales. Natural gas sales, excluding derivative instruments, of $213.6 million, $147.0 million and $93.7 million for 2014, 2013 and 2012, respectively, increased year-over-year due to higher natural gas production and higher realized prices. The increase in natural gas production in 2014 and 2013 was primarily attributable to our Gates Ranch wells in the Eagle Ford area, whose total natural gas production in 2014, 2013 and 2012 was 108.5 MMcf per day, 93.5 MMcf per day and 77.8 MMcf per day, respectively.

Realized natural gas derivative losses of $2.7 million and gains of $4.7 million and $17.4 million for 2014, 2013 and 2012, respectively, are reported as a component of Derivative instruments within Revenues.

Derivative Instruments. In 2014, Derivative instruments included (i) a realized derivative gain of $11.6 million from cash settlements and (ii) an unrealized derivative gain of $282.2 million due to changes in fair value of our commodity derivative contracts.

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

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

Operating Expenses

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

	Year Ended December 31,		
	2014	2013	2012
	(In thousands, except per unit amounts)		
Direct lease operating expense	$69,571	$45,155	$32,874
Insurance expense	1,159	1,015	985
Workover expense	22,472	7,166	1,279
Lease operating expense (Production costs)	$93,202	$53,336	$35,138
Treating and transportation	88,501	71,338	51,826
Taxes, other than income	45,956	31,075	24,013
Depreciation, depletion and amortization (DD&A)	415,823	218,571	154,223
Reserve for commercial disputes	5,800	20,450	—
General and administrative costs	79,297	73,043	68,731
Costs and expenses (per Boe of production)			
Lease operating expense (Production costs)	$3.89	$2.94	$2.58
Treating and transportation	3.69	3.94	3.81
Taxes, other than income	1.92	1.71	1.76
Depreciation, depletion and amortization (DD&A)	17.35	12.06	11.33
General and administrative costs	3.31	4.03	5.05
General and administrative costs, excluding stock-based compensation	2.94	3.42	3.69

Lease Operating Expense. Lease operating expense increased as a result of year-over-year production growth as well as higher unit costs. Higher unit costs were due to increased workover activity in the Eagle Ford area and a larger percentage of our production mix coming from our Permian assets, which have higher unit operating costs.

Treating and Transportation. Treating and transportation expense increased year-over-year as a result of increased daily production of 25% and 33% in 2014 and 2013, respectively, in the Eagle Ford area. In addition, we accrued deficiency fees of $9.7 million, $7.8 million and $5.2 million in 2014, 2013 and 2012, respectively, related to shortfalls in delivering the minimum volumes required under our transportation and processing agreements.

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 2014 was primarily due to a $14.5 million increase in production taxes resulting from a 32% increase in production as well as a $0.3 million increase in ad valorem taxes. The 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.

Depreciation, Depletion, and Amortization. DD&A expense increased year-over-year in 2014 and 2013 due to an increase in daily production and an increase in DD&A rate due to the inclusion of higher-cost Permian reserves in our depletion pool.

Reserve for commercial disputes. In 2014 and 2013, we recorded reserves of $5.8 million and $20.5 million, respectively, related to commercial disputes concerning the calculation of royalty amounts earned and royalty deductions taken over specified periods in 2009 through 2013. The dispute for which we recorded a $5.8 million reserve arose in the third quarter of 2014, and we are in ongoing discussions with those royalty holders regarding their royalty claim. Our recorded reserve represents our best estimate of the probable loss exposure associated with this dispute, and the final resolution of this matter may differ from the recorded reserve. The disputes for which we established a $20.5 million reserve in 2013 were resolved by the first quarter of 2014 through our payment of $20.5 million to certain royalty holders. See Part II. Item 8. "Financial Statements and Supplementary Data, Note 11 – Commitments and Contingencies."

General and Administrative Costs. The increase in 2014 was primarily due to an $11.3 million increase in personnel costs due to higher headcount in addition to a $0.7 million increase in other administrative costs, partially offset by a $2.2 million decrease in stock-based compensation expense driven by our performance share units, a $2.0 million decrease in rent expense related to our previous office lease and a $1.5 million decrease in consultant costs related to acquisition activities and various internal projects.

The increase in 2013 was primarily related to a $7.4 million increase in personnel costs 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.

Total Other Expense

Total other expense, which includes Interest expense, net of interest capitalized; Interest income; and Other expense (income), net, increased $51.4 million in 2014 from 2013 primarily due to the issuance of our 5.875% Senior Notes due 2024 in 2014, which resulted in higher interest expense partially offset by an increase in capitalized interest. The increase in 2014 from 2013 also reflects a $9.5 million call premium and the write-off of $3.1 million of remaining unamortized debt issuance costs associated with the redemption of our 9.500% Senior Notes in 2014.

Total other expense 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.

Provision for Income Taxes

Our 2014 income tax expense was $174.9 million. For the year ended December 31, 2014, our effective tax rate was 35.8% compared to an effective tax rate of 35.7% for the year ended December 31, 2013 and 37.6% for the year ended December 31, 2012. 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 non-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, 2014, we had a net deferred tax liability of $280.3 million, compared to a net deferred tax liability of $108.4 million at December 31, 2013.

In connection with our asset divestitures in 2012, 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, borrowings under our Credit Facility and our cash on hand.

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 our exposure to commodity price risk, 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, 2014, we had $200 million outstanding with $600 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 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 under the Credit Facility for the year ended December 31, 2014 was 1.98%, exclusive of 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 required 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 ("EBITDA"), 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, 2014, our current ratio was 2.2 and our leverage ratio was 2.8. 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, 2014. On February 18, 2015, we entered into the Ninth Amendment to our Credit Facility. The amendment, among other things, modified our financial covenant requirements by replacing our debt to EBITDA leverage ratio with two additional covenants, a senior secured leverage ratio, where secured debt to EBITDA cannot be greater than 2.5 to 1.0, and an interest coverage ratio, where EBITDA to gross interest expense cannot be less than 2.5 to 1.0. These ratios will be 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, beginning with the quarter ended March 31, 2015.

9.500% Senior Notes due 2018. In accordance with the provisions of the indenture governing our 9.500% Senior Notes, on May 5, 2014, we redeemed all of the outstanding notes in full at a price of 104.75% of the principal amount, plus accrued and unpaid interest. We paid an aggregate amount of $210.6 million for such redemption, consisting of a call premium of $9.5 million and $1.1 million of accrued and unpaid interest. The call premium of $9.5 million and remaining unamortized debt issuance costs of $3.1 million were included in Other expense, net in the Company's Consolidated Statement of Operations for the year ended December 31, 2014.

5.625% Senior Notes due 2021. 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 (as so supplemented, the "5.625% Senior Notes Indenture") with Wells Fargo Bank, National Association, as trustee. Provisions of the 5.625% 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 5.625% Senior Notes Indenture also contains customary events of default. At December 31, 2014, 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 2013 Permian Acquisition.

5.875% Senior Notes due 2022. On November 15, 2013, we completed our public offering of $600.0 million in aggregate principal amount of 5.875% Senior Notes due 2022. Interest is payable on the 5.875% Senior Notes due 2022 semi-annually on June 1 and December 1. The 5.875% Senior Notes due 2022 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 5.625% Senior Notes Indenture. At December 31, 2014, 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.

5.875% Senior Notes due 2024. On May 29, 2014, we completed our public offering of $500.0 million in aggregate principal amount of 5.875% Senior Notes due 2024. Interest is payable on the 5.875% Senior Notes due 2024 semi-annually on June 1 and December 1. The 5.875% Senior Notes due 2024 were issued under the Base Indenture, as supplemented by a third supplemental indenture with Wells Fargo Bank, National Association, as trustee, which contains covenants and events of default substantially similar to those in the 5.625% Senior Notes Indenture. At December 31, 2014, we were in compliance with the terms and provisions as contained in our indenture. Net proceeds from the debt offering were used repay borrowings outstanding under our Credit Facility and for general corporate purposes.

