Rosetta Resources Inc.
Form 10-K
April 20, 2006
Table of Contents

Index to Financial Statements

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x **Annual Report Pursuant To Section 13 or 15(d) of The Securities Exchange Act of 1934 For The Fiscal Year Ended December 31, 2005**

¨ **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:

None

SECURITIES LISTED PURSUANT TO SECTION 12(g) OF THE ACT:

Common Stock, $.001 Par Value	**Nasdaq National Market**
(Title of Class)	**(Name of Exchange on which registered)**

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Exchange Act of 1933. Yes ¨ No x

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. 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 ¨ No x

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 registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer as defined in Rule 12b-2 of the Securities Exchange Act of 1934.

¨ Large accelerated filer ¨ Accelerated filer x Non-Accelerated filer

Indicate by check mark whether the registrant is a shell company as defined by Rule 12b-2 of the Securities Exchange Act of 1934. Yes ¨ No x

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of April 10, 2006 was approximately $934 million based on the closing price of $18.55 per share on the Nasdaq National Market.

The number of shares of the registrant s Common Stock, $.001 par value per share outstanding as of April 10, 2006 was 50,587,269.

DOCUMENTS INCORPORATED BY REFERENCE

Information required by Part III will either be included in Rosetta Resources Inc. definitive proxy statement filed with the Securities and Exchange Commission or filed as an amendment to this Form 10-K no later than 120 days after the end of the Company s fiscal year, to the extent required by the Securities Exchange Act of 1934, as amended.

Table of Contents

Index to Financial Statements

TABLE OF CONTENTS

Table of Contents

Index to Financial Statements

Cautionary Note

This annual report contains forward-looking statements of our management 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, although made in good faith, 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 Forward-Looking Statements in Item 7. 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 gas terms, see page 119.

PART I

Item 1. Business.

GENERAL

Rosetta Resources Inc. (the Company) is comprised of the domestic oil and natural gas business formerly owned by Calpine Corporation and affiliates (predecessor, Calpine) acquired in July 2005 by the Company (successor). The Company is engaged in oil and natural gas exploration, development, production and acquisition activities in the United States, and operates in one business segment. Our operations are primarily concentrated in the Sacramento Basin of California, Lobo and Perdido Trends in South Texas, the State Waters of Texas, the Gulf of Mexico and the Rocky Mountains. The Company was formed in June 2005 to acquire the domestic oil and natural gas business of Calpine. This acquisition closed in July 2005.

Pursuant to the acquisition, we entered into several operative contracts with Calpine, including a purchase and sale agreement under which we have indemnification rights and obligations with respect to Calpine. Currently, Calpine provides pipeline services, including personnel, under the transition services agreement and markets our gas under a marketing agreement. We sell a significant portion of our gas to Calpine pursuant to certain gas purchase and sales contracts.

In October 1999, Calpine purchased Sheridan Energy, Inc. (Sheridan), a natural gas exploration and production company operating in northern California and the Gulf Coast region. The Sheridan acquisition provided the initial management team an operational infrastructure to evaluate and acquire oil and natural gas properties for Calpine. In December 1999, Calpine purchased Vintage Petroleum, Inc. s interest in the Rio Vista Gas Unit and related areas, representing primarily natural gas reserves located in the Sacramento Basin in northern California. Sheridan was purchased by Calpine in 1999 and renamed Calpine Natural Gas Company and then was merged into Calpine in April 2002, and Rosetta Resources Operating LP (formerly known as Calpine Natural Gas L.P.; RROLP) was subsequently established. In October 2001, Calpine completed the acquisition of 100% of the voting stock of Michael Petroleum Corporation, a natural gas exploration and production company with operations in south Texas. In September 2004, Calpine sold its natural gas reserves in the New Mexico San Juan Basin and Colorado Piceance Basin and such properties have been reflected as discontinued operations for all periods presented herein. Several members of the Calpine management team, who were responsible for operating Calpine s oil and natural gas business, joined the Company concurrently with the acquisition of the properties from Calpine.

Table of Contents

Index to Financial Statements

OUR STRENGTHS

We believe our historical success is, and future performance will be, directly related to the following combination of strengths:

High Quality, Diversified Asset Base. We own a geographically diversified asset base comprised of long-lived reserves along with shorter-lived, higher return reserves. Approximately 96% of our reserves are natural gas, and almost all of our assets are located in the Sacramento Basin of California, South Texas, the Gulf of Mexico and the Rocky Mountains. We believe this geographic and production profile diversity will enhance the stability of our cash flows while providing us with a large number of development and exploration opportunities, as well as support for additional acquisitions.

