PRB Gas Transportation, Inc.
Form 10-K
April 14, 2006

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

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission file number: 001-32471

PRB GAS TRANSPORTATION, INC.

(Exact Name of Registrant as specified in its Charter)

Nevada	**20-0563497**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
1875 Lawrence Street, Suite 450 **Denver, Colorado 80202**	**80202**
(Address of Principal Executive Offices)	(Zip Code)

Registrant s Telephone Number, including area code: **(303) 308-1330**

(Former name, former address and former fiscal year, if changed since last report): **None**

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Exchange on Which Registered
Common Stock, $.001 par value	American Stock Exchange

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 o No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or section 15(d) of the Exchange Act. Yes o No x

Indicate by check mark whether 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 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. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. Large accelerated filer o Accelerated filer o Non-accelerated filer x

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 registrant s common stock held by non-affiliates of the registrant as of June 30, 2005 was $52,706,175 computed by reference to the price at which the registrant s common stock was last traded on that date.

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date.

Class	**Outstanding at April 5, 2006**
Common Stock, $.001 par value	**7,461,894 shares**

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant s definitive proxy statement to be delivered to stockholders in connection with the Annual Meeting of stockholders to be held on June 14, 2006 are incorporated by reference into Part III of this Form 10-K.

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Statement of Forward Looking Statements

This Annual Report on Form 10-K includes forward-looking statements. All statements other than statements of historical facts contained herein, including statements regarding our future financial position, business strategy and plans and objectives of management for future operations, are forward-looking statements. The words believe, may, will, estimate, continue, anticipate, intend, should, plan, expect and sim they relate to us, are intended to identify forward-looking statements. We have based these forward-looking statements largely on our current expectations and projections about future events and financial trends that we believe may affect our financial condition, results of operations, business strategy and financial needs. These forward-looking statements are subject to a number of risks, uncertainties and assumptions.

We undertake no obligation to update publicly or revise any forward-looking statements. You should not rely upon forward-looking statements as predictions of future events or performance. We cannot assure you that the events and circumstances reflected in the forward-looking statements will be achieved or occur. Although we believe that the expectations reflected in the forward-looking statements are reasonable, we cannot guarantee future results, levels of activity, performance or achievements.

You should read the following discussion in conjunction with our audited financial statements, and the notes thereto, and other financial information appearing elsewhere in this document.

PART I

ITEM 1. BUSINESS

Description of Business

PRB Gas Transportation, Inc. (the Company, us, our or we) is an energy company with both oil and gas exploration and development and mid-stream operations in the Rocky Mountain states.

The Company was incorporated in December 2003. We were capitalized and commenced operations in January 2004 when we acquired certain gas gathering and related assets of TOP Gathering, LLC (TOP). In August 2004, we acquired certain gas gathering and related assets of Bear Paw Energy, LLC (BPE). Both the TOP and BPE gas gathering systems are located in the Powder River basin of Wyoming. The Company utilizes these assets to provide gas gathering, processing and compression services (the Company s gathering and processing segment) to third parties. See Recent Developments for further discussion on our TOP system.

During the third quarter of 2005, the Company expanded the scope of its operations into a new segment (the Company s exploration and production segment) that includes exploring for, developing, producing and marketing coal-bed methane natural gas. In July 2005, the Company formed PRB Energy, Inc., a 100% wholly-owned subsidiary established to conduct the Company s exploration and production activities.

During September 2005, the Company entered into a Farm-In and Development Agreement, a Management Services Agreement and an Operating Agreement with Enterra Energy Trust and its wholly-owned subsidiary Rocky Mountain Gas (Rocky Mountain Gas). The Farm-In and Development Agreement provided the Company an opportunity to earn interests in Rocky Mountain Gas undeveloped leaseholds located in an area of mutual interest by making acquisition and development expenditures during the term of the agreement. In addition, the Company earned a 50% interest in the wells that it drilled and/or completed in the area of mutual interest. Through December 31, 2005, the Company made $2.070 million in development expenditures and drilled and/or completed 28 wells in the area of mutual interest. As a result, the Company earned an approximate 4.7% interest in Rocky Mountain Gas undeveloped leaseholds in the area of mutual interest and a 50% interest in the 28 wells as of

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December 31, 2005. Once completed wells become productive, future operations will be controlled by the Operating Agreement and this agreement will also control future operations in the case of termination of the Farm-In and Development Agreement.

The Management Services Agreement provided for the Company to earn management fees by operating certain Rocky Mountain Gas properties and by providing technical and administrative support on a cost-plus basis. During the year ended December 31, 2005, the Company earned $270 thousand in management fees under the Management Services Agreement.

See Recent Developments for further discussion of the termination of the agreements with Rocky Mountain Gas.

Currently, the Company is expanding its operations to include projects located outside of the Powder River Basin and to include crude oil projects and projects involving conventional natural gas and natural gas liquids. These projects are in various stages of evaluation and or negotiation.

Business Strategy

We were originally organized as a mid-stream energy company providing gathering and processing services to coal-bed methane gas producers. Recently, we expanded into oil and gas exploration and production. Our strategy is to continue this expansion and, where feasible, also provide complimentary gathering and processing services. It is our plan to seek opportunities in conventional oil and gas exploration and production activities in the Powder River Basin and in other basins in the continental United States.

We also plan to improve and grow our existing gas gathering and processing operations by:

- enhancing the profitability of our gathering systems through system consolidation, improving operating efficiencies as well as through development of oil and gas leases;
- divesting our assets relating to the TOP gas gathering system;
- designing and building new gathering systems and acquiring existing gathering systems; and
- acquiring working interests in oil and gas producing properties and attempting to expand in areas where there may be opportunities to build new gathering systems or operate existing systems.

Recent Developments

During the first quarter 2006, we raised $21.965 million, before expenses, by issuing convertible subordinated notes. We intend to use these funds for our capital and acquisition programs.

During the first quarter of 2006, we acquired two gas gathering systems in the Recluse area of Wyoming. In addition, the Termo Company (Termo) designated the Company as its preferred gatherer for its Homestead Draw Area and this arrangement included a 9.25% working interest to be owned by the Company. There are approximately 30,000 undedicated acres in the Recluse area that offer us the opportunity to expand both our exploration and production and gathering and processing segments. In addition, we signed an agreement to farm-in on acreage that is dedicated to our BPE gas gathering system. For additional information see Note 17 Subsequent Events to our consolidated financial statements in Item 15 of this report.

On March 20, 2006, the Company elected to terminate the Farm-In and Development Agreement and Management Services Agreement (referred to in Description of Business) and agreed to continue to operate the Rocky Mountain Gas properties and provide management services for at least 60 days from the termination date. We have agreed to continue to drill certain wells that had previously been approved by the State of Wyoming and Rocky Mountain Gas under the terms of the Operating Agreement.

On March 21, 2006, we notified our customers served by the TOP system that we were raising our rates to cover cash costs plus 15% for a 2 month period. We also advised these customers that we were planning to shut down the TOP system after the two month period has elapsed. These customers have the right to purchase the TOP system from us on terms to be negotiated, as per the related gas gathering agreements.

Employees

As of December 31, 2005, we had 18 full-time employees.

Competition

Gas Gathering and Processing

Gas gathering systems are generally either acquired or developed pursuant to long-term contracts with gas producers or the shippers they service. The contracts generally run over a period of time which approximates a majority of the economic life of the gas producers wells. We believe that having such contracts and an existing gathering system in place provides a significant barrier to entry to third parties seeking to compete with us upon the expiration of our contracts.

When developing new gathering systems in areas where we do not have the advantage of existing systems in proximity to the development, we may be competing with other gathering system operators or the producer may elect to construct and own the system. In the case of other gathering system operators, many possess financial, technical and personnel resources substantially greater than ours.

Exploration and Production

The Company s oil and gas exploration activities take place in a highly competitive and speculative business atmosphere. In seeking suitable oil and gas properties for exploration, development or acquisition, the Company competes with a number of other companies, including large oil and gas companies and other independent operators with greater financial resources.

Environmental Regulation

All facilities and gathering systems that utilize compressors fueled by natural gas require Wyoming Oil and Gas Corporation Commission operating permits. All of our systems have these permits.

At the time of construction, storm water discharge permits are required as well as permits for surface discharging of hydrostatic test water. The Company has obtained all necessary construction permits.

Federal Spill Prevention Control and Countermeasure requirements apply to our facilities and we have approved plans in place.

County and state road crossing permits apply to pipelines and gathering systems crossing county and state highways. The Company is in compliance with these permitting requirements.

Intrastate Regulation

No regulatory body within the state of Wyoming controls the gathering rates we may charge.

Safety and Maintenance

Gas Gathering and Processing

We contract with third parties to perform preventive and normal maintenance on our gathering systems and make repairs and replacements when necessary or appropriate. On our behalf, third parties

also conduct routine and required inspections of our gathering and other assets as required by applicable code or regulation. External coatings and cathodic protection systems are used to protect against external corrosion. The systems are continually monitored and tested, and the results recorded, to ensure the early identification of any problem that may arise. We have contracted a third party to provide the necessary training to our employees as required by the Occupational Safety and Health Administration.

Exploration and Production

We conduct safety training classes for all of our field employees dealing with oil and gas development and production. As of December 31, 2005, all employees have participated in these classes and are in compliance with safety regulations.