Total Indebtedness. As of December 31, 2014 and 2013, we had total outstanding indebtedness of $2.0 billion and $1.5 billion, respectively, and for the years ended December 31, 2014 and 2013, our weighted average borrowing rate was 5.82% and 5.99%, 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, 2014, we had a working capital surplus of $33.6 million, and at December 31, 2013, we had a working capital surplus of $85.8 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,		
	2014	2013	2012
Cash provided by (used in):	(In thousands)		
Operating activities	$648,605	$591,009	$370,630
Investing activities	(1,297,553)	(1,829,288)	(533,641)
Financing activities	489,561	1,395,277	152,747
Net (decrease) increase in cash and cash equivalents	$(159,387)	$156,998	$(10,264)

Operating Activities. Net cash provided by operating activities in 2014 reflects higher operating income as a result of increased overall production and higher realized pricing of natural gas. 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 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 2014 reflects additions to oil and natural gas assets of $1.2 billion and acquisitions of oil, NGL and natural gas properties of $79.6 million. These capital expenditures were used to drill 140 gross wells, the majority of which were located in the Eagle Ford area.

Net cash used in investing activities in 2013 reflects acquisitions of oil, NGL and natural gas properties of $956.9 million and additions to oil, NGL 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.

Financing Activities. Net cash provided by financing activities in 2014 primarily reflects the issuance of the $500 million 5.875% Senior Notes due 2024, net borrowings of $200.0 million under the Credit Facility, partially offset by the retirement of the $200 million 9.500% Senior Notes due 2018, $8.4 million in deferred loan fees and treasury stock purchases of $2.8 million.

Net cash provided by financing activities in 2013 primarily reflects the issuance of the $700 million 5.625% Senior Notes due 2021 and $600 million 5.875% Senior Notes due 2022, $329.0 million in proceeds from the issuance of common stock, excess tax benefit from share-based awards of $6.7 million and proceeds of $5.0 million from exercised stock options, 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.

Commodity Price Risk and Related Derivative Activities

The energy markets have historically been very volatile and oil, NGL and natural gas prices may be subject to wide fluctuations in the future. To mitigate our exposure to changes in commodity prices, management has hedged oil, NGL and natural gas prices from time to time, primarily through the use of certain derivative instruments, including fixed price swaps, basis swaps and costless collars. 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 anticipated production upon inception of the derivative instruments. The notional volumes hedged equate to a substantial portion of our 2015 projected equivalent production and a portion of our 2016 projected equivalent production.

As of December 31, 2014, 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, 2014, we had no deposits for collateral in regard to our commodity derivative instruments.

Capital Expenditures and Requirements

Excluding acquisitions, our capital expenditures for the year ended December 31, 2014 were $1.2 billion, including capitalized interest of $32.3 million and capitalized internal costs directly identified with acquisition, and exploration and development activities of $7.3 million. We have plans to execute a capital program in 2015 of up to $350 million that will be funded primarily from internally generated cash flows and cash on hand, supplemented by 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, NGL 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, 2014, the aggregate amounts of our contractually obligated payment commitments for the next five years and thereafter were as follows:

	Payments Due By Period				
	Total	2015	2016 to 2017	2018 to 2019	Thereafter
	(In thousands)				
Senior secured revolving line of credit	$200,000	$—	$—	$200,000	$—
Senior notes	1,800,000	—	—	—	1,800,000
Operating leases	47,557	8,183	9,665	9,732	19,977
Interest payments on long-term debt (1)	807,708	110,090	220,191	209,711	267,716
Drilling rig commitments	24,019	19,627	4,392	—	—
Completion service agreements	3,879	3,587	292	—	—
Firm transportation and processing	186,525	22,120	43,840	34,059	86,506
Total contractual obligations	$3,069,688	$163,607	$278,380	$453,502	$2,174,199

(1) Future interest payments were calculated based on interest rates, commitment fees and amounts outstanding at December 31, 2014.

Asset Retirement Obligations. At December 31, 2014, we had total liabilities of $20.0 million related to asset retirement obligations ("ARO") that are excluded from the table above. Of the total ARO, the current portion of $5.3

million at December 31, 2014 was included in Accrued liabilities on the Consolidated Balance Sheet. The long-term portion of ARO of $14.7 million at December 31, 2014 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, including an aggregate minimum commitment to deliver 4.5 MMBbls of oil by the end of 2017 and 588 million MMBtu of natural gas by mid-2028. 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. However, 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 may expose us to additional volume deficiency payments. 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.”

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 reserves of $5.8 million and $20.5 million in 2014 and 2013, respectively, related to commercial disputes concerning the calculation of royalty amounts earned and royalty deductions taken over specified periods in 2009 through 2013. The dispute for which we recorded a $5.8 million reserve arose in the third quarter of 2014, and we are in ongoing discussions with those royalty holders regarding their royalty claim. Our recorded reserve represents our best estimate of the probable loss exposure associated with this dispute, and the final resolution of this matter may differ from the recorded reserve. The disputes for which we established a $20.5 million reserve in 2013 were resolved by the first quarter of 2014 through our payment of $20.5 million to certain royalty holders.

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 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, NGL 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 $0.83 per Boe, while a five percent negative revision to proved reserves would increase our depletion rate by approximately $0.93 per Boe. This estimated impact is based on current data at December 31, 2014, 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.

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, 2014, our full cost pool had approximately $551.0 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 technology changes 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, NGL 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, NGL and natural gas reserves reduced by future operating expenses, development expenditures, abandonment costs (net of salvage values) to the extent not included in oil, NGL 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 remain at current depressed levels, or if we have downward revisions to our estimated proved reserves, it is likely that write-downs of our oil, NGL and natural gas properties will 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.

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. 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. As of December 31, 2013, all frozen mark-to-market values included in Accumulated other comprehensive income had been reclassified into earnings. With the election to de-designate hedging instruments, all of our derivative instruments are 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 produce a degree of earnings volatility that can be significant from period to period, but such adjustments 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, 2014, 2013 and 2012, no options were granted to our employees, officers or directors, and all options granted prior to 2012 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 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."

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.

Revenue from Contracts with Customers. In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2014-09, Revenue from Contracts with Customers. The ASU will supersede most of the existing revenue recognition requirements in GAAP and will require entities to recognize revenue at an amount that reflects the consideration to which the company expects to be entitled in exchange for transferring goods or services to a customer. The new standard also requires disclosures sufficient to enable users to understand an entity’s nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The pronouncement is effective for annual and interim reporting periods beginning after December 15, 2016, and is to be applied retrospectively, with early application not permitted. This guidance is not expected to have a material impact on the Company’s consolidated financial position, results of operations, or cash flows.

Off-Balance Sheet Arrangements

At December 31, 2014, 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.

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, 2014, we had open crude oil derivative contracts in a net asset position with a fair value of $205.6 million. A 10% increase in crude oil prices would reduce the fair value by approximately $44.2 million, while a 10% decrease in crude oil prices would increase the fair value by approximately $45.6 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, 2014, we had open NGL derivative contracts in a net asset position with a fair value of $36.0 million. A 10% increase in NGL prices would reduce the fair value by approximately $4.5 million, while a 10% decrease in NGL prices would increase the fair value by approximately $4.5 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, 2014, we had open natural gas derivative contracts in a net asset position with a fair value of $45.1 million. A 10% increase in natural gas prices would reduce the fair value by approximately $15.5 million, while a 10% decrease in natural gas prices would increase the fair value by approximately $16.6 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, 2014.

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

As of December 31, 2014, 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, 2014, we had no deposits for collateral regarding commodity derivative positions. 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, 2014. 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 $0.7 million as of December 31, 2014. We are not aware of any circumstances which currently exist that would limit access to our Credit Facility or require a change in our debt or hedging structure.

We have entered into oil, NGL and natural gas derivative contracts through 2016 which hedge our exposure to commodity price risk. These derivative contracts may limit our potential revenue if oil, NGL and natural gas prices exceed the prices established by the contracts. As of December 31, 2014, 44% of our crude oil derivative transactions represented hedged prices of crude oil at West Texas Intermediate on the NYMEX with the remaining 56% at Light Louisiana Sweet; 100% of our total NGL derivative transactions represented hedged prices of NGLs at Mont Belvieu; and 82% of our natural gas derivative transactions represented hedged prices of natural gas at Houston Ship Channel, with the remaining 18% at Tennessee, zone 0.

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.

