Rosetta Resources Inc.
Form 10-K
February 27, 2012
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x **Annual Report Pursuant To Section 13 or 15(d) of the Securities Exchange Act of 1934**
For The Fiscal Year Ended December 31, 2011

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	**43-2083519**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
717 Texas, Suite 2800, Houston, TX	**77002**
(Address of principal executive offices)	**(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. ¨

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, 2011 was approximately $2.7 billion based on the closing price of $51.54 per share on the Nasdaq Global Select Market.

The number of shares of the registrant s Common Stock, $.001 par value per share, outstanding as of February 17, 2012 was 53,266,855.

Documents Incorporated By Reference

Portions of the definitive proxy statement relating to the 2012 annual meeting of stockholders to be filed with the Securities and Exchange Commission are incorporated by reference in answer to Part III of this Form 10-K.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Form 10-K contains forward-looking statements regarding factors that we believe may affect our performance in the future. Such statements typically are identified by terms expressing our future expectations or projections of revenues, earnings, earnings per share, cash flow, market share, capital expenditures, effects of operating initiatives, gross profit margin, debt levels, interest costs, tax benefits and other financial items. All forward-looking statements are based on assumptions about future events and are therefore inherently uncertain, and actual results may differ materially from those expected or projected. Important factors that may cause our actual results to differ materially from expectations or projections include those described under the heading Risk Factors in Item 1A of this Form 10-K. Forward-looking statements speak only as of the date of this report, and we undertake no obligation to update or revise such statements to reflect new circumstances or unanticipated events as they occur.

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 primarily located in South Texas, including our largest producing area in the Eagle Ford shale, and in the Southern Alberta Basin in Northwest Montana. Our headquarters are located in Houston, Texas, and we have field offices in Laredo and Catarina, Texas.

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

Our Strategy

Our strategy is to increase stockholder value by delivering visible and sustainable growth from unconventional onshore domestic basins. As part of this strategy, we expect to continue developing as a successful unconventional resource player with sufficient project inventory to drive production growth. We recognize that there may be market cycles that could impact our growth strategy on a short-term basis. However, we believe our plan is fundamentally sound and emphasizes (i) developing our high return inventory in the Eagle Ford shale in South Texas, (ii) establishing new positions in resource plays through a balanced approach of exploration and producing property acquisitions, (iii) expanding our unconventional resource initiatives through the divestiture of lower return assets, (iv) applying technological expertise, (v) focusing on cost control and (vi) maintaining financial flexibility. We seek to continue our strategy while increasing stockholder value through sound stewardship, wise capital resource management, taking advantage of business cycles and emerging trends and minimizing liabilities through governmental compliance and protecting the environment. Below is a discussion of the key elements of our strategy.

Develop Our High Return Inventory in the Eagle Ford Shale. In 2010, Rosetta successfully delineated Gates Ranch comprised of approximately 26,500 acres in the liquids-rich portion of the Eagle Ford shale. We continued to build upon this success in 2011 by completing closer spaced wells in two pilot areas in the north

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half of Gates Ranch. The wells drilled in both pilot areas initially produced with similar rates to previous wells drilled on wider spacing and we will evaluate the long-term production results over the next few months from the pilot areas to determine optimum future spacing. We have also tested with positive results three new locations across 13,600 net acres outside Gates Ranch.

The Eagle Ford shale has become our largest producing area providing approximately 78% of our total production for 2011. In addition, approximately 53% of the production from the Eagle Ford shale in 2011 was from crude oil and natural gas liquids (NGLs). In a weak natural gas market, our extensive inventory of investment opportunities in the Eagle Ford shale provides higher economic returns than other opportunities in areas previously considered core to our operations. The Eagle Ford shale has become a major source of production and reserves for Rosetta and reflects the success of our transition to an unconventional resource player.

Establish New Positions in Resource Plays. We intend to extend our operational footprint into new areas within the U.S. characterized by a significant presence of resource potential that can be exploited utilizing our technological expertise. We strive to minimize the cost of entry into these plays through financial discipline in our leasehold acquisition activities and prudent management of financial and operational resources during the testing phase.

Expand Our Unconventional Resource Initiatives Through Divestiture of Lower Return Assets. With the growth of our shale activities, we have taken steps to streamline our operations by divesting assets that no longer fit our operating model and redeploying the sales proceeds from such divestitures into our growth initiatives. Since 2010, we have executed purchase and sale agreements relating to the sale of properties in nine states for an aggregate consideration of approximately $345 million. This strategy has allowed us to establish a competitive operating presence in the Eagle Ford shale, one of the most active shale basins in the U.S. that offers a growing inventory of drilling locations with attractive economics. As we continue to focus on our unconventional resource plays, we would consider divesting additional lower-return assets in 2012.

Apply Technological Expertise. We intend to maintain, further develop and apply the technological expertise that helped us achieve a net drilling success rate of 100% in 2011 and helped us establish a major production base in the Eagle Ford shale. Our definition of drilling success is a well that is producing or capable of production, including wells awaiting pipeline connections to commence deliveries or awaiting connection to production facilities. 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.

Focus on Cost Control. We manage all elements of our cost structure, including drilling and operating costs as well as overhead costs. We strive to minimize our drilling and operating costs by concentrating our activities within existing and new unconventional resource play areas where we can achieve efficiencies through economies of scale. As part of our strategy to minimize costs, we have taken aggressive steps to ensure access to transportation and processing facilities and oilfield services, specifically within the Eagle Ford shale, a region where midstream services are in high demand and infrastructure is under construction. In 2011, we incurred $22.3 million of costs related to these services and as we increase production within the Eagle Ford shale, our midstream service related costs will increase.

Maintain Financial Flexibility. As of December 31, 2011, we had drawn $30.0 million and had $295.0 million available for borrowing under our revolving credit facility. In early 2012, we borrowed an additional $50.0 million to invest in capital expenditures and as a result, we have $245.0 million available for borrowing under our revolving credit facility. We expect internally generated cash flows and cash on hand, supplemented by borrowings under the revolving credit facility and proceeds from asset divestitures, to provide financial flexibility to further develop our assets in the next few years. We intend to continue to actively manage our exposure to commodity price risk in the marketing of our oil, NGL and natural gas production. As of December 31, 2011, we have entered into a series of commodity derivative contracts for 2012 and 2013 as part of this strategy.

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Our Strengths

Our business strategy is to continue our development as a successful unconventional resource player delivering continued growth and enhanced stockholder value. We believe the following key strengths have enabled us to achieve that strategy.

Early Entry and Highly Competitive Position in the Eagle Ford Shale. We hold an asset position in the Eagle Ford shale that we believe will provide a strong foundation for future growth. As of December 31, 2011, we held a 65,000 net acre leasehold position with approximately 78% lying in the liquids-rich area of the Eagle Ford shale.

Resource Assessment Capability and Inventory Generation. We have established multi-disciplinary teams that are skilled at conducting comprehensive resource assessments on a field and regional basis. This work helps us to indentify and catalog an inventory of low to moderate risk opportunities for multiple years of drilling projects. We expect to continue to add to our diversified portfolio of non-proved project inventory by entering into additional emerging unconventional resource plays.

Operational Control. We operate approximately 99% of our estimated proved reserves, which allows us to more effectively manage expenses and control the timing of capital spending on our exploration and development operations.

Experienced Management and Technical Team. Our executive management team has a broad knowledge of the exploration and production business with specific expertise in the areas where we operate. With the transition to an unconventional resource player, Rosetta recruited additional management and technical talent with previous experience in finding and developing unconventional resources. This collective ability is a competitive advantage in the execution of our business strategy.

Our Operating Areas

We own producing and non-producing oil and gas properties in proven or prospective basins that are primarily located in South Texas, including our largest producing area in the Eagle Ford shale, and in the Southern Alberta Basin in Northwest Montana. In 2011, we drilled 64 gross and 53 net wells, with a net success rate of 100%. The following is a summary of our major operating areas.

South Texas

As of December 31, 2011, we owned approximately 115,000 net acres in South Texas. Our production in South Texas comes from the Eagle Ford shale trend and the Lobo and Olmos fields, which averaged 25.3 MBoe/d (152 MMcfe/d) in 2011, an increase of approximately 116% from the prior year. In 2011, our production from properties outside the Eagle Ford shale averaged 3.9 MBoe/d (23 MMcfe/d), which was 27% lower than prior year, reflecting our decision to divert capital away from lower priced natural gas producing areas to our higher return program in the Eagle Ford shale.

Eagle Ford Shale Trend. The Eagle Ford shale has become our largest producing area where we hold approximately 65,000 net acres, with 50,000 net acres located in the liquids-rich area of the play. Our 2010 and 2011 activities were focused in our 26,500-acre position in the Gates Ranch area in Webb County. We also began testing our acreage position outside Gates Ranch located in the liquids portion of the Eagle Ford shale and drilled three discovery wells in 2011. In total, we drilled 55 gross wells in the Eagle Ford shale in 2011, all of which were successful. For 2011, the Eagle Ford shale provided approximately 78% of our total production. In addition, approximately 53% of our production mix from the Eagle Ford shale in 2011 was attributable to crude oil and NGLs.

Lobo Trend. Discovered in 1973, the South Texas Lobo trend is a complex, highly faulted sand trend that has produced over 8 Tcf of natural gas. The Lobo trend produces from tight sands with low permeability and high pressures at depths from 7,500 to 10,000 feet. In the South Texas Lobo trend, we have 470 square miles of

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3-D seismic and 258 operated producing wells. Our working interests range primarily from 50% to 100%, but most of our acreage is 100% owned and operated. In 2011, our average net daily production from the Lobo trend was 3.2 MBoe/d (19 MMcfe/d).

Olmos Trend. We acquired a 70% non-operated working interest in 231 gross wells in the Olmos trend of South Texas in late 2008. In 2010, we acquired the remaining 30% working interest and obtained operatorship of these wells. Production from these wells averaged 0.7 MBoe/d (4 MMcfe/d) in 2011.

Rockies

Our Rockies operating area has historically included our DJ Basin, Pinedale, San Juan and Southern Alberta Basin assets. With the exception of our Southern Alberta Basin assets, most of these properties were divested in 2011 and 2010. The divestitures of these properties were not material to our operations but affect the comparability between periods. Remaining operations in the Rockies include our Southern Alberta Basin assets as well as multiple non-operated assets.

In 2011, we continued our exploratory initiative in the Southern Alberta Basin in Northwest Montana. The play is a westward analog of the industry s Bakken and Three Forks plays of the Williston Basin in Montana and North Dakota. We control approximately 300,000 net acres in the play, either through option or lease agreements.

In late 2009, we began an eleven-well vertical drilling program to assess the commerciality of the play that was completed during the second quarter of 2011. The results from that effort have increased our understanding of the play and contributed to the design of a horizontal drilling program that is currently underway. In 2011, we drilled four of the seven planned horizontal wells and drilling operations will continue on the remaining three wells in 2012.

Divestiture Activities

As part of our strategic decision to focus on the Eagle Ford shale, we divested certain gas-based assets that we believe did not offer the same investment opportunities or rates of return as our unconventional resources. In 2011, we divested our assets located in the DJ Basin in Colorado and in the Sacramento Basin in California for $255 million, and in 2010, we divested our assets located in Arkansas, Oklahoma, Mississippi, Texas, Louisiana, New Mexico and Wyoming for approximately $90 million. These divestitures were all subject to post-closing adjustments. See Item 8. Financial Statements and Supplementary Data, Note 4 - Property, Plant and Equipment.

On February 15, 2012, we entered into an agreement to sell our Lobo assets and a portion of our Olmos assets for $95.0 million, subject to customary adjustments and the receipt of appropriate consents for assignment.

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 facilities. 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 gas industry. As is customary in the oil and 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.

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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:

	For the Year Ended December 31, 2011			
	Oil (MBbls)	NGLs (MBbls)	Natural Gas (Bcf)	Equivalents (MBoe) (1)
Eagle Ford	1,747.4	2,396.2	22.1	7,824.2
South Texas	43.0	247.1	6.9	1,448.4
California	43.7		3.4	617.0
Rockies	9.5		0.9	153.2
Gulf Coast	19.6		0.1	29.2
Other Onshore	0.1			0.1
Total	1,863.3	2,643.3	33.4	10,072.1

	For the Year Ended December 31, 2010			
	Oil (MBbls)	NGLs (MBbls)	Natural Gas (Bcf)	Equivalents (MBoe) (1)
Eagle Ford	536.0	690.0	6.6	2,329.8
South Texas	68.0	381.0	11.2	2,311.6
California	27.0		13.6	2,295.3
Rockies	21.0	1.0	6.6	1,120.2
Gulf Coast	47.0	15.0	0.5	148.5
Other Onshore	39.0	9.0	0.7	163.6
Total	738.0	1,096.0	39.2	8,369.0

	For the Year Ended December 31, 2009			
	Oil (MBbls)	NGLs (MBbls)	Natural Gas (Bcf)	Equivalents (MBoe) (1)
Eagle Ford	9.0	12.0	0.4	88.4
South Texas	121.9	549.1	17.2	3,526.4
California	28.0		15.3	2,580.5
Rockies	20.0		6.8	1,152.7
Gulf Coast	135.0	38.0	3.3	720.6
Other Onshore	80.0	21.0	1.5	356.5
Total	393.9	620.1	44.5	8,425.1

(1) 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 commodity pricing. Therefore, the reserve information in this report

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represents only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of oil, NGLs and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent that we acquire additional properties containing proved reserves or conduct successful exploration and development activities, or both, our proved reserves will decline as reserves are produced.

As of December 31, 2011, we had an estimated 161 MMBoe (965 Bcfe) of proved reserves, including 36,370 MBbls of oil, 50,219 MBbls of NGLs and 446 Bcf of natural gas, of which 36% was proved developed. Based on the 2011 twelve-month first-day-of-the-month historical average prices as adjusted for basis and quality differentials for West Texas Intermediate oil of $92.71 per Bbl and Henry Hub natural gas of $4.12 per MMBtu, our reserves had an estimated standardized measure of discounted future net cash flows of $1.7 billion as of December 31, 2011.

The following table sets forth, by operating area, a summary of our estimated net proved reserve information as of December 31, 2011:

	Estimated Proved Reserves at December 31, 2011 (1)(2)									
	Developed				Undeveloped					Percent
	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Total (MMBoe) (3)	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Total (MMBoe) (3)	Total (MMBoe) (3)	of Total Reserves
Eagle Ford	11.4	14.8	121.0	46.3	24.6	33.6	268.7	103.0	149.3	93%
South Texas	0.3	1.8	55.8	11.4					11.4	7%
Rockies (4)	0.1		0.2	0.1					0.1	0%
Other Onshore			0.3	0.1					0.1	0%
Total	11.8	16.6	177.3	57.9	24.6	33.6	268.7	103.0	160.9	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) 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.
(4) Our Rockies operating area has historically included our DJ Basin, Pinedale, San Juan and Southern Alberta Basin assets. With the exception of our Southern Alberta Basin assets, most of these properties were divested in 2011 and 2010. Remaining operations in the Rockies include our Southern Alberta Basin assets as well as multiple non-operated assets.

All of our proved undeveloped reserves at December 31, 2011 are scheduled for development within five years from the date recorded as a proved undeveloped reserve.

As of December 31, 2011, we had proved undeveloped reserves of 103 MMBoe (618 Bcfe), an increase of 64 MMBoe (384 Bcfe) from December 31, 2010. Significant additions of proved reserves resulted primarily from the completion of 39 successful producing wells and the addition of 62 proved undeveloped locations in the Gates Ranch area. The successful drilling and completion of wells in all lease line directions and interior wells in the north half of Gates Ranch provided evidence of a continuous accumulation of hydrocarbons in the north half of Gates Ranch. We spent approximately $214 million in 2011 for the development of 17 MMBoe (102 Bcfe) of

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proved undeveloped reserves from 29 wells in the Gates Ranch area, reflecting the development of 44% of our 2010 year-end proved undeveloped reserves. Twenty-three wells that were more than one location from a 2010 producing well were successfully completed and producing in 2011. The increase in reserves is also attributable to an increase of 22 MMBoe (134 Bcfe) of performance revisions due to better than expected performance in the Eagle Ford shale.

Technology Used to Establish Proved Reserves

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

- The review of internal reserve estimates by well and by area by the Corporate Engineering Manager. 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 and the Corporate Engineering Manager to ensure the best estimate of remaining reserves.

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

The Company s primary reserves estimator is Mark D. Petrichuk, Corporate Engineering Manager. Mr. Petrichuk has 34 years of experience in the petroleum industry spent almost entirely in the evaluation of reserves and income attributable to oil and 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 Corporate Engineering Manager maintains oversight and compliance responsibility for the internal reserve estimate process and provides appropriate data to and oversees the independent third party engineers for the annual audit of our year-end reserves.

Qualifications of Third Party Engineers

The reserves estimates shown herein have been independently audited by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under the Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for auditing the estimates set forth in the NSAI audit incorporated herein are Mr. Danny Simmons and Mr. David Nice. Mr. Simmons has been a practicing consulting petroleum engineer at NSAI since 1976. Mr. Simmons is a Registered Professional Engineer in the State of Texas (License No. 45270) and has more than 30 years of practical experience in petroleum engineering, with over 35 years experience in the estimation and evaluation of

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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 Certified Petroleum Geologist and Geophysicist in the State of Texas (License No. 346) and has over 26 years of practical experience in petroleum geosciences, with over 12 years 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 Geophysics. 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, 2011, 2010 and 2009:

	Year Ended December 31,		
	2011	2010	2009
	(In thousands)		
Capital expenditures	$ 452,304	$ 268,578	$ 90,524
Leasehold	10,605	49,328	22,066
Acquisitions		5,986	3,624
Delay rentals	1,144	1,193	1,683
Geological and geophysical/seismic	2,638	518	8,558
Exploration overhead	7,049	7,775	4,806
Capitalized interest	5,511	4,017	1,174
Other corporate	296	2,042	2,942
Total capital expenditures	$ 479,547	$ 339,437	$ 135,377

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, 2011. Gross represents the total number of acres or wells in which we own a working interest. Net represents our proportionate working interest resulting from our ownership in the gross acres or wells. Productive wells are wells in which we have a working interest and that are capable of producing oil or natural gas.

	Undeveloped Acres		Developed Acres		Productive Wells (2)			
					Gross		Net	
	Gross	Net	Gross	Net	Oil	Natural Gas	Oil	Natural Gas
Eagle Ford	92,347	53,042	12,401	12,402	2	62	2	60
South Texas	131	131	56,103	51,435	2	495	2	460
California								
Rockies (1)	86,853	70,193	2,802	610	2	1		
Gulf Coast			13,372	6,319			1	
Other Onshore	22,902	21,340				7		3
Total	202,233	144,706	84,678	70,766	6	565	5	523

(1) Excludes approximately 228,000 net undeveloped acres under exploration option in the Southern Alberta Basin.

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(2) Of our productive wells listed above, there were nine multiple completions in Texas.

The following table shows our interest in undeveloped acreage as of December 31, 2011 that is subject to expiration in 2012, 2013, 2014 and thereafter:

2012		2013		2014		Thereafter	
Gross	Net	Gross	Net	Gross	Net	Gross	Net
16,611	14,804	55,823	19,251	12,624	11,016	117,175	99,635

Drilling Activity

The following table sets forth the number of gross exploratory and gross development wells 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
2011	5.0		5.0	59.0		59.0
2010	10.0		10.0	115.0	2.0	117.0
2009	7.0		7.0	30.0	6.0	36.0

The following table sets forth, for each of the last three fiscal years, the number of net exploratory and net development wells drilled by us based on our proportionate working interest in such wells.

	Net Wells					
	Exploratory			Development		
	Productive	Dry	Total	Productive	Dry	Total
2011	5.0		5.0	47.9		47.9
2010	9.9		9.9	112.4	2.0	114.4
2009	6.1		6.1	23.4	6.0	29.4

At December 31, 2011, we had 16 wells in process. Of these wells, 15 were located in the Eagle Ford shale where we own a 90% working interest in six wells and a 100% working interest in the remaining nine wells. We own a 100% working interest in one well located in the Southern Alberta Basin that was in the process of being drilled.

Marketing

We market the oil, NGL and natural gas production from properties we operate for both our account and the accounts of the other working interest owners in our properties. We sell our production to a variety of purchasers under purchase contracts with daily, monthly, seasonal, annual or multi-year terms, all at market prices. Our oil production is sold to third parties who collect the oil at the wellhead on the lease or at a truck loading terminal we have contracted with to gather and load oil onto purchasers trucks. We sell our oil production under contracts priced on the daily settlement price of the New York Mercantile Exchange (NYMEX), prompt month contract for West Texas Intermediate or regional oil postings. All prices are adjusted for location, quality, gravity and transportation differentials. Our natural gas is transported and sold under contract at a negotiated price the majority of which is based on the Houston Ship Channel index, adjusted for transportation or market conditions. Our NGLs that are extracted from the natural gas during processing are purchased by the processors and priced based on the average daily price of NGLs at Mont Belvieu. We do not believe the loss of any one of our purchasers would materially affect our ability to sell the oil and natural gas we produce. We believe other purchasers are available in our areas of operations.

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Major Customers

In 2011, four customers, Shell Trading (US) Company, Regency Gas Services, LLC, Calpine Energy Services and ExxonMobil Corporation, accounted for the majority of our consolidated revenue, excluding hedging. The loss of any one of these customers would not have a material adverse effect on our operations as we believe 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 for, produce and market oil and natural gas, carry on refining operations and market the resulting products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and natural gas properties, securing sufficient capacity from processing and/or refining facilities for our NGL production, and obtaining purchasers and transporters of the oil, NGLs and natural gas we produce. There is also competition between producers of oil, NGLs and natural gas and other industries 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 the federal, state and local government. 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 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, but not always, the demand for oil and natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or abnormally hot summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other oil and natural gas operations in certain areas. These seasonal anomalies can increase competition for equipment, supplies and personnel.

Government Regulation

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

Exploration and Production Regulation

Oil, NGL and natural gas production is regulated under a wide range of federal, state and local statutes, rules, orders and regulations, including laws related to the location, drilling and casing of wells; well production 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 gas companies can encounter delays in drilling from the permitting process and requirements. Our operations are subject to regulations governing

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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

General. 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. On July 28, 2011 the U.S. Environmental Protection Agency (EPA) proposed new air emissions regulations targeted primarily at the upstream oil and gas industry. Although, they are expected to be finalized on April 3, 2012 with no phase-in period, it is anticipated that they will be challenged by industry associations.

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 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 EPA has begun to regulate greenhouse gas emissions. In 2009 and 2010, the EPA promulgated new greenhouse gas reporting rules, requiring certain petroleum and natural gas facilities and facilities that emit more than 25,000 tons per year of carbon dioxide equivalents (CO_2e) to prepare and file annual emission reports. These rules, which are currently in effect and to which some of our facilities are subject, require some data reporting in 2012 for our facilities that emitted more than 25,000 tons of CO_2e in 2011. In addition, on May 13, 2010, the EPA issued a new tailoring rule, which imposes additional permitting requirements on certain stationary sources emitting over 75,000 tons per year of CO_2e. This rule does not currently affect our operations but may as our operations grow. As a result of these regulatory initiatives, our operating costs may increase due to compliance with these programs, although we are not situated differently in this respect from our competitors in the industry.

Hydraulic Fracturing. Various federal and state initiatives are underway to regulate, or further investigate, the environmental impacts of hydraulic fracturing, a practice that involves the pressurized injection of water, chemicals and other substances into rock formation to stimulate production of oil and natural gas. The U.S.

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Congress has considered legislation to amend the federal Safe Drinking Water Act (SDWA) to subject hydraulic fracturing operations to regulation under the SDWA s Underground Injection Control Program and to require the disclosure of chemicals used in the hydraulic fracturing process. Any such legislation could make it easier for third parties opposed to hydraulic fracturing to initiate legal proceedings against us. In addition, the federal government is currently undertaking several studies of hydraulic fracturing s potential impacts. The Secretary of Energy Advisory Board published their ninety-day report that included a number of recommendations. On December 14, 2011 the EPA published a draft of a report, Investigation of Ground Water Contamination near Pavillion, Wyoming that implicates hydraulic fracturing in the contamination of groundwater near Pavillion, Wyoming. This report is a draft and is being contested by the industry. The results of the other studies are expected by the end of 2012. The EPA is developing permitting guidance under the SDWA for hydraulic fracturing activities that use diesel fuels in fracturing fluids. In addition, on October 21, 2011, the EPA announced its intention to propose regulations by 2014 under the federal Clean Water Act to regulate waste water discharges from hydraulic fracturing and other natural gas production. While we are in material compliance with applicable environmental laws and regulations and do not use diesel fuels as one of our hydraulic fracturing fluid components, the increased legislation, regulation or enforcement of hydraulic fracturing operations at the federal level could lead to operational delays, increased operating costs and additional regulatory burdens for our business.

Furthermore, a number of states, local governments and regulatory commissions have adopted, or are evaluating the adoption of, legislation or regulations that could impose more stringent permitting, disclosure, well construction and wastewater disposal requirements on hydraulic fracturing operations. On December 13, 2011 the Texas Railroad Commission adopted the Hydraulic Frac Fluid Disclosure rule that requires disclosure of hydraulic fracturing fluid contents via the FracFocus.com website for drilling permits issued after February 1, 2012. Additionally, on August 26, 2011, the Montana Board of Oil and Gas Conservation adopted rules that would require the public disclosure of fracturing fluid constituents. Because we already participate in public disclosure on the FracFocus.com internet site we do not anticipate experiencing a material adverse effect from such 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.