Access to Information

Our website address is www.prbtrans.com. We make available, free of charge, on the Investor Relations section of our website, our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and all amendments to those reports, as soon as reasonably practicable after these reports are electronically filed with or furnished to the Securities and Exchange Commission (SEC). We also make available through our website other reports electronically filed with the SEC under the Securities Exchange Act of 1934, including our proxy statements and reports filed by officers and Directors under Section 16(a) of that Act. We do not intend for information contained in our website to be part of this Annual Report on Form 10-K.

Acquisitions and Divestitures

We did not acquire any properties during the year ended December 31, 2005. During the year ended December 31, 2004 we acquired the TOP and BPE gas gathering systems and paid $2.960 million and $7.646 million, respectively, for these acquisitions during 2004. During the year ended December 31, 2005, we paid an additional $200 thousand in respect to accrued TOP system acquisition costs and $25 thousand in respect to the TOP system compressor disposal liability.

During the quarter ended March 31, 2006 the Company entered into the following transactions:

- The purchase of a gas gathering system from Storm Cat Energy Corporation and the signing of a related gas gathering and compression services agreement with Storm Cat covering 6,600 acres. The agreement guarantees the Company minimum throughput volumes.

- The farm-in of a 15% working interest in leaseholds underlying the BPE gas gathering system. The leaseholds cover 5 townships and total approximately 2,500 net acres.

- The Company was designated as the preferred gas gatherer by Termo and this included a participation in Termo s Homestead Draw Coal Bed Natural Gas Project near Recluse, WY in the Powder River Basin, with a 9.25% working interest in the development of approximately 3,400 existing net acres and any future lease acquisitions in or around the existing leases.

- The acquisition of a high pressure natural gas gathering line from Clear Creek Natural Gas, LLC.

Major Customers

Gathering and Processing

Our gathering and processing systems service several customers in the Powder River Basin area of Wyoming. Pennaco Energy, Inc. is our largest gathering and processing customer at approximately 54% of total revenue for the year ended December 31, 2005.

Exploration and Production

We sold 100% of our gas production on a spot sale basis to Enserco Energy, Inc. during the year ended December 31, 2005. We will be evaluating options to market our future natural gas production during 2006.

Seasonality

Gathering and Processing

Generally, but not always, the demand and price levels for natural gas increase during the colder winter months and decrease during the warmer summer months. In addition, pipelines, utilities, local distribution companies and industrial users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. Seasonal anomalies such as mild winters and summers sometimes lessen these fluctuations.

Exploration and Production

In addition to the seasonal demands applicable to natural gas mentioned above, the demand for crude oil and heating oil are also impacted by generally higher prices in the winter. Seasonal anomalies such as mild winters sometimes lessen these fluctuations. The impact of seasonality has been somewhat mitigated by the overall supply and demand economics related to crude oil because there is a narrow margin of production capacity in excess of existing worldwide demand.

ITEM 1A. RISK FACTORS

The risks and uncertainties described below are not the only risks facing us. Additional risks not presently known to us or which we consider immaterial based on information currently available to us may also materially adversely affect us. If any of the following risks or uncertainties actually occurs, our business, financial condition and results of operations could be adversely affected.

We incurred a net loss of $4.625 million and $651 thousand for the years ended December 31, 2005 and December 31, 2004, respectively. Our future performance is difficult to evaluate because we have a limited operating history.

Our operations commenced with our acquisition of certain assets of TOP as of January 1, 2004 and expanded with our acquisition of certain assets of BPE effective August 1, 2004. In addition, we have recently expanded into the exploration and production business. As a result, we have little historical financial and operating information available to help you evaluate our performance or an investment in our common stock.

To fund our future growth we will require additional capital, which may not be available or may only be available on unfavorable terms.

During the first quarter of 2006, we raised $21.965 million, before costs, by issuing convertible subordinated notes. We anticipate that this capital will be adequate for the current calendar year. Our future capital requirements depend on many factors, including development and acquisition opportunities, the availability of debt financing and the cash flow from our operations. To the extent that the funds available are insufficient to meet future capital requirements, we may need to reduce our development activity. Any equity or debt financing, if available at all, may be on terms that are not favorable to us. If we cannot obtain adequate capital on favorable terms or at all, our business, operating results and financial condition could be adversely affected.

Our convertible subordinated notes include interest accruing at ten percent per annum.

Our new debt arrangements, as referenced above, include quarterly interest payments of approximately $550 thousand. We may not be able to fully service these interest payments in the future.

Our convertible subordinated notes may not be converted to our common shares.

If the recently issued notes are not converted to our common stock before or at maturity during the third quarter of 2008, we will have to refinance this debt. We may not be able to refinance these notes and this could adversely affect our financial position and future operations.

Our convertible subordinated notes are secured by certain gas gathering assets.

In the event of our default in respect to these notes, we could lose control of these assets. Should this occur, our future operating results, financial condition and performance could be adversely affected.

Restrictions in credit agreements may prevent us from engaging in some beneficial transactions.

As we expand and require capital, we intend to enter into credit agreements with financial institutions to fund a portion of the capital requirements. To obtain funds under credit agreements we may be required to accept operating restrictions which would impair or prevent us from future transactions we deem to be beneficial for our future growth.

We depend on our chief executive and chief operating officers for critical management decisions and industry contacts.

We do not have employment agreements with our chief executive officer and chief operating officer and do not carry key person insurance on their lives. The loss of the services of either of these executive officers, through incapacity or otherwise, could have a material adverse effect on our business and would require us to seek and retain other qualified personnel.

Competition for experienced technical personnel may negatively impact our operations.

Our exploratory and development drilling success depends, in part, on our ability to attract and retain experienced professional personnel. The loss of any key executives or other key personnel could have a material adverse effect on our operations. As we continue to grow our asset base and the scope of our operations, our future profitability will depend on our ability to attract and retain qualified personnel, particularly individuals with a strong background in geology, geophysics, engineering and operations.

A significant decrease in the supply of natural gas from our gas gathering customers could materially affect our results of operations and financial condition.

Investments by our gas gathering customers in the maintenance of existing wells and the further development of their reserves will affect their production rates and the volume of gas we gather. Drilling activity generally decreases as gas prices decrease. We have no control over our customers level of drilling activity, the amount of reserves underlying their wells and the rate at which their production from a well will decline. Drilling activity of our customers is affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, geological considerations, governmental regulation and the availability and cost of capital.

Any material nonpayment or nonperformance by our key customers could materially affect our results of operations and financial condition.

As of December 31, 2005, one of our customers, Pennaco Energy, Inc., accounted for approximately 54% of our 2005 revenue. No other customers exceed 10% of our revenue. Some of our customers may be highly leveraged and subject to their own operating and regulatory risks.

Our operations are subject to operational hazards and unforeseen interruptions for which we may be inadequately insured.

Our operations, both gathering and processing and exploration and production, are subject to operational hazards and unforeseen interruptions such as natural disasters, adverse weather, accidents, fires, explosions, hazardous materials releases, mechanical failures and other events beyond our control. These events might result in a loss of equipment or life, injury or extensive property damage, as well as an interruption in our operations. We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our results of operations and financial condition.

Growing our business by constructing new gathering systems, or expanding existing ones, subjects us to construction and other risks.

We plan to grow our business, in part, by constructing new gathering systems and by expanding existing ones. We have no material significant commitments for new construction or expansion projects as of the date of this report. The construction of a new gathering system or the expansion of an existing gathering system, by adding compressor stations or by adding a second gathering line along an existing gathering line, involves numerous regulatory, environmental, political and legal uncertainties, most of which are beyond our control. These projects may not be completed on schedule or at all or at the budgeted cost. In addition, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we build a new gathering system, the construction will occur over an extended period of time and we will not receive a material increase in revenue until after completion of the project. This could adversely affect our results of operations and financial condition.

Our business depends on the level of activity in the oil and gas industry, which is significantly affected by volatile energy prices.

Our business depends on the level of activity in oil and gas exploration, development and production in markets worldwide. Oil and gas prices, market expectations of potential changes in these prices and a variety of political and economic and weather-related factors significantly affect this level of activity. Oil and gas prices are extremely volatile and are affected by numerous factors, including:

- worldwide demand for oil and gas;
- the ability of the Organization of Petroleum Exporting Countries, commonly called OPEC, to set and maintain production levels and pricing;
- the level of production in non-OPEC countries;
- the policies of the various governments regarding exploration and development of their oil and gas reserves;
- local weather;
- fluctuating pipeline takeaway capacity;
- advances in exploration and development technology;
- the political environment surrounding the production of oil and gas;
- level of consumer product demand; and
- the price and availability of alternative fuels.

Future oil and gas price declines or unsuccessful exploration efforts may result in write-downs of our exploration and production asset carrying values.

We follow the successful efforts method of accounting for our oil and gas properties. All property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending the determination of whether proved reserves have been discovered. If proved reserves are not discovered with an exploratory well, the costs of drilling the well are expensed.

The capitalized costs of our oil and gas properties, on a field basis, cannot exceed the estimated future net cash flows of that field. If net capitalized costs exceed future net revenues, we must write down the costs of each such field to our estimate of fair market value. Unproved properties are evaluated at the lower of cost or fair market value. Accordingly, a significant decline in oil or gas prices or unsuccessful exploration efforts could cause a future write-down of capitalized costs.

We review the carrying value of our properties quarterly based on prices in effect as of the end of each quarter or as of the time of reporting our results. Once incurred, a write-down of oil and gas properties cannot be reversed at a later date even if oil or gas prices increase.

Substantial capital is required to find, acquire, develop and replace our reserves.