Item 8. Financial Statements and Supplementary Data
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, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 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, 2014, based on criteria established in Internal Control - Integrated Framework (2013) 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.

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 23, 2015

Item 8. Financial Statements and Supplementary Data

Rosetta Resources Inc.

Consolidated Balance Sheet

(In thousands, except par value and share amounts)

	December 31, 2014	2013
Assets		
Current assets:		
Cash and cash equivalents	$34,397	$193,784
Accounts receivable	117,070	122,677
Derivative instruments	221,250	4,307
Prepaid expenses	8,142	9,860
Deferred income taxes	—	27,976
Other current assets	3,535	1,284
Total current assets	384,394	359,888
Oil and natural gas properties using the full cost method of accounting:		
Proved properties	5,337,537	3,951,397
Unproved/unevaluated properties, not subject to amortization	550,979	755,438
Gathering systems and compressor stations	285,989	168,730
Other fixed assets	34,339	26,362
Total	6,208,844	4,901,927
Accumulated depreciation, depletion and amortization, including impairment	(2,434,003)	(2,020,879)
Total property and equipment, net	3,774,841	2,881,048
Other assets:		
Debt issuance costs	25,741	25,602
Derivative instruments	65,419	5,458
Other long-term assets	272	4,622
Total other assets	91,432	35,682
Total assets	$4,250,667	$3,276,618
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$179,353	$190,950
Royalties and other payables	98,972	78,264
Derivative instruments	—	4,913
Deferred income taxes	72,445	—
Total current liabilities	350,770	274,127
Long-term liabilities:		
Derivative instruments	—	433
Long-term debt	2,000,000	1,500,000
Deferred income taxes	207,854	136,407
Other long-term liabilities	22,930	17,317
Total liabilities	$2,581,554	$1,928,284

Commitments and contingencies (Note 11)		
Stockholders' equity:		
Preferred stock, $0.001 par value; authorized 5,000,000 shares; no shares issued in 2014 or 2013	—	—
Common stock, $0.001 par value; authorized 150,000,000 shares; issued 62,306,601 shares and		
62,032,162 shares at December 31, 2014 and 2013, respectively	62	61
Additional paid-in capital	1,192,836	1,182,672
Treasury stock, at cost; 788,493 shares and 724,755 shares at December 31, 2014 and 2013, respectively	(27,414)	(24,592)
Accumulated other comprehensive loss	(234)	(108)
Retained earnings	503,863	190,301
Total stockholders' equity	1,669,113	1,348,334
Total liabilities and stockholders' equity	$4,250,667	$3,276,618

See accompanying notes to the consolidated financial statements.

Rosetta Resources Inc.

Consolidated Statement of Operations

(In thousands, except per share amounts)

	Year Ended December 31,		
	2014	2013	2012
Revenues:			
Oil sales	$574,552	$475,119	$318,782
NGL sales	222,682	198,966	160,461
Natural gas sales	213,609	147,028	93,711
Derivative instruments	293,836	(7,095)	40,545
Total revenues	1,304,679	814,018	613,499
Operating costs and expenses:			
Lease operating expense	93,202	53,336	35,138
Treating and transportation	88,501	71,338	51,826
Taxes, other than income	45,956	31,075	24,013
Depreciation, depletion and amortization	415,823	218,571	154,223
Reserve for commercial disputes	5,800	20,450	—
General and administrative costs	79,297	73,043	68,731
Total operating costs and expenses	728,579	467,813	333,931
Operating income	576,100	346,205	279,568
Other expense (income):			
Interest expense, net of interest capitalized	75,292	35,957	24,316
Interest income	(15)	(2)	(7)
Other expense, net	12,379	314	60
Total other expense	87,656	36,269	24,369
Income before provision for income taxes	488,444	309,936	255,199
Income tax expense	174,882	110,584	95,904
Net income	$313,562	$199,352	$159,295
Earnings per share:			
Basic	$5.10	$3.40	$3.03
Diluted	$5.09	$3.39	$3.01
Weighted average shares outstanding:			
Basic	61,455	58,571	52,496
Diluted	61,649	58,830	52,887

See accompanying notes to the consolidated financial statements.

Rosetta Resources Inc.

Consolidated Statement of Comprehensive Income

(In thousands)

	Year Ended December 31,		
	2014	2013	2012
Net income	$313,562	$199,352	$159,295
Other comprehensive (loss) income:			
Amortization of accumulated other comprehensive gain (loss) related to de-designated hedges, net of income taxes of ($37) and $968 for the years ended December 31, 2013 and 2012, respectively	—	63	(1,695)
Postretirement medical benefits prior service cost, net of income tax benefit of $71 and $61 for the years ended December 31, 2014 and 2013, respectively	(126)	(108)	—
Other comprehensive loss	(126)	(45)	(1,695)
Comprehensive income	$313,436	$199,307	$157,600

See accompanying notes to the consolidated financial statements.

Rosetta Resources Inc.

Consolidated Statement of Cash Flows

(In thousands)

	Year Ended December 31,		
	2014	2013	2012
Cash flows from operating activities:			
Net income	$313,562	$199,352	$159,295
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	415,823	218,571	154,223
Deferred income taxes	172,042	100,876	95,904
Amortization of deferred loan fees recorded as interest expense	3,838	8,421	2,856
Loss on debt extinguishment	3,101	—	—
Stock-based compensation expense	8,806	10,979	18,539
(Gain) loss due to change in fair value of derivative instruments	(282,250)	16,345	(19,662)
Change in operating assets and liabilities:			
Accounts receivable	5,607	(18,849)	(26,454)
Prepaid expenses	3,001	21	(2,780)
Other current assets	(2,250)	172	680
Long-term assets	99	(108)	650
Accounts payable and accrued liabilities	(12,565)	37,370	(19,997)
Royalties and other payables	20,707	16,627	10,948
Other long-term liabilities	(813)	3,413	(3,572)
Income taxes	(103)	(2,181)	—
Net cash provided by operating activities	648,605	591,009	370,630
Cash flows from investing activities:			
Acquisitions of oil and gas assets	(79,600)	(956,892)	—
Additions to oil and gas assets	(1,218,614)	(871,092)	(622,168)
Disposals of oil and gas assets	661	(1,304)	88,527
Net cash used in investing activities	(1,297,553)	(1,829,288)	(533,641)
Cash flows from financing activities:			
Borrowings on Credit Facility	1,050,000	670,000	290,000
Payments on Credit Facility	(850,000)	(880,000)	(110,000)
Repayments on Restated Term Loan	—	—	(20,000)
Issuance of Senior Notes	500,000	1,300,000	—
Retirement of Senior Notes	(200,000)	—	—
Proceeds from issuance of common stock	—	329,008	—
Deferred loan fees	(8,364)	(28,280)	(1,980)
Proceeds from stock options exercised	618	4,981	910
Purchases of treasury stock	(2,822)	(7,113)	(6,183)
Excess tax benefit from share-based awards	129	6,681	—
Net cash provided by financing activities	489,561	1,395,277	152,747
Net (decrease) increase in cash	(159,387)	156,998	(10,264)

Cash and cash equivalents, beginning of year	193,784	36,786	47,050
Cash and cash equivalents, end of year	$34,397	$193,784	$36,786
Supplemental disclosures:			
Cash paid for interest expense, net of capitalized interest	$73,426	$24,824	$20,834
Cash paid (received) for income taxes	$3,248	$2,941	$(105)
Supplemental non-cash disclosures:			
Capital expenditures included in Accounts payable and accrued liabilities	$118,284	$118,725	$88,844

See accompanying notes to the consolidated financial statements.

Rosetta Resources Inc.

Consolidated Statement of Stockholders' Equity

(In thousands, except share amounts)

	Common Stock			Treasury Stock				
	Shares	Amount	Additional Paid-In Capital	Shares	Amount	Accumulated Other Comprehensive (Loss)/Income	Retained Earnings / (Accumulated Deficit)	Total Stockholders' Equity
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)
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
Stock options exercised	34,000	1	618	—	—	—	—	619
Treasury stock - employee tax payment	—	—	—	63,738	(2,822)	—	—	(2,822)
Stock-based compensation	—	—	9,417	—	—	—	—	9,417
Vesting of restricted stock	240,439	—	—	—	—	—	—	—
Excess tax benefit from share-based awards	—	—	129	—	—	—	—	129
Net income	—	—	—	—	—	—	313,562	313,562
Other comprehensive loss	—	—	—	—	—	(126)	—	(126)
Balance at December 31, 2014	62,306,601	$ 62	$ 1,192,836	788,493	$ (27,414)	$ (234)	$ 503,863	$ 1,669,113

See accompanying notes to the consolidated financial statements.