Development and Exploration Drilling Inventory. We have identified over 500 drillable, low to moderate risk opportunities providing us with multiple years of drilling inventory, and we expect to drill approximately one-third of these locations during 2006. Approximately 123 of these locations are classified as proved undeveloped. We also have a large and diversified portfolio of what we designate as development and exploration prospects. Our capital expenditure budget, including potential acquisitions, is approximately $199 million for 2006. We will manage our exploratory risks and expenditures by selectively reducing our capital exposure in certain high risk projects by partnering with others in our industry.

Operational Control. We operate approximately 90% of our estimated proved reserves, which allows us to more effectively manage expenses and control the timing of capital allocation of our development and exploration activities.

Experienced Management Team. Our executive management has an average of over 25 years of experience in the oil and natural gas industry.

Proven Management Team, Including Technical and Land Personnel, with Access to Technological Resources. Our technical staff includes 26 geologists, geophysicists, landmen, engineers and technicians with an average of over 20 years of relevant technical experience. Our staff has a proven record of analyzing complex structural and stratigraphic plays using 3-D geophysical expertise, producing and optimizing low pressure natural gas reservoirs, detecting low contrast, low permeability pay opportunities, drilling, completing and fracing of deep tight natural gas reservoirs, conducting Gulf of Mexico operations and managing horizontal drilling and coalbed methane operations. These core competencies helped us to achieve a drilling success rate of over 80% for the six months ended December 31, 2005 and has helped maximize recovery from our reservoirs. Our definition of drilling success is a well that produces hydrocarbons at sufficient rates, to allow us to recover, at a minimum, our capital investment and operating costs.

OUR STRATEGY

Our strategy is to increase stockholder value by profitably increasing our reserves, production, cash flow and earnings using a balanced program of (1) developing existing properties, (2) exploring undeveloped properties, (3) completing strategic acquisitions and (4) maintaining financial flexibility. The following are key elements of our strategy:

Further Development to Existing Properties. We intend to further develop the significant remaining upside potential of our properties by working over existing wells, drilling infill locations, drilling step-out wells to expand known field outlines, tapping logged behind pipe pays and lowering field line pressures for additional recoveries. Many of these opportunities were not fully exploited prior to the formation of Rosetta.

Exploration Growth. We intend to focus on niche areas in which we have technological and operational advantages. This growth will come from higher-risk, higher-impact opportunities offshore in the Gulf of Mexico, along the Wilcox Trend in South Texas, in deep horizons in the Sacramento Basin, and from lower-risk, longer-lived drilling in the shallow Sacramento Basin, the Lobo Sand Trend in South Texas, the Wasatch and Mesa

Table of Contents

Index to Financial Statements

Verde formations in the Uinta Basin, Niobrara chalk in the DJ Basin and coalbed methane in the San Juan Basin. While the majority of our prospects will be internally generated, we will, from time to time, participate in third party drilling opportunities.

Acquisition Growth. We will continually review opportunities to acquire producing properties, undeveloped acreage and drilling prospects. We will particularly focus on opportunities where we believe our reservoir management and operational expertise will enhance the value and performance of acquired properties. Initial acquisition targets will be in and around our major producing and activity areas. We will also use our minor producing field ownerships as islands of control and knowledge to make strategic acquisitions. Our management team has demonstrated success in acquisitions in the past ten years and has developed a significant knowledge base of producing oil and natural gas fields throughout the United States.

Maintain Technological Expertise. We intend to maintain the technological expertise that helped us to achieve a drilling success rate of over 80% for the six months ended December 31, 2005 and helped us maximize field recoveries. We will use advanced geological and geophysical technologies, detailed petrophysical analyses, state-of-the-art reservoir engineering and sophisticated completion and stimulation techniques to grow our reserves and production.

Endeavor to be a Low Cost Producer. We will strive to minimize our operating costs by concentrating our assets within geographic areas where we can consolidate operating control and capture operating efficiencies. This is particularly true in the Sacramento Basin because of our position as the dominant producer in the region.