We need to make substantial capital expenditures to find, acquire, develop and replace oil and natural gas reserves. Future cash flows and the availability of financing are subject to a number of factors, such as the level of production from existing wells, our success in locating and producing new reserves and prices of oil and natural gas. If oil or gas prices decrease or we encounter operating difficulties that result in our cash flows from operations being less than expected, we may have to reduce our capital expenditures unless we can raise additional funds through debt or equity financing. Debt or equity financing may not always be available to us in sufficient amounts or on acceptable terms.

If our revenues were to decrease due to lower oil or gas prices, decreased production or other reasons, and if we could not obtain capital through debt or equity financing arrangements, our ability to execute our development plans, replace our reserves or maintain production levels could be greatly limited.

Future oil and gas price declines may affect our ability to raise capital.

If oil and gas prices decrease there will be a corresponding negative impact on the value of our reserves. This could negatively affect our ability to borrow funds or raise capital in the equity markets.

Exploration and development drilling may not result in commercially productive reserves.

Oil and gas drilling and production activities are subject to numerous risks, including the risk that no commercially productive oil or natural gas will be found. The cost of drilling and completing wells is often uncertain, and oil and gas drilling and production activities may be shortened, delayed or canceled as a result of a variety of factors, many of which are beyond our control. These factors include:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental requirements;
- shortages or delays in the availability of or increases in the cost of drilling rigs and the delivery of equipment; and
- lack of availability of experienced drilling crews.

Competition in our industry is intense, and many of our competitors have greater financial and technical resources than we do.

We face intense competition from major oil companies, independent oil and gas exploration and production companies, financial buyers and institutional and individual investors who are actively seeking oil and gas properties throughout the world, along with the equipment, expertise, labor and materials required to operate oil and gas properties. Many of our competitors have financial and technical resources vastly exceeding those available to us, and many oil and gas properties are sold in a competitive bidding process in which our competitors may be able to pay more for development prospects and productive properties or in which our competitors have technological information or expertise to evaluate and successfully bid for the properties that is not available to us. In addition, shortages of equipment, labor or materials as a result of intense competition may result in increased costs or the inability to obtain those resources as needed. We may not be successful in acquiring and developing profitable properties in the face of this competition.

The actual quantities and present values of our proved oil and gas reserves may be less than we have estimated.

This Form 10-K contains estimates of our proved oil and gas reserves and the estimated future net revenues from those reserves. Reserve estimates are based on various assumptions, including assumptions required by the SEC relating to oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. These estimates are dependent on many variables and, therefore, changes often occur as these variables evolve and commodity prices fluctuate. As a result, these estimates are inherently imprecise. As of December 31, 2005, all of our estimated proved reserves (by volume) were proved developed producing.

Management has based the estimated discounted future net cash flows from proved reserves on prices and costs as of the date of the estimate, in accordance with SEC requirements, whereas actual future prices and costs may be materially higher or lower.

Our revenue projections include assumptions on de-watering time for our coal-bed methane wells in the Powder River Basin in Wyoming. These estimated de-watering times may be longer than we expect.

Our future period revenue and financial position could be adversely affected if we experience delays in selling natural gas due to longer than expected de-watering times.

We may be required to rescind the sale of up to $1.233 million of stock if our private placement of Series C preferred stock is deemed to have violated federal and state securities laws.

In December 2004, we received $1.233 million from the sale of 411,000 shares of Series C convertible preferred stock. We paid no cash or other commissions or finders fees in connection with this offering. This placement might not have been eligible for an exemption from registration under the Securities Act of 1933. In the absence of such an exemption, investors could bring suit against us to rescind their stock purchases, in which event we could be liable for rescission payments to these investors of up to $1.233 million exclusive of interest and costs. As of December 31, 2005, 371,000 Series C convertible preferred shares converted to common shares and 40,000 Series C convertible shares remain outstanding. During the first quarter of 2006 an additional 30,000 Series C convertible shares converted to common shares.

Concentration of share ownership among our existing executive officers, Directors and principal stockholders may prevent others from influencing significant corporate decisions.

At December 31, 2005, our executive officers, Directors and principal stockholders beneficially own approximately 25.2% of our outstanding common stock. As a result, these stockholders, acting together, will have the ability to exert substantial influence over all matters requiring approval by our stockholders, including the election and removal of Directors and any proposed merger, consolidation or sale of all or substantially all of our assets and other corporate transactions. This concentration of ownership could be disadvantageous to other stockholders with interests different from those of our officers, Directors and principal stockholders.

In 2005, the Company was advised by its auditor of material weaknesses in the Company s internal controls and procedures, the correction of which will result in increased cost to the Company.

Our independent registered public accounting firm has advised our management and Board of Directors that there were material weaknesses in our internal controls and procedures during the year ended December 31, 2005. Management believes that until these material weaknesses are corrected, a potential misapplication of generally accepted accounting principles or potential accounting error in our financial statements could occur. Enhancing our internal controls to correct the material weaknesses has and will result in increased costs to us. The identified material weaknesses relate to significant deficiencies were identified in our internal control over financial reporting relating to the preparation and review of financial statements and disclosures, identification and resolution of complex accounting issues, segregation of duties, accounting policies and procedures, information technology systems, and revenue recognition and billing. Management and Ehrhardt Keefe Steiner & Hoffman PC have determined that these significant deficiencies, in the aggregate, constitute a material weakness in internal control over financial reporting. Specifically, our staffing levels were inadequate to facilitate the design, implementation and maintenance of an effective system of internal control.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Description of Properties

Powder River Basin Geology

In December 1994, there were approximately 200 wells in the Powder River Basin producing coal-bed methane gas. Since 1994, over 15,000 gas wells have been drilled in this area and the State of Wyoming and the Bureau of Land Management (BLM) have the authority to grant over 15,000 additional drilling permits. Production in 1994 was 2.4 billion cubic feet, and production in 2003 was 3.46 billion cubic feet (Source: Wyoming Oil and Gas Conservation Commission). The average well-life of a coal-bed methane well is estimated by the BLM to be eight to ten years.

Gas produced from Powder River Basin coals is almost 100% methane. The gas is generated during the coal forming process and is trapped in the coal beds by water. In order to produce the coal gas, the formation must first be dewatered. As the water is removed from the coal, the gas is desorbed from the coal. All of the coal-bed reservoirs are low pressure and require compression in order for the gas to be delivered to a pipeline transportation system.

Natural gas wells in the Powder River Basin area typically experience sharp declines in production volume in the first several years of production. Production then stabilizes and declines more ratably over a gas well s average life of approximately eight to ten years. Other factors which influence the initial and long term productivity of the coal-bed methane wells are the depths of the coal fields, the initial gas saturation levels of the coal field and the well spacing.

TOP Gathering System

Effective January 1, 2004, we acquired the TOP gathering system located in Campbell County, Wyoming. The TOP system was constructed in late 2001 and began operations early in 2002. The system consists of 4.5 miles of 8-inch coated steel pipeline. The pipeline services producers of coal-bed methane in the Powder River Basin and is currently gathering from 56 wells operated by 2 independent natural gas companies, transporting approximately 2 million cubic feet of gas per day.

The gathering system has a current throughput capacity of approximately 4 million cubic feet (MMcf) of gas per day and is presently averaging approximately 2 million cubic feet per day or approximately 50% of capacity. Our current fees range from $0.55 to $0.84 per thousand cubic feet (Mcf) of natural gas from 2 producers. Gathering fees are subject to contracts which are life of lease or 10-year contracts expiring in 2012.

As a result of a lack of drilling in the areas around our TOP system, we determined the system s carrying value was higher than its fair market value. Accordingly, we recorded a non-cash impairment charge to adjust the carrying value to the fair market value. We plan on shutting down or selling the TOP system. See Note 17 Subsequent Events to our consolidated financial statements in Item 8 of this report. For additional information on this impairment see Note 5 Property, Equipment and Contracts to our consolidated financial statements in Item 15 of this report.

Bear Paw Gathering Systems

Effective August 1, 2004, we acquired certain gathering systems and related contracts from BPE located in Campbell County, Wyoming. The systems acquired include the following:

- GAP gas gathering system;
- Bone Pile gas gathering system;
- South Kitty delivery line; and
- Antelope Valley delivery line.

Concurrent with the acquisition, we entered into an operations agreement with BPE. The agreement requires BPE to operate the systems for us, including repairs, maintenance and compression services, for a monthly fee of $80,000. We are responsible for any major repair and/or maintenance expenditure in excess of $5,000 per occurrence. The agreement originally was a two-year agreement with two one-year extensions at our option. If we terminate the agreement before the four year period is up, for reasons other than a change of control at BPE, we will enter into an agreement to lease compression from BPE for the remainder of the four year period. All other expenses associated with ownership of the acquired properties are our responsibility, including property taxes, rights of way payments and insurance.

GAP Gas Gathering System. The system was constructed in 1999 and consists of approximately 25 miles of 12 to 20-inch steel pipe and 127 ditch miles of low pressure poly pipe. The gathering system services nine producers of coal-bed methane in the Powder River Basin.

The gathering line has a current throughput capacity of approximately 18 million cubic feet of gas per day and is presently averaging approximately 3.5 million cubic feet per day or approximately 19% of capacity. This system gathers gas from approximately 300 coal-bed wells. Current fees average $0.80 per Mcf of methane gas. One producer accounts for approximately 60% of our revenues from this system.

All of the gas gathering lines within the GAP gathering system send gas to the South GAP facility where the gas is compressed and dehydrated. This high pressure gas stream is then delivered to our Antelope Valley Delivery Line.

Bone Pile Gas Gathering System. The system was constructed in 2000 and consists of approximately 9 miles of 8-inch and 16-inch pipeline and 25 miles of low pressure poly pipe. The system services producers of coal-bed methane in the Powder River Basin and is currently gathering from 125 wells owned by 1 producer and approximately 20 wells from other producers.