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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, 2014 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 contingencies, 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, NGL 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.

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, 2014 and 2013, 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, NGL 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 $7.3 million, $7.2 million and $6.0 million of internal costs for the years ended December 31, 2014, 2013 and 2012, 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, NGL 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 ranging from 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 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 $32.3 million, $28.3 million, and $3.8 million in 2014, 2013 and 2012, 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 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 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, 2014 or 2013.

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, 2014, 2013 and 2012, no options were granted to the Company's employees, officers or directors and all options granted prior to 2012 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 windfall or shortfall arising from the Company's stock-based compensation plans is recognized as an increase or decrease to additional paid-in capital when realized and is calculated as the amount by which the tax effect of the tax deduction received differs from the deferred tax asset associated with recorded stock-based compensation expense. To the extent that the shortfall exceeds the cumulative windfall previously recorded in additional paid-in capital, the impact is recognized in income tax 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, 2014 and 2013, 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.

Revenue Recognition

Oil, NGL and natural gas revenue from our 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, 2014 or 2013.

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.

Revenue from Contracts with Customers. In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2014-09, Revenue from Contracts with Customers. The ASU will supersede most of the existing revenue recognition requirements in GAAP and will require entities to recognize revenue at an amount that reflects the consideration to which the company expects to be entitled in exchange for transferring goods or services to a customer. The new standard also requires disclosures sufficient to enable users to understand an entity's nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The pronouncement is effective for annual and interim reporting periods beginning after December 15, 2016, and is to be applied retrospectively, with early application not permitted. This guidance is not expected to have a material impact on the Company’s consolidated financial position, results of operations, or cash flows.

(3) Accounts Receivable

Accounts receivable consists of the following:

	December 31,	
	2014	2013
	(In thousands)	
Oil, NGL and natural gas sales	$96,780	$96,576
State severance tax refunds	15,350	19,157
Joint interest billings	4,669	4,696
Other	271	2,248
Total	$117,070	$122,677

As of December 31, 2014 and 2013, the Company had no allowance for doubtful accounts.

(4) Property and Equipment

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

	December 31,	
	2014	2013
	(In thousands)	
Proved properties	$5,337,537	$3,951,397
Unproved/unevaluated properties	550,979	755,438
Gathering systems and compressor stations	285,989	168,730
Other fixed assets	34,339	26,362
Total	6,208,844	4,901,927
Less: Accumulated depreciation, depletion and amortization	(2,434,003)	(2,020,879)
Total property and equipment, net	$3,774,841	$2,881,048

Acquisitions

2014 Permian Acquisition. On December 30, 2013, the Company entered into a definitive agreement with several private parties to acquire Delaware Basin assets covering 5,034 net acres located in Reeves County (the "2014 Permian Acquisition"). These assets include 13 gross producing wells, of which 11 are operated by the Company. The Company completed the 2014 Permian Acquisition on February 28, 2014, with an effective date of December 1, 2013, for total cash consideration of $83.8 million.

Gates Ranch Acquisition. In the second quarter of 2013, the Company acquired the remaining 10% working interest in certain producing wells along with a third party's option to participate in future 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 senior secured revolving credit facility (the "Credit Facility"), as described in Note 10 – Debt and Credit Agreements. As of the Gates Acquisition Date, the Company owns a 100% working interest in the entire Gates Ranch leasehold.

2013 Permian Acquisition. On March 14, 2013, the Company entered into a purchase and sale agreement with Comstock Oil & Gas, LP to purchase producing and undeveloped oil, NGL and natural gas interests in the Permian Basin in Gaines and Reeves Counties, Texas (the "2013 Permian Acquisition"). The Company completed the 2013 Permian Acquisition on May 14, 2013, with an effective date of January 1, 2013, for total cash consideration of $825.2 million. The 2013 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 2013 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.

The above transactions were accounted for under the acquisition method of accounting, whereby each respective 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 final purchase price allocations for these acquisitions, no goodwill or bargain purchase was recognized. The final purchase price allocations for these transactions, representing consideration paid, assets acquired and liabilities assumed as of the respective acquisition dates, are shown in the tables below.

	2014 Permian Acquisition	2013 Permian Acquisition and Gates Ranch Acquisition
	Total Purchase Price Allocation (in thousands)	
Cash consideration	$83,752	$ 953,242
Fair value of assets acquired:		
Other fixed assets	$-	$ 600
Oil and natural gas properties		
Proved properties	61,520	290,273
Unproved/unevaluated properties	22,525	663,300
Total assets acquired	$84,045	$ 954,173
Fair value of liabilities assumed:		
Asset retirement obligations	$293	$ 931
Net assets acquired	$83,752	$ 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 value of oil and natural gas properties and asset retirement obligations was 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) future production, including adjustments for risk; (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. See Note 7 – Fair Value Measurements for additional information.

The results of operations attributable to the 2014 Permian Acquisition were included in the Company's Consolidated Statement of Operations beginning on March 1, 2014 and increased Total revenues by $10.2 million and Operating income by $2.7 million for the year ended December 31, 2014.

The results of operations attributable to the 2013 Permian Acquisition and the Gates Ranch Acquisition were included in the Company's Consolidated Statement of Operations beginning on May 14, 2013 (2013 Permian Acquisition) and June 5, 2013 (Gates Acquisition), respectively. Revenues of $68.4 million and Operating 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 assumes the transactions and related financings for the 2013 Permian Acquisition and the Gates Acquisition occurred on January 1, 2012 and the 2014 Permian Acquisition occurred on January 1, 2013. The unaudited pro forma information includes the effects of issuing 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 as described above. 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 sellers, the Company's knowledge of the acquired properties and the impact of the Company's 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 acquisitions or any estimated costs that have been or will be incurred by the Company to integrate these assets. The unaudited pro forma information does not purport to represent what the Company's actual results of operations would have been if the 2013 Permian Acquisition and Gates Acquisition had occurred on January 1, 2012, and the 2014 Permian Acquisition had occurred on January 1, 2013.

	Year Ended December 31,	
	2014 (1)	2013
	(In thousands, except per share and share data)	
Total revenues	$ 1,307,776	$ 870,172
Net income	314,307	216,727
Earnings per share:		
Basic	$ 5.11	$ 3.55
Diluted	$ 5.10	$ 3.53
Weighted average shares outstanding:		
Basic	61,455	61,081
Diluted	61,649	61,339

(1) No pro forma adjustments were made related to the 2013 Permian Acquisition and Gates Acquisition for the period as the acquisitions are included in the Company's historical results.

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, prior to customary post-closing adjustments. 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.

Additional Disclosures about Property and Equipment

Included in the Company's oil and natural gas properties are asset retirement costs of $28.8 million and $22.2 million as of December 31, 2014 and 2013, respectively, including additions of $2.5 million and $2.7 million for the years ended December 31, 2014 and 2013, 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, 2014, which were based on a West Texas Intermediate oil price of $91.48 per Bbl and a Henry Hub natural gas price of $4.35 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, 2014 and as a result, no write-down was recorded. It is likely that a write-down of the Company’s oil and gas properties will occur in future periods in the event that oil and natural gas prices remain at current depressed levels or the Company experiences significant downward adjustments to its estimated proved reserves.

The Company did not record any write-downs or impairments for the years ended December 31, 2014, 2013 and 2012. 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.

