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.

Table of Contents

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;

- 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				