Maintain Financial Flexibility. We intend to optimize unused borrowing capacity under our revolving line of credit by periodically refinancing our bank debt in the capital markets when conditions are favorable. As of December 31, 2005, we had $160 million available for borrowing under our revolving line of credit. Additionally, we expect internally generated cash flow to provide additional financial flexibility, allowing us to pursue our business strategy. We intend to actively manage our exposure to commodity price risk in the marketing of our oil and natural gas production. As part of this strategy and in connection with our credit facilities, we entered into natural gas fixed-price swaps for a significant portion of our expected production through 2009. Additionally, in the fourth quarter 2005, we entered into costless collar contracts for a portion of our 2006 production. We may enter into other agreements, including fixed price, forward price, physical purchase and sales contracts, futures, financial swaps, option contracts and put options.

CALPINE BANKRUPTCY

On December 20, 2005, Calpine and certain of its subsidiaries, including Calpine Fuels, filed for federal bankruptcy protection in the Southern District of New York. The filing raises certain concerns regarding aspects of our relationship with Calpine which we will closely monitor as the Calpine bankruptcy proceeds. Following are our principal areas of concern:

- The bankruptcy court may challenge the fairness of our acquisition. For a number of reasons, including the process which Calpine followed in allowing market forces to set the purchase price for the acquisition, we believe that it is unlikely that any challenge to the fairness of our acquisition would be successful.

- The bankruptcy proceeding may prevent, frustrate or delay our ability to receive record legal title to certain properties originally determined to be non-consent properties which we are entitled to obtain under our purchase and sale agreement with Calpine and certain subsidiaries.

- Additionally, the bankruptcy proceeding may prevent, frustrate or delay our ability to receive corrective documentation from Calpine for certain properties which we bought from Calpine and paid for, where the documentation delivered by Calpine was incomplete, including documentation related to certain ministerial governmental approvals.

[Table of Contents](#)

[Index to Financial Statements](#)

- Calpine may stop purchasing gas from us under our gas purchase contract with Calpine. Since the date of the bankruptcy filing, Calpine has continued buying natural gas from us and paying for it timely. The bankruptcy court for Calpine, as debtor-in-possession, has given approval to continue payments to us for our delivery of natural gas under our gas purchase and sale agreement. Under the terms of this contract, we are entitled to sell this gas to third parties at comparable prices and terms if this occurs and expect to be able to minimize our exposure to four days of sales under the contract, or approximately $1.4 million in lost sales at production rates and prices as of December 31, 2005.

- Calpine may stop providing us certain services, including natural gas marketing services and pipeline services, which Calpine, through separate subsidiaries, currently provides to us. Management does not believe that cessation of these services would have a material impact on our operations.

As to all of these matters, see also Risk Factors Risks Relating to Our Business Calpine s recent bankruptcy filing may adversely affect us in several respects for a further discussion of the potential risks relating to Calpine s bankruptcy. We have engaged bankruptcy counsel to monitor this proceeding and advocate our interests as necessary and have initiated plans to mitigate the operational risks presented by the Calpine bankruptcy.

We believe the structure of the equity offering of our common stock and the process followed by Calpine allowed market action to determine the $1.05 billion in proceeds, before fees and expenses, received by Calpine in the acquisition. Senior management of Calpine, in consultation with its various advisors, structured the acquisition and the private issuance of our common stock to fund the acquisition. Our equity was purchased by sophisticated investors knowledgeable in oil and natural gas transactions.

Transfers Pending at Calpine s Bankruptcy

At July 7, 2005, we retained approximately $75 million of the purchase price in respect to properties identified as requiring third party consents that were not received before closing. Subsequent analysis determined that a portion of these properties, with an approximate allocation value of $29 million, under the purchase and sale agreement with Calpine (PSA) did not require consent. For that portion of the properties for which third party consents were in fact required having an approximate value of $39 million under the PSA and those properties that did not require consent, we believe that Calpine was obligated to have transferred to us the record title, free of any mortgages, for all properties for which any required consents were received or were otherwise cured at the close of each month for the first six months after closing by no later than 5 days after the end of each month of cure.

The approximate allocated value under the PSA for the portion of these properties subject to a preferential right is $7.1 million. We will retain $7.4 million for the properties subject to this preferential right, which total amount includes approximately $0.3 million for a property which was transferred to us but will be transferred to the appropriate third party under an exercised preferential purchase right.

We believe all conditions for our receipt of record title, free of any mortgages for all of these properties (excluding that portion of these properties subject to this preferential right) were satisfied on or before December 15, 2005. We believe we are the equitable owner of all of these properties (excluding that portion of these properties subject to this preferential right) and that same are not part of Calpine s bankruptcy estate. Upon our receipt from Calpine of record title, free of any mortgages, we are prepared to pay Calpine approximately $68 million, subject to appropriate adjustment for the associated net revenues for the cured non-consent properties through December 15, 2005. Rosetta s statement of operations for the six months ended December 31, 2005 does not include any net revenues or production from these properties (excluding that portion of these properties subject to this preferential right).