Derivative Transactions. On July 21, 2010, the President signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), which, among other provisions, establishes federal oversight and regulation of the derivatives market and entities that participate in that market. The legislation requires the Commodities Futures Trading Commission (the CFTC) and the SEC to promulgate rules and regulations implementing the legislation within 360 days from the date of enactment. CFTC rulemaking is ongoing. Some rules have been finalized, while other rules are still in the proposed or earlier stages. The effect of the rules and any additional regulations on our business is currently uncertain. Of particular concern, the Dodd-Frank Act does not explicitly exempt end users (such as us) from the requirements to post margin in connection with hedging activities. The requirements to be enacted, to the extent applicable to us or our derivatives counterparties, may result in increased costs and cash collateral requirements for the types of derivative instruments we use to hedge and otherwise manage our financial and commercial risks related to fluctuations in oil, NGL and natural gas commodity prices. Any of the foregoing consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

Insurance Matters

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

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Filings of Reserve Estimates with Other Agencies

We annually file estimates of our oil and natural gas reserves with the U.S. Department of Energy (DOE) for those properties which we operate. During 2011, we filed estimates of our oil and natural gas reserves as of December 31, 2010 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, 2010. For information concerning proved reserves, refer to Item 8. Financial Statements and Supplementary Data, Supplemental Oil and Gas Disclosures.

Employees

As of February 17, 2012, we had 165 full time employees. We also contract for the services of consultants involved in land, regulatory, accounting, financial, legal and other disciplines, as needed. None of our employees are represented by labor unions or covered by any collective bargaining agreement. We believe that our relations with our employees are satisfactory.

Available Information

Through our website, *http://www.rosettaresources.com,* you can access, free of charge, our filings with the SEC, including our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, our proxy statements, our Code of Business Conduct and Ethics, Nominating and Corporate Governance Committee Charter, Audit Committee Charter, and Compensation Committee Charter. You may also read and copy any materials that we file with the SEC at the SEC s Public Reference Room at 100 F Street, NE, Room 1580, Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains a website that contains reports, proxy and information statements and other information that is filed electronically with the SEC. The website can be accessed at *http://www.sec.gov*.

Item 1A. Risk Factors

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

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

- Domestic and foreign supply of oil, NGLs and natural gas;
- Price and quantity of foreign imports of oil, NGLs and natural gas;
- Actions of the Organization of Petroleum Exporting Countries and state-controlled oil companies relating to oil price and production controls;
- 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 the current conflicts in the Middle East and conditions in South America and Russia;

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- The availability of refining capacity;
- Weather conditions and natural disasters;
- Technological advances affecting oil, NGL and natural gas production and consumption;
- Overall U.S. and global economic conditions;
- Price and availability of alternative fuels;
- Seasonal variations in oil, NGL and natural gas prices;
- Variations in levels of production; and
- The completion of large domestic or international exploration and production projects.

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

- Negatively impact the value of our reserves, because declines in oil, NGL and natural gas prices would reduce the value and amount of oil, NGLs and natural gas that we can produce economically;
- Reduce the amount of cash flow available for capital expenditures, repayment of indebtedness, and other corporate purposes; and
- Result in a decrease in the borrowing base under our revolving credit facility or otherwise limit our ability to borrow money or raise additional capital.

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

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

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 revolving credit facility and second lien term loan and/or the ability or willingness of other lenders to participate in such credit facilities. These market conditions may adversely affect our liquidity by limiting our ability to access these credit facilities.

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

While we seek to fund our capital expenditures primarily from cash flows from operating activities, we have in the past also drawn on unused capacity under our existing revolving credit facility for capital expenditures. Borrowings under our existing revolving 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. A reduction in our ability to borrow under our existing revolving credit facility may require us 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 gas leases, we may be unable to produce adequate quantities of oil and gas to retain these leases and they may expire due to a lack of production. The loss of leases could have a material adverse effect on our results of operations.

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

Development and exploration drilling and strategic acquisitions are the main methods of replacing reserves. However, development and exploration drilling operations may not result in any increases in reserves for various reasons. Our future oil, NGL and natural gas production depends on our success in finding or acquiring additional reserves. If we fail to replace reserves through drilling or acquisitions, our level of production and cash flows will be affected adversely. In general, production from oil and natural gas properties declines as reserves are depleted, with the rate of decline depending 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.

We will require additional capital to fund our future activities. If we fail to obtain additional capital, we may not be able to implement fully our business plan, which could lead to a decline in reserves.

In the future, we will require substantial capital to fund our business plan and operations. Sufficient capital may not be available on acceptable terms or at all. If we cannot obtain additional capital resources, we may curtail our drilling, development and other activities or be forced to sell some of our assets on unfavorable terms.

The terms of our credit facilities contain a number of covenants. If we are unable to comply with these covenants, our lenders could accelerate the repayment of our indebtedness.

The terms of our credit facilities subject us to a number of covenants 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 facilities to comply with financial covenants. A more detailed description of our credit facilities 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 Consolidated Financial Statements.

A breach of any of the covenants imposed on us by the terms of our indebtedness, including the financial covenants under our credit facilities, could result in a default under such indebtedness. In the event of a default, the lenders for our revolving credit facility could terminate their commitments to us, and they and the lender of our second lien term loan 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 under the credit facilities 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 revolving credit facility also limits the amounts we can borrow to a borrowing base amount, as determined by the lenders in accordance with the credit agreement. Outstanding borrowings in excess of the borrowing base will be required to be repaid immediately, or we will be required to pledge other oil and natural gas properties as additional collateral.

Our exploration and development activities may not be commercially successful.

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

- Reductions in oil, NGL and natural gas prices;

- Unexpected drilling conditions;

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- Pressure or irregularities in formations;
- Equipment failures, including corrosion of aging equipment, systems failures and extended downtime, or accidents;
- Unavailability or high cost of drilling rigs, equipment or labor;
- Lost or damaged oilfield development and services tools;
- Limitations in midstream infrastructure or the lack of markets for oil, NGLs and natural gas;
- Unavailability or high cost of processing and transportation;
- Human error;
- Community unrest;
- Sabotage, terrorism and border issues, including encounters with illegal aliens and drug smugglers;
- Adverse weather conditions, including severe droughts resulting in new restrictions on water usage;
- Environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases;
- Compliance with environmental and other governmental regulations;
- Possible federal, state, regional and municipal regulatory moratoriums on new permits, delays in securing new permits, changes to existing permitting requirements without grandfathering of existing permits and possible prohibition and limitations with regard to certain completion activities; and
- Increase 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 producible economically. 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 present value calculations may not be accurate. Any material inaccuracies in these reserve estimates or underlying assumptions will affect materially 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

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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, 2011 were based on the trailing twelve-month first-day-of-the-month historical unweighted-averages of West Texas Intermediate oil prices adjusted for basis and quality differentials of $92.71 per Bbl and Henry Hub gas prices adjusted for basis and quality differentials of $4.12 per MMBtu. Actual future prices and costs fluctuate over time and may differ materially from those used in the present value estimate. In addition, discounted future net cash flows are estimated assuming royalties to the Bureau of Ocean Energy Management, Regulation and Enforcement (formerly known as the Minerals Management Service) of the U.S. Department of the Interior, royalty owners and other state and federal regulatory agencies with respect to our affected properties, and will be paid or suspended during the life of the properties based upon prices as of the date of the estimate.

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

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

Under the full cost method, we are subject to quarterly calculations of a ceiling, or limitation, on the amount of our oil and gas properties that can be capitalized on our balance sheet. If the net capitalized costs of our oil and 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, it 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 for us to re-evaluate the calculation subsequent to the end of the period if prices increase. It also dictates that costs in effect as of the last day of the quarter are held constant. The risk that we will be required to write-down the carrying value of oil and natural gas properties increases when oil and natural gas prices are depressed or volatile. In addition, a write-down of proved oil and natural gas properties may occur if we experience substantial downward adjustments to our estimated proved reserves. It is possible that we may recognize revisions to our proved reserves in the future. Write-downs recorded in one period will not be reversed in a subsequent period even though higher oil and natural gas prices may have increased the ceiling applicable in the subsequent period.

We did not record any write-down or impairment for the years ended December 31, 2011 or 2010. We recognized a non-cash, pre-tax ceiling test impairment of $379.5 million in the first quarter of 2009. Due to the volatility of commodity prices, however, should oil and natural gas prices decline in the future, it is possible that write-downs could occur.

See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates for further information.

Government laws and regulations can change.

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

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and regulations could affect our costs of operations, production levels, royalty obligations, price levels, environmental requirements, and other aspects of our business, including our general profitability. We are unable to predict changes to existing laws and regulations. For example, the EPA has recently focused on public concerns about the risk of water contamination and public health problems from drilling and hydraulic fracturing activities. This renewed focus could lead to additional federal and state regulations affecting the oil and gas industry. On July 28, 2011, the EPA proposed new air emissions regulations targeted primarily at the upstream oil and gas industry. Although, they are expected to be finalized on April 3, 2012 with no phase-in period, it is anticipated that they will be challenged by industry associations. Additional regulations or other changes to existing laws and regulations could significantly impact our business, results of operations, cash flows, financial position and future growth.

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

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

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

Market conditions, the unavailability of satisfactory oil, NGL and natural gas processing and transportation to available markets or the remote location of certain of our drilling operations may hinder our access to markets or delay our production. The availability of a ready market for our various products depends on a number of factors, including the demand for and supply of oil, NGLs and natural gas and the proximity of reserves to pipelines, terminals and trucking, railroad and/or barge transportation and processing facilities. Our ability to market our production also depends in substantial part on the availability and capacity of gathering systems, pipelines, terminals, other means of transportation and processing facilities. We may be required to shut in wells or delay production for lack of a market or because of inadequacy or unavailability of gathering systems, 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 certain geographic areas, such as the Eagle Ford shale, 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 realization of revenues.

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

We operate in a highly competitive environment for acquiring prospects and productive properties, marketing oil, NGLs and natural gas and securing equipment and trained personnel. Our competitors include major and large independent oil and natural gas companies that possess financial, technical and personnel resources substantially greater than our resources. Those companies may be able to develop and acquire more prospects and productive properties at a lower cost and more quickly than our financial or personnel resources

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permit. Our ability to acquire additional prospects and discover reserves in the future will depend on our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. Larger competitors may be better able to withstand sustained periods of unsuccessful drilling and absorb the burden of changes in laws and regulations more easily than we can, which would adversely affect our competitive position. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital.

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

Currently our operations are highly concentrated in South Texas, primarily in the Eagle Ford shale. As our largest producing area, this play provided approximately 83% of our total revenue for 2011, excluding the impact of hedging, and represents approximately 93% of our estimated total proved reserves as of December 31, 2011. This concentration increases the potential impact that many of the risks stated herein may have upon our ability to perform. For example, we have greater exposure to regulatory actions impacting Texas, natural disasters in the geographic area, competition for equipment, services and materials available in the area and access to infrastructure and markets.

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

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. If oil and natural gas prices increase in the future, increasing levels of exploration and production could result in response to these stronger prices, and as a result, the demand for oilfield services could rise, and the costs of these services could increase, while the quality of these services may suffer. If the unavailability or high cost of drilling rigs, equipment, supplies or qualified personnel were particularly severe in the Eagle Ford shale, we could be materially and adversely affected because our operations and properties are concentrated in this area.

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, earthquakes, mud slides, and flooding;

Pollution;

Releases of toxic gas; and

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

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

Our current insurance policies provide some coverage for losses arising out of our hydraulic fracturing operations. However, these policies may not cover fines, penalties or costs and expenses related to government-mandated clean-up activities, and total losses related to a spill, contamination or blowout during completion operations could exceed our per occurrence or aggregate policy limits. Furthermore, our current insurance policies do not provide coverage for ground water contamination due to any migration if not discoverable within 30 days, from fractured areas or from leaking associated with inadequate casing or cementing or defective and/or inadequate pipe and/or casing in the vertical sections of any of our shale wells that traverse aquifers in the locations of our producing properties. Any losses due to hydraulic fracturing that are not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

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

Hydraulic fracturing activities are required for all of our wells on our shale producing properties located in the Eagle Ford and Southern Alberta Basin regions in South Texas and Northwest Montana, respectively. All of our shale properties in these two regions are dependent on our ability to hydraulically fracture the producing formations. Commonly referred to as fracking, hydraulic fracturing is an integral part of the well completion process for all of our shale properties, including all of our exploration and development activities related to these properties.

The fracking involves pumping fluid at high pressure into underground shale formations through steel pipe that is perforated at the location of the hydrocarbons. The composition of the fluid is generally 99% water and sand or a ceramic material called proppant and less than 1% of highly diluted chemical additives, many of which are commonly found in household items. The high pressure creates small fractures that allow the oil and 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 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, both Montana and Texas have adopted regulations requiring certain hydraulic fracturing disclosures, in August and December of 2011, respectively. Hydraulic fracturing has also generated publicity regarding its potential environmental impact. 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. The adoption of any future federal, state or local laws or regulations imposing additional permitting, disclosure or regulatory

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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.

Although it is not possible at this time to predict the final outcome of the proposed legislation and regulations regarding hydraulic fracturing, any new restrictions on hydraulic fracturing that may be imposed in areas in which we conduct business 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 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, especially if this shortage occurred in South Texas or the Southern Alberta Basin, could materially and adversely affect our operations and the timeliness of executing our development plans within our budget.

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

Environmental matters and costs can be significant.

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

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

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases, may be contributing to the warming of the Earth s atmosphere. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of refined oil products and natural gas, are examples of greenhouse gases. The U.S. Congress is considering 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

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greenhouse gas emissions from certain facilities and is considering additional regulation of greenhouse gases as air pollutants under the existing federal Clean Air Act. In November 2010, the EPA adopted rules expanding the industries subject to greenhouse gas reporting to include certain petroleum and natural gas facilities. These rules require data collection beginning in 2011 and reporting beginning in 2012. Some of our facilities are subject to these rules. Passage of climate change legislation or other regulatory initiatives by Congress or various states, or the adoption of other regulations by the EPA or analogous state agencies, that regulate or restrict emissions of greenhouse gases (including methane or carbon dioxide) in areas in which we conduct business could have an adverse effect on our operations and the demand for oil 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 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 revolving 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 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, 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.

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Derivative transactions may limit our potential revenue, result in financial losses or 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 2013. 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. As of December 31, 2011, 62% of our crude oil derivative transactions represented hedged prices of crude oil at the West Texas Intermediate on the NYMEX with the remaining 38% at Light Louisiana Sweet, 100% of the total NGL derivative transactions represented hedged prices of NGLs at Mont Belvieu and 100% of total natural gas derivative transactions represented hedged prices of natural gas at the Houston Ship Channel. In addition, 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 in our credit facilities. Our lenders are comprised of banks and financial institutions that could default or fail to perform under our contractual agreements. A default under any of these agreements could negatively impact our financial performance.

Federal legislation regarding derivatives could have an adverse effect on our ability and cost of entering into derivative transactions.

On July 21, 2010, the President signed into law the Dodd-Frank Act which, among other provisions, establishes federal oversight and regulation of the derivatives market and entities that participate in that market. The legislation requires the CFTC and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. CFTC rulemaking is ongoing. Some rules have been finalized, while other rules are still in the proposed or earlier stages. The effect of the rules and any additional regulations on our business is currently uncertain. Of particular concern, the Dodd-Frank Act does not explicitly exempt end users (such as us) from the requirements to post margin in connection with hedging activities. The requirements to be enacted, to the extent applicable to us or our derivatives counterparties, may result in increased costs and cash collateral requirements for the types of derivative instruments we use to hedge and otherwise manage our financial and commercial risks related to fluctuations in oil, NGL and natural gas commodity prices. Any of the foregoing consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

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 that include commercial banks, investment banks, insurance companies, other investment funds and other institutions. Further deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us. We may have significant exposure to our derivative counterparties and the value of our derivative positions may provide a significant amount of cash flow. In addition, if any lender under our revolving 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 revolving credit facility. Currently, no single lender in our credit facility has commitments representing more than 12% 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 gas exploration and development may be eliminated as a result of future legislation.

Among the changes contained in the President s Fiscal Year 2013 budget proposal, released by the White House on February 13, 2012, is the elimination of certain U.S. federal income tax deductions and credits currently available to oil and 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 gas properties; (ii) the elimination of current

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deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Recently, members of the U.S. Congress have considered similar changes to the existing federal income tax laws that affect oil and gas exploration and production companies. It is unclear, however, whether any such changes will be enacted or, if enacted, how soon such changes would be effective. The passage of any legislation as a result of the budget proposal or any other similar change in U.S. federal income tax law could eliminate or defer certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition, results of operations and cash flows.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

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.

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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:

2011	High	Low	2010	High	Low
January 1 March 31	$ 49.55	$ 33.30	January 1 March 31	$ 25.20	$ 17.21
April 1 June 30	53.87	37.64	April 1 June 30	26.92	18.39
July 1 September 30	58.04	34.03	July 1 September 30	24.18	18.77
October 1 December 31	54.58	30.42	October 1 December 31	38.98	23.02

The number of shareholders of record on February 17, 2012 was approximately 171. 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 existing revolving credit facility, the indenture governing our 9.500% Senior Notes due 2018 (Senior Notes), and our existing term loan. 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, 2011:

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	2,107	$ 35.05		
November 1 November 30	1,645	42.32		
December 1 December 31	942	53.56		
Total	4,694	$ 41.31		

(1) All of the shares were surrendered by our employees and directors to pay tax withholding upon the vesting of restricted stock awards. Other than to satisfy tax withholding obligations, we do not have a publicly announced program to repurchase shares of common stock.

Stock Performance Graph

The following performance graph and related information shall not be deemed soliciting material or to be filed with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each *as amended, except to the extent that the Company specifically incorporates it by reference into such filing.*

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The following common stock performance graph shows the performance of Rosetta Resources Inc. common stock up to December 31, 2011. 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 Rosetta Resources Inc. common stock at the closing trade price of $18.67 per share on December 29, 2006 (the last full trading day of the year), 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 29, 2006.

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 O&G E&P Index

	12/31/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/31/2011
ROSE	$ 100.00	$ 106.21	$ 37.92	$ 106.70	$ 201.61	$ 232.99
S&P 500	100.00	105.49	66.46	84.05	96.71	98.76
S&P 400 E&P	100.00	144.46	65.72	117.07	167.66	137.57

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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,				
	2011	2010	2009 (1)	2008 (1)	2007
	(In thousands, except per share data)				
Operating Data:					
Total revenues	$ 446,200	$ 308,430	$ 293,951	$ 499,347	$ 363,489
Net income (loss)	100,546	19,046	(219,176)	(188,110)	57,205
Net Income (loss) per share:					
Basic	$ 1.93	$ 0.37	$ (4.30)	$ (3.71)	$ 1.14
Diluted	1.91	0.37	(4.30)	(3.71)	1.13
Cash dividends declared and paid per common share:	$	$	$	$	$
Balance Sheet Data (At the end of the period):					
Total assets	$ 1,065,345	$ 989,440	$ 872,042	$ 1,134,996	$ 1,336,822
Long-term debt	230,000	350,000	288,742	300,000	245,000
Total other long-term liabilities	14,949	28,275	31,261	26,584	99,464
Stockholders equity	632,836	528,816	493,095	726,372	872,955

(1) Includes a $379.5 million and a $444.4 million non-cash, pre-tax impairment charge for 2009 and 2008, respectively.

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

Overview

During 2011, we solidified our strategy as an unconventional resource player with the development of our assets in the Eagle Ford shale in South Texas, one of the most active shale plays in the U.S.. Our success in the area resulted in double-digit increases in production and a doubling of total proved reserves from the end of 2010. These assets also contributed to an overall decrease in our total cost structure and to a more balanced commodity mix with oil and NGLs accounting for 45% of the year s production.

Our performance in 2011 demonstrated the quality of the assets that we have assembled in the Eagle Ford shale and our technical, commercial and financial abilities to fully realize their value. The Eagle Ford shale is our largest producing area and provided approximately 78% of our total production in 2011. Our primary focus has been the development of our 26,500-acre Gates Ranch acreage in Webb County where we have completed 56 wells as of December 31, 2011. We plan to continue development of Gates Ranch in 2012. We have also announced our intention to increase our well density to 65 acre spacing from the past practice of drilling on 100 acre spacing. We believe this may result in increased recovery of hydrocarbons from this field.

During the year, we also tested with positive results three new Eagle Ford areas across 13,600 net acres in the liquids windows outside Gates Ranch. The newly delineated acreage expands our already strong liquids-rich position, and we intend to begin development of these areas, as well as to evaluate an additional 10,000 acres in the liquids windows in 2012.

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The success of our Eagle Ford drilling program was the basis for a significant increase in reserve estimates for the year. As of December 31, 2011, our estimated proved reserves were 161 MMBoe (965 Bcfe), a 101% increase from our estimate of 80 MMBoe (479 Bcfe) as of December 31, 2010.

With our new production base in the Eagle Ford shale, we continued to shift our production portfolio to higher levels of oil and NGLs. For the month ended December 31, 2011, more than 50% of our production was from oil and NGLs. This trend reduced our exposure to current low natural gas prices. Approximately 57% of the reserves that we have discovered in the Eagle Ford shale are liquids.

In 2011, our average annual production rate was 27.6 MBoe/d (166 MMcfe/d) and we exited 2011 with a production rate of 32.5 MBoe/d (195 MMcfe/d). Year over year, we achieved a 20% increase in our annual production despite several major divestitures of legacy natural gas assets that no longer fit our unconventional resource strategy. During the year, we completed the sale of properties in the DJ Basin in Colorado and in the Sacramento Basin in California for $255 million, less customary closing adjustments. The proceeds were utilized to reduce our debt, and the balance was redeployed to take advantage of higher-return opportunities in our Eagle Ford shale program. As we streamlined our business, we finalized the reorganization of our Houston staff to consolidate all of our technical resources in one location.

The timely and efficient development of our Eagle Ford resources has been challenging in a region where midstream services are in high demand and infrastructure is under construction. In response, we have diligently worked to secure long-term contracts for firm transportation and processing capacity to meet our growing production demand. We now have access to four separate processing facilities which gives us more flexibility to manage service issues. We also have agreements in place that will increase our current Eagle Ford firm daily gas transportation and processing capacity from 160 MMcf/d to 195 MMcf/d of gross wellhead production contracted to be available by the middle of 2012. Total firm capacity of 245 MMcf/d is contracted to be available in early 2013.

The overall performance of our business has been greatly improved with our success in the Eagle Ford shale. Our average revenue increased by $7.45 per Boe in 2011 compared to the previous year primarily due to significant growth in higher-valued oil and NGL production. For 2011, approximately 45% of our overall production mix was attributable to oil and NGL production compared to 22% a year ago. Our effective cost control and divestiture of certain assets also resulted in a decrease in lease operating expense, which declined to $3.47 per Boe in 2011 from $6.10 per Boe in 2010.

Our other shale focus area lies in the Southern Alberta Basin in Northwest Montana. We control approximately 300,000 net acres in the exploration play to test the economic potential in the Banff, Bakken, and Three Forks reservoirs. In late 2009, we began an eleven-well vertical drilling program that was completed during the second quarter of 2011. The results from that initiative contributed to the design of a seven-well horizontal drilling program that is currently underway. As of December 31, 2011, four wells have been drilled and the remaining three wells will be drilled in 2012. The initial test results from the two wells completed and evaluated at year end confirmed the complexity of the play and the need for continued evaluation by us and the industry.

Our business goals for 2012 are based on an announced capital program of $640 million with more than 90% allocated to the evaluation and development of our Eagle Ford assets, which are expected to deliver significant production growth year over year. Our plans for 2012 include a four-rig program in the Eagle Ford shale and the completion of 60 new wells located both in the Gates Ranch area, as well as in other liquids areas of the play. Based on current development plans, market conditions and our understanding of the play, we expect the Eagle Ford shale program to be self-funding by the end of 2012. Approximately 5% of the capital funds will be spent for leasehold costs and continued evaluation of the Southern Alberta Basin. In addition to our focus on execution in the Eagle Ford, we will also begin to evaluate new opportunities to drive the long-term growth and sustainability of Rosetta. We will continue our strategy of looking at unconventional resources which will provide a viable inventory of projects. We expect these opportunities will be a blend of new higher risk exploration, as well as producing property acquisitions.

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Financial Highlights

Our consolidated financial statements reflect total revenue of $446.2 million based on total volumes of 10.1 MMBoe (60.4 Bcfe) and derivative gains of $18.7 million for 2011.

Significant transactions which affect comparisons between the periods 2011 and 2010 include the 2011 divestitures of our Sacramento Basin and DJ Basin assets and the 2010 divestitures of our Pinedale, San Juan, Arklatex, and Gulf Coast Sabine Lake assets.