The system has a current throughput capacity of approximately 9 million cubic feet of gas per day and is presently averaging approximately 0.6 million cubic feet per day or approximately 7% of capacity. The system is scheduled to be reconfigured during 2006 to decrease costs, increase operating efficiency and optimize compression. Current fees average $0.52 per Mcf of methane gas. One customer accounts for 90% of our revenues from this system.

After the gas is gathered, it is compressed, dehydrated and delivered to our Antelope Valley Delivery Line.

South Kitty Delivery Line. The system was constructed in 2002 and consists of 6 miles of 12-inch pipeline. The line services the South Kitty coal-bed methane development area. Certain shippers move gas down this line in order to sell gas in the local market. The South Kitty line delivers gas into the Bone Pile gathering system and is then sent to our Antelope Valley Delivery Line.

The line has a current throughput capacity in excess of 10 million cubic feet of gas per day and is presently averaging approximately 1.9 million cubic feet per day or approximately 19% of capacity.

Antelope Valley Delivery Line. The system was constructed in 1999 and consists of 14 miles of 10-inch pipeline. The line had an original capacity of approximately 50 million cubic feet of gas per day and is currently configured for 27 million cubic feet per day. The system is presently averaging approximately 5.7 million cubic feet per day or approximately 21% of capacity. The gas received from the Bone Pile and GAP gathering systems is transported down the Antelope Valley line and delivered into two major transportation lines.

Reserves

We engage Sproule Associates Inc., geological and petroleum engineering consultants, to estimate our natural gas reserves. We emphasize that reserve estimates are imprecise by their nature, and that reserve estimates on new discoveries and developments are less precise than reserve estimates for existing fields. Accordingly, the Company expects these estimates to change as time passes and information as to actual well performance can be included in those future estimates. The Company also reviews the calculations and assumptions that Sproule Associates Inc. uses to calculate our reserves.

Proved oil and gas reserves are estimates of recoverable quantities of oil, natural gas and natural gas liquids that are determined using engineering and geological data with reasonable certainty. The reserve estimates are based on existing economic and operating conditions and include only existing wells from known reservoirs with existing equipment and technology. All of the Company s proved reserves are located in the Powder River Basin area of Wyoming.

The following table summarizes proved reserves data at December 31, 2005:

Year Ended December 31, 2005	
Gas (MMcf)	396
Standardized measure of discounted future net cash flows (in thousands)	$ 688
Proved developed reserves	100 %

Production

The following table summarizes the production volumes and realized prices for gas sold from our properties during the year ended December 31, 2005.

Year Ended December 31, 2005	
Net gas production (MMcf)	6
Average net daily gas production (Mcf)	85
Average realized price of gas per Mcf	$8.50
Lease operating expense per Mcf	$4.22
Production taxes per Mcf	$1.06
Transportation expense per Mcf	$0.38

Productive Wells

As of December 31, 2005 we had working interests in 10 productive wells (4 wells net). Productive wells are either producing or capable of producing although shut-in or de-watering.

Drilling Activity

All of our drilling activity is performed by independent drilling contractors. During the year ended December 31, 2005, we participated in the drilling of the wells listed in the following table:

	Year Ended December 31, 2005	
Gas Wells	**Gross**	**Net**
Exploratory	18	7
Development	6	3
Total	24	10

As part of our Farm-In and Development Agreement with Rocky Mountain Gas we also earned a 50% interest in 4 gross wells (2 wells net) by completing these wells, although these wells had been drilled prior to the initial date of our agreement.

Acreage

The following table details the gross and net acres of developed and undeveloped properties that we hold. All of the developed and undeveloped acreage included herein has been earned as part of the Company s Farm-In and Development Agreement with Rocky Mountain Gas.

	Developed		**Undeveloped**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Montana			5,893	2,357	5,893	2,357
Wyoming	2,240	896	737	638	2,977	1,534
Total	2,240	896	6,630	2,995	8,870	3,891

Office Facilities

We currently lease office space for our Corporate Headquarters in Denver, Colorado as well as office space for our Gillette Wyoming Field Operations office.

ITEM 3. LEGAL PROCEEDINGS

None.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

On October 14, 2005, the Company held a special meeting where the stockholders approved an amendment to Article Sixth of the Company s Amended and Restated Articles of Incorporation to provide that the number of Directors shall be a variable number consisting of at least one Director but no more than nine Directors and that the exact number of Directors shall be established by the Board of Directors. Prior to this amendment Article Sixth stipulated that the number of Directors would be five. This amendment passed by a vote of 1,453,875 for, 1,250 against, 2,838 withheld. There were no abstentions or broker non-votes.

PART II

ITEM 5. MARKET FOR REGISTRANT S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Principal Market and Price Range of Common Stock

Our common stock began trading on the American Stock Exchange on April 12, 2005 under the trading symbol PRB. The following table presents the reported high and low sales prices for periods ended:

2005	**High**	**Low**
Second quarter	$ 9.95	$ 6.21
Third quarter	$ 10.32	$ 5.38
Fourth quarter	$ 7.60	$ 5.41

As of April 5, 2006, we had approximately 29 holders of record of our common stock. This does not include holdings in street or nominee names. On April 5, 2006, the closing price of our common stock was $5.66 per share.

Dividend Policy

We have never paid cash dividends on our common stock and we do not anticipate paying dividends in the foreseeable future. We expect that we will retain all available earnings generated by our operations for the development and growth of our business. In addition, under the terms of our convertible subordinated notes that were issued in the first quarter 2006, we are prohibited from declaring or paying cash dividends on our common stock during the period that any note is outstanding and unpaid. Payment of any future dividends will be at the discretion of our Board of Directors after taking into account many factors, including our operating results, financial condition, current and anticipated cash needs, plans for expansion and the above-noted debt agreement.

ITEM 6. SELECTED FINANCIAL DATA

The selected consolidated financial data for each of the two years in the period ended December 31, 2005 and the selected consolidated balance sheet data as of December 31, 2005 and 2004 are derived from, and qualified by reference to, our audited Consolidated Financial Statements in Item 15 of this report. The selected financial data for each of the periods presented ending December 31, 2003, 2002 and 2001and the selected balance sheet data as of December 31, 2003, 2002 and 2001 are derived from audited financial statements of TOP, our predecessor company.

The following financial data should be read in conjunction with, and are qualified by reference to, our Consolidated Financial Statements and related notes thereto in Item 8 of this report and Management s Discussion and Analysis of Financial Condition and Results of Operations included in Item 7 of this report.

	PRB Gas Transportation, Inc.		**TOP Gathering, LLC (Predecessor)**		
	Year Ended December 31,		**Year Ended December 31,**		**Period from Inception through December 31,**
	2005	**2004 (As restated)**	**2003**	**2002**	**2001**
	(in thousands, except per share and volume amounts)				
Statement of operations data:					
Total revenue	$ 3,155	$ 2,532	$ 1,999	$ 2,097	$
Operating expenses	7,822	3,154	1,900	2,725	2
Operating (loss) income	(4,667)	(622)	99	(627)	(2)
Net (loss) income Note (1)	(4,625)	(651)	79	(636)	(2)
Net loss per share basic and diluted	$ (0.69)	$ (1.33)	$	$	$
Weighted average shares of common stock outstanding	6,959,025	1,398,907			
Balance sheet data (at year end):					
Cash and equivalents	$ 6,434	$ 320	$ 155	$ 15	$ 316
Property and equipment, net	6,024	8,136	618	1,125	908
Oil and gas properties	1,531				
Total assets	17,440	11,399	1,603	1,899	1,253
Long term liabilities	434	65	86	260	
Stockholders equity	15,257	9,318	820	1,241	913
Working capital (deficit)	7,014	(1,169)	287	376	(24)
Dividends on preferred stock	204	1,212			
Cash dividends declared and paid per common share	0.00	0.00	0.00	0.00	0.00
Cash flow data:					
Cash (used in) provided by operating activities	$ (781)	$ 72	$ 655	$ (414)	$ 309
Cash used in investing activities	(2,298)	(10,647)	(14)	(1,150)	(908)
Cash provided by (used in) financing activities	9,193	10,895	(500)	1,262	915
Reserve data:					
Gas (MMcf)	396				

Note (1) The net loss in 2005 includes a non-cash impairment charge of $2.487 million ($0.36 per basic and diluted share) and $76 thousand for cumulative effect of change in accounting principle ($0.01 per basic and diluted share). For additional information on these items see Note 5 Property, Equipment and Contracts, and Note 7 Asset Retirement Obligations to our consolidated financial statements in Item 8 of this report.

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

General Overview

We own and operate natural gas gathering systems and coal-bed methane gas wells in the Powder River Basin of Wyoming. We commenced operations in January 2004 upon our acquisition of certain gas gathering and related assets of TOP and increased our gathering and processing activities in August 2004 when we acquired certain gas gathering and related assets of BPE. We were originally organized as a mid-stream energy company providing gathering and processing services to coal-bed methane gas producers. During the third quarter of 2005, we expanded our operations to include exploring for, developing, producing and marketing natural gas, operating coal-bed methane properties and providing management services as contract operator (our exploration and production segment). These activities are in addition to our gas gathering and processing segment.

Our strategy is to continue this expansion and, where feasible, also provide complimentary gathering and processing services. It is our plan to seek opportunities in conventional oil and gas exploration and production activities in the Powder River Basin and in other basins in the continental United States. We also plan to improve and grow our existing gas gathering and processing operations.

