Rosetta Resources Inc.
Form 10-K
February 25, 2011

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, 2010

OR

o Transition Report Pursuant To Section 13 Or 15(d) of the Securities Exchange Act of 1934

Commission File Number: 000-51801

ROSETTA RESOURCES INC.
(Exact name of registrant as specified in its charter)

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

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

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

Common Stock, $.001 Par Value (Title of Class)	The Nasdaq Stock Market LLC (Nasdaq Global Select Market) (Name of Exchange on which registered)

Securities Registered Pursuant to Section 12 (g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes o 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 o

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 o No o

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. o

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 o

Non-Accelerated filer o

Smaller Reporting Company o

(Do not check if a 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 o 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, 2010 was approximately $1.0 billion based on the closing price of $19.81 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 18, 2011 was 52,879,723.

Documents Incorporated By Reference

Portions of the definitive proxy statement relating to the 2011 annual meeting of stockholders to be filed with the Securities and Exchange Commission are incorporated by reference in answer to Part III of this Form 10-K.

Table of Contents

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This 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 glossary of oil and natural gas terms, see page 80.

Part I

Items 1 and 2. Business and Properties

General

We are an independent exploration and production company engaged in the exploration, development, production and acquisition of onshore oil and gas resources in the United States of America. Our operations are concentrated in South Texas, including our largest producing area in the Eagle Ford shale, the Sacramento Basin of California, and the Rockies, including the Southern Alberta Basin in Montana. Our headquarters are located at 717 Texas, Suite 2800, Houston, Texas 77002. We also have field offices in Laredo and Catarina, Texas, Rio Vista, California and Wray, Colorado.

Rosetta Resources Inc. (together with its consolidated subsidiaries, “we,” “our,” “us,” the “Company” or “Rosetta”) w incorporated in Delaware in June 2005 to acquire the domestic oil and natural gas business formerly owned by Calpine Corporation and its affiliates (“Calpine”). We have grown our existing 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 non-core properties. We operate in one business segment. See Item 8. “Financial Statements and Supplementary Data, Note 15 - Operating Segments.”

We sell most of our California gas to Calpine pursuant to certain gas purchase and sales contracts, including the gas sales agreement for the dedicated California production which was amended and restated in connection with the parties’ settlement agreement dated October 22, 2008. These original gas purchase and sales contracts and the amended and restated gas purchase and sales contract for the dedicated California production are discussed further under Part I. Items 1 and 2. “Business and Properties - Marketing and Customers.”

Our Strategy

Our strategy is to increase stockholder value by delivering visible and sustainable growth from unconventional onshore domestic basins. This approach is consistent with our strategy to become a successful unconventional resource player with sufficient project inventory to drive significant growth. We recognize that there may be market cycles that could impact our ability to fully execute our 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 and testing positions in emerging resource plays, (iii) divesting lower return assets to fund and accelerate our unconventional resource initiatives, (iv) applying technological expertise, (v) focusing on cost control and (vi) maintaining financial flexibility. We seek to implement 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. During 2010, Rosetta successfully delineated Gates Ranch comprised of approximately 26,500 acres in the liquids-rich portion of the Eagle Ford shale in South Texas. In addition, the Company is continuing to successfully explore other areas of its approximate 65,000 acre leasehold position. During 2010, the Eagle Ford shale became the largest producing area for Rosetta. Approximately 53% of the production from this area is comprised of oil, condensate and natural gas liquids ("NGLs"). In the currently weak natural gas market, the Company's extensive inventory of investment opportunities in the Eagle Ford shale provides higher economic returns than other opportunities in areas previously considered core to the Company's operations. We expect that the Eagle Ford shale will be a major source of production and reserves for the Company in the future and reflects the success of its transition to an unconventional resources player.

Establish and Test Positions in Emerging Resource Plays. We intend to extend our operational footprint into new core areas within the United States 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.