Capitalized costs excluded from DD&A as of December 31, 2014 and 2013, all of which are located onshore in the U.S., are as follows by the year in which such costs were incurred:

	December 31, 2014				
	Total	2014	2013	2012	Prior
	(In thousands)				
Development costs	$108,555	$108,555	$—	$—	$—
Exploration costs	—	—	—	—	—
Acquisition cost of undeveloped acreage	400,677	35,011	357,476	3,074	5,116
Capitalized interest	41,747	29,672	10,293	978	804
Total capitalized costs excluded from DD&A	$550,979	$173,238	$367,769	$4,052	$5,920

	December 31, 2013				
	Total	2013	2012	2011	Prior
	(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

It is anticipated that development costs of $108.6 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 $442.4 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 $286.0 million and $168.7 million at December 31, 2014 and 2013, respectively, and is being depreciated on a straight-line basis over 15 years. Accumulated depreciation related to these assets at December 31, 2014 and 2013 was $29.4 million and $13.7 million, respectively. Depreciation expense associated with the gathering systems and compressor stations for the years ended December 31, 2014, 2013, and 2012 was $15.9 million, $7.9 million, and $4.0 million, respectively.

Other fixed assets. Other fixed assets at December 31, 2014 and 2013 of $34.3 million and $26.4 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, 2014 and 2013 was $6.5 million and $2.9 million, respectively. For the years ended December 31, 2014, 2013 and 2012, depreciation expense for Other fixed assets was $4.7 million, $3.4 million and $1.4 million, respectively.

(5) Debt Issuance Costs

As of December 31, 2014 and 2013, debt issuance costs, net were $29.7 million and $27.5 million, respectively. Total amortization expense for such costs was $3.8 million, $8.4 million and $2.9 million for the years ended December 31, 2014, 2013 and 2012, 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 conditions, operating strategies and available derivative prices. The Company utilizes various types of derivative instruments to manage commodity price risk, including fixed price swaps, basis 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, 2014, 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 Prices per Bbl	Average Ceiling Prices per Bbl
Crude oil	2015	Costless Collar	6,962	2,541,001	$ 55.00	$ 84.78
Crude oil	2015	Swap	12,000	4,380,000	89.81	
Crude oil	2016	Swap	6,000	2,196,000	90.28	
				9,117,001		

Product	Settlement Period	Derivative Instrument	Notional Daily Volume (Bbls)	Total Notional Volume (Bbls)	Average Fixed Prices per Bbl
NGL-Ethane	2015	Swap	3,476	1,268,810	11.31
NGL-Propane	2015	Swap	1,750	638,750	43.35
NGL-Isobutane	2015	Swap	617	225,082	53.05
NGL-Normal Butane	2015	Swap	579	211,179	52.53
NGL-Pentanes Plus	2015	Swap	579	211,179	77.72
				2,555,000	

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	2015	Costless Collar	50,000	18,250,000	$ 3.60	$ 5.04
Natural gas	2016	Costless Collar	40,000	14,640,000	3.50	5.58
Natural gas	2015	Swap	50,000	18,250,000	4.13	
Natural gas	2016	Swap	30,000	10,980,000	4.04	
				62,120,000		

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, 2014, the Company had no deposits for collateral regarding commodity derivative positions.

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. 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 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 had been reclassified into earnings.

With the election to de-designate hedging instruments, all of the Company's derivative instruments are 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, 2014 and 2013, respectively:

Commodity derivative contracts	Location on Consolidated Balance Sheet	Asset (Liability) Fair Value December 31, 2014	December 31, 2013
		(in thousands)	
Oil	Derivative instruments - current assets	$151,363	$ 1,299
Oil	Derivative instruments - non-current assets	54,187	2,117
Oil	Derivative instruments - current liabilities	-	(5,629)
NGL	Derivative instruments - current assets	35,992	2,834
NGL	Derivative instruments - non-current assets	-	(129)
NGL	Derivative instruments - current liabilities	-	461
NGL	Derivative instruments - non-current liabilities	-	(433)
Natural gas	Derivative instruments - current assets	33,895	174
Natural gas	Derivative instruments - non-current assets	11,232	3,470
Natural gas	Derivative instruments - current liabilities	-	255
Total derivative fair value, net, not designated as hedging instruments		$286,669	$ 4,419

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, 2014, 2013 and 2012, respectively:

Location on Consolidated Statement of Operations	Description of Gain (Loss)	For the Year Ended December 31, 2014	2013	2012
		(in thousands)		
Derivative instruments	Gain recognized in income	$11,586	$9,250	$20,883
	Realized gain recognized in income	$11,586	$9,250	$20,883
Derivative instruments	Gain (loss) recognized in income due to changes in fair value	$282,250	$(16,245)	$16,999
Derivative instruments	(Loss) gain reclassified from Accumulated OCI	-	(100)	2,663
	Unrealized gain (loss) recognized in income	$282,250	$(16,345)	$19,662
Total commodity derivative gain (loss) recognized in income		$293,836	$(7,095)	$40,545

(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, 2014, 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, 2014.

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, 2014 and 2013:

	Fair value as of December 31, 2014				
	Level 1	Level 2	Level 3	Netting (1)	Total
	(In thousands)				
Assets:					
Commodity derivative contracts	$—	$—	$289,878	$(3,209)	$286,669
Liabilities:					
Commodity derivative contracts	—	—	(3,209)	3,209	—
Total fair value	$—	$—	$286,669	$—	$286,669

	Fair value as of December 31, 2013				
	Level 1	Level 2	Level 3	Netting (1)	Total
	(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

(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.

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 the Company's 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, 2014 (in thousands):

Level 3 Instrument	Asset (Liability)	Valuation Technique	Unobservable Input	Range Minimum	Range Maximum	Weighted Average
Oil swaps	$ 196,691	Discounted cash flow	Forward price curve-swaps	$53.44	$ 67.84	$ 59.85
Oil costless collars	8,859	Option model	Forward price curve- costless collar option value	(2.07)	5.49	3.49
NGL swaps	35,991	Discounted cash flow	Forward price curve-swaps	0.17	1.08	0.42
Natural gas swaps	26,535	Discounted cash flow	Forward price curve-swaps	(0.08)	3.75	3.19
Natural gas costless collars	18,593	Option model	Forward price curve-costless collar option value	(0.11)	1.02	0.57
Total	$ 286,669					

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 $0.7 million as of December 31, 2014 due to nonperformance risk.

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.

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

	Derivative Asset (Liability) (In thousands)
Balance at December 31, 2012	$ 20,664
Total Gains or (Losses) (Realized or Unrealized):	
Included in Earnings	(6,995)
Purchases, Issuances and Settlements	
Settlements	(9,250)
Balance at December 31, 2013	$ 4,419
Total Gains or (Losses) (Realized or Unrealized):	
Included in Earnings	293,836
Purchases, Issuances and Settlements	
Settlements	(11,586)

Balance at December 31, 2014	$ 286,669

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, 2014, 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, 2014 and 2013, the estimated fair value of total debt was $1.8 billion and $1.5 billion, respectively.

(8) Accounts Payable, Accrued Liabilities, Royalties and Other Payables

The Company's accrued liabilities consist of the following:

	As of December 31,	
	2014	2013
	(In thousands)	
Accrued capital costs	$103,684	$93,725
Accounts payable	24,523	29,682
Accrued reserve for commercial disputes	5,800	20,000
Accrued payroll and employee incentive expense	9,518	10,516
Accrued lease operating expense	10,300	12,064
Accrued interest	12,171	15,025
Asset retirement obligation	5,340	3,930
Other	8,017	6,008
Total Accounts payable and accrued liabilities	$179,353	$190,950

At December 31, 2014, Royalties and other payables of $99.0 million includes $74.1 million of royalty revenues payable to landowners, $16.7 million of accrued transportation costs and $8.2 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 through 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:

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
ARO at the beginning of the period	$13,057	$8,400	$14,313
Liabilities incurred during period	4,660	1,795	866
Liabilities settled during period	(2,005)	(1,566)	(8,538)
Revision of previous estimate	3,248	3,850	935
Accretion expense	997	578	824
ARO at the end of the period	$19,957	$13,057	$8,400

As of December 31, 2014 and 2013, the current portion of ARO of $5.3 million and $3.9 million, respectively, was included in Accrued liabilities on the Consolidated Balance Sheet. The long-term portion of ARO of $14.7 million and $9.2 million as of December 31, 2014 and 2013, respectively, was included in Other long-term liabilities on the Consolidated Balance Sheet. The increase in ARO in 2014 was primarily due to a revision in the timing of abandonment of certain wells in South Texas, as well as an increase in the total number of well and facility locations added during the year. 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.