Results of Operations

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

	Year Ended December 31,		
	2011	2010	2009
	(In thousands, except per unit amounts)		
Revenue:			
Oil sales	$ 157,517	$ 54,542	$ 21,763
NGL sales	125,301	45,200	21,504
Natural gas sales	163,382	208,688	250,684
Total revenue	$ 446,200	$ 308,430	$ 293,951
Production:			
Oil (MBbls)	1,863.3	738.0	393.9
NGLs (MBbls)	2,643.3	1,096.0	620.1
Gas (Bcf)	33.4	39.2	44.5
Total equivalents (MBoe)	10,072.1	8,369.0	8,425.1
$ per unit:			
Avg. oil price per Bbl, excluding hedging	$ 85.03	$ 73.91	$ 55.25
Avg. oil price per Bbl	84.54	73.91	55.25
Avg. NGL price per Bbl, excluding hedging	51.26	41.24	34.68
Avg. NGL price per Bbl	47.40	41.24	34.68
Avg. natural gas price per Mcf, excluding hedging	4.00	4.50	3.91
Avg. natural gas price per Mcf	4.89	5.32	5.63
Avg. revenue per Boe	44.30	36.85	34.89

Revenue

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

Excluding the effects of hedging, revenue for 2011, 2010 and 2009 was $427.5 million, $276.0 million and $217.4 million, respectively, and year over year growth in 2011 and 2010 was attributable to higher average realized oil and NGL prices and increased oil and NGL production. Excluding the effects of hedging, revenue attributable to oil and NGL sales in 2011, 2010 and 2009 was approximately 69%, 36% and 20%, respectively, of total revenue.

Crude Oil. Oil revenue, excluding the effects of hedging, increased to $158.4 million, or 191%, from $54.5 million in 2010, which was an increase of 151% from $21.8 million in 2009. The increase in both periods was

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attributable to an increase in oil production of 152% and 87% from 2010 and 2009, respectively, due to newly completed wells in the Eagle Ford shale. Higher oil revenue, excluding the effects of hedging, was also attributable to an increase of $11.12 per Bbl and $18.66 per Bbl in the average realized oil prices from 2010 and 2009, respectively. The effect of oil hedging activities on oil revenue for 2011 resulted in a loss of $0.9 million. There was no effect of oil hedging activities on oil revenue for 2010 or 2009 because no oil derivative transactions settled during those periods.

NGLs. NGL revenue, excluding the effects of hedging, increased to $135.5 million, or 200%, from $45.2 million in 2010, which was an increase of 110% from $21.5 million in 2009. The increase in both periods was attributable to an increase in NGL production of 141% and 77% from 2010 and 2009, respectively, due to newly completed wells in the Eagle Ford shale. Higher NGL revenue, excluding the effects of hedging, was also attributable to an increase of $10.02 per Bbl and $6.56 per Bbl in the average realized NGL prices from 2010 and 2009, respectively. The effect of NGL hedging activities on NGL revenue for 2011 resulted in a loss of $10.2 million. There was no effect of NGL hedging activities on NGL revenue for 2010 or 2009 because no NGL derivative transactions settled during those periods.

Natural Gas. Natural gas revenue, excluding the effects of hedging, decreased to $133.6 million, or 24%, from $176.2 million in 2010, which was an increase of 1% from $174.1 million in 2009. Natural gas production decreased by 15% and 12% in 2011 and 2010, respectively, primarily due to asset divestitures of more gas-based assets, the suspension of drilling programs in areas that produce primarily from dry gas reservoirs and the natural decline of gas-based properties. With the decline in production year over year, the average realized price decreased in 2011 by $0.50 per Mcf and increased in 2010 by $0.59 per Mcf. The effect of natural gas hedging activities on natural gas revenue for 2011, 2010 and 2009 resulted in gains of $29.8 million, $32.5 million and $76.6 million, respectively.

Operating Expenses

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

	Year Ended December 31,		
	2011	**2010**	**2009**
	(In thousands, except per unit amounts)		
Lease operating expense	$ 34,900	$ 51,085	$ 60,773
Treating and transportation	22,316	6,963	6,268
Production taxes	12,073	5,953	6,131
Depreciation, depletion and amortization (DD&A)	123,244	116,558	121,042
Impairment of oil and gas properties			379,462
General and administrative costs	75,256	56,332	46,993
$ per unit:			
Avg. lease operating expense per Boe	$ 3.47	$ 6.10	$ 7.21
Avg. treating and transportation per Boe	2.22	0.83	0.74
Avg. production taxes per Boe	1.20	0.71	0.73
Avg. DD&A per Boe	12.24	13.93	14.37
Avg. General and administrative costs per Boe	7.47	6.73	5.58
Avg. General and administrative costs per Boe, excluding stock-based compensation	4.59	5.04	4.69
Avg. production costs per Boe (1)	15.70	20.03	21.58
Avg. production costs per Boe (2)	15.10	18.90	19.86

(1) Production costs per Boe include lease operating expense and DD&A.
(2) Production costs per Boe include lease operating expense and DD&A and excludes production and ad valorem taxes.

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Lease Operating Expense. Lease operating expense in 2011 decreased to $34.9 million, or 32%, from $51.1 million in 2010, which was a decrease of 16% from $60.8 million in 2009. The decrease in both 2011 and 2010 was primarily due to our divestiture activities, such as our 2011 divestitures of our Sacramento Basin assets in California and our DJ Basin assets in Colorado as well as the 2010 divestiture of our Gulf Coast Sabine Lake asset, and our overall lease operating expense reduction efforts. Lease operating expense included workover costs of $0.06 per Boe, ad valorem taxes of $0.60 per Boe and insurance of $0.09 per Boe in 2011 as compared to workover costs of $0.26 per Boe, ad valorem taxes of $1.13 per Boe and insurance of $0.19 per Boe in 2010. Lease operating expense in 2009 included workover costs of $0.48 per Boe, ad valorem taxes of $1.72 per Boe and insurance of $0.20 per Boe.

Treating and Transportation. Treating and transportation expense in 2011 increased to $22.3 million, or 220%, from $7.0 million in 2010, which was an increase of 11% from $6.3 million in 2009. The increase was a result of increased production primarily in the Eagle Ford shale, where infrastructure is still under construction and transportation and processing capacity is in high demand.

Production Taxes. Production taxes are highly correlated to unhedged revenues and stronger commodity prices have impacted results for this expense item. Production taxes as a percentage of unhedged oil, NGL and natural gas sales were 2.8%, 2.2% and 2.8% for 2011, 2010 and 2009, respectively. The 2010 decrease was primarily due to certain production tax credits in the State of Texas.

Depreciation, Depletion, and Amortization. DD&A expense in 2011 increased to $123.2 million, or 6%, from $116.6 million in 2010, which was a decrease of 4% from $121.0 million in 2009. The increase in 2011 was due to a 20% increase in total production, as well as a lower DD&A rate as a result of a 101% increase in reserves due to significant additions of proved reserves primarily in the Gates Ranch area. The decrease in 2010 was due to a 1% decrease in total production and a lower DD&A rate for 2010 as compared to 2009 due to the full cost ceiling test impairment charges recognized in the first quarter of 2009, which decreased the carrying value of our full cost pool.

Impairment of Oil and Gas Properties. Based on quarterly ceiling test computations using twelve-month first-day-of-the-month historical average prices, adjusted for hedges of oil and natural gas, we were not required to record a write-down at December 31, 2011 or 2010, and no write-down occurred during 2011 or 2010. However, based on the quarterly ceiling test computations using hedge adjusted market prices during 2009, the net capitalized costs of oil and natural gas properties exceeded the cost center ceiling and we recorded a pre-tax, non-cash impairment expense of $379.5 million.

General and Administrative Costs. General and administrative costs, net of capitalized exploration and development overhead costs of $7.0 million, increased by $18.9 million in 2011 from 2010. The increase in 2011 was primarily related to a $14.9 million increase in stock-based compensation expense as a result of our increased stock price and incentive compensation related to performance share units, a $5.3 million increase in consultant costs related to various internal projects and divestiture activities and an increase of $0.2 million of other administrative costs, offset by a decrease of $1.5 million in salaries, wages and bonuses due to lower headcount as a result of closing the Denver office.

In 2010, general and administrative costs, net of capitalized exploration and development overhead costs of $7.8 million, increased by $9.3 million from 2009. The increase in 2010 was primarily related to a $6.7 million increase in stock-based compensation due to our increased stock price, a $3.0 million increase in salaries, wages and bonuses and a $2.5 million increase in benefit costs, offset by a $2.6 million decrease in geological and geophysical expenses that were capitalized and a $0.3 million decrease of other administrative costs.

Total Other Expense

Total other expense includes Interest expense, net of interest capitalized, Interest income and Other income/expense, net which decreased $3.8 million in 2011 from 2010. The decrease in Total other expense was primarily due to our repayment of $100.0 million under the Restated Revolver in April 2011 resulting in lower interest expense and an increase in capitalized interest resulting from an increase in our weighted average interest rate.

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The weighted average interest rate of 8.45% in 2011 was higher than the 2010 rate of 7.06% due to the higher interest rate associated with the Senior Notes, which were issued in April 2010.

For 2010, Total other expense increased $7.6 million from 2009. The increase in Total other expense was primarily due to an increase in interest expense associated with higher amounts of outstanding debt. Long-term debt outstanding as of December 31, 2010 was $61.3 million higher as compared to December 31, 2009. The weighted average interest rate of 7.06% in 2010 was higher than the 2009 rate of 5.18% due to the higher interest rate associated with the Senior Notes.

Provision for Income Taxes

Our 2011 income tax expense was $55.7 million. For the year ended December 31, 2011, the effective tax rate was 35.7% compared to the effective tax rate of 58.2% for the year ended December 31, 2010 and 36.5% for the year ended December 31, 2009. The provision for income taxes differs from the taxes computed at the federal statutory income tax rate primarily due to the effect of state taxes, the non-deductibility of certain incentive compensation and a valuation allowance against certain state deferred tax assets.

The Company provides for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in the financial statements in accordance with authoritative guidance for accounting for income taxes. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in determining when these events may occur and whether recovery of an asset is more likely than not. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. As of December 31, 2011, the Company had a net deferred tax asset of $85.2 million, compared to a net deferred tax asset of approximately $135.6 million at December 31, 2010, resulting primarily from the difference between the book basis and tax basis of our oil and natural gas properties and net operating loss carryforwards. Realization of the deferred tax asset is dependent, in part, on generating sufficient taxable income from the production of oil and natural gas properties prior to the expiration of loss carryforwards.

In connection with the asset divestitures in the DJ Basin in Colorado and in the Sacramento Basin in California, the Company concluded in 2010 that it was more likely than not that the deferred tax assets for these states including NOLs would not be realized. Therefore, valuation allowances were established for these items as well as state NOLs in other jurisdictions in which the Company previously operated but had since divested of operating assets. In 2011, the Company released $2.3 million of valuation allowance to reflect revised estimates of the utilization of state NOLs against gains on sale of assets in some states. The Company will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods.

Liquidity and Capital Resources

Our primary source of liquidity and capital is our operating cash flow and cash on hand. We also maintain a revolving line of credit, which can be accessed as needed to supplement operating cash flow.

Operating Cash Flow. Our cash flows depend on many factors, including the price of oil, NGLs and natural gas and the success of our development and exploration activities as well as future acquisitions. We actively manage our exposure to commodity price fluctuations by executing derivative transactions to hedge the change in prices of a portion of our production, thereby mitigating our exposure to price declines, but these transactions may also limit our earnings potential in periods of rising commodity prices. The effects of these derivative transactions on our oil, NGL and natural gas sales are discussed above under Results of Operations Revenues. The majority of our capital expenditures are discretionary and could be curtailed if our cash flows decline from expected levels. Economic conditions and lower commodity prices could adversely affect our cash flow and liquidity. We will continue to monitor our cash flow and liquidity and, if appropriate, we may consider adjusting our capital expenditure program.

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Senior Secured Revolving Credit Facility. On May 10, 2011, we entered into an amendment to our Amended and Restated Senior Revolving Credit Agreement (the Restated Revolver). Under this amendment, among other things, our senior secured revolving line of credit was increased from $600.0 million to $750.0 million and the term of the Restated Revolver was extended from July 1, 2012 to May 10, 2016. Availability under the Restated Revolver is restricted to the borrowing base, which is subject to review and adjustment on a semi-annual basis and other interim adjustments, including adjustments based on our hedging arrangements as well as asset divestitures. The amount of the borrowing base is affected by a number of factors, including our level of reserves, as well as the pricing outlook at the time of the redetermination. Therefore, a significant reduction in capital spending could result in a reduced level of reserves that could cause a reduction in the borrowing base.

We utilized a portion of the proceeds from our asset divestitures to repay $100.0 million of outstanding debt under the Restated Revolver on April 21, 2011. As of December 31, 2011, we had $30.0 million outstanding with $295.0 million of available borrowing capacity under the Restated Revolver. Amounts outstanding under the Restated Revolver bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 1.75% to 2.75%. The weighted average borrowing rate for the year ended December 31, 2011 under the Restated Revolver was 2.30%. Borrowings under the Restated Revolver are collateralized by perfected first priority liens and security interests on substantially all of our assets, including a mortgage lien on oil and natural gas properties having at least 80% of the pre-tax SEC PV-10 proved reserve value, a guaranty by all of our domestic subsidiaries, and a pledge of 100% of the membership and limited partnership interests of our domestic subsidiaries. Collateralized amounts under the mortgages are subject to semi-annual reviews based on updated reserve information. We are also subject to certain financial covenants, including the requirement to maintain (i) a minimum current ratio of consolidated current assets, including the unused amount of available borrowing capacity, to consolidated current liabilities, excluding certain non-cash obligations, of not less than 1.0 to 1.0 as of the end of each fiscal quarter and (ii) a maximum leverage ratio of total debt to earnings before interest expense, income taxes and noncash items, such as depreciation, depletion, amortization and impairment, of not greater than 4.0 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended, measured quarterly after giving pro forma effect to acquisitions and divestitures. At December 31, 2011, our current ratio was 2.4 and our leverage ratio was 0.8. In addition, we are subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. We were in compliance with all covenants at December 31, 2011. In early 2012, we borrowed an additional $50.0 million to invest in capital expenditures and as a result, we have $245.0 million available for borrowing under our revolving credit facility.

Second Lien Term Loan. Our amended and restated term loan (the Restated Term Loan) matures on October 2, 2012. As of December 31, 2011, we had $20.0 million of fixed rate borrowings outstanding under the Restated Term Loan bearing interest at 13.75%. We have the right to prepay the fixed rate borrowings outstanding with a make-whole amount at a discount factor equal to 1% plus the U.S. Treasury yield security having a maturity closest to the remaining life of the loan. The loan is collateralized by second priority liens on substantially all of our assets. We are also subject to certain financial covenants, including the requirement to maintain (i) a minimum reserve ratio of total reserve value to total debt of not less than 1.5 to 1.0 as of the end of each fiscal quarter and (ii) a maximum leverage ratio of total debt to earnings before interest expense, income taxes and noncash items, such as depreciation, depletion, amortization and impairment, of not greater than 4.0 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended. At December 31, 2011, our reserve coverage ratio was 4.2 and our leverage ratio was 0.8. In addition, we are subject to covenants, including limitations on dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. We were in compliance with all covenants at December 31, 2011.

Senior Notes. On April 15, 2010, we issued and sold $200.0 million in aggregate principal amount of 9.500% Senior Notes due 2018 in a private offering. The Senior Notes were issued under an indenture (the Indenture) with Wells Fargo Bank, National Association, as trustee. Provisions of the Indenture limit our ability to, among other things, incur additional indebtedness; pay dividends on our capital stock or purchase,

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repurchase, redeem, defease or retire capital stock or subordinated indebtedness; make investments; incur liens; create any consensual restriction on the ability of our restricted subsidiaries to pay dividends, make loans or transfer property to us; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. The Indenture also contains customary events of default. At December 31, 2011, we were in compliance with the terms and provisions as contained within the Indenture. Proceeds from the Senior Notes offering were used to repay $114.0 million outstanding under our Restated Revolver and $80.0 million of variable rate borrowings outstanding under our Restated Term Loan, and to pay for fees and expenses associated with the offering. Interest is payable on the Senior Notes semi-annually on April 15 and October 15. On September 21, 2010, we exchanged all of the privately placed Senior Notes for registered Senior Notes which contain terms substantially identical to the terms of the privately placed notes.

As of December 31, 2011, we had total outstanding borrowings of $250.0 million and for the year ended December 31, 2011, our weighted average borrowing rate was 8.45%.

Working Capital

Our working capital fluctuates primarily as a result of changes in commodity pricing and production volumes, capital spending to fund our exploratory and development initiatives and the impact of our outstanding derivative instruments. At December 31, 2011, we had a working capital deficit of $36.0 million as compared to a working capital surplus of $22.8 million at December 31, 2010. The decrease in our working capital was largely due to increased liabilities associated with royalty payables resulting from increased production and higher commodity prices, increased capital spending primarily in the Eagle Ford shale, increased accrued compensation associated with the performance share units that are to be cash settled and a decrease in the fair value of short-term commodity derivative positions. We believe we have adequate availability under our credit facility and liquidity available to meet our working capital requirements.

Cash Flows

	Year Ended December 31,		
	2011	**2010**	**2009**
		(In thousands)	
Cash flows provided by operating activities	$ 299,537	$ 176,861	$ 160,501
Cash flows used in investing activities	(190,363)	(251,621)	(123,865)
Cash flows (used in) provided by financing activities	(103,758)	55,138	(18,235)
Net increase (decrease) in cash and cash equivalents	$ 5,416	$ (19,622)	$ 18,401

Operating Activities. Key drivers of net cash provided by operating activities are commodity prices, production volumes and costs and expenses, which primarily include operating costs, taxes other than income taxes, transportation, interest expense and general and administrative expenses. Net cash provided by operating activities continued to be a primary source of liquidity and capital used to finance our capital expenditures in 2011.

Cash flows provided by operating activities increased by $122.7 million in 2011 as compared to 2010. This increase was largely due to higher oil and NGL prices and increased oil and NGL production during 2011 compared to 2010.

Cash flows provided by operating activities increased by $16.4 million in 2010 as compared to 2009. This increase was largely due to higher oil, NGL and natural gas prices and increased oil and NGL production during 2010 compared to 2009.

Investing Activities. The primary driver of cash used in investing activities is capital spending, net of divestiture proceeds.

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Cash flows used in investing activities decreased by $61.3 million in 2011 as compared to 2010. The decrease was primarily attributable to net asset divestiture proceeds of $242.6 million offset by expenditures of $433.0 million for purchases to develop oil and natural gas assets. In 2011, we incurred $479.5 million in capital expenditures as compared to $339.4 million in 2010. During 2011, we participated in the drilling of 64 gross wells as compared to the drilling of 127 gross wells in 2010.

Cash flows used in investing activities increased by $127.8 million in 2010 as compared to 2009. The increase was primarily attributable to increased expenditures of $187.9 million for purchases to develop oil and gas properties offset with a decrease in investing activities of $63.6 million due to asset sales. In 2010, we incurred approximately $339.4 million in capital expenditures as compared to approximately $135.4 million in 2009. During 2010, we participated in the drilling of 127 gross wells as compared to the drilling of 43 gross wells in 2009.

Financing Activities. The primary drivers of cash (used in) provided by financing activities are borrowings and repayments under the Restated Revolver, equity transactions associated with the exercise of stock options and the acquisition of treasury shares from employees and directors to pay tax withholding upon the vesting of restricted stock.

Cash flows used in financing activities increased by $158.9 million in 2011 as compared to 2010. The net increase was primarily related to the $100.0 million repayment under the Restated Revolver in April 2011 and the net impact of the $200.0 million issuance of our Senior Notes, net repayments under the Restated Revolver of $60.0 million and repayment of $80.0 million under the Restated Term Loan in 2010.

Cash flows provided by financing activities increased by $73.4 million in 2010 as compared to 2009. The net increase was primarily related to the activities in 2010 noted above and the net repayment of $11.6 million under the Restated Revolver in 2009.

Commodity Price Risk and Related Derivative Activities

The energy markets have historically been very volatile and oil, NGL and natural gas prices will be subject to wide fluctuations in the future. To mitigate our exposure to changes in commodity prices, management hedges oil, NGL and natural gas prices from time to time, primarily through the use of certain derivative instruments, including fixed price swaps, basis swaps, NYMEX roll swaps, costless collars and put options. Although not risk-free, we believe these activities will reduce our exposure to commodity price fluctuations and thereby enable us to achieve a more predictable cash flow. Consistent with this policy, we have entered into a series of oil, NGL and natural gas fixed price swaps, basis swaps, NYMEX roll swaps and costless collars for each year through 2013. Our fixed price swap, basis swap, NYMEX roll swap and costless collar agreements require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a notional quantity of oil, NGLs and natural gas, as applicable, without the exchange of underlying volumes. The notional amounts of these financial instruments were based on expected production from existing wells at inception of the derivative instruments.

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The following table sets forth the results of commodity and interest rate derivative settlements:

	For the Year Ended December 31, 2011	2010	2009
Crude Oil			
Quantity settled (Bbl)	959,800		
Decrease in crude oil sales revenue (In thousands) (1)	$ (2,149)	$	$
NGL			
Quantity settled (Bbl)	613,000		
Decrease in NGL sales revenue (In thousands)	$ (10,190)	$	$
Natural Gas			
Quantity settled (MMBtu)	18,250,000	14,645,000	20,856,465
Increase in natural gas sales revenue (In thousands) (2)	$ 18,751	$ 30,740	$ 76,567
Interest Rate Swaps			
(Increase) in interest expense (In thousands)	$	$ (978)	$ (1,289)

(1) For 2011, excludes approximately $1.2 million of unrealized gain associated with the change in fair value of our crude oil basis and NYMEX roll swaps.

(2) For 2011, excludes approximately $11.1 million of realized gains associated with the 2011 termination of derivatives used to hedge production from our divested DJ Basin and Sacramento Basin properties. For 2010, excludes approximately $1.7 million of realized gains associated with the 2010 termination of derivatives used to hedge production from our divested Pinedale properties.

In accordance with the authoritative guidance for derivatives, all derivative instruments, unless designated as a normal purchase and normal sale, are recorded on the balance sheet at fair market value. For derivative instruments that are designated and qualify as a cash flow hedge, the effective portion of the gain or loss on the derivative is reported as a component of other comprehensive income and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. We assess the effectiveness of these hedging transactions on a quarterly basis, consistent with the documented risk management strategy for the particular hedging relationship. Gains and losses on the derivative instruments representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings.

Our crude oil basis and NYMEX roll swap derivative instruments do not qualify as cash flow hedges and are recorded on the balance sheet at their fair values under Derivative instruments, as assets and/or liabilities, as applicable, and are marked-to-market each period with the change in fair value representing unrealized gains and losses recognized immediately as a component of Oil sales. These mark-to-market adjustments produce a degree of earnings volatility that can be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the settlement of the underlying contract occurs.

As of December 31, 2011, our commodity hedge and non-qualifying derivative instruments are with counterparties that are also lenders under our credit facilities. This allows us to satisfy any need for any margin obligation resulting from a negative change in the fair market value of the derivative contracts with the collateral securing our credit facilities, thus eliminating the need for independent collateral postings. As of December 31, 2011, we had no deposits for collateral in regard to our commodity derivative instruments.

Effective January 1, 2012, we have elected to de-designate all of our commodity contracts that had previously been designated as cash flow hedges as of December 31, 2011, and we have elected to discontinue hedge accounting prospectively. At December 31, 2011, Accumulated Other Comprehensive Income consisted of $2.6 million ($1.6 million after tax) of unrealized gains, representing the mark-to-market value of the Company s cash flow hedges as of the balance sheet date. As a result of discontinuing hedge accounting, such mark-to-market values that are included in Accumulated Other Comprehensive Income as of the de-designation date will be frozen and reclassified into earnings in future periods as the underlying hedged transactions affect earnings. We expect to reclassify into earnings from Accumulated Other Comprehensive Income the frozen value related to de-designated commodity cash flow hedges over the next two years.

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Capital Requirements

Our capital expenditures for the year ended December 31, 2011 were $479.5 million, including capitalized internal costs directly identified with acquisition, exploration and development activities of $7.0 million and capitalized interest of $5.5 million. We have plans to execute an organic capital program in 2012 of $640 million that can be funded from internally generated cash flows, divestiture proceeds and available cash, supplemented by borrowings under the revolving credit facility to fund capital expenditures, including acquisitions.

Commitments and Contingencies

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

Contractual Obligations. At December 31, 2011, the aggregate amounts of our contractually obligated payment commitments for the next five years and thereafter were as follows:

	Payments Due By Period				
	Total	2012	2013 to 2014	2015 to 2016	Thereafter
	(In thousands)				
Senior secured revolving line of credit	$ 30,000	$	$	$ 30,000	$
Second lien term loan	20,000	20,000			
Senior notes	200,000				200,000
Operating leases	10,103	5,714	4,389		
Interest payments on long-term debt (1)	124,198	21,688	39,218	38,826	24,466
Field service agreements	11,726	11,417	309		
Rig commitments	17,515	17,515			
Firm transportation	306,465	11,003	62,247	67,526	165,689
Total contractual obligations	$ 720,007	$ 87,337	$ 106,163	$ 136,352	$ 390,155

(1) Future interest payments were calculated based on interest rates and amounts outstanding at December 31, 2011.

Asset Retirement Obligations. At December 31, 2011, we had total liabilities of $14.3 million related to asset retirement obligations (ARO) that are excluded from the table above. Of the total ARO, the current portion was approximately $1.6 million at December 31, 2011 and was included in Accrued liabilities on the Consolidated Balance Sheet. The long-term portion of ARO was approximately $12.7 million at December 31, 2011 and was included in Other long-term liabilities on the Consolidated Balance Sheet. Due to the nature of these obligations, we cannot determine precisely when the payments will be made to settle these obligations. See Item 8. Financial Statements and Supplementary Data, Note 9 Asset Retirement Obligations.