If Calpine does not provide us with record title, free of any mortgages for all of these properties (excluding that portion of these properties subject to this preferential right), we will have a total of approximately $68 million available to us for general corporate purposes, including for the purpose of acquiring additional

Table of Contents

Index to Financial Statements

properties. We will also have approximately $7.4 million for that portion of these properties subject to a preferential right, available to us for general Corporate purposes, including for the purpose of acquiring additional properties.

In addition, as to certain of the properties we purchased from Calpine and paid Calpine for on July 7, 2005, we will seek additional documentation from Calpine to eliminate any issue as to the clarity of our ownership. The specific nature of our request will depend on the particular facts and circumstances surrounding each property involved. Certain of these properties are subject to ministerial governmental action approving us as qualified assignee and operator, even though in most cases Calpine specifically conveyed the property to us free and clear of mortgages and liens previously recorded by Calpine s creditors. As to certain other properties, the documentation delivered by Calpine at closing was incomplete. We remain hopeful that we will be able to work cooperatively with Calpine to secure these ministerial governmental approvals and to accomplish the curative corrections for all of these properties. In addition, as to all these properties, Calpine contractually agreed to provide us with such further assurances as we may reasonably request. Nevertheless, as a result of the recency of Calpine s bankruptcy filing, it remains uncertain as to how, when and if Calpine will respond cooperatively. If Calpine does not fulfill its contractual obligations and does not complete the documentation necessary to resolve these conveyancing issues, we will pursue all available remedies, including but not limited to a declaratory judgment to enforce our rights and actions to quiet title. After pursuing these matters, if we experience a loss of ownership with respect to these properties without receiving adequate consideration for any resulting loss to us, an outcome our management considers to be remote, then we could experience losses which could have a material adverse effect on our assets, financial condition, earnings and statement of cash flows.

RESTATEMENT OF FINANCIAL RESULTS FOR THIRD QUARTER 2005

In connection with the preparation of our audited financial statements for the six-months ended December 31, 2005, we determined that certain costs of $1.1 million incurred in connection with our issuance of common stock in the third quarter 2005 were incorrectly accounted for as a reduction of the proceeds from such issuance in additional paid-in capital on our balance sheet and should initially have been accounted for as operating expenses on our income statement. In addition, we had over accrued certain costs of $0.1 million in additional paid-in capital. As a consequence, we have restated our financial results for the fiscal quarter ended September 30, 2005, as included in the Selected Data Quarterly Information included herein, from what we previously disclosed in our registration statement on Form S-1 (333-128888), specifically in our Selected Financial Data, our Historical Unaudited Pro Forma Financial Data, and our unaudited consolidated financial statements as of September 30, 2005 and for the three months ended September 30, 2005.

The changes to correct the error are as follows:

General and administrative costs are increased by $1.1 million;

Net income for third quarter 2005 is reduced by $1.1 million to $8.2 million; and

Earnings per share basic and diluted are reduced by $0.03 and $0.02 to $0.16 and $0.16 per share, respectively.

Additional paid-in Capital is increased by $1.1 million to $748.6 million;

Retained earnings are reduced by $1.1 million to $8.2 million.

See Selected Data Quarterly Information for the restated financial data.

OUR OPERATING AREAS

We own, subject to the pending transfers above, producing and non-producing oil and natural gas properties in the Sacramento Basin of California, the Lobo and Perdido Trends in South Texas, the State Waters of Texas,

Table of Contents

Index to Financial Statements

the Gulf of Mexico, the Rocky Mountains and Other located in various geographical areas in the United States. In each area, we are pursuing geological objectives and projects that are consistent with our technical expertise. Our strength and strategies, as discussed above, which include this technical expertise, are concentrated in these particular areas and fields in order to provide the highest potential economic returns. Since the date of our acquisition, we have drilled 29 gross and 19.8 net wells, of which 83% found commercial quantities of production. The following is a summary of our major operating areas in which we discuss their various characteristics. With respect to acreage information in this report, we have included acreage relating to properties which were not transferred to us on the original date of acquisition because consents to transfer had not been obtained at that time. That information is not available without undue time and expense as of the date of this report.