(10) Debt and Credit Agreements

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

	As of December 31,	
	2014	2013
	(In thousands)	
Credit Facility	$200,000	$—
9.500% Senior Notes due 2018	—	200,000
5.625% Senior Notes due 2021	700,000	700,000
5.875% Senior Notes due 2022	600,000	600,000
5.875% Senior Notes due 2024	500,000	—
Total debt	$2,000,000	$1,500,000

Senior Secured Revolving Credit Facility. As of December 31, 2014, the Company had $200.0 million outstanding with $600.0 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 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 under the Credit Facility for the year ended December 31, 2014 was 1.98%, exclusive of commitment fees. For the year ended December 31, 2014, interest expense was $2.2 million and commitment fees were $2.6 million under the Credit Facility. 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 ("EBITDA"), 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, 2014, the Company's current ratio was 2.2 and leverage ratio was 2.8. 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. On February 18, 2015, the Company entered into the Ninth Amendment to its Credit Facility. The amendment, among other things, modified the Company's financial covenant requirements by replacing its debt to EBITDA leverage ratio with two additional covenants, a senior secured leverage ratio, where secured debt to EBITDA cannot be greater than 2.5 to 1.0, and an interest coverage ratio, where EBITDA to gross interest expense cannot be less than 2.5 to 1.0. These ratios will be 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, beginning with the quarter ended March 31, 2015.

9.500% Senior Notes due 2018. In accordance with the provisions of the indenture governing the Company's 9.500% Senior Notes, on May 5, 2014, the Company redeemed all of the outstanding notes in full at a price of 104.75% of the principal amount, plus accrued and unpaid interest. The Company paid an aggregate amount of $210.6 million for such redemption, consisting of a call premium of $9.5 million and $1.1 million of accrued and unpaid interest. The call premium of $9.5 million and remaining unamortized debt issuance costs of $3.1 million were included in Other expense, net in the Company's Consolidated Statement of Operations for the year ended December 31, 2014.

5.625% Senior Notes due 2021. 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 Indenture"), as supplemented by a first supplemental indenture (as so supplemented, the "5.625% Senior Notes Indenture") with Wells Fargo Bank, National Association, as trustee. Provisions of the 5.625% 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 5.625% Senior Notes Indenture also contains customary events of default.

5.875% Senior Notes due 2022. On November 15, 2013, the Company completed its public offering of $600.0 million in aggregate principal amount of 5.875% Senior Notes due 2022. Interest is payable on the 5.875% Senior Notes due 2022 semi-annually on June 1 and December 1. The 5.875% Senior Notes due 2022 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 5.625% Senior Notes Indenture.

5.875% Senior Notes due 2024. On May 29, 2014, the Company completed its public offering of $500.0 million in aggregate principal amount of 5.875% Senior Notes due 2024. Interest is payable on the 5.875% Senior Notes due 2024 semi-annually on June 1 and December 1. The 5.875% Senior Notes due 2024 were issued under the Base Indenture, as supplemented by a third supplemental indenture with Wells Fargo Bank, National Association, as trustee, which contains covenants and events of default substantially similar to those in the 5.625% Senior Notes Indenture.

Total Indebtedness. As of December 31, 2014, the Company had total outstanding borrowings of $2.0 billion, and for the year ended December 31, 2014 the Company’s weighted average borrowing rate was 5.82%. The Company does not have any debt that matures within the five years ending December 31, 2019, other than the Credit Facility which matures on April 12, 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, including an aggregate minimum commitment to deliver 4.5 MMBbls of oil by the end of 2017 and 588 million MMBtus of natural gas by mid-2028. 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. However, 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 may expose the Company to additional volume deficiency payments. As of December 31, 2014, the Company has accrued deficiency fees of $9.7 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, 2014 are as follows:

	December 31, 2014 (In thousands)
2015	22,120
2016	22,132
2017	21,708
2018	18,159
2019	15,900
Thereafter	86,506
Total future obligations	$ 186,525

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. As of December 31, 2014, the Company had one outstanding drilling rig commitment with a term greater than one year that will expire at the end of 2016, and the minimum contractual commitments due in the next twelve months are $19.6 million. As of December 31, 2014, 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 and other field service commitments were $3.6 million. Payments under these commitments are accounted for as capital additions to oil and gas properties.

Lease Obligations and Other Commitments. The Company has operating leases for office space and other property and equipment. The Company incurred rental expense of $5.5 million, $7.3 million and $5.7 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Future minimum annual rental commitments under non-cancelable leases at December 31, 2014 were as follows:

	December 31, 2014 (In thousands)
2015	$ 8,183
2016	4,934
2017	4,731
2018	4,821
2019	4,911
Thereafter	19,977
	$ 47,557

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. The Company recorded reserves of $5.8 million and $20.5 million in 2014 and 2013, respectively, related to commercial disputes concerning the calculation of royalty amounts earned and royalty deductions taken over specified periods in 2009 through 2013. The dispute for which the Company recorded a $5.8 million reserve arose in the third quarter of 2014, and the Company is in ongoing discussions with those royalty holders regarding their royalty claim. The Company's recorded reserve of $5.8 million represents its best estimate of the probable loss exposure associated with this dispute, and the final resolution of this matter may differ from the recorded reserve. The disputes for which the Company established a $20.5 million reserve in 2013 were resolved by the first quarter of 2014 through the payment of $20.5 million to certain royalty holders. The reserves for these contingencies are reported in Reserve for commercial disputes in the Consolidated Statement of Operations.

(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,		
	2014	2013	2012

	(in thousands)		
Total stock-based compensation expense	$9,417	$11,471	$18,835
Capitalized in oil and gas properties	(611)	(492)	(296)
Net stock-based compensation expense	$8,806	$10,979	$18,539

For the years ended December 31, 2014, 2013 and 2012, the Company had an associated tax benefit of $2.8 million, $3.0 million and $2.8 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 4.95 million 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 3.6 million 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) 0.5 million shares during the fiscal year in which the participant begins work for Rosetta, and (ii) 0.3 million shares during each fiscal year thereafter. As of December 31, 2014, there were 2.7 million shares remaining available for issuance under the 2013 Plan.

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, 2014, 2013 and 2012, no options were granted to employees, officers or directors of the Company and all options granted prior to 2012 under the Plan have vested. Compensation expense was recognized ratably over the requisite service period.

The following table summarizes information related to outstanding and exercisable options held by the Company's employees and directors at December 31, 2014:

	Shares	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term (In years)	Aggregate Intrinsic Value (In thousands) (1)
Outstanding at December 31, 2012	510,651	$ 13.52		
Exercised	(379,145)	13.08		
Outstanding at December 31, 2013	131,506	$ 14.79		
Exercised	(34,000)	18.17		
Outstanding at December 31, 2014	97,506	$ 13.61		
Options vested and exercisable at December 31, 2014	97,506	$ 13.61	3.66	$ 865

(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.

As of December 31, 2014 and 2013, the Company has no unrecognized stock-based compensation expense because all outstanding stock options have vested. Stock-based compensation expense recorded for stock option awards during the year ended December 31, 2012 was less than $0.1 million.

The total intrinsic value of options exercised during the years ended December 31, 2014, 2013 and 2012 was $0.8 million, $13.4 million and $2.3 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 8% 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, 2014:

	Shares	Weighted Average Grant Date Fair Value
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
Granted	394,340	45.08
Lapse of restrictions	(240,439)	44.98
Forfeited	(28,684)	46.43
Non-vested shares outstanding at December 31, 2014	500,066	$ 46.51

The fair value of awards vested for the year ended December 31, 2014 was $10.6 million. Stock-based compensation expense recorded for restricted stock awards for the years ended December 31, 2014, 2013 and 2012 was $10.4 million, $6.7 million and $7.4 million, respectively. Unrecognized expense as of December 31, 2014 for all outstanding restricted stock awards was $12.7 million and will be recognized over a weighted average period of 1.64 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 - Summary of Significant Accounting Policies, 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, 2014, 2013 and 2012, the Company recognized a benefit of $1.0 million, and expense of $4.7 million and $11.4 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, 2014 assuming a 200% payout (the maximum amount):

	PSUs

Unvested PSUs at December 31, 2013	340,811
Granted	244,952
Vested (1)	(75,275)
Forfeited (2)	(42,718)
Unvested PSUs at December 31, 2014	467,770

(1) Reflects settlement of the 2011 PSUs at 150% of the target amount.
(2) Primarily includes PSUs, which expired as a result of performance conditions not being met.