Transportation Commitments. We have various production volume transportation commitments related to our operations in the Eagle Ford shale and have an aggregate minimum commitment to deliver 7.8 MMBbl of oil by the end of 2017 and 417 million MMBtu of natural gas by the end of 2023. We will be required to make periodic deficiency payments for any shortfalls in delivering the minimum volume under these commitments. We expect to fulfill the delivery commitment with production from the development of our proved reserves, as well as from

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the development of resources not yet characterized as proved reserves from our Eagle Ford assets. At the current time, we do not have sufficient proved developed reserves to satisfy this contractual liability, but we intend to develop reserves that will exceed these minimum commitments. See Items 1 and 2, Business and Properties for a description of our production and proved reserves and Item 8. Financial Statements and Supplementary Data, Note 11 Commitments and Contingencies.

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

Critical Accounting Policies and Estimates

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

We also describe the most significant estimates and assumptions we make in applying these policies. See Item 8. Financial Statements and Supplementary Data, Note 2 Summary of Significant Accounting Policies, for a discussion of additional accounting policies and estimates made by management.

Proved Oil and Gas Reserves

The engineering estimates of proved oil and gas reserves directly impact financial accounting estimates, including DD&A expense and the full cost ceiling limitation. Proved oil and gas reserves are the estimated quantities of oil and gas reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under period-end economic and operating conditions. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. Accordingly, our reserve estimates are developed internally and subsequently provided to NSAI who then performs an annual year-end reserve report audit. The data for a given reservoir may change substantially over time as a result of numerous factors including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Changes in oil and gas prices, operating and future development costs and expected performance from a given reservoir also will result in revisions to the amount of our estimated proved reserves. The estimate of proved oil and natural gas reserves primarily impacts property, plant and equipment amounts in the consolidated balance sheet and the DD&A amounts in the consolidated statement of operations. Current guidance dictates the use of a twelve-month first-day-of-the-month historical average price adjusted for basis and quality differentials for oil and natural gas and holds costs in effect as of the

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last day of the quarter or annual period constant in calculating reserves. Prior to December 31, 2009, the guidance dictated that year-end prices adjusted for basis and quality differentials and costs be used in calculating reserves. For more information regarding reserve estimation, including historical reserve revisions, refer to Item 8. Financial Statements and Supplementary Data Supplemental Oil and Gas Disclosures.

Full Cost Accounting Method

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

Depreciation, Depletion and Amortization

The quantities of estimated proved oil and gas reserves are a significant component of our calculation of depletion expense and revisions in such estimates may alter the rate of future depletion expense. Holding all other factors constant, if reserves are revised upward, earnings would increase due to lower depletion expense. Likewise, if reserves are revised downward, earnings would decrease due to higher depletion expense or due to a ceiling test write-down. A five percent positive or negative revision to proved reserves would decrease or increase the DD&A rate by approximately $0.48 to $0.53 per Boe. This estimated impact is based on current data at December 31, 2011 and actual events could result in different adjustments to DD&A.

Costs Withheld From Amortization

Costs associated with unevaluated properties are excluded from our amortization base until we have evaluated the properties. The costs associated with unevaluated leasehold acreage, wells currently drilling, suspended wells and capitalized interest are initially excluded from our amortization base. Leasehold costs are either transferred to our amortization base with the costs of drilling a well on the lease or are assessed quarterly for possible impairment. In addition, a portion of incurred (if not previously included in the amortization base) and future estimated development costs associated with major development projects may be temporarily excluded from amortization due to the size and complexity of the resource play. Incurred and estimated future development costs are allocated between completed and future work. Any costs withheld from the amortization base are subsequently included in the amortization base upon the earlier of when proved reserves are recorded or impairment is indicated.

Our decision to withhold costs from amortization and the timing of the transfer of those costs into the amortization base involve a significant amount of judgment and may be subject to changes over time based on several factors, including our drilling plans, availability of capital, project economics and results of drilling on adjacent acreage. At December 31, 2011, our full cost pool had approximately $141.0 million of costs excluded from the amortization base.

Future Development and Abandonment Costs

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

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production platforms, gathering systems and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon the property s geographic location, type of production structure, well depth, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and future abandonment costs on an annual basis.

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

Full Cost Ceiling Limitation

Under the full cost method, we are subject to quarterly calculations of a ceiling or limitation on the amount of costs associated with our oil and gas properties that can be capitalized on our balance sheet. This ceiling limits such capitalized costs to the present value of estimated future cash flows from proved oil and natural gas reserves (including the effect of any related hedging activities that are designated as cash flow hedges) reduced by future operating expenses, development expenditures, abandonment costs (net of salvage values) to the extent not included in oil and gas properties pursuant to authoritative guidance, and estimated future income taxes thereon. If net capitalized costs exceed the applicable cost center ceiling, we are subject to a ceiling test write-down to the extent of such excess. If required, it would reduce earnings and stockholders equity in the period of occurrence and result in lower DD&A expense in future periods. The discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. The current ceiling calculation utilizes a twelve-month first-day-of-the-month historical average price. The costs in effect as of the last day of the quarter or annual period are held constant. The full cost ceiling test impairment calculations also take into consideration the effects of hedging contracts that are designated for hedge accounting. Effective January 1, 2012, we have elected to de-designate all of our commodity contracts that had previously been designated as cash flow hedges as of December 31, 2011 and have elected to discontinue hedge accounting prospectively. As a result, there will be no future impact to the calculated ceiling value due to cash flow hedges. Given the fluctuation of oil, NGL and natural gas prices, it is reasonably possible that the estimated discounted future net cash flows from our proved reserves will change in the near term. If oil, NGL and natural gas prices decline, or if we have downward revisions to our estimated proved reserves, it is possible that write-downs of our oil and gas properties could occur in the future. For more information regarding the full cost ceiling limitation, refer to Item 8. Financial Statements and Supplementary Data, Note 2 Summary of Significant Accounting Policies.

Derivative Transactions and Activities

We enter into derivative transactions to hedge against changes in oil, NGL and natural gas prices primarily through the use of fixed price swaps, basis swaps, NYMEX roll swaps and costless collars. Consistent with our hedge policy, we entered into a series of derivative transactions to hedge a portion of our expected oil, NGL and natural gas production through 2013.

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

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In accordance with amended guidance, all derivative instruments, unless designated as normal purchase and normal sale, are recorded on the balance sheet at fair market value. For derivative instruments that are designated and qualify as a cash flow hedge, the effective portion of the gain or loss on the derivative is reported as a component of other comprehensive income and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. We assess the effectiveness of hedging transactions quarterly, consistent with our documented risk management strategy for the particular hedging relationship. Gains and losses on the derivative representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings.

Our crude oil basis and NYMEX roll swap derivative instruments do not qualify as cash flow hedges and are recorded on the balance sheet at their fair values under Derivative instruments, as assets and/or liabilities, as applicable, and are marked-to-market each period with the change in fair value representing unrealized gains and losses recognized immediately as a component of Oil sales. These mark-to-market adjustments produce a degree of earnings volatility that can be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying financial instrument contract settlement is made.

Effective January 1, 2012, we have elected to de-designate all of our commodity contracts that had previously been designated as cash flow hedges as of December 31, 2011, and we have elected to discontinue hedge accounting prospectively. At December 31, 2011, Accumulated Other Comprehensive Income consisted of $2.6 million ($1.6 million after tax) of unrealized gains, representing the mark-to-market value of our cash flow hedges as of the balance sheet date. As a result of discontinuing hedge accounting, such mark-to-market values that are included in Accumulated Other Comprehensive Income as of the de-designation date will be frozen and reclassified into earnings in future periods as the underlying hedged transactions affect earnings. We expect to reclassify into earnings from Accumulated Other Comprehensive Income the frozen value related to de-designated commodity cash flow hedges over the next two years. With the election to de-designate hedging instruments, all derivative instruments will be marked-to-market each period with the change in fair value representing unrealized gains and losses which will be recognized immediately in earnings. Similar to the crude oil basis and NYMEX roll swap derivative instruments, these mark-to-market adjustments will produce a degree of earnings volatility that can be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the settlement of the underlying contract occurs.

Fair Value Measurements

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

Stock-Based Compensation

We account for stock-based compensation in accordance with authoritative guidance regarding the accounting for stock-based compensation. Under the provisions of this guidance, stock-based compensation expense for options is estimated at the grant date based on the award s fair value as calculated by the Black-Scholes option-pricing model and is recognized as expense over the requisite service period. The Black-Scholes model requires various highly judgmental assumptions including volatility, forfeiture rates and expected option life. If any of the assumptions used in the Black-Scholes model change significantly, stock-based compensation expense for future grants may differ materially from that recorded in the current period. Stock-based compensation cost for restricted stock is estimated at the grant date based on the award s fair value which is

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equal to the average high and low common stock price on the date of grant and is recognized as expense over the requisite service period. Stock-based compensation for performance share units (PSUs) is measured at the end of each reporting period through the settlement date using the quarter-end closing common stock prices for awards that are solely based on performance conditions or a Monte Carlo model for awards that contain market conditions to reflect the current fair value. Compensation expense is recognized ratably over the performance period based on our estimated achievement of the established metrics. Compensation expense for awards with performance conditions will only be recognized for those awards for which it is probable that the performance conditions will be achieved and which are expected to vest. The compensation expense will be estimated based upon an assessment of the probability that the performance metrics will be achieved, current and historical forfeitures, and the Board s anticipated vesting percentage. Compensation expense for awards with market conditions is measured at the end of each reporting period based on the fair value derived from the Monte Carlo model which incorporates a risk-neutral valuation approach to value these awards. The Monte Carlo model requires various highly judgmental assumptions to determine the fair value of the awards. This model considers stock price movements for our shares and of the S&P 400 O&G E&P Industry Index (the Index) and calculates the resulting change in cash flow multiple at the end of the forecasted performance period. This model iterates these randomly forecasted results until the distribution of results converge on a mean or estimated fair value. Expense related to these awards can be volatile based on the Company s comparative performance at the end of each quarter. If any of the assumptions used in the Monte Carlo model change significantly, stock-based compensation expense may differ materially in the future from that recorded in the current period. See Item 8. Financial Statements and Supplementary Data, Note 12 Stock-Based Compensation .

Revenue Recognition

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

Income Taxes

We recognize deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in our financial statements. These deferred tax assets and liabilities are measured using the enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled, respectively. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

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

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

Authoritative guidance for accounting for uncertainty in income taxes requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more likely than not

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threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority. See Item 8. Financial Statements and Supplementary Data, Note 13 Income Taxes.

Recent Accounting Developments

The following recently issued accounting developments have been applied or may impact the Company in future periods.

Fair Value Measurements. In January 2010, the Financial Accounting Standards Board (FASB) issued authoritative guidance related to improving disclosures about fair value measurements. This guidance requires separate disclosures of the amounts of transfers in and out of Level 1 and Level 2 fair value measurements and a description of the reason for such transfers. In the reconciliation for Level 3 fair value measurements using significant unobservable inputs, information about purchases, sales, issuances and settlements shall be presented separately. These disclosures were required for interim and annual reporting periods effective January 1, 2010, except for the disclosures related to the purchases, sales, issuances and settlements in the roll forward activity of Level 3 fair value measurements, which were effective on January 1, 2011. This guidance requires additional disclosures but did not impact the Company s consolidated financial position, results of operations or cash flows.

In May 2011, the FASB further expanded authoritative guidance clarifying common requirements for measuring fair value instruments and for disclosing information about fair value measurements in accordance with U.S. generally accepted accounting principles (GAAP) and International Financial Reporting Standards (IFRS). In this guidance, the FASB clarifies that the concept of highest and best use and valuation premise in a fair value measurement is only relevant when measuring the fair value of nonfinancial assets and is not relevant when measuring the fair value of financial assets or liabilities. The FASB also addressed measuring the fair value of an instrument classified in shareholders equity whereby an entity should measure the fair value of its own equity instrument from the perspective of a market participant. In addition, this guidance requires disclosure of quantitative information about unobservable inputs used in measuring the fair value of Level 3 instruments. This guidance will be required for interim and annual reporting periods effective January 1, 2012 and early application is not permitted. This guidance will require additional disclosures but will not impact the Company s consolidated financial position, results of operations or cash flows.

Comprehensive Income. In September 2011, the FASB issued authoritative guidance to increase the prominence of items reported in other comprehensive income. This guidance requires an entity to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate and consecutive statements. Irrespective of the presentation method chosen, an entity will be required to present on the face of the financial statement reclassification adjustments for items that are reclassified from other comprehensive income to net income in the statement where the component is presented. Subsequent to the September 2011 pronouncement, the FASB issued guidance deferring the effective date related to the presentation of reclassification adjustments only. No other requirements were deferred and the modified guidance will be required for interim and annual reporting periods effective January 1, 2012 and early application is permitted. This guidance will require presentation adjustments to the face of the Company s consolidated financial statements, including historical periods, but will not impact the Company s consolidated financial position, results of operations or cash flows.

Offsetting Assets and Liabilities. In December 2011, the FASB issued authoritative guidance requiring entities to disclose both gross information and net information about instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. The objective of the disclosure is to facilitate comparison between those entities that prepare their financial statements on the basis of U.S. GAAP and those entities that prepare their financial statements on the basis of IFRS. This guidance will be required for interim and annual reporting periods effective January 1, 2013 and will be retrospectively applied. This guidance will require additional disclosures but will not impact the Company s consolidated financial position, results of operations or cash flows.

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Off-Balance Sheet Arrangements

At December 31, 2011, we did not have any off-balance sheet arrangements.

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, and Section 21E of the Securities Exchange Act of 1934, as amended. 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, expect, plan, project, intend, anticipate, predict, potential, pursue, target or continue, the negative of such terms or variations thereon, or other comparable terminology.

The forward-looking statements contained in this report are largely based on our expectations for the future, which 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:

- the supply and demand for oil, 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;
- the occurrence of property acquisitions or divestitures;

reserve levels;

inflation;

competition in the oil and natural gas industry;

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

the availability and cost of processing and transportation;

changes or advances in technology;

potential reserve revisions;

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- limitations, availability, and constraints on infrastructure required to 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 and exploration risks;

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

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

- present and possible future claims, litigation and enforcement actions;

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

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

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

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

- any other factors that impact or could impact the exploration of oil 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 and natural gas.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

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

Financial Condition and Results of Operations   Liquidity and Capital Resources   Commodity Price Risk and Related Hedging Activities.

Commodity Price Risk. Our major market risk exposure is in the pricing of our oil, NGL and natural gas production. Realized pricing is primarily driven by the prevailing price for crude oil and spot market prices applicable to our U.S. natural gas and NGL production. Pricing for oil, NGL and natural gas production has been volatile and unpredictable for several years and we expect this volatility to continue in the future. Accordingly, we use certain derivative instruments, including fixed price swaps, basis swaps, NYMEX roll swaps and costless collars. Although not risk free, we believe these activities will reduce commodity price fluctuations and thereby enable us to achieve a more predictable cash flow.

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Our fixed price swap agreements are used to fix the sales price for our anticipated future NGL production. Upon settlement, we receive a fixed price for the hedged commodity and pay our counterparty a floating market price, as defined in each instrument. These instruments are settled monthly. When the floating price exceeds the fixed price for a contract month, we pay our counterparty. When the fixed price exceeds the floating price, our counterparty is required to make a payment to us. We have previously designated these swaps as cash flow hedges, however, effective January 1, 2012, we have elected to de-designate all of our commodity contracts and we will discontinue hedge accounting prospectively. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Commodity Price Risk and Related Hedging Activities and Item 8. Financial Statements and Supplementary Data, Note 6 Commodity Derivative Contracts and Other Derivatives. Should the market for this instrument become attractive, we have the ability to enter into fixed price swap agreements for our anticipated future oil and natural gas production, as well as add additional NGL fixed price swaps.

Our basis swaps and NYMEX roll swaps are used to fix the variability between two price indexes and the NYMEX roll price, respectively, for our anticipated future oil production. Upon settlement, we receive a fixed price for the hedged commodity and pay our counterparty a floating market price, as defined in each instrument. These instruments are settled monthly. When the floating price exceeds the fixed price for a contract month, we pay our counterparty. When the fixed price exceeds the floating price, our counterparty is required to make a payment to us. While these trades meet the objective of managing commodity price exposure, they do not qualify for hedge accounting. As a result, these instruments are referred to as non-qualifying.

Our costless collar agreements are used to fix the variability in sales price within a floor price and ceiling price for our anticipated future oil and natural gas production. These instruments are settled monthly when required as defined in each instrument. When the floating market price exceeds the ceiling price, we pay our counterparty. When the floor price exceeds the floating market price, our counterparty is required to make payment to us. If the floating market price is within the floor and ceiling prices, no payments are required by either the Company or the counterparties. We have previously designated these costless collars as cash flow hedges, however, effective January 1, 2012, we have elected to de-designate all of our commodity contracts and we will discontinue hedge accounting prospectively. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Commodity Price Risk and Related Hedging Activities and Item 8. Financial Statements and Supplementary Data, Note 6 Commodity Derivative Contracts and Other Derivatives. Should the market for this instrument become attractive, we have the ability to enter into costless collar agreements for our anticipated future NGL production, as well as add additional oil and natural gas costless collars.

As of December 31, 2011, we had open crude oil derivatives in a net liability position with a fair value of $1.3 million. A 10% increase in crude oil prices would reduce the fair value by approximately $15.7 million, while a 10% decrease in crude oil prices would increase the fair value by approximately $11.9 million. The effects of these derivative transactions on our crude oil sales are discussed above under Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Revenues.

As of December 31, 2011, we had open NGL derivatives in a liability position with a fair value of $9.2 million. A 10% increase in NGL prices would reduce the fair value by approximately $14.0 million, while a 10% decrease in NGL prices would increase the fair value by approximately $14.1 million. The effects of these derivative transactions on our NGL sales are discussed above under Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Revenues.

As of December 31, 2011, we had open natural gas derivatives in an asset position with a fair value of $14.1 million. A 10% increase in natural gas prices would reduce the fair value by approximately $1.9 million, while a 10% decrease in natural gas prices would increase the fair value by approximately $1.9 million. The effects of these derivative transactions on our natural gas sales are discussed above under Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Revenues.

These fair value changes assume volatility based on prevailing market parameters at December 31, 2011.

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Our derivative instruments are with counterparties who are lenders in our credit facilities. We evaluated non-performance risk using current credit default swap values and default probabilities for the Company and counterparties and recorded a downward adjustment to the fair value of our derivative assets in the amount of $0.1 million at December 31, 2011. We currently do not know of any circumstances that would limit access to our credit facilities or require a change in our debt or hedging structure.

At December 31, 2011, we had the following financial fixed price swap, basis swap, NYMEX roll swap and costless collar transactions outstanding with associated notional volumes and average underlying prices that represent hedged prices of commodities at various market locations:

Product	Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume Bbl	Total of Notional Volume Bbl	Average Floor/Fixed Prices per Bbl	Average Ceiling Prices per Bbl	Fair Market Value Asset/ (Liability) In thousands)
Crude oil	2012	Costless Collar	Cash flow	5,600	2,049,600	$ 76.61	$ 112.90	$ (3,631)
Crude oil	2013	Costless Collar	Cash flow	4,750	1,733,750	77.11	119.06	1,087
					3,783,350			$ (2,544)

Product	Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume Bbl	Total of Notional Volume Bbl	Average Floor/Fixed Prices per Bbl	Average Ceiling Prices per Bbl	Fair Market Value Asset/ (Liability) In thousands)
Crude oil	May 2012 December 2012	Basis Swap	Non-qualifying	2,500	612,500	$ 8.70	$	$ 1,209
Crude oil	May 2012 December 2012	NYMEX Roll Swap	Non-qualifying	2,500	612,500	(0.30)		(354)
Crude oil	2013	Basis Swap	Non-qualifying	1,875	684,375	5.80		748
Crude oil	2013	NYMEX Roll Swap	Non-qualifying	1,875	684,375	(0.18)		(370)
					2,593,750			$ 1,233

Product	Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume Bbl	Total of Notional Volume Bbl	Average Floor/Fixed Prices per Bbl	Average Ceiling Prices per Bbl	Fair Market Value Asset/ (Liability) In thousands)
NGL-Propane	2012	Swap	Cash flow	2,500	915,000	$ 53.22	$	$ (2,685)
NGL-Isobutane	2012	Swap	Cash flow	760	278,160	71.70		(2,623)
NGL-Normal Butane	2012	Swap	Cash flow	780	285,480	67.86		(2,027)
NGL-Pentanes Plus	2012	Swap	Cash flow	660	241,560	89.77		(643)
NGL-Propane	2013	Swap	Cash flow	500	182,500	51.66		(498)
NGL-Isobutane	2013	Swap	Cash flow	150	54,750	69.20		(250)
NGL-Normal Butane	2013	Swap	Cash flow	170	62,050	66.89		(241)
NGL-Pentanes Plus	2013	Swap	Cash flow	180	65,700	84.32		(194)
					2,085,200			$ (9,161)

Product

	Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume MMBtu	Total of Notional Volume MMBtu	Average Floor/Fixed Prices per MMBtu	Average Ceiling Prices per MMBtu	Fair Market Value Asset/ (Liability) In thousands)
Natural gas	2012	Costless Collar	Cash flow	20,000	7,320,000	$ 5.13	$ 6.31	$ 14,137
					7,320,000			$ 14,137

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Item 8. Financial Statements and Supplementary Data

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Report of Independent Registered Public Accounting Firm

To the Board of Directors

and Stockholders of Rosetta Resources Inc.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of cash flows and of stockholders equity present fairly, in all material respects, the financial position of Rosetta Resources Inc. and its subsidiaries (the Company) at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Annual Report on Internal Control Over Financial Reporting appearing under Item 9A - Controls and Procedures. Our responsibility is to express opinions on these financial statements and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 2 Summary of Significant Accounting Policies *Property and Equipment, Net,* at December 31, 2009 the Company changed the manner in which its oil and gas reserves are estimated as well as the manner in which prices are determined to calculate the ceiling limit on capitalized oil and gas costs.

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

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

/s/ PricewaterhouseCoopers LLP

Houston, Texas

February 27, 2012

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Item 8. Financial Statements and Supplementary Data

Rosetta Resources Inc.

Consolidated Balance Sheet

(In thousands, except par value and share amounts)

	December 31, 2011	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 47,050	$ 41,634
Accounts receivable, net	77,374	36,159
Derivative instruments	10,171	19,145
Prepaid expenses	2,962	2,711
Current deferred tax asset	11,015	
Other current assets	2,942	5,454
Total current assets	151,514	105,103
Oil and natural gas properties using the full cost method of accounting:		
Proved properties	2,297,312	2,124,615
Unproved/unevaluated properties, not subject to amortization	141,016	91,148
Gas gathering systems and compressor stations	38,580	46,398
Other fixed assets	9,494	14,459
	2,486,402	2,276,620
Accumulated depreciation, depletion, and amortization, including impairment	(1,657,841)	(1,546,631)
Total property and equipment, net	828,561	729,989
Other assets:		
Deferred loan fees	8,575	7,652
Deferred tax asset	74,150	142,710
Derivative instruments	1,633	1,523
Other long-term assets	912	2,463
Total other assets	85,270	154,348
Total assets	$ 1,065,345	$ 989,440
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable	$ 2,489	$ 3,669
Accrued liabilities	107,594	57,006
Royalties and other payables	50,689	14,542
Derivative instruments	6,788	
Deferred income taxes		7,132
Current portion of long-term debt	20,000	
Total current liabilities	187,560	82,349
Long-term liabilities:		

Derivative instruments	1,351	1,011
Long-term debt	230,000	350,000
Other long-term liabilities	13,598	27,264
Total liabilities	$ 432,509	$ 460,624
Commitments and contingencies (Note 11)		
Stockholders equity:		
Preferred stock, $0.001 par value; authorized 5,000,000 shares; no shares issued in 2011 or 2010		
Common stock, $0.001 par value; authorized 150,000,000 shares; issued 52,630,483 shares and 52,031,004 shares at December 31, 2011 and 2010, respectively	52	52
Additional paid-in capital	810,794	793,293
Treasury stock, at cost; 450,173 and 343,093 shares at December 31, 2011 and 2010, respectively	(11,296)	(6,896)
Accumulated other comprehensive income	1,632	11,259
Accumulated deficit	(168,346)	(268,892)
Total stockholders equity	632,836	528,816
Total liabilities and stockholders equity	$ 1,065,345	$ 989,440

See accompanying notes to the consolidated financial statements.

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Rosetta Resources Inc.

Consolidated Statement of Operations

(In thousands, except per share amounts)

	Year Ended December 31, 2011	2010	2009
Revenues:			
Oil sales	$ 157,517	$ 54,542	$ 21,763
NGL sales	125,301	45,200	21,504
Natural gas sales	163,382	208,688	250,684
Total revenues	446,200	308,430	293,951
Operating costs and expenses:			
Lease operating expense	34,900	51,085	60,773
Treating and transportation	22,316	6,963	6,268
Production taxes	12,073	5,953	6,131
Depreciation, depletion, and amortization	123,244	116,558	121,042
Impairment of oil and gas properties			379,462
General and administrative costs	75,256	56,332	46,993
Total operating costs and expenses	267,789	236,891	620,669
Operating income (loss)	178,411	71,539	(326,718)
Other expense (income):			
Interest expense, net of interest capitalized	21,291	27,073	19,258
Interest income	(42)	(38)	(97)
Other expense (income), net	903	(1,087)	(876)
Total other expense	22,152	25,948	18,285
Income (loss) before provision for income taxes	156,259	45,591	(345,003)
Income tax expense (benefit)	55,713	26,545	(125,827)
Net income (loss)	$ 100,546	$ 19,046	$ (219,176)
Earnings (loss) per share:			
Basic	$ 1.93	$ 0.37	$ (4.30)
Diluted	$ 1.91	$ 0.37	$ (4.30)
Weighted average shares outstanding:			
Basic	51,996	51,381	50,979
Diluted	52,616	52,168	50,979

See accompanying notes to the consolidated financial statements.