California-Sacramento Basin

Rio Vista Field and Surrounding Area. 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, 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 a cumulative 3.6 Tcfe of natural gas reserves to date since its discovery in 1936. The California Energy Commission assigns 419 Bcf of remaining reserves to Rio Vista field. We currently produce or have behind-pipe reserves in over 16 different zones at depths ranging from 2,500 feet to 9,600 feet in the field. The natural gas field trap is a faulted, downthrown rollover anticline, elongated to the northwest. The current productive area is approximately ten miles long and nine miles wide. A majority of the reservoirs are depletion driven with long production histories. For the six months ended December 31, 2005 (the period after our acquisition), the average net daily production in the Sacramento Basin was approximately 29 MMcfe/d from 167 producing wells. As of December 31, 2005, we owned approximately 62,000 net acres in the Rio Vista Field and surrounding Sacramento Basin areas. We are the single largest producer and leaseholder in the basin. Our acreage in the basin holds significant low-risk, low-cost upside potential in 140 currently shut-in or idle wells, 34 proved drilling locations, and numerous workover and recompletion projects. Additional reserve potential exists in gathering system optimization projects, numerous fracture stimulation opportunities in lower permeability, low contrast pays, and deeper gas bearing sands.

Sacramento Valley Extension. We believe our existing land position and financial strength will give us the ability to rapidly expand our Sacramento Basin operations. The Sacramento Valley Extension Project is an extension of work and study done in the redevelopment of the Rio Vista Field and non-operated drilling in nearby reservoirs. Numerous plays are being evaluated, including Mokelumme gorge traps and McCormick fault traps, deeper Winters traps, and shallow Emigh/Capay truncation traps on the east side of the Sacramento Basin. Subtle low contrast and low resistivity pays in the Emigh, Capay, Hamilton and Martinez formations are being pursued for under-exploited and unrecognized potential. Over 50 leads and prospects have been catalogued to date and we have identified more than 80 wells which we believe contain bypassed pay. We have approximately 520 square miles of 3-D seismic data and over 1,800 miles of 2-D seismic data in Rio Vista, the extension area, and the greater Sacramento Valley. The area contains 16 prospective producing formations with historically high production rates at shallow to moderate drill depths. These characteristics, along with an expedited regulatory and permitting process, high reserves per well, and a strong local natural gas market should provide for attractive returns on investments.

Other Activities. We are actively pursuing additional lease acquisitions. Since the date of acquisition, we have added 12,658 acres to our leasehold inventory and are in the process of leasing an additional 9,500 acres. We have contracted drilling rigs which has allowed us to drill seven of the 40 wells in the 2005-2006 drilling program since November 2005 with a 100% success rate. Of the remaining 33 wells to be drilled, three are deep wells below 10,000 feet, one of which is currently in progress. There is one completion rig currently working on Rosetta properties in the Rio Vista Field area, and it has performed 14 recompletions since June 30, 2005. We will add a second completion rig during the second quarter of 2006 to help with the remaining 33 recompletions that are planned for 2006.

Table of Contents

Index to Financial Statements

Lobo

Lobo Trend. Discovered in 1973, the Lobo Trend of South Texas is a complex, highly faulted sand that has produced over 7 Tcf of natural gas. The Lobo section produces from tight sands with low permeabilities and high pressures at depths of 7,500 to 10,000 feet. We are a significant producer in the Lobo Trend, with over 60,000 net acres, 81 square miles of 3-D seismic, approximately 220 active operated wells and interests in approximately 100 non-operated wells. We recently added a very prospective 4,500 net acre position in the heart of the Lobo play. For the six months ended December 31, 2005, our average net production from the Trend was 21 MMcfe/d. Our working interests range from 50% to 100%. We have identified 84 potential drilling locations on our acreage.

We completed 41 workover projects in 2005. Additional compression is being put in place to accommodate the expected increase in gas production as a result of these well work projects. We have two drilling rigs under contract and we plan to drill 15 wells in the Trend in 2006.

Perdido

Perdido Sand Trend. We own a 50% non-operating working interest in approximately 20,000 acres in the Perdido Sand Trend. The Perdido Sands are in isolated fault blocks and are stratigraphically trapped below the Upper Wilcox structures. The Perdido section is comprised of tight natural gas sands requiring significant fracture stimulation. Horizontal drilling has been very successful in maximizing natural gas recovery. The primary potential in the Perdido is from 9,500 to 12,000 feet. For the six months ended December 31, 2005, our average net daily production was 8.2 MMcfe/d from 27 producing wells. Since June 30, 2005, 48 additional locations have been identified and three successful wells have been drilled. We plan to drill 10 wells in 2006.