Table of Contents

Divest Lower Return Assets to Fund and Accelerate Our Unconventional Resource Initiatives. In the last two years, Rosetta has established a competitive operating presence in the Eagle Ford shale, one of the most active shale basins in the United States that offers a growing inventory of drilling locations with attractive economics. As a result, we are streamlining our operations and redirecting the proceeds from divestitures of assets that we believe have limited future potential and are no longer core to our long-term growth. In 2010, property sales totaled approximately $90 million. Additional divestitures are planned for 2011.

Apply Technological Expertise. We intend to maintain, further develop and apply the technological expertise that helped us achieve a net drilling success rate of 98% for the year ended December 31, 2010 and helped us establish a major new 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 oil field services, specifically within the Eagle Ford shale.

Maintain Financial Flexibility. As of December 31, 2010, we had drawn $130.0 million and had $195.0 million available for borrowing under our revolving credit facility. Additionally, we expect internally generated cash flow and proceeds from asset sales to provide additional financial flexibility to further develop our core assets in the next few years. We intend to continue to actively manage our exposure to commodity price risk in the marketing of our NGLs, crude oil and natural gas production. As part of this strategy, we have entered into a series of hedging arrangements for each year through 2012.

Our Strengths

Our business strategy is to be a successful resource player delivering continued growth and enhanced shareholder value. We believe the following key strengths will enable 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 the foundation for future growth. As of December 31, 2010, the Company had a 65,000 acre leasehold position with approximately 78% lying in the liquids-rich area of the Eagle Ford shale. Mineral leases were primarily obtained between 2007 and 2010 at a highly competitive average price of approximately $1,036 per acre. For the year ended December 31, 2010, approximately 53% of the Company’s production from the area was comprised of oil, condensate and NGLs, which reduced the Company’s exposure to currently low natural gas prices.

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 that provide us with multiple years of drilling projects. We expect to continue to add to our diversified portfolio of non-proved project inventory from our 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 averages 31 years of service in the energy industry and has a broad knowledge of the exploration and production business with specific expertise in the areas where we are 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.

Table of Contents

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, the Sacramento Basin of California, and the Rockies, including the Southern Alberta Basin in Montana. For the year ended December 31, 2010, we drilled 127 gross and 124 net wells, with a net success rate of 98%. The following is a summary of our major operating areas.

South Texas

As of December 31, 2010, we owned approximately 178,000 net acres in South Texas. Our production in South Texas comes from the Eagle Ford shale trend and the Lobo and Olmos fields and averaged 76.3 MMcfe/d for the year ended December 31, 2010, an increase of approximately 28% from the prior year. In 2010, our production from properties outside the Eagle Ford shale averaged 38.0 MMcfe/d, which was 34% below the prior year, reflecting our decision to divert capital away from natural gas producing areas due to low prices to our higher return delineation and development program in the Eagle Ford shale.

Eagle Ford Shale Trend. In only one year, the Eagle Ford shale trend where we hold approximately 65,000 acres, with 50,000 acres located in the liquids-rich area of the play, has become the largest producing area in our portfolio. Our first delineation program in the 26,500 acre Gates Ranch located on the county line between Webb and Dimmit Counties was a geologic and commercial success. In 2010, we drilled 29 gross wells in the Eagle Ford shale, all of which were successful. Our production from the Eagle Ford shale averaged 38.3 MMcfe/d for the year ended December 31, 2010, with approximately 53% of production comprised of oil, condensate and NGLs. During 2010, we also began an exploratory effort in the Light Ranch portion of the Eagle Ford shale in Central Dimmit County. The first well drilled was a discovery.

Lobo Trend. We are a significant producer in the South Texas Lobo trend, with 470 square miles of 3-D seismic and 249 operated producing wells. Our working interests range from 50% to 100%, but most of our acreage is 100% owned and operated. For the year ended December 31, 2010, our average net daily production from the Lobo trend was 27.8 MMcfe/d.

Discovered in 1973, the South Texas Lobo trend is a complex, highly faulted sand 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.

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 4.1 MMcfe/d for the year ended December 31, 2010.