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Rosetta Resources Inc.

Consolidated Statement of Cash Flows

(In thousands)

	Year Ended December 31,		
	2011	2010	2009
Cash flows from operating activities:			
Net income (loss)	$ 100,546	$ 19,046	$ (219,176)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	123,244	116,558	121,042
Impairment of oil and gas properties			379,462
Deferred income taxes	56,170	26,740	(124,632)
Amortization of deferred loan fees recorded as interest expense	2,248	2,828	2,102
Amortization of original issue discount recorded as interest expense		1,258	342
Stock-based compensation expense	29,010	14,147	7,836
Commodity derivative income	(12,124)	(1,715)	
Change in operating assets and liabilities:			
Accounts receivable	(41,215)	(11,337)	9,194
Prepaid expenses	(226)	852	2,209
Other current assets	287	961	(2,344)
Long-term assets	(450)	(316)	(484)
Accounts payable	(1,180)	1,390	11
Accrued liabilities	1,945	6,848	(1,897)
Royalties payable	37,409	(1,195)	(13,164)
Other long-term liabilities	(8,863)	796	
Derivative instruments	12,736		
Net cash provided by operating activities	299,537	176,861	160,501
Cash flows from investing activities:			
Additions of oil and gas assets	(432,951)	(328,889)	(141,016)
Acquisition of oil and gas properties		(5,874)	(3,844)
Disposals of oil and gas properties and assets	242,588	83,142	19,574
Decrease in restricted cash			1,421
Net cash used in investing activities	(190,363)	(251,621)	(123,865)
Cash flows from financing activities:			
Borrowings on Restated Revolver		64,000	28,400
Payments on Restated Revolver	(100,000)	(124,000)	(40,000)
Issuance of Senior Notes		200,000	
Repayments on Restated Term Loan		(80,000)	
Deferred loan fees	(3,150)	(6,282)	(5,855)
Proceeds from stock options exercised	3,792	4,843	21
Purchases of treasury stock	(4,400)	(3,423)	(801)
Net cash (used in) provided by financing activities	(103,758)	55,138	(18,235)
Net increase (decrease) in cash	5,416	(19,622)	18,401
Cash and cash equivalents, beginning of year	41,634	61,256	42,855

Cash and cash equivalents, end of year	$ 47,050	$ 41,634	$ 61,256
Supplemental disclosures:			
Cash paid for interest expense, net of capitalized interest	$ 19,044	$ 22,987	$ 16,813
Cash paid (received) for income taxes	$ (405)	$ 337	$ (1,196)
Supplemental non-cash disclosures:			
Capital expenditures included in accrued liabilities	$ 57,546	$ 22,945	$ 18,199

See accompanying notes to the consolidated financial statements.

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Rosetta Resources Inc.

Consolidated Statement of Stockholders Equity

(In thousands, except share amounts)

	Common Stock			Treasury Stock		Accumulated	Retained	
	Shares	Amount	Additional Paid-In Capital	Shares	Amount	Other Comprehensive (Loss)/Income	Earnings / Accumulated Deficit	Total Stockholders Equity
Balance at December 31, 2008	51,031,481	$ 51	$ 773,676	155,790	$ (2,672)	$ 24,079	$ (68,762)	$ 726,372
Stock options exercised	14,125		21					21
Treasury stock employee tax payment				44,165	(801)			(801)
Stock-based compensation			6,499					6,499
Vesting of restricted stock	209,103							
Comprehensive loss:								
Net loss							(219,176)	(219,176)
Change in fair value of derivative hedging instruments						43,693		43,693
Hedge settlements reclassified to income						(75,278)		(75,278)
Tax expense related to cash flow hedges						11,765		11,765
Comprehensive loss								(238,996)
Balance at December 31, 2009	51,254,709	$ 51	$ 780,196	199,955	$ (3,473)	$ 4,259	$ (287,938)	$ 493,095
Stock options exercised	287,397	1	4,842					4,843
Treasury stock employee tax payment				143,138	(3,423)			(3,423)
Stock-based compensation			8,255					8,255
Vesting of restricted stock	488,898							
Comprehensive income:								
Net income							19,046	19,046
Change in fair value of derivative hedging instruments						42,632		42,632
Hedge settlements reclassified to income						(31,477)		(31,477)
Tax expense related to cash flow hedges						(4,155)		(4,155)
Comprehensive income								26,046
Balance at December 31, 2010	52,031,004	$ 52	$ 793,293	343,093	$ (6,896)	$ 11,259	$ (268,892)	$ 528,816
Stock options exercised	230,741		3,792					3,792
Treasury stock employee tax payment				107,080	(4,400)			(4,400)
Stock-based compensation			13,709					13,709
Vesting of restricted stock	368,738							
Comprehensive income:								
Net income							100,546	100,546
Change in fair value of derivative hedging instruments						2,033		2,033
Hedge settlements reclassified to income						(17,430)		(17,430)
Tax expense related to cash flow hedges						5,770		5,770
Comprehensive income								90,919
Balance at December 31, 2011	52,630,483	$ 52	$ 810,794	450,173	$ (11,296)	$ 1,632	$ (168,346)	$ 632,836

See accompanying notes to the consolidated financial statements.

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Rosetta Resources Inc.

Notes to Consolidated Financial Statements

(1) Organization and Operations of the Company

Nature of Operations. Rosetta Resources Inc. (together with its consolidated subsidiaries, the Company) is an independent exploration and production company engaged in the acquisition and development of onshore energy resources in the United States of America. The Company s operations are primarily located in South Texas, including our largest producing area in the Eagle Ford shale, and in the Southern Alberta Basin in Northwest Montana.

In preparing these financial statements, events occurring after December 31, 2011 through the release of these financial statements were evaluated by the Company to ensure that any subsequent events that meet the criteria for recognition and/or disclosure in this report, have been included.

Certain reclassifications of prior year balances have been made to conform such amounts to current year classifications. These reclassifications have no impact on net income (loss).

(2) Summary of Significant Accounting Policies

Use of Estimates in Preparation of Financial Statements

The preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expense during the reporting period. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. The Company evaluates its estimates and assumptions on a regular basis. The Company bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of the Company s financial statements. The most significant estimates with regard to these financial statements relate to the provision for income taxes including uncertain tax positions, the outcome of pending litigation, stock-based compensation, valuation of derivative instruments, future development and abandonment costs, estimates to certain oil and gas revenues and expenses and the estimates of proved oil and natural gas reserve quantities which are used to calculate depletion and impairment of proved oil and natural gas properties.

Cash and Cash Equivalents

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

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

Restricted Cash

As of December 31, 2011 and 2010, the Company had no restricted cash.

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Allowance for Doubtful Accounts

The Company regularly reviews all aged accounts receivables for collectability and establishes an allowance as necessary for individual customer balances.

Property and Equipment, net

The Company follows the full cost method of accounting for oil and natural gas properties. Under the full cost method, all costs incurred in acquiring, exploring and developing properties, including salaries, benefits and other internal costs directly attributable to these activities, are capitalized when incurred into cost centers that are established on a country-by-country basis, and are amortized over reserves in the cost center in which they are produced, subject to a limitation that the capitalized costs not exceed the value of those reserves. In some cases, however, certain significant costs, such as those associated with unevaluated properties and significant development projects, are deferred separately without amortization until the specific property to which they relate is found to be either productive or nonproductive, at which time those deferred costs and any reserves attributable to the property are included in the computation of amortization in the cost center. All costs incurred in oil and natural gas producing activities are regarded as integral to the acquisition, discovery and development of reserves that ultimately result from the efforts as a whole, and are thus associated with the Company s reserves. The Company capitalizes internal costs directly identified with acquisition, exploration and development activities. The Company capitalized $7.0 million, $7.8 million and $4.8 million of internal costs for the years ended December 31, 2011, 2010 and 2009, respectively. Unevaluated costs are excluded from the full cost pool and are periodically evaluated for impairment at which time they are transferred to the full cost pool to be amortized. Upon evaluation, costs associated with productive properties are transferred to the full cost pool and amortized. Gains or losses on the sale of oil and natural gas properties are generally included in the full cost pool unless a significant portion of the pool or reserves are sold causing a significant change in the relationship between capitalized costs and proved reserves.

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

Prior to December 31, 2009, the ceiling calculation dictated that prices and costs in effect as of the last day of the quarter be held constant, and for periods in which a write-down was required, if oil and natural gas prices increased subsequent to the end of a quarter or annual period but prior to the issuance of the financial statements, the Company was allowed to adjust the write-down to reflect the higher prices. With the FASB s issuance of Accounting Standards Update 2010-03, Extractive Activities Oil and Gas in January 2010, the use of the recovery of prices after the end of the period is no longer permitted. This guidance became effective December 31, 2009 and requires the ceiling calculation to utilize a twelve-month average price using first-day of-the-month prices, and costs in effect as of the last day of the quarter are to be held constant. This change in accounting was treated in these financial statements as a change in accounting principle inseparable from a change in accounting estimate. The effect of the adoption in 2009 was not significant to the Company s financial statements.

A ceiling test write-down is a charge to earnings and cannot be reinstated even if the cost ceiling increases at a subsequent reporting date. If required, a write-down would reduce earnings and impact shareholders equity in the period of occurrence and result in lower DD&A expense in the future. The Company s average DD&A rates were $12.24, $13.93 and $14.37 per Boe in 2011, 2010 and 2009, respectively.

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It is possible that a write-down of the Company s oil and gas properties could occur in the event that oil and natural gas prices decline or the Company experiences significant downward adjustments to its estimated proved reserves.

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

Future Development and Abandonment Costs

Future development costs include costs incurred to obtain access to proved reserves, such as drilling costs and the installation of production equipment, and such costs are included in the calculation of DD&A expense. Future abandonment costs include costs to plug and abandon wells, dismantle and relocate or dispose of our production platforms, gathering systems and related structures and restoration costs of land and seabed. The Company develops estimates of these costs for each of its properties based upon their geographic location, type of production structure, well depth, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. The Company reviews its assumptions and estimates of future development and future abandonment costs on an annual basis.

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

Capitalized Interest

The Company capitalizes interest on capital invested in projects related to unevaluated properties and significant development projects. As proved reserves are established or impairment determined, the related capitalized interest is included in costs subject to amortization. The Company capitalized interest of $5.5 million, $4.0 million and $1.2 million in 2011, 2010 and 2009, respectively.

Fair Value of Financial Instruments

The carrying value of cash and cash equivalents, accounts receivable, other current assets and current liabilities reported in the Consolidated Balance Sheet approximate fair value because of their short-term nature. Derivatives are recorded on the balance sheet at fair value. The carrying amount of total debt reported in the Consolidated Balance Sheet at December 31, 2011 and 2010 was $250.0 million and $350.0 million, respectively. The Company estimated the fair value of its total debt as of December 31, 2011 and 2010 in accordance with the authoritative guidance for fair value measurements using market quotes for its publicly traded debt and a discounted cash flow technique for non-publicly traded debt that incorporates a market interest yield curve with adjustments for duration, optionality and risk profile. The fair value of debt is the estimated amount a market participant would pay to purchase the Company s debt, and based on this calculation, the Company has determined the fair market value of its debt to be $267.5 million as of December 31, 2011. The fair market value of debt as of December 31, 2010 was $363.6 million.

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Concentrations of Credit Risk

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

Deferred Loan Fees

Loan fees incurred in connection with the Company s Restated Revolver, Restated Term Loan and Senior Notes (each as hereafter defined in Note 10 Debt and Credit Agreements) are recorded on the Company s Consolidated Balance Sheet as Deferred loan fees. The deferred loan fees are amortized to interest expense over the term of the related debt using the straight-line method, which approximates the effective interest method.

Derivative Instruments and Activities

The Company utilizes various types of derivative instruments to manage commodity price risk, including fixed price swaps, basis swaps, New York Mercantile Exchange (NYMEX) roll swaps and costless collars. The Company does not enter into derivative agreements for trading or other speculative purposes and the fair value of derivative contracts is presented on a net basis where the right of offset is provided for in the counterparty agreements. For commodity contracts that qualified, the Company historically elected hedge accounting for those derivative instruments. However, effective January 1, 2012, we have elected to de-designate all of our commodity contracts that had previously been designated as cash flow hedges as of December 31, 2011 and have elected to discontinue hedge accounting prospectively. See Note 6 Commodity Derivative Contracts and Other Derivatives for a more detailed discussion of derivative activities.

Environmental

Environmental expenditures are expensed or capitalized, as appropriate, depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not have future economic benefit, are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and the cost can be reasonably estimated. There were no significant environmental liabilities as of December 31, 2011 or 2010.

Stock-Based Compensation

Stock-based compensation cost for restricted stock is estimated at the grant date based on the award s fair value which is equal to the average high and low common stock price on the date of grant and is recognized as expense over the requisite service period. Stock-based compensation cost for options is estimated at the grant date based on the award s fair value as calculated using the Black-Scholes option-pricing model and is recognized as expense over the requisite service period. The Black-Scholes model requires various highly judgmental assumptions including volatility, forfeiture rates and expected option life. If any of the assumptions used in the Black-Scholes model change significantly, stock-based compensation expense for future grants may differ materially from that recorded in the current period.

Stock-based compensation for performance share units (PSUs) is measured at the end of each reporting period through the settlement date using the quarter-end closing common stock prices for awards that are solely based on performance conditions or a Monte Carlo model for awards that contain market conditions to reflect the current fair value. Compensation expense is recognized ratably over the performance period based on the Company s estimated achievement of the established metrics. Compensation expense for awards with performance conditions will only be recognized for those awards for which it is probable that the performance conditions will be achieved and which are expected to vest. The compensation expense will be estimated based upon an assessment of the probability that the performance metrics will be achieved, current and historical forfeitures, and the Board s anticipated vesting percentage. Compensation expense for awards with market

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conditions is measured at the end of each reporting period based on the fair value derived from the Monte Carlo model. The Monte Carlo model requires various highly judgmental assumptions including volatility and future cash flow projections. If any of the assumptions used in the Monte Carlo model change significantly, stock-based compensation expense may differ materially in the future from that recorded in the current period.

Any excess tax benefit arising from the Company s stock-based compensation plans is recognized as a credit to additional paid in capital when realized and is calculated as the amount by which the tax deduction received exceeds the deferred tax asset associated with the recorded stock-based compensation expense. The Company has approximately $7.0 million of unrealized excess tax benefits relating to $20.0 million of stock-based compensation which will be recognized in Additional paid-in capital upon utilization of the Company s net operating loss carryforward. Current authoritative guidance requires the cash flows that result from tax deductions in excess of the compensation expense to be recognized as financing activities.

Preferred Stock

The Company is authorized to issue 5,000,000 shares of preferred stock with preferences and rights as determined by the Company s Board of Directors. As of December 31, 2011 and 2010, there were no shares of preferred stock outstanding.

Treasury Stock

The Company repurchases shares that are surrendered by employees and directors to pay tax withholding upon the vesting of restricted stock awards. These repurchases are not part of a publicly announced program to repurchase shares of the Company s common stock and the Company does not have a publicly announced program to repurchase shares of common stock.

Revenue Recognition

Oil, NGL and natural gas revenue from our interests in producing wells is recognized upon delivery and passage of title, using the sales method for gas imbalances, net of any royalty interests or other profit interests in the produced product. Under the sales method, if our gas imbalance (amount of production sold in excess of amount entitled) exceeds our portion of the estimated remaining recoverable reserves of the well, a liability is recorded. No receivables are recorded for those wells on which we have taken less than our ownership share of production unless the amount taken by other parties exceeds the estimate of their remaining reserves. There were no significant gas imbalances at December 31, 2011 or 2010.

Income Taxes

The Company uses the liability method of accounting for income taxes. Under this method, deferred income taxes are provided to reflect the tax consequences in future years of differences between the financial statement and tax basis of assets and liabilities. Income taxes are provided based on earnings reported for tax return purposes in addition to a provision for deferred income taxes and are measured using enacted tax rates and laws that will be in effect when the differences are expected to reverse. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

Authoritative guidance for accounting for uncertainty in income taxes requires that the Company recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more likely than not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority.

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Recent Accounting Developments

The following recently issued accounting developments have been applied or may impact the Company in future periods.

Fair Value Measurements. In January 2010, the FASB issued authoritative guidance related to improving disclosures about fair value measurements. This guidance requires separate disclosures of the amounts of transfers in and out of Level 1 and Level 2 fair value measurements and a description of the reason for such transfers. In the reconciliation for Level 3 fair value measurements using significant unobservable inputs, information about purchases, sales, issuances and settlements shall be presented separately. These disclosures were required for interim and annual reporting periods effective January 1, 2010, except for the disclosures related to the purchases, sales, issuances and settlements in the roll forward activity of Level 3 fair value measurements, which were effective on January 1, 2011. This guidance requires additional disclosures but did not impact the Company s consolidated financial position, results of operations or cash flows.

In April 2011, the FASB further expanded authoritative guidance clarifying common requirements for measuring fair value instruments and for disclosing information about fair value measurements in accordance with U.S. generally accepted accounting principles (GAAP) and International Financial Reporting Standards (IFRS). In this guidance, the FASB clarifies that the concept of highest and best use and valuation premise in a fair value measurement is only relevant when measuring the fair value of nonfinancial assets and is not relevant when measuring the fair value of financial assets or liabilities. The FASB also addressed measuring the fair value of an instrument classified in shareholders equity whereby an entity should measure the fair value of its own equity instrument from the perspective of a market participant. In addition, this guidance requires disclosure of quantitative information about unobservable inputs used in measuring the fair value of Level 3 instruments. This guidance will be required for interim and annual reporting periods effective January 1, 2012 and early application is not permitted. This guidance will require additional disclosures but will not impact the Company s consolidated financial position, results of operations or cash flows.

Comprehensive Income. In September 2011, the FASB issued authoritative guidance to increase the prominence of items reported in other comprehensive income. This guidance requires an entity to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate and consecutive statements. Irrespective of the presentation method chosen, an entity will be required to present on the face of the financial statement reclassification adjustments for items that are reclassified from other comprehensive income to net income in the statement where the component is presented. Subsequent to the September 2011 pronouncement, the FASB issued guidance deferring the effective date related to the presentation of reclassification adjustments only. No other requirements were deferred and the modified guidance will be required for interim and annual reporting periods effective January 1, 2012 and early application is permitted. This guidance will require presentation adjustments to the face of the Company s consolidated financial statements, including historical periods, but will not impact the Company s consolidated financial position, results of operations or cash flows.

Offsetting Assets and Liabilities. In December 2011, the FASB issued authoritative guidance requiring entities to disclose both gross information and net information about instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. The objective of the disclosure is to facilitate comparison between those entities that prepare their financial statements on the basis of U.S. GAAP and those entities that prepare their financial statements on the basis of IFRS. This guidance will be required for interim and annual reporting periods effective January 1, 2013 and will be retrospectively applied. This guidance will require additional disclosures but will not impact the Company s consolidated financial position, results of operations or cash flows.

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(3) Accounts Receivable

Accounts receivable consists of the following:

	December 31, 2011	December 31, 2010
	(In thousands)	
Oil, NGL and natural gas revenue sales	$ 62,068	$ 33,982
State severance tax refunds	14,141	
Joint interest billings	1,165	1,823
Short-term receivable for royalty recoupment		354
Total	$ 77,374	$ 36,159

There are no balances in accounts receivable that are considered to be uncollectible and an allowance was unnecessary as of December 31, 2011 and 2010.

(4) Property and Equipment, Net

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

	December 31, 2011	December 31, 2010
	(In thousands)	
Proved properties	$ 2,297,312	$ 2,124,615
Unproved/unevaluated properties	141,016	91,148
Gas gathering systems and compressor stations	38,580	46,398
Other	9,494	14,459
Total	2,486,402	2,276,620
Less: Accumulated depreciation, depletion, and amortization	(1,657,841)	(1,546,631)
Total property and equipment, net	$ 828,561	$ 729,989

Included in the Company s oil and natural gas properties are asset retirement costs of $18.0 million and $24.8 million as of December 31, 2011 and 2010, respectively, including additions of $2.1 million and $0.2 million for the year ended December 31, 2011 and 2010, respectively.

Pursuant to full cost accounting rules, the Company must perform a ceiling test each quarter on its proved oil and gas assets within each separate cost center. The table below sets forth relevant assumptions utilized in the quarterly ceiling test computations for the respective periods noted:

		2011			
	Total Impairment	December 31 (1)	September 30 (1)	June 30 (1)	March 31 (1)
West Texas Intermediate oil price (per Bbl) (2)		$ 92.71	$ 91.00	$ 86.60	$ 80.04
Henry Hub natural gas price (per MMBtu) (2)		4.12	4.16	4.21	4.10
			3,589	9,000	27,797

Increase of calculated ceiling value due to cash flow hedges (pre-tax) (in thousands)	

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	Total Impairment	2010 December 31 (1)	September 30 (1)	June 30 (1)	March 31 (1)
West Texas Intermediate oil price (per Bbl) (2)		$ 75.96	$ 73.85	$ 72.25	$ 66.13
Henry Hub natural gas price (per MMBtu) (2)		4.38	4.41	4.10	3.98
Increase of calculated ceiling value due to cash flow hedges (pre-tax) (in thousands)		27,729	33,652	50,045	60,648

	Total Impairment	2009 December 31 (1)	September 30 (3)	June 30	March 31
West Texas Intermediate oil price (per Bbl) (2)		$ 57.65	$ 76.25	$ 66.25	$ 46.00
Henry Hub natural gas price (per MMBtu) (2)		3.87	4.59	3.89	3.63
Increase of calculated ceiling value due to cash flow hedges (pre-tax) (in thousands)		45,000	29,334	55,299	79,664
Impairment recorded (pre-tax) (in thousands)	$ 379,462				379,462
Potential impairment absent the effects hedging (pre-tax) (in thousands)		29,482		26,337	459,126

(1) For the respective periods, oil and natural gas prices are calculated using a trailing twelve-month, unweighted-average first-day-of-the-month price, adjusted for hedges, based on West Texas Intermediate oil prices and Henry Hub natural gas prices.

(2) Adjusted for basis and quality differentials.

(3) The Company s ceiling test was calculated using hedge adjusted market prices of oil and natural gas at September 30, 2009, which were based on a West Texas Intermediate oil price of $67.00 per Bbl and a Henry Hub natural gas price of $3.30 per MMBtu (adjusted for basis and quality differentials). Cash flow hedges of natural gas production in place at September 30, 2009 increased the calculated ceiling value by approximately $50.7 million (pre-tax). The use of these prices would have resulted in a pre-tax write-down of $18.8 million at September 30, 2009. As allowed under the full cost accounting rules at the time, the Company re-evaluated the ceiling test on October 29, 2009 using the West Texas Intermediate oil price of $76.25 per Bbl and the Henry Hub natural gas price of $4.59 per MMBtu (adjusted for basis and quality differentials). At these prices, cash flow hedges of natural gas production in place increased the calculated ceiling value by approximately $29.3 million (pre-tax). Utilizing higher prices subsequent to period end, the calculated ceiling amount exceeded the Company s net capitalized cost of oil and gas properties. As a result, no write-down was recorded for the quarter ended September 30, 2009.

The Company did not record any write-down or impairment for the years ended December 31, 2011 and 2010 and there was no potential impairment absent the effects of hedging. Effective January 1, 2012, we have elected to de-designate all of our commodity contracts that had previously been designated as cash flow hedges as of December 31, 2011 and have elected to discontinue hedge accounting prospectively. As a result, there will be no future impact to the calculated ceiling value due to cash flow hedges.

Capitalized costs excluded from DD&A as of December 31, 2011 and 2010, all of which are located onshore in the U.S., are as follows by the year in which such costs were incurred:

	December 31, 2011 (In thousands)				
	Total	2011	2010	2009	Prior
Development cost	$ 12,479	$ 12,479	$	$	$
Exploration cost	79,250	60,389	18,861		
Acquisition cost of undeveloped acreage	42,532	6,000	21,486	6,362	8,684
Capitalized interest	6,755	4,506	568	455	1,226
Total capitalized costs excluded from DD&A	$ 141,016	$ 83,374	$ 40,915	$ 6,817	$ 9,910

	December 31, 2010 (In thousands)				
	Total	2010	2009	2008	Prior
Development cost	$ 10,314	$ 10,314	$	$	$
Exploration cost	18,861	18,861			
Acquisition cost of undeveloped acreage	58,161	35,432	8,978	13,751	
Capitalized interest	3,812	1,779	776	1,257	
Total capitalized costs excluded from DD&A	$ 91,148	$ 66,386	$ 9,754	$ 15,008	$

It is anticipated that the development costs of $12.5 million will be included in oil and gas properties subject to amortization within one year. With respect to the remaining capitalized costs excluded from DD&A of $128.5 million, it is anticipated that these costs will be included in oil and gas properties subject to amortization within five years.