On December 31, 2014, the three-year performance period ended for the 2012 PSUs, and in the first quarter of 2015, the Company vested the 2012 PSUs at 0% of the targeted amount. Stock-based compensation expense of $1.0 million associated with the 2012 PSUs that was recognized over the three-year performance period was reversed, and as of December 31, 2014, the Company had no balance accrued as a component of Additional paid-in capital.

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.

As of December 31, 2014 and assuming a 200% payout of the maximum amount, there were 376,264 unvested PSUs associated with the 2013 and 2014 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 $22.31 at December 31, 2014, and assuming the Board elects the maximum available payout of 200% for unvested 2013 and 2014 PSUs, unrecognized stock-based compensation expense related to these awards is approximately $6.4 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.

Postretirement Health Care

Effective January 1, 2013, the Company enacted a postretirement medical benefit plan covering eligible employees and their eligible dependents. Upon enactment, the Company recognized a $0.3 million liability related to the prior service of employees, which is included as a component of Other comprehensive income. The Company recognizes periodic postretirement benefits cost as a component of General and administrative costs. For the years ended December 31, 2014 and 2013, this expense was immaterial.

(13) Income Taxes

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

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
Current:			
Federal	$908	$5,332	$—
State	1,932	4,376	—
	2,840	9,708	—
Deferred:			
Federal	168,538	99,768	92,001
State	3,504	1,108	3,903
	172,042	100,876	95,904
Total income tax expense	$174,882	$110,584	$95,904

For the years ended December 31, 2014, 2013 and 2012, the Company's effective tax rate differs from the federal statutory rate of 35% primarily due to state income taxes and the non-deductibility of certain incentive compensation. The reconciliation of income taxes calculated at the U.S. federal statutory tax rate to the Company's effective tax rate as shown in the Consolidated Statement of Operations is as follows:

Year Ended December 31,

	2014 (In thousands)	(%)	2013 (In thousands)	(%)	2012 (In thousands)	(%)
US statutory rate	$170,955	35.0%	$108,477	35.0%	$89,320	35.0%
State income tax, net of federal benefit	4,253	0.9 %	3,538	1.1 %	1,846	0.7 %
Non-deductible permanent items	433	0.1 %	1,137	0.4 %	4,197	1.6 %
Valuation allowance	(40)	(0.0 %)	(15)	(0.0 %)	954	0.4 %
Other, net	(719)	(0.2 %)	(2,553)	(0.8 %)	(413)	(0.1 %)
Total tax expense	$174,882	35.8%	$110,584	35.7%	$95,904	37.6%

The significant components of the Company's deferred tax assets and liabilities are as follows:

	As of December 31, 2014	2013
	(In thousands)	
Deferred income tax assets:		
Net operating loss carryforwards	$106,574	$119,794
Stock-based compensation	2,515	2,001
Other	10,942	13,737
Gross deferred income tax assets	$120,031	$135,532
Valuation allowance	(5,195)	(5,235)
Net deferred income tax assets	$114,836	$130,297
Deferred income tax liabilities:		
Oil and gas properties basis differences	(293,140)	(237,220)
Derivative financial instruments	(101,995)	(1,508)
Deferred income tax liability	$(395,135)	$(238,728)
Net deferred income tax liability	$(280,299)	$(108,431)

As of December 31, 2014, the total net operating loss (NOL) carryforward consists of $309.0 million of federal NOL carryforwards, which expire between 2029 and 2031, and $106.5 million of state NOL carryforwards, which expire primarily between 2015 and 2031. 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, 2014	2013	2012
	(in thousands)		
Balance at the beginning of the year	$5,235	$5,250	$4,296
Change to provision for income taxes	(40)	(15)	954
Balance at the end of the year	$5,195	$5,235	$5,250

Pursuant to authoritative guidance, the Company's $106.6 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, 2014, 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.

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

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
Basic weighted average number of shares outstanding	61,455	58,571	52,496
Dilution effect of stock option and restricted shares at the end of the period	194	259	391
Diluted weighted average number of shares outstanding	61,649	58,830	52,887
Anti-dilutive stock awards and shares	5	2	1

Common Stock Offering. In April 2013, the Company completed its public offering of 8,050,000 shares of common stock for net proceeds of approximately $329.0 million ($40.87 per share, net of underwriting discounts and commissions) and including offering expenses and reimbursements by the underwriters of certain expenses incurred in connection with the offering.

(15) Operating Segments

The Company has one reportable segment, oil, NGL 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.

	Year Ended December 31,		
	2014	2013	2012
Oil, NGL and Natural Gas Sales	(In thousands)		
Eagle Ford	$857,135	$764,251	$561,143
Permian	152,681	52,603	—

Other (1)	1,027	4,259	11,811
Total	$1,010,843	$821,113	$572,954

(1) The decline in revenues was due to asset divestitures and suspension of capital programs in lower-return areas that produced primarily from dry gas reservoirs. See Note 4 – Property and Equipment.

Major Customers

In 2014, two customers, Shell Trading (US) Company and ETC Texas Pipeline Ltd., accounted for approximately 31% and 14%, respectively, of the Company's consolidated revenue, excluding the effects of derivative instruments.

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.

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.

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, 2014, 2013 and 2012. 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, 2014, 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, NGL 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.

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, 2014 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 37 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 41 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, 2014, 2013 and 2012 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.

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, 2014, 2013 and 2012:

	2014	2013	2012
	(In thousands)		
Proved properties	$5,337,537	$3,951,397	$2,829,431
Unproved properties	550,979	755,438	95,540
Total	5,888,516	4,706,835	2,924,971
Less: Accumulated depletion	(2,398,109)	(2,003,893)	(1,797,203)
Net capitalized costs	$3,490,407	$2,702,942	$1,127,768

Net capitalized costs include asset retirement costs of $28.8 million, $22.2 million and $15.1 million as of December 31, 2014, 2013 and 2012, 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, 2014, 2013 and 2012:

Year Ended December 31,		
2014	2013	2012

	(In thousands)		
Acquisition costs			
Proved	$80,615	$290,273	$—
Unproved	21,671	672,634	18,753
Subtotal	102,286	962,907	18,753
Exploration costs	555,836	534,881	93,542
Development costs	635,291	338,882	531,957
Total	$1,293,413	$1,836,670	$644,252

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

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
Oil, NGL and natural gas sales	$1,010,843	$821,113	$572,954
Production costs	227,659	155,749	110,977
Depreciation, depletion and amortization	415,823	218,571	154,223
Income before income taxes	367,361	446,793	307,754
Income tax provision	131,515	159,505	115,716
Results of operations	$235,846	$287,288	$192,038

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, 2014, 2013 and 2012, 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, 2011	36,370	50,219	445,956	160,915
Revisions of previous estimates (2)	(4,947)	4,923	(10,107)	(1,709)
Purchases in place	70	104	744	298
Extensions, discoveries and other additions (3)	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 (4)	(8,945)	(65)	(9,580)	(10,606)
Purchases in place (5)	10,972	5,857	36,523	22,916
Extensions, discoveries and other additions (6)	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
Revisions of previous estimates	(693)	5,307	(20,954)	1,123
Purchases in place (7)	1,128	262	1,372	1,618
Extensions, discoveries and other additions (8)	7,944	8,125	49,676	24,348
Sales in place	—	—	—	—
Production	(6,955)	(8,408)	(51,616)	(23,966)
Net proved reserves at December 31, 2014	67,886	104,595	655,101	281,664

Proved Developed Reserves				
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
December 31, 2014	30,969	52,198	331,633	138,438
Proved Undeveloped Reserves				
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
December 31, 2014	36,917	52,397	323,468	143,226

(1) Includes crude oil and condensate. As of December 31, 2014, 2013, 2012 and 2011, approximately 58%, 65%, 92%, and 97%, respectively, of our proved oil reserves consisted of condensate, which the Company defines as oil with an API gravity higher than 55 degrees.
(2) 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.
(3) The Company added 65,641 MBoe primarily in the Eagle Ford area by drilling and completing 37 wells and adding 54 proved undeveloped locations.
(4) 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.
(5) The Company added 22,916 MBoe primarily due to the 2013 Permian Acquisition.
(6) 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.
(7) The Company added 1,618 MBoe primarily due to the 2014 Permian Acquisition.
(8) Net proved additions are primarily a result of our 2014 development program where the Company developed 64 gross wells in the Gates Ranch area, 40 gross wells in other Eagle Ford fields and 50 gross wells in the Permian Basin.