California

Historically, the Sacramento Basin has been one of California's most prolific gas producing areas, containing a majority of the state's largest gas fields. It is located near the Northern California natural gas markets and has an established natural gas gathering and pipeline infrastructure. We are one of the largest producers and leaseholders in the basin.

As of December 31, 2010, we had under lease approximately 54,000 net acres in the Rio Vista Field and other fields in the Sacramento Basin area and our average net daily production from this area was 37.7 MMcfe/d. As part of our strategic decision to focus on the Eagle Ford shale, we entered into an aggrement to sell our Sacramento Basin assets on February 24, 2011. See “Recent Developments” below.

We have announced our intention to sell our position in California as part of our strategic shift to a resource player with a more balanced mix of NGLs, crude oil and natural gas production.

Rio Vista Field. The Rio Vista Gas Unit and a significant portion of the deep rights below the Rio Vista Gas Unit, which together constitute the greater Rio Vista Field, is the largest onshore natural gas field in California and one of the 15 largest natural gas fields in the United States. The field has produced in excess of 3.5 Tcfe of natural gas reserves since its discovery in 1936. We currently produce from multiple zones at depths ranging from 2,000 feet to 11,000 feet in the field. The current productive area is approximately ten miles long and nine miles wide.

Table of Contents

Rockies

Since its formation in 2005, Rosetta has produced from three basins in the Rocky Mountains: the DJ Basin in Colorado, San Juan Basin in New Mexico and Greater Green River Basin in Wyoming. During 2010, we produced 18.4 MMcfe/d from these properties. In 2010, we made a strategic decision to divest of our interests in New Mexico and Wyoming in order to focus on the development of the Eagle Ford shale and we completed a divestiture of these interests on December 3, 2010. In 2010, we continued our exploratory initiative in the Southern Alberta Basin in Montana. The play is a westward analog of the industry's Bakken and Three Forks plays of the Williston Basin of Montana and North Dakota. We now control approximately 300,000 net acres in the play, either through option or lease agreements.

DJ Basin, Colorado. As of December 31, 2010, we owned a majority working interest in approximately 69,000 net acres with 160 square miles of 3-D seismic data. For the year ended December 31, 2010, our average net daily production from the DJ Basin was 9.0 MMcfe/d and we drilled 89 gross wells with a 99% success rate. As part of our strategy to further develop the Eagle Ford shale, we entered into an agreement to sell our DJ Basin assets on February 22, 2011. See "Recent Developments" below.

Southern Alberta Basin, Montana. During late 2009 and in the first half of 2010, three exploratory wells were drilled to test the potential of this emerging Devonian shale play. Based on the results from these wells, we launched an eight-well vertical drilling program to further understand the reservoir properties and extent of the play across our leasehold position. As of December 31, 2010, we had drilled six wells. Our evaluations continue and we remain fully committed to testing our holdings in this area where we were an early entrant and hold a competitive position.

Recent Developments

As part of our strategic decision to focus on the development of the Eagle Ford shale, we executed a purchase and sale agreement for $55.0 million on February 22, 2011 for the divestiture of our DJ Basin assets in Colorado. This agreement is subject to due diligence and other termination rights and will be subject to post-closing adjustments. We expect this transaction to close in the second quarter of 2011.

We also executed a purchase and sale agreement with Vintage Petroleum, LLC, for $200.0 million on February 24, 2011 for the divestiture of our Sacramento Basin assets in California. This agreement is subject to due diligence and other termination rights and will be subject to post-closing adjustments. We expect this transaction to close in the second quarter of 2011.