Property Acquisitions and Divestitures. On February 15, 2012, we entered into an agreement to sell our Lobo assets and a portion of our Olmos assets for $95.0 million, subject to customary adjustments and the receipt of appropriate consents for assignment. We expect the transaction to close in the first half of 2012.

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

In the fourth quarter of 2010, the Company entered into a purchase and sale agreement to divest its Pinedale and San Juan assets located in Wyoming and New Mexico for $39.4 million. The sale was effective as of August 1, 2010 and was subject to post-closing purchase price adjustments. Proceeds from the divestiture were recorded as of an adjustment to the full cost pool with no gain or loss recognized.

In the third quarter of 2010, the Company acquired an additional 3,000 acres for $8.9 million in the Eagle Ford shale thereby increasing the Company s acreage within the shale to approximately 65,000 net acres. The Company also entered into a purchase and sale agreement to divest certain non-core properties located in Arkansas, Oklahoma, Mississippi, Texas and Louisiana for $37.1 million. The sale of these assets, collectively known as the Arklatex assets, was effective as of August 1, 2010 and was subject to post-closing purchase price adjustments. Proceeds from the divestiture were recorded as an adjustment to the full cost pool with no gain or loss recognized.

In the second quarter of 2010, the Company acquired the remaining 30% working interest and obtained operatorship in the Catarina Field for $5.9 million. The purchase was effective as of January 1, 2010 and was subject to post-closing purchase price adjustments. The Company divested its Gulf Coast Sabine Lake asset for $10.2 million. The proceeds were recorded as an adjustment to the full cost pool with no gain or loss recognized.

In the first quarter of 2010, the Company acquired a non-producing leasehold in the South Texas Gates Ranch area for $11.3 million with an effective date of March 1, 2010. The Company further increased its working interest from 70% to 100% in certain properties in the South Texas Gates Ranch area for $12.5 million. The purchase was effective as of January 1, 2010 and was subject to post-closing purchase price adjustments.

Gas Gathering Systems and Compressor Stations. The gross book value of the Company s gas gathering systems and compressor stations was $38.6 million and $46.4 million at December 31, 2011 and 2010, respectively, and is depreciated on a straight-line basis over 15 years. The accumulated depreciation for the gas gathering system at December 31, 2011 and 2010 was $2.5 million and $9.5 million, respectively. The depreciation expense associated with the gas gathering systems and compressor stations for the years ended December 31, 2011, 2010, and 2009 was $2.3 million, $3.2 million, and $2.5 million, respectively. In connection with the 2011 divestitures, the Company sold certain of these assets primarily located in the Sacramento Basin in California with no gain or loss recognized.

Other Property and Equipment. Other property and equipment at December 31, 2011 and 2010 of $9.5 million and $14.5 million, respectively, consisted primarily of computer hardware and software, office leasehold, vehicles and furniture and fixtures. The accumulated depreciation associated with other property and equipment at December 31, 2011 and 2010 was $5.9 million and $6.4 million, respectively. For the years ended December 31, 2011, 2010 and 2009 depreciation expense for other property and equipment was $2.6 million, $2.1 million and $1.7 million, respectively.

(5) Deferred Loan Fees

As of December 31, 2011 and 2010, deferred loan fees were $8.6 million and $7.7 million, respectively. Total amortization expense for deferred loan fees was $2.2 million, $2.8 million and $2.1 million for the years ended December 31, 2011, 2010 and 2009, respectively.

(6) Commodity Derivative Contracts and Other Derivatives

The Company is exposed to various market risks, including volatility in oil, NGL and natural gas commodity prices, which are managed through derivative instruments. The level of derivative activity utilized depends on market conditions, operating strategy and available derivative prices. Forward contracts on various commodities are entered into to manage the price risk associated with forecasted sales of the Company s oil, NGL and natural gas production. Interest rate swaps were utilized in 2010 to manage interest rate risk associated with the Company s previous variable-rate borrowings. These interest rate swaps settled during 2010 and the Company did not enter into any interest rate swaps during 2011.

The Company utilizes various types of derivative instruments to manage commodity price risk, including fixed price swaps, basis swaps, NYMEX roll swaps and costless collars. Many of these derivative financial instruments qualify for hedge accounting treatment as set forth in the authoritative accounting guidance. However, while the Company s crude oil basis and NYMEX roll swaps meet the objective of managing commodity price exposure, these trades do not qualify for hedge accounting. As a result, these derivative financial instruments are referred to as non-qualifying.

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At December 31, 2011, the following financial fixed price swap, basis swap, NYMEX roll swap and costless collar transactions were outstanding with associated notional volumes and average underlying prices that represent hedged prices of commodities at various market locations:

Product	Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume Bbl	Total of Notional Volume Bbl	Average Floor/ Fixed Prices per Bbl	Average Ceiling Prices per Bbl	Fair Market Value Asset/ (Liability) In thousands)
Crude oil	2012	Costless Collar	Cash flow	5,600	2,049,600	$ 76.61	$ 112.90	$ (3,631)
Crude oil	2013	Costless Collar	Cash flow	4,750	1,733,750	77.11	119.06	1,087
					3,783,350			$ (2,544)

Product	Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume Bbl	Total of Notional Volume Bbl	Average Floor/ Fixed Prices per Bbl	Average Ceiling Prices per Bbl	Fair Market Value Asset/ (Liability) In thousands)
Crude oil	May 2012 - December 2012	Basis Swap	Non-qualifying	2,500	612,500	$ 8.70	$	$ 1,209
Crude oil	May 2012 - December 2012	NYMEX Roll Swap	Non-qualifying	2,500	612,500	(0.30)		(354)
Crude oil	2013	Basis Swap	Non-qualifying	1,875	684,375	5.80		748
Crude oil	2013	NYMEX Roll Swap	Non-qualifying	1,875	684,375	(0.18)		(370)
					2,593,750			$ 1,233

Product	Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume Bbl	Total of Notional Volume Bbl	Average Floor/ Fixed Prices per Bbl	Average Ceiling Prices per Bbl	Fair Market Value Asset/ (Liability) In thousands)
NGL-Propane	2012	Swap	Cash flow	2,500	915,000	$ 53.22	$	$ (2,685)
NGL-Isobutane	2012	Swap	Cash flow	760	278,160	71.70		(2,623)
NGL-Normal Butane	2012	Swap	Cash flow	780	285,480	67.86		(2,027)
NGL-Pentanes Plus	2012	Swap	Cash flow	660	241,560	89.77		(643)
NGL-Propane	2013	Swap	Cash flow	500	182,500	51.66		(498)
NGL-Isobutane	2013	Swap	Cash flow	150	54,750	69.20		(250)
NGL-Normal Butane	2013	Swap	Cash flow	170	62,050	66.89		(241)
NGL-Pentanes Plus	2013	Swap	Cash flow	180	65,700	84.32		(194)
					2,085,200			$ (9,161)

Product	Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume MMBtu	Total of Notional Volume MMBtu	Average Floor/ Fixed Prices per MMBtu	Average Ceiling Prices per MMBtu	Fair Market Value Asset/ (Liability) In thousands)
Natural gas	2012	Costless Collar	Cash flow	20,000	7,320,000	$ 5.13	$ 6.31	$ 14,137
					7,320,000			$ 14,137

The Company s derivative instruments are with counterparties who are lenders under the Company s credit facilities. This allows the Company to satisfy any need for any margin obligation resulting from a negative change in fair market value of the derivative contracts with the collateral securing its credit facilities, thus eliminating the need for independent collateral postings. As of December 31, 2011, the Company had no deposits for collateral in regard to commodity derivative instruments.

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The following table sets forth the results of derivative settlements for the respective periods as reflected in the Consolidated Statement of Operations:

	For the Year Ended December 31, 2011	2010	2009
Crude Oil			
Quantity settled (Bbl)	959,800		
Decrease in crude oil sales revenue (In thousands) (1)	$ (2,149)	$	$
NGL			
Quantity settled (Bbl)	613,000		
Decrease in NGL sales revenue (In thousands)	$ (10,190)	$	$
Natural Gas			
Quantity settled (MMBtu)	18,250,000	14,645,000	20,856,465
Increase in natural gas sales revenue (In thousands) (2)	$ 18,751	$ 30,740	$ 76,567
Interest Rate Swaps			
(Increase) in interest expense (In thousands)	$	$ (978)	$ (1,289)

(1) For 2011, excludes approximately $1.2 million of unrealized gain associated with the change in fair value of the Company s crude oil basis and NYMEX roll swaps.

(2) For 2011, excludes approximately $11.1 million of realized gains associated with the 2011 termination of derivatives used to hedge production from the Company s divested DJ Basin and Sacramento Basin properties. For 2010, excludes approximately $1.7 million of realized gains associated with the 2010 termination of derivatives used to hedge production from the Company s divested Pinedale properties.

Additional Disclosures about Derivative Instruments and Hedging Activities

Authoritative guidance for derivatives requires companies to recognize all derivative instruments as either assets or liabilities at fair value in the statement of financial position. In accordance with this guidance, the Company has historically designated certain commodity forward contracts as cash flow hedges of forecasted sales of oil, NGL and natural gas production and interest rate swaps as cash flow hedges of interest rate payments due under variable-rate borrowings.

Cash Flow Hedges

For derivative instruments that are designated and qualify as a cash flow hedge, the effective portion of the gain or loss on the derivative is reported as a component of other comprehensive income and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. Gains and losses on the derivative representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings.

Non-Qualifying Hedges

Crude oil basis and NYMEX roll swap derivative instruments that do not qualify as cash flow hedges are recorded on the balance sheet at their fair values under Derivative instruments, as assets and/or liabilities, as applicable, and are marked-to-market each period with the change in fair value representing unrealized gains and losses recognized immediately in the Consolidated Statement of Operations as a component of Oil sales. These mark-to-market adjustments produce a degree of earnings volatility that can be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the settlement of the underlying contract occurs.

Prospective Discontinuance of Hedge Accounting

Effective January 1, 2012, the Company has elected to de-designate all commodity contracts that had previously been designated as cash flow hedges as of December 31, 2011 and has elected to discontinue hedge

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accounting prospectively. At December 31, 2011, Accumulated Other Comprehensive Income included $2.6 million ($1.6 million after tax) of unrealized gains, representing the mark-to-market value of the Company s cash flow hedges as of the balance sheet date. As a result of discontinuing hedge accounting, such mark-to-market values that are included in Accumulated Other Comprehensive Income as of the de-designation date will be frozen and reclassified into earnings in future periods as the underlying hedged transactions affect earnings. The Company expects to reclassify into earnings from Accumulated Other Comprehensive Income the frozen value related to de-designated commodity cash flow hedges over the next two years.

Information on the location and amounts of derivative fair values in the Consolidated Balance Sheet as assets (liabilities) as of December 31, 2011 and December 31, 2010 is as follows:

Fair Values of Derivative Instruments
(In thousands)

		Balance Sheet Location		Fair Value December 31, 2011	Fair Value December 31, 2010
Derivatives designated as hedging instruments					
Commodity contracts	crude oil	Derivative Instruments	current assets	$ (2,937)	$ (2,696)
Commodity contracts	crude oil	Derivative Instruments	non-current assets	1,254	(2,207)
Commodity contracts	crude oil	Derivative Instruments	current liabilities	(695)	
Commodity contracts	crude oil	Derivative Instruments	long-term liabilities	(167)	
Commodity contracts	NGL	Derivative Instruments	current assets	(1,029)	(3,118)
Commodity contracts	NGL	Derivative Instruments	non-current assets		116
Commodity contracts	NGL	Derivative Instruments	current liabilities	(6,948)	
Commodity contracts	NGL	Derivative Instruments	long-term liabilities	(1,184)	(1,011)
Commodity contracts	natural gas	Derivative Instruments	current assets	14,137	24,959
Commodity contracts	natural gas	Derivative Instruments	non-current assets		3,614
Total derivatives designated as hedging instruments				$ 2,431	$ 19,657
Derivatives not designated as hedging instruments					
Commodity contracts	crude oil	Derivative Instruments	non-current assets	$ 379	$
Commodity contracts	crude oil	Derivative Instruments	current liabilities	855	
Total derivatives not designated as hedging instruments				$ 1,234	$
Total derivatives				$ 3,665	$ 19,657

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Information on the location and amounts of derivative gains and losses in the Consolidated Statement of Operations for the years ended December 31, 2011 and December 31, 2010 is as follows:

Derivatives in Cash Flow Hedging Relationships	(Gain) Loss Recognized in OCI on Derivatives (Effective Portion) Twelve Months Ended December 31, 2011	December 31, 2010	December 31, 2009
		(In thousands)	
Commodity hedges	$ 2,033	$ 42,976	$ 45,616
Interest rate swap		(344)	(1,923)
Total	$ 2,033	$ 42,632	$ 43,693

	Hedge Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)		
		Twelve Months Ended	
Location of Gain or (Loss)	December 31, 2011	December 31, 2010	December 31, 2009
		(In thousands)	
Oil sales	$ (2,149)	$	$
NGL sales	(10,190)		
Natural gas sales	18,751	30,740	76,567
Interest expense, net of interest capitalized		(978)	(767)
Total	$ 6,412	$ 29,762	$ 75,800

	Gain (Loss) Recognized in Income (Derivatives Not Designated as Cash Flow Hedges and Amount Excluded from Effectiveness Testing)		
		Twelve Months Ended	
Location of Gain or (Loss)	December 31, 2011	December 31, 2010	December 31, 2009
		(In thousands)	
Oil sales (1)	$ 1,233	$	$
NGL sales			
Natural gas sales (2)	11,018	1,715	
Interest expense, net of interest capitalized			(522)
Total	$ 12,251	$ 1,715	$ (522)

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

(2) For 2011, the amount represents the realized gains associated with the 2011 termination of derivatives used to hedge production from the Company s divested DJ Basin and Sacramento Basin properties. For 2010, the amount represents the realized gains associated with the 2010 termination of derivatives used to hedge production from the Company s divested Pinedale properties.

(7) Fair Value Measurements

The Company s financial assets and liabilities are measured at fair value on a recurring basis. The Company measures its non-financial assets and liabilities, such as asset retirement obligations and other property and equipment, at fair value on a non-recurring basis. For non-financial assets and liabilities, the Company is required to disclose information that enables users of its financial statements to assess the inputs used to develop these measurements. As none of the Company s non-financial assets and liabilities were impaired during the year ended December 31, 2011, and as the Company had no other material assets or liabilities reported at fair value on a non-recurring basis, no additional disclosures are provided as of December 31, 2011.

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As defined in the guidance, fair value is the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (an exit price). To estimate fair value, the Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The guidance establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy are as follows:

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

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

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

Level 3 instruments include money market funds, natural gas and NGL fixed price swaps, crude oil basis and NYMEX roll swaps and natural gas and crude oil zero cost collars. The Company s money market funds represent cash equivalents whose investments are limited to U.S. Government securities, securities backed by the U.S. Government, or securities of U.S. Government agencies. The fair value represents cash held by the fund manager as of December 31, 2011 and 2010. The Company identified the money market funds as Level 3 instruments due to the fact that quoted prices for the underlying investments cannot be obtained and there is not an active market for the underlying investments. The Company utilizes, as one of its inputs, counterparty and third party broker quotes to determine the valuation of its derivative instruments. Fair values derived from counterparties and brokers are further verified using publicly available values for relevant NYMEX futures contracts and exchange traded contracts for each derivative settlement location.

The following table sets forth by level within the fair value hierarchy the Company s financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2011 and 2010. As required, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Fair value as of December 31, 2011			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets (liabilities):				
Money market funds	$	$	$ 1,035	$ 1,035
Commodity derivative contracts			3,665	3,665
Total	$	$	$ 4,700	$ 4,700

	Fair value as of December 31, 2010			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets (liabilities):				
Money market funds	$	$	$ 1,035	$ 1,035
Commodity derivative contracts			19,657	19,657

Total	$	$	$ 20,692	$ 20,692

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The determination of the fair values above incorporates various factors. These factors include the credit standing of the counterparties involved, the impact of credit enhancements and the impact of the Company s nonperformance risk on its liabilities. The Company considered credit adjustments for the counterparties using current credit default swap values and default probabilities for the Company and the counterparties in determining fair value and recorded a downward adjustment to the fair value of its derivative assets in the amount of $0.1 million at December 31, 2011.

The tables below present reconciliations of the assets and liabilities classified as Level 3 in the fair value hierarchy during the indicated periods. Level 3 instruments presented in the tables consist of net derivatives and money market funds that, in management s judgment, reflect the assumptions a marketplace participant would have used at December 31, 2011 and 2010.

	Derivatives Asset (Liability)	Money Market Funds Asset (Liability) (In thousands)	Total
Balance at December 31, 2009	$ 6,787	$ 2,035	$ 8,822
Total Gains or (Losses) (Realized or Unrealized):			
Included in Earnings (1)			
Included in Other Comprehensive Income	42,632		42,632
Purchases, Issuances and Settlements			
Settlements	(31,477)	(1,000)	(32,477)
Purchases	1,715		1,715
Transfers in and out of Level 3			
Balance at December 31, 2010	19,657	1,035	20,692
Total Gains or (Losses) (Realized or Unrealized):			
Included in Earnings	(595)		(595)
Included in Other Comprehensive Income	2,033		2,033
Purchases, Issuances and Settlements			
Settlements	(28,448)		(28,448)
Purchases	11,018		11,018
Transfers in and out of Level 3			
Balance at December 31, 2011	$ 3,665	$ 1,035	$ 4,700

(1) No gains or losses were included in earnings attributable to the change in unrealized gains or losses relating to financial assets and liabilities still held at the end of the period.

(8) Accrued Liabilities, Royalties and Other Payables

The Company s accrued liabilities consist of the following:

	December 31, 2011	December 31, 2010
	(In thousands)	
Accrued capital costs	$ 57,546	$ 22,945
Accrued payroll and employee incentive expense	33,500	11,029
Accrued lease operating expense	7,310	7,059
Accrued interest	3,958	4,270
Asset retirement obligation	1,637	9,261
Other	3,643	2,442

Total	$ 107,594	$ 57,006

At December 31, 2011, Royalties and other payables of $50.7 million includes $36.0 million of royalty revenues payable to landowners, $6.2 million of accrued transportation costs and $8.5 million of other operating liabilities.

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(9) Asset Retirement Obligations

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

	For the Year Ended December 31,		
	2011	2010	2009
		(In thousands)	
ARO at the beginning of the period	$ 27,934	$ 28,920	$ 27,944
Liabilities incurred during period	2,096	629	1,855
Liabilities settled during period	(20,395)	(4,130)	(1,328)
Revision of previous estimate	3,454	322	(1,886)
Accretion expense	1,224	2,193	2,335
ARO at the end of the period	$ 14,313	$ 27,934	$ 28,920

As of December 31, 2011 and 2010, the current portion of ARO was approximately $1.6 million and $9.3 million, respectively, and was included in Accrued liabilities on the Consolidated Balance Sheet. The long-term portion of ARO was approximately $12.7 million and $18.6 million as of December 31, 2011 and 2010, respectively, and was included in Other long-term liabilities on the Consolidated Balance Sheet. The decrease in ARO in 2011 was primarily due to offshore abandonment payments of approximately $9.0 million and adjustments for obligations assumed by the purchasers of divested properties of approximately $11.2 million.

(10) Debt and Credit Agreements

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

	December 31,	
	2011	2010
	(In thousands)	
Amended and Restated Senior Revolving Credit Agreement	$ 30,000	$ 130,000
Amended and Restated Second Lien Term Loan	20,000	20,000
Senior Notes	200,000	200,000
Total debt	250,000	350,000
Less:		
Current portion of long-term debt	(20,000)	
Total long-term debt	$ 230,000	$ 350,000

Senior Secured Revolving Credit Facility. On May 10, 2011, the Company entered into an amendment to its Amended and Restated Senior Revolving Credit Agreement (the Restated Revolver). Under this amendment, among other things, the Company s senior secured revolving line of credit was increased from $600.0 million to $750.0 million and the term of the Restated Revolver was extended from July 1, 2012 to May 10, 2016. Availability under the Restated Revolver is restricted to the borrowing base, which is subject to review and adjustment on a semi-annual basis and other interim adjustments, including adjustments based on the Company s hedging arrangements as well as asset divestitures. The amount of the borrowing base is affected by a number of factors, including the Company s level of reserves, as well as the pricing outlook at the time of the redetermination. Therefore, a significant reduction in capital spending could result in a reduced level of reserves that could cause a reduction in the borrowing base.

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The Company utilized a portion of the proceeds from its asset divestitures to repay $100.0 million of outstanding debt under the Restated Revolver on April 21, 2011. As of December 31, 2011, the Company had $30.0 million outstanding with $295.0 million of available borrowing capacity under its Restated Revolver. Amounts outstanding under the Restated Revolver bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 1.75% to 2.75%. The weighted average borrowing rate for the year ended December 31, 2011 under the Restated Revolver was 2.30%. Borrowings under the Restated Revolver are collateralized by perfected first priority liens and security interests on substantially all of the Company s assets, including a mortgage lien on oil and natural gas properties having at least 80% of the pre-tax SEC PV-10 proved reserve value, a guaranty by all of the Company s domestic subsidiaries, and a pledge of 100% of the membership and limited partnership interests of the Company s domestic subsidiaries. Collateralized amounts under the mortgages are subject to semi-annual reviews based on updated reserve information. The Company is also subject to certain financial covenants, including the requirement to maintain (i) a minimum current ratio of consolidated current assets, including the unused amount of available borrowing capacity, to consolidated current liabilities, excluding certain non-cash obligations, of not less than 1.0 to 1.0 as of the end of each fiscal quarter and (ii) a maximum leverage ratio of total debt to earnings before interest expense, income taxes and noncash items, such as depreciation, depletion, amortization and impairment, of not greater than 4.0 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended, measured quarterly after giving pro forma effect to acquisitions and divestitures. At December 31, 2011, the Company s current ratio as defined under the agreement was 2.4 and the leverage ratio was 0.8. In addition, the Company is subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. The Company was in compliance with all covenants at December 31, 2011. In early 2012, we borrowed an additional $50.0 million to invest in capital expenditures and as a result, we have $245.0 million available for borrowing under our revolving credit facility.

Second Lien Term Loan. The Company s amended and restated term loan (the Restated Term Loan) matures on October 2, 2012. As of December 31, 2011, the Company had $20.0 million of fixed rate borrowings outstanding under the Restated Term Loan bearing interest at 13.75%. The Company has the right to prepay the fixed rate borrowings outstanding with a make-whole amount at a discount factor equal to 1% plus the U.S. Treasury yield security having a maturity closest to the remaining life of the loan. The loan is collateralized by second priority liens on substantially all of the Company s assets. The Company is also subject to certain financial covenants, including the requirement to maintain (i) a minimum reserve ratio of total reserve value to total debt of not less than 1.5 to 1.0 as of the end of each fiscal quarter and (ii) a maximum leverage ratio of total debt to earnings before interest expense, income taxes and noncash items, such as depreciation, depletion, amortization and impairment, of not greater than 4.0 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended. At December 31, 2011, the Company s reserve coverage ratio was 4.2 and the leverage ratio was 0.8. In addition, the Company is subject to covenants, including limitations on dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. The Company was in compliance with all covenants at December 31, 2011.

Senior Notes. On April 15, 2010, the Company issued and sold $200.0 million in aggregate principal amount of 9.500% Senior Notes due 2018 (the Senior Notes) in a private offering. The Senior Notes were issued under an indenture (the Indenture) with Wells Fargo Bank, National Association, as trustee. Provisions of the Indenture limit the Company s ability to, among other things, incur additional indebtedness; pay dividends on capital stock or purchase, repurchase, redeem, defease or retire capital stock or subordinated indebtedness; make investments; incur liens; create any consensual restriction on the ability of the Company s restricted subsidiaries to pay dividends, make loans or transfer property to the Company; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. The Indenture also contains customary events of default. At December 31, 2011, the Company was in compliance with the terms and provisions as contained within the Indenture. Proceeds from the Senior Notes offering were used to repay $114.0 million outstanding under the Restated Revolver and $80.0 million of variable rate borrowings outstanding under the Restated Term Loan and to pay for fees and expenses associated with the offering. Interest is payable on the Senior Notes semi-annually on April 15 and October 15. On September 21, 2010, the Company exchanged all of the privately placed Senior Notes for registered Senior Notes which contain terms substantially identical to the terms of the privately placed notes.

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As of December 31, 2011, the Company had total outstanding borrowings of $250.0 million and for the year ended December 31, 2011, the Company s weighted average borrowing rate was 8.45%. Other than $20.0 million of debt that becomes due in 2012, the Company does not have any debt that matures within the five years ending December 31, 2016.

(11) Commitments and Contingencies

Firm Gas and Oil Transportation Commitments. The Company has various production volume transportation commitments related to its operations in the Eagle Ford shale and has an aggregate minimum commitment to deliver 7.8 MMBbls of oil by the end of 2017 and 417 million MMBtus of natural gas by the end of 2023. The Company will be required to make periodic deficiency payments for any shortfalls in delivering the minimum volume under these commitments. The Company expects to fulfill the delivery commitment with production from the development of its proved reserves, as well as from the development of resources not yet characterized as proved reserves from its Eagle Ford assets. At the current time, the Company does not have sufficient proved developed reserves to satisfy this contractual liability, but intends to develop reserves that will exceed these minimum commitments. See Items 1 and 2, Business and Properties for a description of the Company s production and proved reserves. Future obligations under firm gas and oil transportation agreements as of December 31, 2011 are as follows:

	December 31, 2011 (In thousands)
2012	$ 11,003
2013	28,530
2014	33,717
2015	33,717
2016	33,809
Thereafter	165,689
	$ 306,465

Drilling Rig and Completion Services Commitments. Drilling rig and completion services commitments represent obligations with certain contractors primarily to execute our Eagle Ford shale and Southern Alberta basin drilling programs. As of December 31, 2011, the Company had no outstanding drilling commitments with terms greater than one year and future obligations through 2012 totaled $17.5 million.