Recent Developments

During September 2005, the Company entered into a Farm-In and Development Agreement, a Management Services Agreement and an Operating Agreement with Enterra Energy Trust and its wholly-owned subsidiary Rocky Mountain Gas (Rocky Mountain Gas). The Farm-In and Development Agreement provided the Company an opportunity to earn interests in Rocky Mountain Gas undeveloped leaseholds located in an area of mutual interest by making acquisition and development expenditures during the term of the agreement. In addition, the Company earned a 50% interest in the wells that it drills and/or completed in the area of mutual interest. Through December 31, 2005, the Company made $2.070 million in acquisition and development expenditures and drilled and/or completed 28 wells in the area of mutual interest. As a result, the Company earned an approximate 4.7% interest in Rocky Mountain Gas undeveloped leaseholds in the area of mutual interest and a 50% interest in the 28 wells as of December 31, 2005. Once completed wells are productive, future operations are controlled by the Operating Agreement and this agreement also controls future operations in the case of termination of the Farm-In and Development Agreement.

The Management Services Agreement provided for the Company to earn management fees by operating certain Rocky Mountain Gas properties and by providing technical and administrative support on a cost-plus basis. During the year ended December 31, 2005, the Company earned $270 thousand in management fees under the Management Services Agreement.

On March 20, 2006, the Company elected to terminate the Farm-In and Development Agreement and Management Services Agreement and agreed to continue to operate the Rocky Mountain Gas properties and provide management services for at least 60 days from the termination date. The Company has agreed to continue to drill certain wells that had been previously approved by the State of Wyoming and Rocky Mountain Gas under the terms of the Operating Agreement.

During the year ended December 31, 2006, the Company expects to incur approximately $150 thousand of general and administrative expenses subsequent to the termination of the Management Services Agreement that will not be billed out as management fees. The Company plans to absorb these costs as part of its expansion plan in 2006.

During the first quarter 2006, we raised $21.965 million, before expenses, by issuing convertible subordinated notes. We intend to use these funds for our capital and acquisition programs.

During the first quarter of 2006, we acquired two gas gathering systems in the Recluse area of Wyoming. In addition, Termo designated the Company as its preferred gatherer for its Homestead Draw Area and this arrangement included a 9.25% working interest to be owned by the Company. There are approximately 30,000 undedicated acres in the Recluse area that offer us the opportunity to expand both our exploration and production and gathering and processing segments. In addition, we acquired a working interest in acreage that is dedicated to our BPE gas gathering systems. For additional information see Note 17 Subsequent Events to our consolidated financial statements in Item 15 of this report.

We intend on selling or shutting down our TOP system during the second quarter of 2006. The reduction to our revenue for the year ended December 31, 2006 depends on the date that the TOP system is sold or shut down. The TOP system operated at a loss for the year ended December 31, 2005 and we expect the impact of this decision will improve our financial results for the year ended December 31, 2006.

General Business Trends and Outlook

We expect our business to continue to be affected by some key trends as discussed below. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about or interpretations of available information prove to be incorrect, our expectations may vary materially from actual results.

U.S. Gas Supply and Outlook

We believe that the relatively high levels of demand for natural gas by both the residential and commercial markets will continue to result in steady or increasing natural gas prices which in turn will drive drilling activity. We believe that an increase in U.S. drilling activity and additional sources of supply such as liquefied natural gas or imports will be required for the natural gas industry to meet the expected increased demand for, and compensate for the slowing production of, natural gas in the United States.

Rising Interest Rate Environment

The credit markets recently have experienced 50-year record lows in interest rates. During the last several months, we have witnessed increases in interest rates. This could affect our ability to access the debt capital markets. In addition, interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly.

Results of Operations

Overview

Revenue. Our gas gathering fees are based on contractual rates with our customers and will vary with system throughput as well as the level of services provided and customer mix. Our gas gathering fees are not currently regulated by any governmental authority.

Our management services fees were determined in accordance with our Management Services Agreement with Rocky Mountain Gas and varied depending on the amount of support services that were required to fulfill our obligations under this contract determined on a cost plus 15% basis. On March 20, 2006, we elected to terminate this contract effective May 19, 2006.

Our natural gas revenue will vary based on the price of natural gas and the quantities and quality of the gas we deliver.

Gas Gathering Expense. Gas gathering expense includes compression, operating agreement expense, site supervision costs, maintenance and operating supplies, property taxes, insurance, land use and surface rights payments and contract services, all of which are relatively fixed costs. Operating expenses also include transportation fees paid to others which vary with the throughput on our gathering lines.

Gas Production Costs. Gas production costs include production taxes, well maintenance, monitoring, utilities, pumping and gauging services and supplies required to produce natural gas.

Asset Impairment Charge. Asset impairment charge represents the difference between our carrying value of the TOP system and the estimated fair market value of the TOP system. See Note 5 Property, Equipment and Contracts to our consolidated financial statements in Item 15 of this report.

Exploration Expense. Gas exploration expense includes the costs of drilling unsuccessful exploratory wells. See also our description of exploration expense in our discussion of Critical Accounting Policies and Estimates below.

Depreciation, Depletion, Amortization and Accretion Expense. Depreciation expense relates to our compressor sites, pipelines and other gas gathering equipment, office furniture, office equipment and computers. Depletion expense relates to developed and undeveloped leaseholds, capitalized development costs and related equipment. Amortization expense relates to the customer contracts underlying the gas gathering systems. Accretion expense relates to the change in our asset retirement obligation liability due to the passage of time. Depreciation and amortization expense are based on estimates of the related assets useful lives. Depletion expense is calculated using the unit-of-production method based on estimated proved or estimated proved developed reserves. Accretion expense is calculated using the effective interest method.

General and Administrative Expense. General and administrative expense includes the costs associated with our corporate office, including personnel costs, professional fees, office rent and other office support costs.

Interest Expense. During 2005, we had a note payable to the Bank of Oklahoma under a line of credit in the amount of $1.5 million, secured by our gas gathering assets. Interest was payable monthly at a fluctuating interest rate at the JPMorgan Chase Bank prime rate per annum. The annual interest rate was 5.75% at March 31, 2005. Following the payment of the bank line of credit in full in April 2005, the bank released their security interest in the gathering assets and the $1.0 million certificate of deposit pledged by a preferred stockholder.

The following table summarizes the results of operations for the years ended 2005 and 2004:

	Years Ended December 31, 2005 (dollars in thousands)	2004 (As restated)	Increase / (Decrease) 2005 v 2004	Percentage Change 2005 v 2004
Gas gathering revenue	$ 2,834	$ 2,532	$ 302	12 %
Management fee revenue	270		270	100 %
Natural gas revenue	51		51	100 %
Total revenue	3,155	2,532	623	25 %
Gas gathering expense	1,755	1,314	441	34 %
Gas production costs	34		34	100 %
Asset impairment charge	2,487		2,487	100 %
Exploration expense	450		450	100 %
Depreciation, depletion, amortization and accretion expense	1,067	656	411	63 %
General and administrative	2,029	1,184	845	71 %
Total operating expenses	7,822	3,154	4,668	148 %
Operating loss	(4,667)	(622)	(4,045)	nm
Total other income (expense)	118	(29)	147	nm
Cumulative effect of change in accounting principle	(76)		(76)	(100)%
Net loss	$ (4,625)	$ (651)	$ (3,974)	nm
Cash (used in) provided by operating activities	$ (781)	$ 72	$ (853)	nm
Cash used in investing activities	$ (2,298)	$ (10,647)	$ 8,349	78 %
Cash provided by financing activities	$ 9,193	$ 10,895	$ (1,702)	(16)%

nm percentages greater than 200% and comparisons from positive to negative values are considered not meaningful

2005 Compared to 2004

Revenue. Total revenue increased $623 thousand, or 25%, primarily due to an acquisition-timing related increase of $1.055 million in gas gathering revenue applicable to our BPE systems which we acquired in August 2004. Revenue from management fees and natural gas sales, activities that were initiated during the year ending December 31, 2005, also increased by $270 thousand and $51 thousand, respectively. These revenue increases offset a $753 thousand decrease in gas gathering revenues from our TOP system resulting from a decline in volumes and the loss of a customer. This customer represented 11% of our 2004 revenues. We are currently in the process of divesting our assets relating to our TOP gathering system.

Gas Gathering Expense. Gas gathering expense increased $441 thousand or 34% mainly due to the $721 thousand increase in BPE systems operating costs resulting from the timing of the acquisition of this system. These costs offset a decrease in gas gathering expenses relating to our TOP system as a result of releasing excess compression capacity.

Gas Production Costs. We incurred gas production costs for the first time in 2005 as a result of our entry into exploration and production activities.

Asset Impairment Charge. In 2005, we recorded an asset impairment charge of $2.487 million related to our TOP gas gathering system. As a result of declining volumes and the loss of a customer, we performed an evaluation of the recoverability of our carrying value of this system using undiscounted cash flow projections. We determined that the estimated fair value of these gathering system assets was less than our carrying value.

The estimated fair value was determined using discounted values of probability weighted expected cash inflows and an independent appraiser s valuation of our TOP gas gathering system. We also evaluated our BPE gas gathering system for recoverability of carrying values and we determined that no impairment was warranted at December 31, 2005. See also Note 5 Property, Equipment and Contracts to our consolidated financial statements in Item 15 of this report.

Exploration Expense. We incurred $450 thousand of exploration expense in 2005 relating to the drilling costs of 6 unsuccessful exploratory wells. Four of these six wells were lost due to mechanical failure and have been subsequently re-drilled.