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

Crude Oil 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, 2010			
	Natural Gas (Bcf)	NGLs (MBbls)	Oil (MBbls)	Equivalents (Bcfe) (1)
Eagle Ford	6.6	690.0	536.0	14.0
South Texas	11.2	381.0	68.0	13.8
California	13.6	-	27.0	13.8
Rockies	6.6	1.0	21.0	6.7
Gulf Coast	0.5	15.0	47.0	0.9
Other Onshore	0.7	9.0	39.0	1.0
Total	39.2	1,096.0	738.0	50.2

Table of Contents

	For the Year Ended December 31, 2009			
	Natural Gas (Bcf)	NGLs (MBbls)	Oil (MBbls)	Equivalents (Bcfe) (1)
Eagle Ford	0.4	12.0	9.0	0.5
South Texas	17.2	549.1	121.9	21.3
California	15.3	-	28.0	15.5
Rockies	6.8	-	20.0	6.9
Gulf Coast	3.3	38.0	135.0	4.3
Other Onshore	1.5	21.0	80.0	2.1
Total	44.5	620.1	393.9	50.6

	For the Year Ended December 31, 2008			
	Natural Gas (Bcf)	NGLs (MBbls)	Oil (MBbls)	Equivalents (Bcfe) (1)
Eagle Ford	-	-	-	-
South Texas	18.8	257.8	148.0	21.3
California	15.8	-	31.0	16.0
Rockies	4.5	-	6.0	4.5
Gulf Coast	6.3	158.0	247.4	8.7
Other Onshore	2.3	25.0	114.0	3.1
Total	47.7	440.8	546.4	53.6

(1) Gas equivalents are determined under the relative energy content method by using the ratio of 1.0 Bbl of oil or natural gas liquid to 6.0 Mcf of gas.

For additional information regarding our oil and 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 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 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, 2010, we had an estimated 479.3 Bcfe of proved reserves, including 288.9 Bcf of natural gas, 12,401 MBbls of oil and condensate and 19,326 MBbls of NGLs, of which 51% was proved developed. As of December 31, 2010 and based on the 2010 twelve-month first day of the month historical average prices as adjusted for basis and quality differentials for West Texas Intermediate oil of $75.96 per Bbl and Henry Hub natural gas of

$4.38 per MMBtu, our reserves had an estimated standardized measure of discounted future net cash flows of $697 million.

The following table sets forth, by operating area, a summary of our estimated net proved reserve information as of December 31, 2010:

Estimated Proved Reserves at December 31, 2010 (1)(2)

	Developed				Undeveloped					Percent of
	Natural Gas (Bcf)	NGLs (MMBbls)	Oil (MMBbls)	Total (Bcfe) (3)	Natural Gas (Bcf)	NGLs (MMBbls)	Oil (MMBbls)	Total (Bcfe) (3)	Total (Bcfe) (3)	Total Reserves
Eagle Ford	39.92	4.26	3.26	85.03	102.84	12.85	8.71	232.25	317.3	66 %
South Texas	60.85	2.21	0.32	76.01	-	-	-	-	76.0	16 %
California	42.09	-	0.04	42.32	-	-	-	-	42.3	9 %
Rockies	40.29	-	0.05	40.62	2.13	-	-	2.13	42.8	9 %
Gulf Coast	0.51	0.01	0.01	0.62	-	-	-	-	0.6	0 %
Other Onshore	0.29	-	-	0.29	-	-	-	-	0.3	0 %
Total	183.95	6.48	3.68	244.89	104.97	12.85	8.71	234.38	479.3	100 %

Table of Contents

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(1) These estimates are based upon a reserve report prepared using internally developed reserve estimates and criteria in compliance with the 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) Gas equivalents are determined under the relative energy content method by using the ratio of 1.0 Bbl of oil or natural gas liquid to 6.0 Mcf of gas.

All of our proved undeveloped reserves at December 31, 2010 are scheduled for development within five years from the date recorded as a proved undeveloped reserve.

As of December 31, 2010, we had proved undeveloped reserves of 234.4 Bcfe, an increase of 148.0 Bcfe relative to December 31, 2009. Significant additions of proved undeveloped reserves resulted primarily from additional proved undeveloped locations in our Eagle Ford shale acreage. Approximately $22.6 million was spent in 2010 associated with the development of 10.3 Bcfe of proved undeveloped reserves. The 10.3 Bcfe includes positive performance revisions of 4.0 Bcfe due to better than expected performance in the Eagle Ford shale. Of the $22.6 million, $18.9 million is related to the Company's development in the Eagle Ford shale that resulted in the development of 9.1 Bcfe (including positive performance revisions).