The Company has agreements with completion service contractors for the stimulation, cementing and providing of drilling fluids product service lines to support current operations. As of December 31, 2011, the minimum contractual commitments for these agreements totaled $11.7 million. Payments under these agreements are accounted for as capital additions to our oil and gas properties.

Lease Obligations and Other Commitments

The Company has operating leases for office space and other property and equipment. The Company incurred rental expense of $3.4 million, $5.0 million and $4.3 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Future minimum annual rental commitments under non-cancelable leases at December 31, 2011 were as follows:

	December 31, 2011 (In thousands)
2012	$ 5,714
2013	3,677
2014	712
2015	
2016	
Thereafter	

	$	10,103

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Contingencies. The Company is party to various legal and regulatory proceedings arising in the normal course of business. The ultimate outcome of each of these matters cannot be absolutely determined, and in the event of a negative outcome as to any proceeding, the liability the Company may ultimately incur with respect to any such proceeding may be in excess of amounts currently accrued, if any. After considering 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 the Company s financial position, results of operations or cash flows.

(12) Stock-Based Compensation

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

	Year Ended December 31,		
	2011	2010	2009
		(in thousands)	
Total stock-based compensation expense	$ 29,676	$ 14,712	$ 7,837
Capitalized in oil and gas properties	(666)	(565)	(381)
Net stock-based compensation expense	$ 29,010	$ 14,147	$ 7,456

The Company had an associated tax benefit of $10.6 million, $5.0 million and $2.7 million, respectively, related to stock-based compensation.

2005 Long-Term Incentive Plan

In July 2005, the Board of Directors adopted the Rosetta 2005 Long-Term Incentive Plan (the Plan) whereby stock is granted to employees, officers and directors of the Company. The Plan allows for the grant of stock options, stock awards, restricted stock, restricted stock units, stock appreciation rights, performance awards and other incentive awards. Employees, non-employee directors and other service providers of the Company and its affiliates who, in the opinion of the Compensation Committee or another Committee of the Board of Directors (the Committee), are in a position to make a significant contribution to the success of the Company and the Company s affiliates are eligible to participate in the Plan. The Plan provides for administration by the Committee, which determines the type and size of award and sets the terms, conditions, restrictions and limitations applicable to the award within the confines of the Plan s terms. The plan was recently amended to provide for the immediate vesting of awards in the event of the death or disability of a participant. The maximum number of shares available for grant under the Plan was increased from 3,000,000 shares to 4,950,000 shares by vote of the shareholders in 2008. The shares available for grant include these 4,950,000 shares plus any shares of common stock that become available under the Plan for any reason other than exercise, such as shares traded for the related tax liabilities of employees. The maximum number of shares of common stock available for grant of awards under the Plan to any one participant is (i) 300,000 shares during any fiscal year in which the participant begins work for the Company and (ii) 200,000 shares during each fiscal year thereafter.

Stock Options

The Company has granted stock options under the Plan, which generally expire ten years from the date of grant. The exercise price of the options cannot be less than the fair market value per share of the Company s common stock on the grant date. The majority of options generally vest over a three year period.

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During the years ended December 31, 2011 and 2010, no options were granted to employees. The weighted average fair value at date of grant for options granted during the year ended December 31, 2009 was $3.42 per share. The fair value of options granted is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions:

	Year Ended December 31,		
	2011	2010	2009
Expected option term (years)			6.5
Expected volatility			42.45% 56.95%
Expected dividend rate			0.00%
Risk free interest rate			2.42% 3.19%

The Company has assumed an annual forfeiture rate of 13% for the options granted in 2009 based on the Company s history for this type of award to various employee groups. Compensation expense is recognized ratably over the requisite service period.

The following table summarizes information related to outstanding and exercisable options held by the Company s employees and directors at December 31, 2011:

	Shares	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term (In years)	Aggregate Intrinsic Value (In thousands) (1)
Outstanding at December 31, 2009	1,247,969	$ 14.80		
Granted				
Exercised	(287,397)	16.13		
Forfeited	(149,318)	14.69		
Outstanding at December 31, 2010	811,254	$ 14.36		
Granted				
Exercised	(230,741)	16.55		
Forfeited				
Outstanding at December 31, 2011	580,513	$ 13.48		
Options vested and exercisable at December 31, 2011	426,135	$ 15.61	5.90	$ 11,988

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

Stock-based compensation expense recorded for stock option awards for the years ended December 31, 2011, 2010 and 2009 was $0.4 million, $0.6 million and $1.1 million, respectively. Unrecognized expense as of December 31, 2011 for all outstanding stock options was less than $0.1 million and will be recognized over a weighted average period during the next twelve months.

The total intrinsic value of options exercised during the years ended December 31, 2011, 2010 and 2009 was $7.1 million, $4.1 million and $0.1 million, respectively.

Restricted Stock

The Company has granted restricted stock under the Plan. The majority of restricted stock vests over a three-year period. The fair value of restricted stock grants is based on the value of the Company s common stock on the date of grant. Compensation expense is recognized ratably over the requisite service period. The Company has assumed an annual forfeiture rate of 14% for these awards based on the Company s history for this type of award to various employee groups.

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The following table summarizes information related to restricted stock held by the Company s employees and directors at December 31, 2011:

	Shares	Weighted Average Grant Date Fair Value
Non-vested shares outstanding at December 31, 2009	1,124,658	$ 12.55
Granted	299,811	20.91
Vested	(488,898)	13.66
Forfeited	(172,560)	14.15
Non-vested shares outstanding at December 31, 2010	763,011	$ 14.76
Granted	214,044	41.94
Vested	(368,738)	16.60
Forfeited	(66,095)	19.74
Non-vested shares outstanding at December 31, 2011	542,222	$ 23.43

The non-vested restricted stock outstanding at December 31, 2011 generally vests at a rate of 25% on the first anniversary of the date of grant, 25% on the second anniversary and 50% on the third anniversary. The fair value of awards vested for the year ended December 31, 2011 was $15.2 million.

Stock-based compensation expense recorded for restricted stock awards for the years ended December 31, 2011, 2010 and 2009 was $4.9 million, $6.1 million and $5.1 million, respectively. Unrecognized expense as of December 31, 2011 for all outstanding restricted stock awards was $5.6 million and will be recognized over a weighted average period of 1.08 years.

Performance Share Units

Pursuant to the approved PSU plans, the Company s Compensation Committee agreed to allocate a portion of the 2009, 2010 and 2011 long-term incentive grants to executives as PSUs. The PSUs are payable, at the Company s option, either in shares of common stock or as a cash payment equivalent to the fair market value of a share of common stock at settlement based on the achievement of certain performance metrics or market conditions at the end of a three-year performance period. The Company s current intent is to settle the 2009 PSU awards in a mixture of cash and common stock and the 2010 and 2011 PSU awards in common stock. Consequently, a portion of the 2009 PSU awards are accounted for as liability-classified awards and are included as a component of Accrued liabilities. The remaining 2009 awards as well as the 2010 and 2011 PSU awards are accounted for as equity-classified awards and are included as a component of Additional paid-in capital. At the end of the three-year performance periods, the number of shares vested can range from 0% to 200% of the targeted amounts as determined by the Compensation Committee of the Board of Directors. None of these PSUs have voting rights and they may be vested solely at the discretion of the Board in the event of a participant s involuntary termination of employment for reasons other than cause or termination for good reason, but they will be forfeited in the event of the participant s voluntary termination or involuntary termination for cause. Any PSUs not vested by the Board at the end of a performance period will expire.

As discussed in Note 2, compensation expense associated with PSUs is measured at the end of each reporting period through the settlement date using the quarter-end closing common stock prices for awards that are solely based on performance conditions, or using a Monte Carlo model for awards that contain market conditions to reflect the current fair value. Compensation expense is recognized ratably over the performance period based on the Company s estimated achievement of the established metrics. Compensation expense for awards with performance conditions will only be recognized for those awards for which it is probable that the performance conditions will be achieved and which are expected to vest. The compensation expense will be estimated based upon an assessment of the probability that the performance metrics will be achieved, current and

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historical forfeitures and the Board s anticipated vesting percentage. Compensation expense for awards with market conditions is measured at the end of each reporting period based on the fair value derived from the Monte Carlo model.

The following table summarizes information related to PSUs held by the Company s officers at December 31, 2011:

	2009 PSU Plan	2010 PSU Plan	2011 PSU Plan
Unvested PSUs at December 31, 2010	320,859	153,252	
Granted			74,743
Vested			
Forfeited			
Unvested PSUs at December 31, 2011	320,859	153,252	74,743

On December 31, 2011, the performance period ended for the 2009 PSUs. The calculations to determine the achievement of the performance metrics and market condition at the end of the three-year performance period were completed in the first quarter of 2012 and were certified by the Compensation Committee in February 2012. As the Company exceeded the performance metrics and the market condition, 200% of the award was granted to executive management with settlement in a mixture of cash and common stock. The cash-settled portion valued at $23.8 million was based on the average of the high and low stock price on the last trading date of the three-year performance period and is included as a component of Accrued liabilities as of December 31, 2011. The common stock-settled portion is payable in 98,481 shares of common stock valued at $4.2 million on the grant date and is reflected as an adjustment to Additional paid-in capital as of December 31, 2011. For the year ended December 31, 2011, the Company recognized $20.3 million of compensation expense associated with the 2009 PSU plan. The cash settlement and vesting of shares will be paid and awarded in the first quarter of 2012.

At December 31, 2011, one-third of the 2010 PSUs granted to executive employees included various market-based components requiring complex modeling to value the grant; these grants vest at the end of a three-year performance period based on the comparative performance of the Company s change in cash flow multiple (share price divided by trailing twelve months cash flow per share) against the change in cash flow multiple of the S&P 400 O&G E&P Industry Index (the Index). The Company uses a Monte Carlo model which incorporates a risk-neutral valuation approach to value these awards. This model samples paths of the Company s and the Index s stock price and calculates the resulting change in cash flow multiple at the end of the forecasted performance period. This model iterates these randomly forecasted results until the distribution of results converge on a mean or estimated fair value. The five primary inputs for the Monte Carlo model are the risk-free rate, independent analyst cash flow per share estimates for the Company and the Index, volatility of the equities of the Company and the Index, expected dividends, where applicable, and various historical market data. The risk-free rate was generated from Bloomberg for U.S. Treasuries with a two-year tenor. Volatility was set equal to the annualized daily volatility measured over a historic 400-day period ending on the reporting date for the Company and the Index. No forfeiture rate is assumed for these types of awards. Compensation expense related to these awards can be volatile based on the Company s comparative performance at the end of each quarter.

The following assumptions were used as of December 31, 2011 for the Monte Carlo model to value the expense and Additional paid-in capital component of the 2010 awards that contain a market condition:

	2010 PSU Plan
Expected term of award (years)	3
Risk-free interest rate	0.66%
Rosetta volatility	55.77%
Index volatility	37.92%
Rosetta/Index correlation	76%

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The fair value per unit at December 31, 2011 was $43.50 for the 2010 and 2011 PSU awards with performance conditions and $15.74 for the 2010 PSU awards with a market condition. For the year ended December 31, 2011, the Company recognized $2.6 million and $0.8 million of compensation expense associated with the 2010 and 2011 PSU plans, respectively. As of December 31, 2011, the Company has recorded a $3.5 million and $0.8 million increase to Additional paid-in capital associated with the 2010 and 2011 PSU plans, respectively.

At the current fair value and assuming that the Board elects 100% payout for the 2010 and 2011 PSUs for all metrics, total compensation expense related to these PSUs to be recognized ratably over the 3-year service periods would be $13.3 million and $6.5 million, respectively, at December 31, 2011. The total compensation expense will be measured and adjusted quarterly until settlement based on the quarter-end closing common stock prices and the Monte Carlo model valuations.

(13) Income Taxes

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

	Year Ended December 31,		
	2011	2010	2009
		(In thousands)	
Current:			
Federal	$	$ (535)	$ (1,611)
State	(457)	340	416
	(457)	(195)	(1,195)
Deferred:			
Federal	52,327	17,739	(119,111)
State	3,843	9,001	(5,521)
	56,170	26,740	(124,632)
Total income tax expense (benefit)	55,713	$ 26,545	$ (125,827)

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

	Year Ended December 31,					
	2011		2010		2009	
	(In thousands)	(%)	(In thousands)	(%)	(In thousands)	(%)
US Statutory Rate	54,691	35.0%	$ 15,957	35.0%	$ (120,751)	35.0%
State income tax, net of federal benefit	3,348	2.2%	2,682	5.9%	(5,545)	1.6%
Non-deductible permanent items	677	0.4%	1,477	3.2%	181	0.0%
Valuation Allowance	(2,262)	(1.4)%	6,558	14.4%		
Other, net	(741)	(0.5)%	(129)	(0.3)%	288	(0.1)%
Total tax expense (benefit)	55,713	35.7%	$ 26,545	58.2%	$ (125,827)	36.5%

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

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

	December 31, 2011	December 31, 2010
	(In thousands)	
Deferred tax assets:		
Oil and gas properties basis differences	$	$ 71,862
Net operating loss carryforwards	121,725	69,179
Stock-based compensation	13,347	6,563
Accrued bonus and other	2,957	1,664
Deferred tax assets, gross	$ 138,029	$ 149,268
Valuation allowance	(4,296)	(6,558)
Deferred tax assets	$ 133,733	$ 142,710
Deferred tax liabilities:		
Oil and gas properties basis differences	(47,024)	
Derivative financial instruments	(1,544)	(7,132)
Deferred tax liability	$ (48,568)	$ (7,132)
Net deferred tax asset	$ 85,165	$ 135,578

The Company generated a federal NOL of $133.5 for the year ended December 31, 2011, and no current income taxes are expected to be paid. As of December 31, 2011, the total NOL carryforward consists of $353.9 million of federal NOL carryforwards, which expire between 2027 and 2031, and $95.7 million of state NOL carryforwards, which expire primarily between 2014 and 2031. The tax benefits of carryforwards are recorded as an asset to the extent that management assesses the utilization of such carryforwards to be more likely than not. When the future utilization of some portion of the carryforward is determined not to be more likely than not, a valuation allowance is provided to reduce the recorded tax benefits from such assets. Management believes that the Company s taxable temporary differences and future taxable income will more likely than not be sufficient to utilize substantially all of its federal tax carryforwards prior to their expiration.

However, in connection with the asset divestitures in the DJ Basin in Colorado and in the Sacramento Basin in California, the Company concluded that it is more likely than not that the deferred tax assets for these states, including NOLs, will not be realized. Therefore, valuation allowances were established at December 31, 2010 for these items as well as state NOLs in jurisdictions in which the Company previously operated but has since divested of the operating assets. In 2011, the Company released $2.3 million of valuation allowance to reflect a revised estimate of the utilization of state NOLs against gains on sale of assets in some states. The Company will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods.

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

	Year Ended December 31, 2011	2010	2009
		(in thousands)	
Balance at the beginning of the year	$ 6,558	$	$
Charged to provision for income taxes	(2,262)	6,558	
Balance at the end of the year	$ 4,296	$ 6,558	$

Pursuant to authoritative guidance, the Company s $121.7 million deferred tax asset related to NOL carryforwards is net of $7.0 million of unrealized excess tax benefits related to $20.0 million of stock-based compensation which will be recognized in Additional paid-in capital upon utilization of the Company s NOL carryforward.

Accounting for uncertainty in income taxes prescribes a recognition threshold and measurement methodology for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax

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return. As of December 31, 2011, the Company had no unrecognized tax benefits. The Company files income tax returns in the U.S. and in various state jurisdictions. With few exceptions, the Company is subject to U.S. federal, state and local income tax examinations by tax authorities for tax periods 2005 and forward.

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

(14) Earnings Per Share

Basic earnings per share (EPS) is computed by dividing income available to common stockholders by the weighted average number of shares outstanding for the period. Diluted EPS reflects the potential dilution that could occur if outstanding common stock awards and stock options were exercised at the end of the period.

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

	Year Ended December 31,		
	2011	2010	2009
		(In thousands)	
Basic weighted average number of shares outstanding	51,996	51,381	50,979
Dilution effect of stock option and awards at the end of the period (1)	620	787	
Diluted weighted average number of shares outstanding	52,616	52,168	50,979
Anti-dilutive stock options and awards	4	26	1,364

(1) Because the Company recognized a net loss for the year ended December 31, 2009, no unvested stock awards and options were included in computing earnings per share because the effect was anti-dilutive. In computing earnings per share, no adjustments were made to reported net income (loss).

(15) Operating Segments

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

Geographic Area Information

The Company has owned oil and natural gas interests in six main geographic areas, all within the U.S. or its territorial waters. Geographic revenue information below is based on the physical location of the assets at the end of each period. Certain amounts in prior periods have been reclassified to conform to the current presentation.

	Year Ended December 31,		
	2011 (1)	2010 (1)	2009 (1)
		(In thousands)	
Oil, NGL, and Natural Gas Revenue			
Eagle Ford	$ 354,741	$ 94,913	$ 2,730
South Texas (2)	48,694	74,569	94,315
California (2)	18,127	65,532	65,295

Rockies (2)	4,152	27,597	21,999
Gulf Coast (2)	1,823	6,755	22,310
Other Onshore (2)		6,609	10,735
Total	$ 427,537	$ 275,975	$ 217,384

(1) Excludes the effects of derivative gains of $18.7 million, $32.5 million and $76.6 million, respectively, for the years ended December 31, 2011, 2010 and 2009.

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(2) The decline in revenues in certain areas was primarily due to the divestiture of these assets and suspension of capital programs in these areas that produce primarily from dry gas reservoirs. See Note 4 Property and Equipment.

Major Customers

In 2011, four customers, Shell Trading (US) Company, Regency Gas Services, LLC, Calpine Energy Services and ExxonMobil Corporation, accounted for the majority of the Company s consolidated revenue, excluding hedging. The loss of any one of these customers would not have a material adverse effect on our operations as we believe other purchasers are available in our areas of operations.

In 2010, two customers accounted for approximately 48% and 16%, respectively, of consolidated revenue, excluding hedging, and in 2009, one customer accounted for approximately 57% of consolidated revenue, excluding hedging.

(16) Guarantor Subsidiaries

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

Supplemental Oil and Gas Disclosures

(Unaudited)

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

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

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Proved developed reserves are proved reserves that can be expected to be recovered (a) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or (b) through installed extraction equipment and infrastructure operational at the time of the reserve estimate if the extraction is by means not involving a well.

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

Estimates of proved developed and proved undeveloped reserves as of December 31, 2011 are based on estimates made by the Company s engineers and audited by the Company s independent engineers, Netherland, Sewell & Associates, Inc. (NSAI). The Company s primary reserves estimator is the Company s Corporate Engineering Manager who has 34 years of experience in the petroleum industry spent almost entirely in the evaluation of reserves and income attributable to oil and gas properties. He holds a Bachelor of Science in Mechanical Engineering from Texas A&M University. He is also a licensed Professional Engineer in the State of Texas and is a member of the Society of Petroleum Engineers. The Company makes representations to the independent engineers that it has provided all relevant operating data and documents, and in turn, the Company reviews these reserve reports provided by the independent engineers to ensure completeness and accuracy. NSAI performs petroleum engineering consulting services under the Texas Board of Professional Engineers. NSAI s President and Chief Operating Officer is a licensed professional engineer with more than 31 years of experience and the engineer and geologist charged with the Company s audit are both licensed professionals with more than 50 years of experience combined.

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

A twelve-month first-day-of-the-month historical average price as of December 31, 2011, 2010 and 2009 was used for future sales of oil, NGLs and natural gas. Future operating costs, production and ad valorem taxes and capital costs were based on current costs as of each year-end, with no escalation. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. Reserve data represent estimates only and should not be construed as being exact. Moreover, the standardized measure should not be construed as the current market value of the proved oil and natural gas reserves or the costs that would be incurred to obtain equivalent reserves. A market value determination would include many additional factors including (a) anticipated future changes in natural gas and crude oil prices, production and development costs, (b) an allowance for return on investment, (c) the value of additional reserves, not considered proved at present, which may be recovered as a result of further exploration and development activities, and (d) other business risk.

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Capitalized Costs Relating to Oil, NGL and Gas Producing Activities

The following table sets forth the capitalized costs relating to the Company s oil, NGL and natural gas producing activities at December 31, 2011, 2010 and 2009:

	2011	2010 (In thousands)	2009
Proved properties	$ 2,297,312	$ 2,124,615	$ 1,931,054
Unproved properties	141,016	91,148	42,344
Total	2,438,328	2,215,763	1,973,398
Less: Accumulated depletion	(1,649,403)	(1,530,799)	(1,421,743)
Net capitalized costs	$ 788,925	$ 684,964	$ 551,655

Net capitalized costs include asset retirement costs of $18.0 million, $24.8 million and $27.3 million as of December 31, 2011, 2010 and 2009, respectively.

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

The following table sets forth costs incurred related to the Company s oil, NGL and natural gas producing activities for the years ended December 31, 2011, 2010 and 2009:

	Year Ended December 31,		
	2011	2010 (In thousands)	2009
Acquisition costs of properties			
Proved	$	$ 28,445	$ 11,490
Unproved	10,605	26,658	28,246
Subtotal	10,605	55,103	39,736
Exploration costs	98,781	49,108	24,550
Development costs	369,865	233,184	65,183
Total	$ 479,251	$ 337,395	$ 129,469

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

	Year Ended December 31,		
	2011 (1)	2010 (1) (In thousands)	2009 (1)
Oil, NGL and Natural gas producing revenues	$ 427,537	$ 275,975	$ 217,384
Production costs	69,289	64,001	73,172
Depreciation, depletion, and amortization	123,244	116,558	121,042
Impairment of oil and gas properties			379,462
Income (loss) before income taxes	235,004	95,416	(356,292)

Income tax provision (benefit)	83,896	55,555	(130,047)
Results of operations	$ 151,108	$ 39,861	$ (226,245)

(1) Excludes the effects of derivative gains of $18.7 million, $32.5 million and $76.6 million, respectively, for the years ended December 31, 2011, 2010 and 2009.

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

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Net Proved and Proved Developed Reserve Summary

The following table sets forth the Company s net proved and proved developed reserves (all within the U.S.) at December 31, 2011, 2010 and 2009, as estimated by the Company s reservoir engineers and audited by independent petroleum consultants in 2011, 2010 and 2009 and the changes in the net proved reserves for each of the three years then ended.

	Oil (MBbl) (1)	Natural gas liquids (MBbl)	Natural gas (Bcf)	Equivalents (MBoe) (2)
Net proved reserves at December 31, 2008 (3)	3,383	220	376	66,336
Revisions of previous estimates (4)	(231)	3,377	(67)	(7,943)
Purchases in place	25		3	487
Extensions, discoveries and other additions	1,359	2,244	32	8,921
Sales in place	(317)		(3)	(888)
Production	(394)	(620)	(44)	(8,425)
Net proved reserves at December 31, 2009	3,825	5,221	297	58,488
Revisions of previous estimates (5)	347	497	(54)	(8,208)
Purchases in place	561	887	9	2,903
Extensions, discoveries and other additions	9,321	14,139	132	45,492
Sales in place	(915)	(322)	(56)	(10,487)
Production	(738)	(1,096)	(39)	(8,369)
Net proved reserves at December 31, 2010	12,401	19,326	289	79,819
Revisions of previous estimates (6)	4,839	7,192	61	22,212
Purchases in place				
Extensions, discoveries and other additions	21,027	26,344	210	82,420
Sales in place	(34)		(81)	(13,464)
Production	(1,863)	(2,643)	(33)	(10,072)
Net proved reserves at December 31, 2011	36,370	50,219	446	160,915

Net proved developed reserves

		Proved Developed Reserves		
	Oil (MBbl) (1)	Natural gas liquids (MBbl)	Natural gas (Bcf)	Equivalents (MBoe) (2)
December 31, 2009	2,324	2,345	237	44,104
December 31, 2010	3,687	6,471	184	40,817
December 31, 2011	11,766	16,635	177	57,947

(1) Includes crude oil and condensate.
(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.
(3) There was no restatement of 2008 proved developed reserves as a result of the new reserve reporting guidance.
(4) Downward revision of 7,943 MBoe of proved reserves primarily due to the use of the twelve-month first-day-of-the-month historical average oil and gas price used to calculate the December 31, 2009 reserves instead of the use of year-end commodity prices as previously required.
(5) Upward revision of 1,849 MBoe due to twelve-month first-day-of-the-month historical average commodity prices. Downward revision of 10,057 MBoe primarily due to reducing proved undeveloped reserves (PUDs) in the South Texas Lobo trend and in the Sacramento Basin

trend as these reserves were not scheduled to be developed within five years.

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(6) Upward revision of 22,212 MBoe resulting from positive performance revisions primarily due to an increase in the estimated ultimate recovery of hydrocarbons on 35 Gates Ranch wells. Twenty-two of these Gates wells have greater than 12 months of production history and some of these wells have been producing for over two years. The decline profiles on wells with significant production history indicate that the estimated ultimate recovery is much more likely to increase or remain constant than to decline.