Depreciation, Depletion, Amortization and Accretion Expense. Depreciation, depletion, amortization and accretion expense increased $411 thousand or 63% primarily due to $491 thousand of additional depreciation and amortization expense applicable to the BPE assets which were acquired in August 2004. This increase was offset by lower TOP system depreciation and amortization as a result of the TOP impairment.

General and Administrative Expense. General and administrative expense increased $845 thousand or 71% mainly due to increases of $381 thousand in professional fees, $166 thousand in additional expenses associated with being a public company and $134 thousand in increased payroll costs. Professional fees increased due to additional legal, accounting and engineering activities associated with our entering the exploration and production business and expanding our gas gathering and processing business. All other general and administrative expense increased $164 thousand, net, during 2005 as compared to 2004.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

At December 31, 2005, cash and cash equivalents totaled $6.434 million and we had working capital of $7.014 million. Since our inception, we have financed our operating cash flow needs principally through public and private offerings of our equity securities. During the first quarter of 2006, we raised $21.965 million, before expenses, by issuing convertible subordinated notes. See Note 17 Subsequent Events to our consolidated financial statements in Item 15 of this report. We intend to use these funds for our capital and acquisition programs.

We believe that our cash and cash equivalents on hand, internally generated cash flows and future financing activities will be sufficient to fund our planned operational, drilling and acquisition expenditures for the foreseeable future. The amount and allocation of future capital and exploration expenditures will depend upon a number of factors including the number and size of available economic acquisitions and drilling opportunities, our cash flows from operating and financing activities and our ability to assimilate acquisitions we make. Also, the impact of oil and gas prices on investment opportunities, the availability of capital and borrowing facilities and the success of our development and exploratory activities could lead to changes in funding requirements for future development.

On April 12, 2005, we completed our initial public offering of 2,300,000 shares of common stock at $5.50 per share and our shares commenced trading on the American Stock Exchange under the trading symbol PRB. On closing the offering on April 15, 2005, we received proceeds of $11.273 million net of underwriter s discounts, commissions and expenses. Including the additional costs of the offering of $1.104 million, including warrants valued at $583 thousand, our net proceeds were $10.169 million.

We used a portion of the proceeds to retire the $1.550 million balance outstanding under our $1.750 million bank line of credit. The bank line of credit was cancelled upon payment in full in April 2005 and the security interest in our gathering assets and the $1.0 million certificate of deposit pledged by a preferred stockholder was released.

Cash Flow Used in Operating Activities. In 2005, our net loss of $4.625 million was mainly comprised of non-cash charges including $2.487 million of asset impairment expense and $1.067 million of depreciation, depletion, amortization and accretion expense. In addition, our net loss includes $450 thousand of exploration expense resulting from writing off 6 unsuccessful exploratory wells.

Cash used in operating activities of $781 thousand for the year ended December 31, 2005 was $853 thousand greater than the cash used in operating activities for the year ended December 31, 2004. This increase was mainly attributable to higher general and administrative expenses and exploration expense and increased inventories offset by a larger year-end accounts payable balance resulting from increased operating activities.

Cash Flow Used in Investing Activities. Cash used in investing activities was $2.298 million for the year ended December 31, 2005 representing a decrease of $8.349 million as compared to the year ended December 31, 2004. During 2004, we acquired the TOP gas gathering system for $2.960 million and the BPE systems for $7.646 million. During 2005, we made $2.115 million of capital expenditures, including leasehold acquisition costs, primarily for our exploration and production drilling activities.

During 2005, these capital expenditures included $1.531 million of exploratory drilling costs. During 2005, we charged $450 thousand of these exploratory drilling costs, relating to 6 wells, to exploration expense. At December 31, 2005, $1.081 million of exploratory drilling costs, relating to 12 wells, remained capitalized as wells-in-progress pending the determination of proved reserves. None of these wells are in areas requiring major capital expenditures before production can begin, nor were any of these wells completed more than one year ago. These wells are currently undergoing de-watering and we believe that after these wells are de-watered we will be able to determine if we have discovered proved reserves. We estimate that in mid 2006 we will be able to make this determination.

Currently, our 2006 capital expenditure program calls for investing approximately $30 million in oil and gas exploration, development and acquisition projects and gas gathering systems projects. We believe that cash on hand, cash from operating activities and cash from future financing actives will be sufficient to meet our operating and capital expenditure plans for the foreseeable future.

Cash Flow from Financing Activities. Cash provided by financing activities of $9.193 million for the year ended December 31, 2005 represents a decrease of $1.702 million as compared to the year ended December 31, 2004. During 2005, we raised $11.007 million, net of costs, from our initial public offering and used $1.550 million of those proceeds to retire our bank debt. During 2004, we raised $10.604 million, net of the costs in respect to our Series A and B preferred private placements, we borrowed $1.5 million and we repurchased 800,000 common shares for $800 thousand. During 2004 and 2005, we paid accrued dividends on our Series A and B preferred shares, with an increase of $91 thousand during 2005 due to issuance timing.

During the first quarter of 2006, we raised $21.965 million, before expenses, through the issuance of convertible subordinated notes. It is our current plan to establish new credit facilities, most likely with financial institutions, to supplement cash on hand and cash generated from operating activities for use in our 2006 capital expenditure program.

We do not have any off-balance sheet financing arrangements as of December 31, 2005.

Contractual Obligations

The following table summarizes our future commitments as of December 31, 2005 (in thousands):

	2006	2007	2008	2009	2010	Thereafter	Total
Operating leases	$ 525	$ 254	$ 236	$ 235	$ 215	$ 514	$ 1,979
Operations contracts	560						560
Total commitments	$ 1,085	$ 254	$ 236	$ 235	$ 215	$ 514	$ 2,539

The above table does not include asset retirement obligations, debt, accounts payable or other accrued liabilities recorded on our consolidated balance sheet as of December 31, 2005. Asset retirement obligations are not included as the Company cannot determine with accuracy the timing of such payments. The table does not include any commitments entered into after December 31, 2005. See Note 17 Subsequent Events to our consolidated financial statements in Item 15 of this report.

The Company has acquired gas gathering properties and contracts that include operating leases in respect to surface-use rights that are cancelable in the event that gas gathering activities cease as a result of declining production. The Company also has purchase commitments for future field operations and maintenance activities with third party providers. In addition, the Company is a party to non-cancelable operating leases for office space, office equipment and other items required for operations, including a compressor for our TOP gas gathering system. The table above includes estimated future purchase commitments relating to these operations support contracts. With regard to the operating leases, future minimum lease payments are calculated based on the contractual rate and period, or if the contract was a surface-use agreement, future minimum lease payments were calculated based on the estimated lives of the associated gas reserves (through 2014) and the applicable contract rate.

Preferred Stock Dividends

All of our Series A 10% preferred stockholders and Series B 5% preferred stockholders converted to common stock on April 12, 2005. On April 15, 2005, we paid $155 thousand in accrued dividends up to the conversion date. Our Series C Convertible Preferred stock does not pay dividends.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon consolidated financial statements which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires management to make estimates and judgments that affect the reported amounts of consolidated assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities as of the date of the financial statements. Actual results may differ from these estimates under different assumptions or conditions. We consider the following policies to be the most critical to understanding the judgments that are involved and the uncertainties that could impact our results of operations, financial condition and cash flows.

Revenue Recognition

We recognize gas gathering revenue in the period that the gas gathering and transportation services are provided. Our gas gathering and transportation contracts specify the rate that can be charged on the basis of cents per thousand cubic feet or Mcf of natural gas. Each contract has a separately negotiated rate and terms may vary. Certain of our contracts include separate charges for compression in addition to a transportation fee. Our gas gathering revenue will increase or decrease in proportion to gas volume delivered over our system. There are measurement points throughout each gathering system which enable the gas to be accurately measured and allocated back to either different operators or wells. One of our gas gathering contracts has a monthly minimum billing clause.

We recognize natural gas revenue when the natural gas is delivered to the purchaser and title of the product has passed.

We recognize management fee revenue during the period when the services are provided.

Long-lived Assets

We calculate depreciation and amortization based on estimated useful lives and salvage values of our assets. When assets are placed into service, we make estimates with respect to their useful lives that we believe are reasonable. However, factors such as competition, regulation or environmental matters could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization. We evaluate long-lived assets for potential impairment by identifying whether indicators of impairment exist and, if so, assessing whether the long-lived assets are recoverable from estimated future undiscounted cash flows. The actual amount of impairment loss, if any, to be recorded is equal to the amount by which a long-lived asset s carrying value exceeds its fair value. Estimates of future discounted cash flows and fair values of assets require subjective assumptions with regard to future operating results and actual results could differ from those estimates. During the year ended December 31, 2005, we recorded a $2.487 million asset impairment charge in respect to our TOP gas gathering system assets. See Note 5 Property, Equipment and Contracts to our consolidated financial statements in Item 15 of this report. We recorded no impairments of long-lived assets during the year ended December 31, 2004.

Asset Retirement Obligations

We follow Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations and Financial Accounting Standards Board (FASB) Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations (FIN No. 47), and related pronouncements. The estimated fair value of the future costs associated with dismantlement, abandonment and restoration of facilities was recorded as of the effective date of the TOP and BPE acquisitions. In addition, the estimated fair value of the future costs to plug and abandon gas wells was recorded when the related wells were placed into service. The net estimated costs are discounted to present values using a risk adjusted rate over the estimated economic life of the related asset. Such costs are capitalized as part of the cost of the related asset and depreciated. The associated liability is classified as a long-term liability and is adjusted when circumstances change and for the accretion of expense which is recorded as a component of depreciation and amortization.