Gulf of Mexico

Federal Waters. Subject to pending MMS approval of the conveyances made by Calpine to us at closing, we own and believe we have satisfied the regulators requirements to earn operating rights in seven blocks in the Gulf of Mexico. For the six months ended December 31, 2005, our average net production from these blocks was 5.4 MMcfe/d, which was affected by Hurricanes Katrina and Rita. As the recovery process from the hurricanes nears completion, our average net production from these blocks was 12.3 MMcfe/d for February 2006. We have operated and non-operated working interests in these blocks ranging from 20% to 100%. Production from these working interests represents approximately 10% of Rosetta s total current production.

We have entered into an area of mutual interest agreement in which we have the right to participate in up to a 50% working interest in wells within 150 OCS blocks on the Louisiana offshore shelf. Over the next three years, we intend to participate in the drilling of at least ten new prospects in these blocks.

Through our participation in a joint venture, we have contracted to acquire a 25% non-operated working interest in two offshore blocks, Main Pass Block 118 and Main Pass Block 117. Main Pass Block 118 well No. 1 was drilled, production casing set, successfully tested and is awaiting platform installation. The Block 117 well No. 1 will spud in the first half of 2006.

State Waters of Texas

We are exploring in the Vicksburg and Frio trends in Galveston Bay, Texas, specifically pursuing sands that exhibit strong hydrocarbon indicators on 3-D seismic. In January 2005, we drilled and operated a discovery well in the Vicksburg Sand. Two additional intervals are present in the well, which have log characteristics that indicate productive zones. We expect to acquire and drill two to three prospects in this trend in the next 12 months with additional wells planned in 2007.

We have acquired a 7% non-operating working interest in the TB-2 prospect in Galveston Bay. The State Tract 251 well No. 5 completed drilling in February 2006 and tested at 4.9 MMcfe/d.

[Table of Contents](#)

[Index to Financial Statements](#)

We will participate in an additional exploratory well which we will begin drilling in the first quarter of 2006.

Other Onshore

Live Oak County Prospect. Through the interpretation of 3-D seismic data, we have identified four structures at approximately 16,500 feet in the Sligo Reef Trend in Live Oak County, Texas. Two of these structures were previously drilled and produced by other operators. One structure has produced 33 Bcfe since 1983 from one well on the south end of our 3-D data coverage, and a second structure on the north end of our data coverage produced 12 Bcfe since 1987, also from one well. We currently have approximately 2,500 net acres under lease and plan to obtain a suitable industry partner(s) to join in the drilling of the initial test well to evaluate our prospect.

Frio, Vicksburg, Yegua and Wilcox Trends. In the Frio Trend, the Dunn Peach discovery well was drilled in 2004 on Padre Island in Kleberg County, Texas. Two more development wells and one exploratory dry hole were drilled in 2005. A fifth well was drilled and logged in December 2005 and is currently on production. Two additional development wells will be drilled in 2006. In Colorado County, we are pursuing amplitude plays between 3,500 and 7,000 feet in the Frio and Yegua trends. In the Wilcox, we are pursuing normally pressured structural closures at 10,000 feet and over-pressured closures from 14,000 to 17,500 feet. All of these projects are based on high quality 3-D seismic data. As of December 31, 2005, we have eight prospects in the Frio, Yegua and Upper Wilcox trends of Colorado County, Texas, with six wells expected to be drilled within the next twelve months. We are pursuing numerous additional opportunities in these trends.

Colorado County Prospect. In January 2006, we completed drilling a lower Wilcox prospect in Colorado County, Texas, which resulted in a dry hole.

Rocky Mountains

We are active in the DJ, Uinta and the San Juan Basins in the Rocky Mountains.

DJ Basin, Colorado. As of December 31, 2005, we had a majority working interest in approximately 52,000 net acres, identified 17 drillable, 3-D seismic-supported, 80-acre locations on these lands that have been approved for 40-acre spacing and drilled 16 other locations during the year. We expect to drill approximately 213 additional locations on our existing leases and other leases currently under negotiation with 70 wells planned for 2006. Additional leasing has added approximately 18,500 acres to our land position.