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 2014, 2013 and 2012 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, NGL 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.

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, 2014, 2013 and 2012:

	Year Ended December 31, 2014		
	Proved Developed	Proved Undeveloped	Total
	(In millions)		
Future cash inflows	$5,251	$ 6,294	$11,545
Future production costs	(1,862)	(1,971)	(3,833)
Future development costs	(28)	(1,460)	(1,488)
Future income taxes	(670)	(571)	(1,241)
Future net cash flows	2,691	2,292	4,983
Discount to present value at 10% annual rate	(1,278)	(1,088)	(2,366)
Standardized measure of discounted future net cash flows relating to proved oil, NGL and natural gas reserves	$1,413	$ 1,204	$2,617

	Year Ended December 31, 2013		
	Proved Developed	Proved Undeveloped	Total
	(In millions)		
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	Total
	(In millions)		
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	$866	$ 975	$1,841

relating to proved oil, NGL and natural gas reserves

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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, 2014, 2013 and 2012:

	Year Ended December 31		
	2014	2013	2012
	(in millions)		
Standardized measure - beginning of year	$2,294	$1,841	$1,706
Sales and transfers of crude oil, NGLs and natural gas produced, net of production costs	(783)	(665)	(462)
Revisions to estimates of proved reserves:			
Net changes in prices and production costs	(275)	(268)	(591)
Extensions, discoveries, additions and improved recovery, net of related costs	397	849	814
Development costs incurred	504	275	220
Changes in estimated future development costs	52	86	54
Revisions of previous quantity estimates	22	(127)	(12)
Accretion of discount	301	244	229
Net change in income taxes	94	(113)	(17)
Purchases of reserve in place	37	216	6
Sales of reserves in place	—	—	(104)
Changes in timing and other	(26)	(44)	(2)
Standardized measure - end of year	$2,617	$2,294	$1,841

Quarterly Selected Financial Data

(Unaudited)

Summaries of the Company's results of operations by quarter for the years ended 2014 and 2013 are as follows:

	2014			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share data)			
Revenues	$214,566	$220,890	$365,593	$503,630
Operating income	69,849	52,642	144,319	309,290
Net income	35,243	14,444	78,408	185,467
Basic earnings per share	0.57	0.24	1.28	3.02
Diluted earnings per share	0.57	0.23	1.27	3.01

	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

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 Exchange Act, as of December 31, 2014. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2014, 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, 2014 of the effectiveness of our internal control over financial reporting based on the framework in Internal Control –Integrated Framework (2013) 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, 2014, 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, 2014, 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, 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information
Ninth Amendment to the Credit Agreement

On February 18, 2015, the Company entered into the ninth amendment (the "Ninth Amendment") to the Amended and Restated Senior Revolving Credit Agreement, effective as of February 18, 2015, among Rosetta Resources Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders signatory thereto (the "Credit Agreement"). The Ninth Amendment, among other things, modified the existing financial covenant requirements by replacing the maximum total debt to EBITDA ratio with a maximum total senior secured leverage ratio, where total senior secured debt to EBITDA cannot be greater than 2.5 to 1.0. The Ninth Amendment also added a new minimum interest coverage ratio, where EBITDA to interest expense cannot be less than 2.5 to 1.0.

Additionally, under the terms of the Credit Agreement as amended by the Ninth Amendment, subject to certain conditions set forth in the Credit Agreement, the Company is permitted to incur up to $600,000,000 of additional unsecured senior or senior subordinated debt. Subject to certain limited exceptions specified in the Credit Agreement (including an exception for debt under the Credit Agreement), the Company is prohibited from issuing additional secured debt without consent of the lenders.

The foregoing description of the Ninth Amendment to the Credit Agreement is a summary only and is qualified in its entirety by reference to the Ninth Amendment to the Credit Agreement, attached hereto as Exhibit 10.21, which is incorporated herein by reference.

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 2015 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 2015 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 2015 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 2015 annual meeting under the heading “Certain Transactions” and “Corporate Governance and Committees of the Board.”

Item 14. Principal Accounting 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 2015 annual meeting under the heading “Audit and Non-Audit Fees Summary.”

Part IV

Item 15. Exhibits, 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	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)).
4.2	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)).
4.3	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)).
4.4	Third Supplemental Indenture, dated as of May 29, 2014, 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 29, 2014 (Registration No. 000-51801)).
10.1 †	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)).
10.2 †	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 (Registration No. 000-51801)).
10.3 †	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)).
10.4 †*	Form of 2013 Long-Term Incentive Plan Restricted Stock Award Agreement.
10.5 †	Form of 2005 Long-Term Incentive Plan 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)).
10.6 †*	Form of 2013 Long-Term Incentive Plan Performance Share Unit Award Agreement.
10.7 †	Form of 2005 Long-Term Incentive Plan Performance Share Unit Award Agreement (incorporated herein by reference to Exhibit 10.39 to the Company's Annual Report on Form 10-K filed on February 26, 2013 (Registration No. 000-51801)).

Exhibit Number	Description
10.8 †*	Form of 2013 Long-Term Incentive Plan – 2014 Incentive Plan Restricted Stock Award Agreement.
10.9 †	Form of 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)).
10.10 †	Executive Severance Plan, effective as of July 1, 2008 (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)).
10.11 †	2009 Change in Control Plan for Executive Officers, effective as of December 7, 2009 (incorporated herein by reference to Exhibit 10.55 to the Company's Annual Report on Form 10-K filed on February 24, 2014 (Registration No. 000-51801)).
10.12	Amended and Restated Senior Revolving Credit Agreement, dated as of April 9, 2009, among Rosetta Resources Inc., as borrower, BNP Paribas, as administrative agent, and the lenders party thereto (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)).
10.13	First Amendment to Amended and Restated Senior Revolving Credit Agreement, effective as of October 1, 2009, among Rosetta Resources Inc., as borrower, BNP Paribas, as administrative agent, and the lenders party thereto (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)).
10.14	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)).
10.15	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)).
10.16	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)).
10.17	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)).

10.18	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)).
10.19	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 Quarterly Report on Form 10-Q filed on November 6, 2013 (Registration No. 000-51801)).
10.20	Omnibus Eighth Amendment to Amended and Restated Senior Revolving Credit Agreement effective as of April 2, 2014, 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 10.1 to the Company's Current Report on Form 8-K filed on April 3, 2014 (Registration No. 000-51801)).
10.21 *	Ninth Amendment to Amended and Restated Senior Revolving Credit Agreement, effective as of February 18, 2015, among Rosetta Resources Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders signatory thereto.

Exhibit Number	Description
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.

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 23, 2015.

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 23, 2015
/s/ John E. Hagale John E. Hagale	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 23, 2015
/s/ Don O. McCormack Don O. McCormack	Senior Vice President, Treasurer and Chief Accounting Officer (Principal Accounting Officer)	February 23, 2015
/s/ Philip L. Frederickson Philip L. Frederickson	Lead Director	February 23, 2015
/s/ Matthew D. Fitzgerald Matthew D. Fitzgerald	Director	February 23, 2015
/s/ Carin S. Knickel Carin S. Knickel	Director	February 23, 2015
/s/ Holli C. Ladhani Holli C. Ladhani	Director	February 23, 2015

/s/ Donald D. Patteson, Jr. Donald D. Patteson, Jr.	Director	February 23, 2015
/s/ Jerry R. Schuyler Jerry R. Schuyler	Director	February 23, 2015

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.

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.

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, NGL 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.

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.

MMBoe. 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.

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.

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 (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.