In accordance with SEC guidelines, the reserve engineers' estimates of future net revenues from our properties, and the present value of the properties, are made using the twelve-month first day of the month historical average oil and gas prices for the December 31, 2010 reserves and oil and gas sales prices in effect as of the end of the period of such estimates for prior periods, and are held constant throughout the life of the properties, except where the guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. Historically, the prices for oil and gas have been volatile and are likely to continue to be volatile in the future.

Internal Control

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

– A comparison of historical expenses is made to the lease operating costs in the reserve database.

– Updated capital costs are supplied by Rosetta's Operations Department.

– Internal reserves estimates are reviewed 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.

– Material reserve variances are discussed among the internal reservoir engineers and the Corporate Engineering Manager to insure the best estimate of remaining reserves.

– The internal reserves estimates are reviewed by senior management prior to publication.

The Company's primary reserves estimator is Mark D. Petrichuk, Corporate Engineering Manager. Mr. Petrichuk has 33 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-002699. 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 over 38 years of practical experience in petroleum engineering, with over 35 years experience in the estimation and evaluation of reserves. He graduated from the University of Tennessee in 1973 with a Bachelor of Science Degree in Mechanical Engineering. Mr. Nice has been a practicing consulting petroleum geologist at NSAI since 1998. Mr. Nice is a 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.

Table of Contents

2010 Capital Expenditures

The following table summarizes information regarding our development and exploration capital expenditures for the years ended December 31, 2010, 2009 and 2008:

	Year Ended December 31, 2010	2009	2008
	(In thousands)		
Capital expenditures	$ 268,578	$ 90,524	$ 197,026
Leasehold	49,328	22,066	57,261
Acquisitions	5,986	3,624	62,570
Delay rentals	1,193	1,683	1,451
Geological and geophysical/seismic	518	8,558	4,571
Exploration overhead	7,775	4,806	7,140
Capitalized interest	4,017	1,174	1,422
Other corporate	2,042	2,942	3,046
Total capital expenditures	$ 339,437	$ 135,377	$ 334,487

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, 2010. “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 Gross		Productive Wells Net	
	Gross	Net	Gross	Net	Natural Gas	Oil	Natural Gas	Oil
Eagle Ford	104,951	62,875	2,310	2,284	22	-	21	-
South Texas	41,325	36,435	67,606	66,042	431	2	400	2
California	16,875	9,463	53,504	44,188	140	-	131	-
Rockies (1)	148,870	135,593	20,490	18,156	208	2	205	1
Gulf Coast	5,000	2,500	12,532	5,660	1	-	-	-
Other Onshore	2,904	1,341	-	-	9	1	3	-
Total	319,925	248,207	156,442	136,330	811	5	760	3

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

Of our productive wells listed above, there were nine and ten multiple completions in Texas and California, respectively.

The following table shows our interest in undeveloped acreage as of December 31, 2010 that is subject to expiration in 2011, 2012, 2013 and thereafter:

2011		2012		2013		Thereafter	
Gross	Net	Gross	Net	Gross	Net	Gross	Net
77,684	66,722	48,037	40,525	15,854	19,649	134,975	120,403

Drilling Activity

The following table sets forth the number of gross exploratory and 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.

	Exploratory			Development		
	Productive	Dry	Total	Productive	Dry	Total
2010	10.0	-	10.0	115.0	2.0	117.0
2009	7.0	-	7.0	30.0	6.0	36.0
2008	3.0	1.0	4.0	160.0	20.0	180.0

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
2010	9.9	-	9.9	112.4	2.0	114.4
2009	6.1	-	6.1	23.4	6.0	29.4
2008	1.9	1.0	2.9	132.7	15.9	