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

The following information has been developed utilizing procedures prescribed by authoritative guidance and based on natural gas and crude oil reserve and production volumes estimated by internal reserves engineers and audited by independent petroleum engineers. This information may be useful for certain comparison purposes but should not be solely relied upon in evaluating the Company or its performance. In accordance with SEC requirements, the estimated discounted future net revenues from proved reserves are generally based on average first-day-of-the-month oil and gas prices in effect for the prior twelve months in 2011, 2010 and 2009 and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower than the average prices and costs are as of the date of the estimate. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the current value of the Company s oil and natural gas assets. Changes in reserve reporting requirements negatively impacted the Company s Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves as the twelve-month first-day-of-the-month historical average price was significantly lower than the year-end price at December 31, 2009.

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

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

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The following table sets forth the standardized measure of discounted future net cash flows from projected production of the Company s natural gas and crude oil reserves for the years ended December 31, 2011, 2010 and 2009:

	Year Ended December 31, 2011		
	Proved Developed	Proved Undeveloped (In millions)	Total
Future cash inflows	$ 2,527	$ 4,765	$ 7,292
Future production costs	(542)	(816)	(1,358)
Future development costs	(18)	(990)	(1,008)
Future income taxes	(584)	(878)	(1,462)
Future net cash flows	1,383	2,081	3,464
Discount to present value at 10% annual rate	(702)	(1,056)	(1,758)
Standardized measure of discounted future net cash flows relating to proved natural gas, natural gas liquids and crude oil reserves	$ 681	$ 1,025	$ 1,706

	Year Ended December 31, 2010		
	Proved Developed	Proved Undeveloped (In millions)	Total
Future cash inflows	$ 1,351	$ 1,638	$ 2,989
Future production costs	(471)	(235)	(706)
Future development costs	(23)	(493)	(516)
Future income taxes	(165)	(175)	(340)
Future net cash flows	692	735	1,427
Discount to present value at 10% annual rate	(453)	(277)	(730)
Standardized measure of discounted future net cash flows relating to proved natural gas, natural gas liquids and crude oil reserves	$ 239	$ 458	$ 697

	Year Ended December 31, 2009		
	Proved Developed	Proved Undeveloped (In millions)	Total
Future cash inflows	$ 1,153	$ 407	$ 1,560
Future production costs	(503)	(90)	(593)
Future development costs	(58)	(142)	(200)
Future income taxes (1)			
Future net cash flows	592	175	767
Discount to present value at 10% annual rate	(209)	(93)	(302)
Standardized measure of discounted future net cash flows relating to proved natural gas, natural gas liquids and crude oil reserves	$ 383	$ 82	$ 465

(1) For the year ended December 31, 2009, the future revenues and expenses associated with oil and gas properties did not exceed the Company s tax basis of oil and gas properties, thus resulting in no future income tax expense. This is calculated using the twelve-month first day of the month historical average pricing.

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Changes in Standardized Measure of Discounted Future Net Cash Flows

The following table sets forth the changes in the standardized measure of discounted future net cash flows at December 31, 2011, 2010 and 2009:

	Year ended December 31		
	2011	2010	2009
		(in millions)	
Standardized measure beginning of year	$ 697	$ 465	$ 741
Sales and transfers of crude oil, NGLs and natural gas produced, net of production costs	(358)	(212)	(221)
Revisions to estimates of proved reserves:			
Net changes in prices and production costs	39	126	(348)
Extensions, discoveries, additions and improved recovery, net of related costs	1,117	495	69
Development costs incurred	370	219	65
Changes in estimated future development costs	(26)	(91)	49
Revisions of previous quantity estimates	357	(95)	(71)
Accretion of discount	143	47	84
Net change in income taxes	(549)	(206)	100
Purchases of reserve in place		33	5
Sales of reserves in place	(79)	(83)	(9)
Changes in timing and other	(5)	(1)	1
Standardized measure end of year	$ 1,706	$ 697	$ 465

Quarterly Selected Financial Data

(Unaudited)

Summaries of the Company s results of operations by quarter for the years ended 2011 and 2010 are as follows:

	2011			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share data)			
Revenues	$ 97,071	$ 111,557	$ 101,257	$ 136,315
Operating income	22,345	45,037	55,114	55,915
Net income (1)	10,997	25,400	31,948	32,201
Basic earnings per share	0.21	0.49	0.61	0.62
Diluted earnings per share	0.21	0.48	0.61	0.61

	2010			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share data)			
Revenues	$ 70,148	$ 68,622	$ 80,267	$ 89,393
Operating income	16,079	15,776	20,615	19,069
Net income (loss)	7,263	4,312	8,850	(1,379)
Basic earnings (loss) per share	0.14	0.08	0.17	(0.02)

Diluted earnings (loss) per share (2)	0.14	0.08	0.17	(0.02)

(1) Certain items were identified and corrected within the fourth quarter of 2011. The corrections did not have a significant impact on any prior interim or annual periods.

(2) Because the Company recognized a net loss for the quarter ended December 31, 2010, no unvested stock awards or options were included in computing earnings per share because the effect was anti-dilutive. In computing earnings per share, no adjustments were made to reported net income (loss).

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

None

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act), as of December 31, 2011. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2011, our disclosure controls and procedures were effective in providing reasonable assurance that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and that such information is accumulated and communicated to our management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management s Annual Report on Internal Control Over Financial Reporting

Management, including our Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a 15(f). Management conducted an assessment as of December 31, 2011 of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2011, based on criteria in *Internal Control Integrated Framework* issued by the COSO.

The effectiveness of the Company s internal control over financial reporting as of December 31, 2011, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report, which is included in Item 8. Financial Statements and Supplementary Data of this Annual Report on Form 10-K.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the quarter ended December 31, 2011 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2012 annual meeting under the headings Security Ownership of Directors and Executive Officers, Company Nominees for Director, Section 16(a) Beneficial Ownership Reporting Compliance, and Corporate Governance and Committees of the Board.

Item 11. Executive Compensation

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2012 annual meeting under the headings Executive Compensation, Information Concerning the Board of Directors, and Compensation Committee Report.

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

This information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2012 annual meeting under the headings Security Ownership of Certain Beneficial Owners and Management and Securities Authorized for Issuance Under Equity Compensation Plans.

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

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2012 annual meeting under the heading Certain Transactions and Corporate Governance and Committees of the Board.

Item 14. Principal Accountant Fees and Services

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2012 annual meeting under the heading Audit and Non-Audit Fees Summary.

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Part IV

Item 15. Exhibits and Financial Statement Schedules

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

(1) Our Consolidated Financial Statements are listed on page 53 of this report.

(2) Financial Statement Schedules:

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

(3) Exhibits:

The following documents are included as exhibits to this report:

Exhibit Number	Description
3.1	Certificate of Incorporation (incorporated herein by reference to Exhibit 3.1 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
3.2	Amended and Restated Bylaws (incorporated herein by reference to Exhibit 3.1 to the Company s Current Report on Form 8-K filed on December 10, 2010 (Registration No. 000-51801)).
4.1	Registration Rights Agreement (incorporated herein by reference to Exhibit 4.1 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
4.2	Indenture, dated April 15, 2010, among the Company, the Subsidiary Guarantors parties thereto and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K filed on April 19, 2010 (Registration No. 000-51801)).
4.3	Form of the 9.500% Senior Notes due 2018 (incorporated by reference to Exhibit 4.2 of the Company s Current Report on Form 8-K filed on April 19, 2010 (Registration No. 000-51801)).
10.1	Purchase and Sale Agreement with Calpine Corporation, Calpine Gas Holdings, L.L.C. and Calpine Fuels Corporation (incorporated herein by reference to Exhibit 10.1 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.2	Transfer and Assumption Agreements with Calpine Corporation and Subsidiaries of Rosetta Resources Inc. (incorporated herein by reference to Exhibit 10.2 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.3	Settlement Agreement and Amendment with Calpine Corporation (incorporated herein by reference to Exhibit 10.3 to the Company s Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.4	Amended and Restated Base Contract for Sale and Purchase of Natural Gas with Calpine Energy Services, L.P. (incorporated herein by reference to Exhibit 10.4 to the Company s Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).

10.5	Services Agreement with Calpine Producer Services, L.P. (incorporated herein by reference to Exhibit 10.5 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.9	Amended and Restated 2005 Long-Term Incentive Plan, effective January 1, 2011 (incorporated herein by reference to Exhibit 10.9 to the Company s Annual Report on Form 10-K filed on February 25, 2011 (Registration No. 000-51801)).

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Exhibit Number	Description
10.10	Form of Option Grant Agreement (incorporated herein by reference to Exhibit 10.10 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.11	Form of Restricted Stock Agreement (incorporated herein by reference to Exhibit 10.11 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.12	Form of Bonus Restricted Stock Agreement (incorporated herein by reference to Exhibit 10.12 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.18	Amended and Restated Senior Revolving Credit Agreement (incorporated herein by reference to Exhibit 10.18 to the Company s Current Report on Form 8-K filed on April 15, 2009 (Registration No. 000-51801)).
10.19	Amended and Restated Second Lien Term Loan Agreement (incorporated herein by reference to Exhibit 10.19 to the Company s Current Report on Form 8-K filed on April 15, 2009 (Registration No. 000-51801)).
10.20	Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.20 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.21	Second Lien Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.21 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.24	First Amendment to Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.24 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.25	First Amendment to Second Lien Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.25 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.26	Deposit Account Control Agreement (incorporated herein by reference to Exhibit 10.26 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.31	Amended and Restated Employment Agreement with Randy L. Limbacher (incorporated herein by reference to Exhibit 10.31 to the Company s Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.34	Partial Transfer and Settlement Agreement with Calpine Corporation (incorporated herein by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q filed on November 9, 2007 (Registration No. 000-51801)).
10.35	Marketing and Related Services Agreement with Calpine Natural Gas Services, L.P. (incorporated herein by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q filed on November 9, 2007 (Registration No. 000-51801)).
10.36	Indemnification Agreement with Directors and Officers (incorporated herein by reference to Exhibit 10.36 to the Company s Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).

Exhibit Number	Description
10.37	Amended and Restated Employment Agreement with Michael H. Hickey (incorporated herein by reference to Exhibit 10.37 to the Company s Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.39	2005 Long-Term Incentive Plan Performance Share Unit Award Agreement (incorporated herein by reference to Exhibit 10.39 to the Company s Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.40	Executive Employee Change of Control Plan (incorporated herein by reference to Exhibit 10.40 to the Company s Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.41	Executive Employee Severance Plan (incorporated herein by reference to Exhibit 10.41 to the Company s Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.42	Executive Employee Change of Control Plan (incorporated herein by reference to Exhibit 10.42 to the Company s Annual Report on Form 10-K filed on February 26, 2010 (Registration No. 000-51801)).
10.44	First Amendment dated October 22, 2009 to Amended and Restated Senior Revolving Credit Agreement (incorporated herein by reference to Exhibit 10.44 to the Company s Quarterly Report on Form 10-Q filed on November 6, 2009 (Registration No. 000-51801)).
10.45	First Amendment dated October 22, 2009 to Amended and Restated Second Lien Term Loan Agreement (incorporated herein by reference to Exhibit 10.45 to the Company s Quarterly Report on Form 10-Q filed on November 6, 2009 (Registration No. 000-51801)).
10.46	Second Amendment to Amended and Restated Senior Revolving Credit Agreement, effective as of April 5, 2010, among Rosetta Resources Inc., as borrower, BNP Paribas, as administrative agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q filed on May 10, 2010 (Registration No. 000-51801)).
10.47	Second Amendment to Amended and Restated Second Lien Term Loan, effective as of April 5, 2010, among Rosetta Resources Inc., as borrower, BNP Paribas, as administrative agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.2 to the Company s Quarterly Report on Form 10-Q filed on May 10, 2010 (Registration No. 000-51801)).
10.48	Third Amendment to Amended and Restated Senior Revolving Credit Agreement, effective as of December 2, 2010, among Rosetta Resources Inc., as borrower, BNP Paribas, as administrative agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.48 to the Company s Annual Report on Form 10-K filed on February 25, 2011 (Registration No. 000-51801)).
10.49	Third Amendment to Amended and Restated Second Lien Term Loan, effective as of December 2, 2010, among Rosetta Resources Inc., as borrower, BNP Paribas, as administrative agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.49 to the Company s Annual Report on Form 10-K filed on February 25, 2011 (Registration No. 000-51801)).
10.50	Fourth Amendment to Amended and Restated Senior Revolving Credit Agreement, effective as of May 10, 2011, among Rosetta Resources Inc., as borrower, BNP Paribas, as administrative agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.5 to the Company s Current Report on Form 8-K filed on May 16, 2011 (Registration No. 000-51801)).
21.1 *	Subsidiaries of the registrant
23.1 *	Consent of PricewaterhouseCoopers LLP
23.2 *	Consent of Netherland, Sewell & Associates, Inc.

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Exhibit Number	Description
31.1 *	Certification of Periodic Financial Reports by Randy L. Limbacher in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002
31.2 *	Certification of Periodic Financial Reports by John E. Hagale in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002
32.1 *	Certification of Periodic Financial Reports by Randy L. Limbacher and John E. Hagale in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002 and 18 U.S.C. Section 1350
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* Filed herewith
Management contract or compensatory plan or arrangement required to be filed as an exhibit hereto.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized, on February 27, 2012.

ROSETTA RESOURCES INC.
By: /s/ Randy L. Limbacher
Randy L. Limbacher, Chairman of the Board,

Chief Executive Officer and President

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Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacity and on the dates indicated:

Signature	Title	Date
/s/ Randy L. Limbacher Randy L. Limbacher	Chairman of the Board, Chief Executive Officer and President (Principal Executive Officer)	February 27, 2012
/s/ John E. Hagale John E. Hagale	Executive Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)	February 27, 2012
/s/ Stephen A. Coan Stephen A. Coan	Vice President and Controller (Principal Accounting Officer)	February 27, 2012
/s/ Philip L. Frederickson Philip L. Frederickson	Lead Director	February 27, 2012
/s/ Richard W. Beckler Richard W. Beckler	Director	February 27, 2012
/s/ Matthew D. Fitzgerald Matthew D. Fitzgerald	Director	February 27, 2012
/s/ D. Henry Houston D. Henry Houston	Director	February 27, 2012
/s/ Josiah O. Low, III Josiah O. Low, III	Director	February 27, 2012
/s/ Donald D. Patteson, Jr. Donald D. Patteson, Jr.	Director	February 27, 2012

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Glossary of Oil and Natural Gas Terms

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

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

Amplitude. The difference between the maximum displacement of a seismic wave and the point of no displacement, or the null point.

(Amplitude plays) anomalies. An abrupt increase in seismic amplitude that can in some instances indicate the presence of hydrocarbons.

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

Anticline. An arch-shaped fold in rock in which layers are upwardly convex, often forming a hydrocarbon trap. Anticlines may form hydrocarbon traps, particularly in folds with reservoir-quality rocks in their core and impermeable seals in the outer layers of the fold.

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

Bcf. Billion cubic feet of natural gas.

Behind Pipe Pays. Reserves expected to be recovered from zones in existing wells, which will require additional completion work or future recompletion prior to the start of production.

Block. A block depicted on the Outer Continental Shelf Leasing and Official Protraction Diagrams issued by the U.S. Minerals Management Service or a similar depiction on official protraction or similar diagrams, issued by a state bordering on the Gulf of Mexico.

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

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

Coalbed methane. Coal is a carbon-rich sedimentary rock that forms from the remains of plants deposited as peat in swampy environments. Natural gas associated with coal, called coal gas or coalbed methane, can be produced economically from coal beds in some areas.

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

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

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

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

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

Development well. A well drilled within the proved boundaries of an oil or natural gas reservoir with the intention of completing the stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceeds production expenses and taxes.

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

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

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

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

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

Fault. A break or planar surface in brittle rock across which there is observable displacement.

Faulted downthrown rollover anticline. An arch-shaped fold in rock in which the convex geological structure is tipped as opposed to perpendicular to the ground and in which a visible break or displacement has occurred in brittle rock, often forming a hydrocarbon trap.

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

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

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

Gas. Natural gas.

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

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

Hydraulic Fracturing. See *Fracking or fracture stimulation technology* above.

Hydrocarbon indicator. A type of seismic amplitude anomaly, seismic event, or characteristic of seismic data that can occur in a hydrocarbon-bearing reservoir.

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

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

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

MBbls. Thousand barrels of crude oil or other liquid hydrocarbons.

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

MBoe/d. One thousand barrels of crude oil equivalent per day.

Mcf. Thousand cubic feet of natural gas.

MMBbls. Million barrels of oil or other liquid hydrocarbons.

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

MMBoe/d. One million barrels of crude oil equivalent per day.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

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

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

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NYMEX. New York Mercantile Exchange.

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

Pay. A reservoir or portion of a reservoir that contains economically producible hydrocarbons. The overall interval in which pay sections occur is the gross pay; the smaller portions of the gross pay that meet local criteria for pay (such as a minimum porosity, permeability and hydrocarbon saturation) are net pay.

Payout. Generally refers to the recovery by the incurring party of its costs of drilling, completing, equipping and operating a well before another party s participation in the benefits of the well commences or is increased to a new level.

Permeability. The ability, or measurement of a rock s ability, to transmit fluids, typically measured in darcies or millidarcies. Formations that transmit fluids readily are described as permeable and tend to have many large, well-connected pores.

Porosity. The percentage of pore volume or void space, or that volume within rock that can contain fluids.

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

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

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

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

Proved oil and gas reserves or Proved reserves. Proved oil and gas reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulation prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time.

The area of the reservoir considered as proved includes all of the following: (i) the area identified by drilling and limited by fluid contacts, if any; and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil and gas on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the twelve-month first day of the month historical average price during the twelve-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved undeveloped reserves. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves will not be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

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

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

Reliable technology. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In

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addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market and all permits and financing required to implement the project.

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

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

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

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

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

Shelf. Areas in the Gulf of Mexico with depths less than 1,300 feet. Our shelf area and operations also includes a small amount of properties and operations in the onshore and bay areas of the Gulf Coast.

Stratigraphy. The study of the history, composition, relative ages and distribution of layers of the earth s crust.

Stratigraphic trap. A sealed geologic container capable of retaining hydrocarbons that was formed by changes in rock type or pinch-outs, unconformities, or sedimentary features such as reefs.

Tcf. Trillion cubic feet of natural gas.

Tcfe. Trillion cubic feet equivalent determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

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

Unconventional resource. A term used in the oil and natural gas industry to refer to a play in which the targeted reservoirs generally fall into one of four categories: (1) tight sands, (2) coal beds, (3) gas shales, or (4) oil shales. These reservoirs tend to cover large areas and lack the readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require fracture stimulation treatments or other special recovery processes in order to product economic flow rates.

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

Undeveloped oil and gas reserves or Undeveloped reserves. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited

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

Waterflooding. A secondary recovery operation in which water is injected into the producing formation in order to maintain reservoir pressure and force oil toward and into the producing wells.

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

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

Workover rig. A portable rig used to repair or adjust downhole equipment on an existing well.

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

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Index to Exhibits

Exhibit Number	Description
3.1	Certificate of Incorporation (incorporated herein by reference to Exhibit 3.1 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
3.2	Amended and Restated Bylaws (incorporated herein by reference to Exhibit 3.1 to the Company s Current Report on Form 8-K filed on December 10, 2010 (Registration No. 000-51801)).
4.1	Registration Rights Agreement (incorporated herein by reference to Exhibit 4.1 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
4.2	Indenture, dated April 15, 2010, among the Company, the Subsidiary Guarantors parties thereto and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.1 of the Company s Current Report on Form 8-K filed on April 19, 2010 (Registration No. 000-51801)).
4.3	Form of the 9.500% Senior Notes due 2018 (incorporated by reference to Exhibit 4.2 of the Company s Current Report on Form 8-K filed on April 19, 2010 (Registration No. 000-51801)).
10.1	Purchase and Sale Agreement with Calpine Corporation, Calpine Gas Holdings, L.L.C. and Calpine Fuels Corporation (incorporated herein by reference to Exhibit 10.1 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.2	Transfer and Assumption Agreements with Calpine Corporation and Subsidiaries of Rosetta Resources Inc. (incorporated herein by reference to Exhibit 10.2 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.3	Settlement Agreement and Amendment with Calpine Corporation (incorporated herein by reference to Exhibit 10.3 to the Company s Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.4	Amended and Restated Base Contract for Sale and Purchase of Natural Gas with Calpine Energy Services, L.P. (incorporated herein by reference to Exhibit 10.4 to the Company s Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.5	Services Agreement with Calpine Producer Services, L.P. (incorporated herein by reference to Exhibit 10.5 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.9	Amended and Restated 2005 Long-Term Incentive Plan, effective January 1, 2011 (incorporated herein by reference to Exhibit 10.9 to the Company s Annual Report on Form 10-K filed on February 25, 2011 (Registration No. 000-51801)).
10.10	Form of Option Grant Agreement (incorporated herein by reference to Exhibit 10.10 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.11	Form of Restricted Stock Agreement (incorporated herein by reference to Exhibit 10.11 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.12	Form of Bonus Restricted Stock Agreement (incorporated herein by reference to Exhibit 10.12 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).

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Exhibit Number	Description
10.18	Amended and Restated Senior Revolving Credit Agreement (incorporated herein by reference to Exhibit 10.18 to the Company s Current Report on Form 8-K filed on April 15, 2009 (Registration No. 000-51801)).
10.19	Amended and Restated Second Lien Term Loan Agreement (incorporated herein by reference to Exhibit 10.19 to the Company s Current Report on Form 8-K filed on April 15, 2009 (Registration No. 000-51801)).
10.20	Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.20 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.21	Second Lien Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.21 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.24	First Amendment to Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.24 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.25	First Amendment to Second Lien Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.25 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.26	Deposit Account Control Agreement (incorporated herein by reference to Exhibit 10.26 to the Company s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)).
10.31	Amended and Restated Employment Agreement with Randy L. Limbacher (incorporated herein by reference to Exhibit 10.31 to the Company s Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.34	Partial Transfer and Settlement Agreement with Calpine Corporation (incorporated herein by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q filed on November 9, 2007 (Registration No. 000-51801)).
10.35	Marketing and Related Services Agreement with Calpine Natural Gas Services, L.P. (incorporated herein by reference to Exhibit 10.5 to the Company s Quarterly Report on Form 10-Q filed on November 9, 2007 (Registration No. 000-51801)).
10.36	Indemnification Agreement with Directors and Officers (incorporated herein by reference to Exhibit 10.36 to the Company s Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.37	Amended and Restated Employment Agreement with Michael H. Hickey (incorporated herein by reference to Exhibit 10.37 to the Company s Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.39	2005 Long-Term Incentive Plan Performance Share Unit Award Agreement (incorporated herein by reference to Exhibit 10.39 to the Company s Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.40	Executive Employee Change of Control Plan (incorporated herein by reference to Exhibit 10.40 to the Company s Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).
10.41	Executive Employee Severance Plan (incorporated herein by reference to Exhibit 10.41 to the Company s Annual Report on Form 10-K filed on March 2, 2009 (Registration No. 000-51801)).

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Exhibit Number	Description
10.42	Executive Employee Change of Control Plan (incorporated herein by reference to Exhibit 10.42 to the Company s Annual Report on Form 10-K filed on February 26, 2010 (Registration No. 000-51801)).
10.44	First Amendment dated October 22, 2009 to Amended and Restated Senior Revolving Credit Agreement (incorporated herein by reference to Exhibit 10.44 to the Company s Quarterly Report on Form 10-Q filed on November 6, 2009 (Registration No. 000-51801)).
10.45	First Amendment dated October 22, 2009 to Amended and Restated Second Lien Term Loan Agreement (incorporated herein by reference to Exhibit 10.45 to the Company s Quarterly Report on Form 10-Q filed on November 6, 2009 (Registration No. 000-51801)).
10.46	Second Amendment to Amended and Restated Senior Revolving Credit Agreement, effective as of April 5, 2010, among Rosetta Resources Inc., as borrower, BNP Paribas, as administrative agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q filed on May 10, 2010 (Registration No. 000-51801)).
10.47	Second Amendment to Amended and Restated Second Lien Term Loan, effective as of April 5, 2010, among Rosetta Resources Inc., as borrower, BNP Paribas, as administrative agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.2 to the Company s Quarterly Report on Form 10-Q filed on May 10, 2010 (Registration No. 000-51801)).
10.48	Third Amendment to Amended and Restated Senior Revolving Credit Agreement, effective as of December 2, 2010, among Rosetta Resources Inc., as borrower, BNP Paribas, as administrative agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.48 to the Company s Annual Report on Form 10-K filed on February 25, 2011 (Registration No. 000-51801)).
10.49	Third Amendment to Amended and Restated Second Lien Term Loan, effective as of December 2, 2010, among Rosetta Resources Inc., as borrower, BNP Paribas, as administrative agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.49 to the Company s Annual Report on Form 10-K filed on February 25, 2011 (Registration No. 000-51801)).
10.50	Fourth Amendment to Amended and Restated Senior Revolving Credit Agreement, effective as of May 10, 2011, among Rosetta Resources Inc., as borrower, BNP Paribas, as administrative agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.5 to the Company s Current Report on Form 8-K filed on May 16, 2011 (Registration No. 000-51801)).
21.1 *	Subsidiaries of the registrant
23.1 *	Consent of PricewaterhouseCoopers LLP
23.2 *	Consent of Netherland, Sewell & Associates, Inc.
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