Inventory

We record inventories at cost and adjust the carrying value of inventory based on the lower of cost or market.

Stock-based Compensation

We account for employee stock options using the intrinsic value method in accordance with Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees and related interpretations, and provide pro forma disclosures of net income (loss) as if a fair value method had been applied in measuring compensation expense. Stock compensation expense, which is a non-cash charge, is measured as the excess, if any, of the fair value of our underlying common stock at the date of grant over the amount an employee must pay to acquire such stock. This compensation cost is amortized over the related vesting periods, generally four years, using an accelerated method. See also Recently Issued Accounting Pronouncements below.

We determine the fair value of our common stock by evaluating a number of factors, including our financial condition and business prospects, our stage of development and the valuations of similar companies in our industry.

Contingencies

In the future, we may be subject to adverse proceedings, lawsuits and other claims related to environmental, labor, contractual and other matters. We will be required to assess the likelihood of any adverse judgments or outcomes of these matters as well as potential ranges of probable losses. A determination of the amount of reserves required, if any, for these contingencies is made after careful analysis of each individual issue. The required reserves may change in the future due to developments in each matter or changes in approach such as a change in settlement strategy in dealing with these potential matters.

Oil and Gas Properties

We follow the successful efforts method of accounting for our oil and gas activities. Under this method we capitalize the costs of leasehold acquisitions, all successful exploratory wells and the costs of all development wells. We expense the costs associated with exploratory wells that are unsuccessful. Also under this method we expense geological and geophysical costs and the costs of maintaining leasehold interests. In the event that the fair market values of our properties decline as a result of lower oil and gas prices, the carrying value of those properties is reduced by an impairment charge.

Exploration Expense

The Company accounts for exploration and development activities utilizing the successful efforts method of accounting. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and gas leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found proved reserves in commercial quantities. The application of the successful efforts method of accounting requires managerial judgment to determine that proper classification of wells designated as developmental or exploratory is made to determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive but actually deliver oil and gas in quantities insufficient to be economic. This may result in the abandonment of the wells at a later date. Wells are drilled that have targeted geologic structures that are both developmental and exploratory in nature and an allocation of costs is required to properly account for the results. The evaluation of oil and leasehold acquisition costs requires managerial judgment to estimate the fair value of these costs with reference to drilling activity in a given area.

Recently Adopted Accounting Pronouncements

We implemented and follow FIN No. 47, Accounting for Conditional Asset Retirement Obligations. FIN No. 47 clarifies that the term conditional asset retirement obligation refers to a legal obligation to perform an asset retirement activity in which the timing and or method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. FIN No. 47 was effective for us December 31, 2005. We implemented FIN No. 47 on December 31, 2005, and accordingly, we recorded a $259 thousand asset retirement obligation associated with our BPE gas gathering systems in our consolidated balance sheets and also recorded the cumulative effect of adopting this change in accounting principle of $76 thousand in our consolidated statements of operations.

Recently Issued Accounting Pronouncements

In December 2004, the FASB issued SFAS No. 123R, Share-Based Payment (SFAS No. 123R). SFAS No. 123R requires that compensation costs relating to share-based payment transactions be recognized in financial statements based on the fair value of the equity or liability instruments issued. SFAS No. 123R covers a wide range of share-based compensation arrangements including share options, restricted share plans, performance-based awards, share appreciation rights and employee share purchase plans. Effective April 2005, the Securities and Exchange Commission extended the implementation date to the beginning of a registrant s next fiscal year beginning after June 15, 2005. The provisions of SFAS No. 123R were adopted by the Company effective January 1, 2006. As a result of the adoption of SFAS No. 123R, the Company expects to record compensation expense associated with unvested stock options totaling $432 thousand in future periods under the modified-prospective adoption method.

In May 2005, the FASB, as part of an effort to conform to international accounting standards, issued SFAS No. 154, Accounting Changes and Error Corrections (SFAS No. 154), that is effective for us beginning on January 1, 2006. SFAS No. 154 requires that all voluntary changes in accounting principles be retrospectively applied to prior financial statements as if that principle had always been used, unless it is impracticable to do so. When it is impracticable to calculate the effects on all prior periods, SFAS No. 154 requires that the new principle be applied to the earliest period practicable. The adoption of SFAS No. 154 is not anticipated to have a material effect on our financial position or results of operations.

SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, specifies that drilling costs for completed exploratory wells should be expensed if the related reserves cannot be classified as proved within one year unless certain criteria are met. In April 2005, the FASB issued FASB Staff Position 19-1, Accounting for Suspended Well Costs (FSP 19-1). FSP 19-1 provides guidance for evaluating whether sufficient progress is being made to determine whether reserves can be classified as proved. FSP 19-1 is effective for all reporting periods beginning after April 4, 2005, and the Company adopted FSP 19-1 upon incurrence of its initial exploratory drilling costs during the fourth quarter of 2005.

We have disclosed our accounting policy for capitalization of exploratory drilling costs in the Exploration Expense section of Critical Accounting Policies and Estimates discussed above. We have disclosed capitalized exploratory drilling cost amounts in our discussion of Cash Flow Used in Investing Activities in the Liquidity and Capital Resources section above.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to certain market risks inherent within the intrastate natural gas gathering industry. We intend to manage our operations in a manner designed to minimize our exposure to such market risks.

Credit Risk

Credit risk is the risk of loss resulting from non-performance of contractual obligations by a customer or joint venture partner. A substantial portion of our accounts receivable are with customers in the energy industry and are subject to normal industry credit risk. We assess the financial strength of our customers through regular credit reviews in order to minimize the risk of non-payment.

Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. Because we sell natural gas at spot prices our financial results will be affected by changes in the price of natural gas.

Interest Rate Risk

Interest rate risk will exist with respect to new debt offerings that bear interest at floating rates. At December 31, 2005 we had no bank indebtedness. See Note 17 Subsequent Events to our consolidated financial statements in Item 15 of this report with respect to our debt offering that we closed during the first quarter of 2006.

ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The financial statements required pursuant to this item are included in Item 15 of this Annual Report on Form 10-K and begin on page F-1.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

We maintain disclosure controls and procedures designed to provide reasonable assurance that information required to be disclosed in our reports under the Securities and Exchange Act of 1934, as amended, 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 our Chief Executive Officer and Principal Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. Our management, with the participation and oversight of our Chief Executive Officer and Principal Financial Officer, evaluated the design and effectiveness of our disclosure controls and procedures as of December 31, 2005. In conducting this evaluation, several significant deficiencies were identified in our internal control over financial reporting relating to the preparation and review of financial statements and disclosures, identification and resolution of complex accounting issues, segregation of duties, accounting policies and procedures, information technology systems, and revenue recognition and billing. Management has determined that these significant deficiencies, in the aggregate, constitute a material weakness in internal control over financial reporting. Specifically, our staffing levels were inadequate to facilitate the design, implementation and maintenance of an effective system of internal control.

On the basis of these findings, our Chief Executive Officer and our Principal Financial Officer have concluded that our disclosure controls and procedures were not effective, as of December 31, 2005. In connection with the 2005 audit of our financial statements, our independent registered public accounting firm issued a draft communication letter which noted that we had the significant deficiencies and material weakness, described above, in our internal control over financial reporting.

Remediation of the Material Weaknesses

In response to the control deficiencies listed above, we have taken (or plan to take during 2006) the following steps to remediate the significant deficiencies identified above:

- We plan to increase the accounting staff to provide additional expertise in the areas of SEC reporting and complex accounting issues. Additionally, we have engaged outside help to assist us with complex accounting and financial reporting matters. Continued training of current staff and the need for additional resources will be evaluated from time to time.

- We plan to implement disclosure controls and procedures and form a Disclosure Committee which will provide additional oversight and control over the completeness and accuracy of the Company s financial statements and disclosures included in periodic filings with the SEC.

- We plan to document our accounting policies and procedures and enhance our month end close and financial reporting processes to include additional controls to improve the completeness and accuracy of our periodic financial statements.

- We plan to replace our current general ledger software with a more robust accounting and reporting software package that will enable us to increase our controls over system generated reports.

However, until we have completed a formal review of our internal controls, and even upon completion of such review, there is no assurance that we will have adequately addressed the identified deficiencies, as has been characteristic of companies that have completed their review of internal control and have had to report on the results of such review. Accordingly, our internal control over financial reporting may be subject to additional material weaknesses and significant deficiencies that we have not identified.

On September 21, 2005, the SEC extended the compliance dates related to Section 404 of the Sarbanes-Oxley Act (Section 404) for non-accelerated filers. Under this extension a company that is not required to file its annual and quarterly reports on an accelerated basis (non-accelerated filer) must begin to comply with the Section 404 internal control over financial reporting evaluation and reporting requirements for its first fiscal year ending on or after July 15, 2007. We anticipate that we may become an accelerated filer in calendar 2006 and therefore we could be required to comply with these requirements for the year ending December 31, 2006. We are currently in the process of documenting our internal control structure.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2005 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The required information for this item is incorporated by reference to our Proxy Statement for the 2006 Annual Meeting of Stockholders, since such Proxy Statement will be filed with the Securities and Exchange Commission not later than 120 days after the end of our fiscal year pursuant to Regulation 14A.