By December 31, 2005, we had acquired 17.1 square miles of 3D seismic data with an additional 38 square miles currently in the process of acquisition. We are using 3-D seismic data as a critical tool in identifying potential drilling opportunities. We recently upgraded the gathering infrastructure and installed new 4   and 6   production lines with compression to enlarge the gathering system and allow us to deliver larger volumes of gas.

Uinta Basin, Utah. We are pursuing plays in the Uinta Basin in the emerging Mesa Verde and Wasatch basin-centered natural gas play in eastern Utah. This play is similar to that in the adjacent Piceance Basin, where we had significant success in the past. Average producing depth is approximately 6,500 feet. As of December 31, 2005, we own a 100% working interest in approximately 2,800 net acres as a result of the acquisition of an additional 626 net acres in the Utah State lease sale. We have identified 35 drillable locations and plan to drill six wells in 2006.

San Juan Basin, New Mexico. The San Juan Basin is the second most prolific gas basin in North America, according to published articles, with 34 Tcf of production, 14 Tcf of which comes from the Fruitland Coal CBM (Coal Bed Methane   ). There is Fruitland Coal production from depths of 1,600 feet surrounding our leasehold. We are pursuing this coalbed methane play and had, as of December 31, 2005, a 100% working interest position

Table of Contents

Index to Financial Statements

in approximately 6,800 acres. Since then, 640 acres have been added to our leasehold in this play. The well permitting process is underway and we plan to begin our 26-well program by the middle of this year. We have identified 44 drillable locations on our San Juan Basin leases.

Texas Panhandle Price Ranch Project. On February 10, 2006, we acquired a farmout from BP on approximately 12,800 acres in Sherman County, Texas, to explore for oil and gas reserves in the Marmaton Limestone and Morrow Sandstone. The acreage is held by production by shallower Chase Formation Hugoton gas production. The farmout includes access to a proprietary BP 22 square miles of 3D seismic survey, which is being reprocessed for prospect development. We recently acquired a 3.5-mile 2D seismic line to evaluate several well locations offsetting existing Marmaton production. Further seismic and geologic evaluations are ongoing.

CRUDE OIL AND NATURAL GAS OPERATIONS

Production by Operating Area

The following table presents certain information with respect to our production data for the periods presented:

	Successor(1) Six Months Ended December 31, 2005			Predecessor Six Months Ended June 30, 2005		
	Natural Gas (Bcf)	Oil (MMBbls)	Equivalents (Bcfe)	Natural Gas (Bcf)	Oil (MMBbls)	Equivalents (Bcfe)
California	5.2		5.3	6.5		6.6
Lobo	3.8		3.9	3.7	0.0	3.9
Perdido	1.5		1.5	1.8	0.0	1.8
State Waters	0.7		0.7	0.3		0.3
Gulf of Mexico	0.4	0.1	1.0	1.1	0.1	1.5
Other Onshore	0.7	0.1	0.9	1.0	0.1	1.3
Rocky Mountains						
Mid-Continent	0.1		0.2	0.1		0.1
Totals	12.4	0.2	13.5	14.5	0.2	15.5

(1) Excludes properties not conveyed as part of the acquisition of the domestic oil and natural gas properties of Calpine, as described in the footnotes on the next page.

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 can not 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, 2005, we had 359 Bcfe of proved oil and natural gas reserves, including 344 Bcf of natural gas and 2,481 MBbls of oil and condensate. Using prices as of December 31, 2005, the estimated present value of future net revenues from proved reserves before income taxes, using SEC pricing guidelines, and

Table of Contents

Index to Financial Statements

discounted at an annual rate of 10% was approximately $1.3 billion. The following table sets forth by operating area a summary of our estimated net proved reserve information as of December 31, 2005:

	Estimated Proved Reserves at December 31, 2005(1)(3)(4)				
	Developed (Bcfe)	Undeveloped (Bcfe)	Total (Bcfe)	Percent of Total Reserves	PV-10 (Millions)(2)
California	110.5	37.2	147.7	41%	$ 605.7
Lobo	74.0	77.2	151.2	42%	463.1
Perdido	9.2	1.0	10.2	3%	44.1
State Waters	3.4		3.4	1%	17.8
Gulf of Mexico	12.7	3.9	16.6	5%	99.6
Other Onshore	15.9	7.7	23.6	6%	76.5
Rocky Mountains	2.5	1.0	3.5	1%	9.7
Mid-Continent	2.3	0.5	2.8	1%	10.2
Total	230.5	128.5	359.00	100%	$ 1326.7

(1) These estimates are based upon a reserve report prepared by Netherland Sewell & Associates, Inc. (hereafter Netherland Sewell) using criteria in compliance with SEC guidelines and excludes 19.6 Bcfe of proved oil and gas reserves and a value of $72.5 million representing the total allocated value of wells and the associated leases described in footnote 3 below.

(2) Our PV-10 value has been calculated using a spot market natural gas price and posted oil price at December 31, 2005 of $10.08/MMBtu and $57.75/Bbl, respectively, adjusted for basis differentials and held flat for the life of the reserves and adjusted for quality differentials.

(3) At the July 2005 closing, we withheld $68 million for properties (excluding that portion of the properties subject to the preferential right) which Calpine agreed to transfer to us as part of the acquisition but for which Calpine had not then secured consents to assign. Subsequent analysis determined that a portion of these properties, having an allocated value withheld under the PSA at closing of $29 million, did not require consent. Consents now have been received for the remaining properties as to which the allocated value under the PSA withheld at closing, was $39 million (Cured Non-consent Properties). We are prepared to pay Calpine the retained portion of the original purchase price, upon our receipt from Calpine of record title on these properties, free of any encumbrance, subject to appropriate adjustment for the net revenues through December 15, 2005 related to these properties.

(4) Includes properties subject to additional documentation or completion of ministerial actions by federal or state agencies necessary to perfect title issues discovered during routine post-closing analysis after completion of our acquisition of the domestic oil and natural gas business from Calpine, for which Calpine is contractually obligated to assist in resolving.

Table of Contents

Index to Financial Statements

Operating Data

The following table presents certain information with respect to our production and operating data for the periods presented, all of which is domestic production.

	Successor	Predecessor		
			Years	
	Six Months Ended December 31, 2005	Six Months Ended June 30, 2005	Ended December 31, 2004	2003
Production				
Natural gas (Bcf)	12.4	14.5	37.3	49.6
Oil (MMBbls)	0.2	0.2	0.6	0.4
Equivalents (Bcfe)	13.5	15.5	40.9	52.2
Average realized sales price per unit				
Natural gas ($/Mcf)(1)	$ 9.57	$ 6.59	$ 6.02	$ 5.38
Oil ($/Bbl)	$ 59.52	$ 49.86	$ 39.05	$ 29.67
Equivalents ($/Mcfe)	$ 8.38	$ 6.70	$ 6.06	$ 5.36
Expenses ($/Mcfe)				
Lease operating expense(2)	$ 1.16	$ 1.08	$ 0.75	$ 0.57
Transportation, treating and marketing fees	$ 0.20	$ 0.19	$ 0.13	$ 0.15
General and administrative, net(3)	$ 1.09	$ 0.63	$ 0.48	$ 0.32
Depreciation, depletion and amortization (excluding ceiling test write-downs and impairment)	$ 3.00	$ 1.98	$ 2.00	$ 1.39

(1) The average realized natural gas sales price per Mcf inclusive of the effects of hedging for the six months ended December 31, 2005 was $8.23. There were no other hedging arrangements during any other period presented.

(2) The six months ended December 31, 2005 (successor) includes workover expense, ad valorem taxes and insurance of $0.22 per Mcfe, $0.25 per Mcfe and $0.04 per Mcfe, respectively. The high rate of workover expense relates to the workover of our High Island #A-442 well and an aggressive rehabilitation program to boost production on existing wells. The six months ended June 30, 2005 (predecessor) includes workover expense, ad valorem taxes and insurance of $0.22 per Mcfe, $0.22 per Mcfe, and $0.06 per Mcfe, respectively. Ad valorem taxes for the six months ended June 30, 2005 (predecessor) includes higher taxes in South Texas and a special reclamation tax in California. Lease operating expense for 2004 (predecessor) includes workover expense and ad valorem taxes of $0.04 per Mcfe and $0.15 per Mcfe, respectively. Lease operating expense for 2003 (predecessor) includes workover expense and ad valorem taxes of $0.04 per Mcfe and $0.09 per Mcfe, respectively.

(3) Net of overhead reimbursements received from other working interest owners.

Table of Contents

Index to Financial Statements

2005 Capital Expenditures

The following table summarizes information regarding historical capital expenditures for the six months ended December 31, 2005 (successor), the six months ended June 30, 2005 (predecessor) and the historical capital expenditures for the year ended December 31, 2004 (predecessor).

	Successor	Predecessor	
	Six Months Ended December 31, 2005	Six Months Ended June 30, 2005	Year Ended December 31, 2004