Our Board of Directors has adopted a Code of Business Conduct & Ethics, included as Exhibit 14.1 to this annual report on Form 10-K, that applies to our Directors, executives, officers and employees. Our Code of Business Conduct & Ethics can be found on our website, which is located at www.prbtrans.com. We intend to make all required disclosures concerning any amendments to, or waivers from, our Code of Business Conduct & Ethics on our website. Any person may request a copy of the Code of Ethics, at no cost, by writing to us at the following address: PRB Gas Transportation, Inc., 1875 Lawrence Street, Suite 450, Denver, Colorado 80202, attention: Corporate Secretary.

ITEM 11. EXECUTIVE COMPENSATION

The required information for this item is incorporated by reference to our Proxy Statement for the 2006 Annual Meeting of Stockholders, since such Proxy Statement will be filed with the Securities and Exchange Commission not later than 120 days after the end of our fiscal year pursuant to Regulation 14A.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The required information for this item is incorporated by reference to our Proxy Statement for the 2006 Annual Meeting of Stockholders, since such Proxy Statement will be filed with the Securities and Exchange Commission not later than 120 days after the end of our fiscal year pursuant to Regulation 14A.

Equity Compensation Plan

The following table is a summary of the shares of Common Stock authorized for issuance under the Company s Equity Compensation Plan as of December 31, 2005.

Plan category	Number of securities to be issued upon exercise of outstanding options and other rights	Weighted-average exercise price of outstanding options and other rights	Number of securities remaining available for future issuance under equity compensation plans(1)
Equity compensation plan approved by stockholders	463,250	$ 6.74	279,939
Equity compensation plans not approved by stockholders			
Total	463,250	$ 6.74	279,939

(1) Our Board of Directors and stockholders approved our Equity Compensation Plan in May 2004. We have authorized a total of 10% of the number of shares outstanding for issuance under this plan. As of December 31, 2005, a total of 743,189 shares of Common Stock are authorized for issuance.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The required information for this item is incorporated by reference to our Proxy Statement for the 2006 Annual Meeting of Stockholders, since such Proxy Statement will be filed with the Securities and Exchange Commission not later than 120 days after the end of our fiscal year pursuant to Regulation 14A.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The required information for this item is incorporated by reference to our Proxy Statement for the 2006 Annual Meeting of Stockholders, since such Proxy Statement will be filed with the Securities and Exchange Commission not later than 120 days after the end of our fiscal year pursuant to Regulation 14A.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

15(a)(1) Consolidated Financial Statements.

The following consolidated financial statements of PRB Gas Transportation, Inc. are filed as part of this report:

15(a)(2) Financial Statement Schedules.

Schedules are omitted because they are not required or because the information is provided elsewhere in the financial statements.

15(a)(3) Exhibits.

Exhibit Number	**Description**
(1.1)	Form of Underwriting Agreement (filed as an exhibit to Form S-1/A filed on April 12, 2005 and incorporated by reference herein).
(3.1)	Amended Articles of Incorporation of the Registrant (filed as an exhibit to Form S-1/A filed on January 28, 2005 and incorporated by reference herein).
(3.2)	Amended By-laws of the Registrant (filed as an exhibit to Form S-1/A filed on January 28, 2005 and incorporated by reference herein).
(3.3)	Series A Preferred Stock Certificate of Designation (filed as an exhibit to Form S-1 filed on November 1, 2004 and incorporated by reference herein).
(3.4)	Series B Preferred Stock Certificate of Designation Filed (filed as an exhibit to Form S-1 filed on November 1, 2004 and incorporated by reference herein).
(3.5)	Series C Preferred Stock Certificate of Designation Filed (filed as an exhibit to Form S-1/A filed on January 28, 2005 and incorporated by reference herein).
(4.1)	Form of Lockup Agreement Officers, Directors and 5% Stockholders (filed as an exhibit to Form S-1/A filed on November 1, 2004 and incorporated by reference herein).
(4.2)	Form of Lockup Agreement Series A and B Preferred Stockholders (filed as an exhibit to Form S-1 filed on November 1, 2004 and incorporated by reference herein).
(4.3)	Form of Underwriter s Warrant Agreement (filed as an exhibit to Form S-1/A filed on January 28, 2005 and incorporated by reference herein).

(4.4)	Form of Lockup Agreement Series C Preferred Stockholders (filed as an exhibit to Form S-1/A filed on January 28, 2005 and incorporated by reference herein).
(4.5)	Sample Common Stock Certificate (filed as an exhibit to Form 8-A filed on April 8, 2005).
4.6	Form of Senior Subordinated Convertible Note
4.7	Form of Regitration Rights Agreement between the Company and the holders of the Company s Senior Subordinated Convertible Notes
(5.1)	Opinion of Resch Polster Alpert & Berger LLP (filed as an exhibit to Form S-8 on September 14, 2005 and incorporated by reference herein).
(10.1)*	Equity Compensation Plan Filed (filed as an exhibit to Form S-1 filed on November 1, 2004 and incorporated by reference herein).
(10.2)	Form of Amended and Restated Warrant Certificate (filed as an exhibit to Form S-1/A filed on March 1, 2005 and incorporated by reference herein).
(10.3)	TOP Gathering, LLC Asset Purchase Agreement (filed as an exhibit to Form S-1/A filed on January 28, 2005 and incorporated by reference herein).
(10.4)	Bear Paw Energy, LLC Purchase and Sale Agreement (filed as an exhibit to Form S-1 filed on November 1, 2004 and incorporated by reference herein).
(10.5)	Bear Paw Energy, LLC Mortgage, Security Agreement, Assignment of Proceeds, and Financing Statement (filed as an exhibit to Form S-1/A filed on January 28, 2005 and incorporated by reference herein).
(10.6)	Bear Paw Energy, LLC Promissory Note (filed as an exhibit to Form S-1/A filed on January 28, 2005 and incorporated by reference herein).
(10.7)	Bear Paw Energy, LLC Operations Agreement (filed as an exhibit to Form S-1 filed on November 1, 2004 and incorporated by reference herein).
(10.8)	Bank of Oklahoma Promissory Note (filed as an exhibit to Form S-1/A filed on March 1, 2005 and incorporated by reference herein).
(10.9)	Bank of Oklahoma Mortgage and Security Agreement (filed as an exhibit to Form S-1/A filed on March 1, 2005 and incorporated by reference herein).
(10.10)	Gathering Services Agreement United Energy Trading, LLC (filed as an exhibit to Form S-1/A filed on March 1, 2005 and incorporated by reference herein).
(10.11)	Gathering Services Agreement Pennaco Energy Inc. (filed as an exhibit to Form S-1/A filed on March 1, 2005 and incorporated by reference herein).
(10.12)	Gathering Services Agreement Natural Gas Fuel Company, Inc. (filed as an exhibit to Form S-1/A filed on March 1, 2005 and incorporated by reference herein).
(10.13)	Farmout and Development Agreement dated August 1, 2005 between Rocky Mountain Gas, Inc. and PRB Energy, Inc. (filed as an exhibit to Form 8-K filed on September 9, 2005).
(10.14)	Management Services Agreement dated August 1, 2005 between Rocky Mountain Gas Inc., Enterra Energy Trust and PRB Energy, Inc. (filed as an exhibit to Form 8-K filed on September 9, 2005).
10.15	Form of Subscription Agreement between the Company and the subscribers to the Company s Senior Subordinated Convertible Notes

14.1	Code of Business Conduct and Ethics
(23.1)	Consent of Resch Polster Alpert & Berger LLP see exhibit 5.1
23.2	Consent of Ehrhardt Keefe Steiner & Hottman PC
(23.3)	Consent of Brownstein. Hyatt and Farber P.C. (filed as an exhibit to Form S-1/A filed on March 1, 2005 and incorporated by reference herein).
24.1	Powers of Attorney, incorporated by reference to Signature page attached hereto.
31.1	Chief Executive Officer Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Principal Financial Officer Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

These exhibits are available upon request. Exhibits identified in parentheses below are on file with the SEC and are incorporated herein by reference. All other exhibits are provided as part of this electronic submission.

() Previously filed.

* Management contract or compensatory plan or arrangements.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, PRB Gas Transportation, Inc. has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	PRB Gas Transportation, Inc.
	(Registrant)
Date: April 13, 2006	/s/ WILLIAM P. BRAND, JR.
	William P. Brand, Jr.
	Vice President Finance

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints William P. Brand, Jr. as his attorney-in-fact, with full power of substitution, for him in any and all capacities to sign any amendments to this Report on Form 10-K, and to file the same, with exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, hereby ratifying and confirming all that said attorneys-in-fact, or their substitutes, may do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Act of 1934, this report has been signed by the following persons in the capacities and on April 13, 2006.

Signature	Title
/s/ ROBERT W. WRIGHT Robert W. Wright	Chairman and Chief Executive Officer
/s/ WILLIAM F. HAYWORTH William F. Hayworth	President, Chief Operating Officer and Director
/s/ WILLIAM P. BRAND, JR. William P. Brand, Jr.	Vice President Finance
/s/ THOMAS J. JACOBSEN Thomas J. Jacobsen	Director
/s/ REUBEN SANDLER Reuben Sandler	Director
/s/ JAMES P. SCHADT James P. Schadt	Director
/s/ JOSEPH W. SKEEHAN Joseph W. Skeehan	Director
/s/ JUSTIN W. YORKE Justin W. Yorke	Director

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
PRB Gas Transportation, Inc. and subsidiary
Denver, Colorado

We have audited the accompanying consolidated balance sheets of PRB Gas Transportation, Inc. and its subsidiary as of December 31, 2004 and 2005 and the related consolidated statements of operations, changes in stockholders equity and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of PRB Gas Transportation, Inc. and its subsidiary as of December 31, 2004 and 2005, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 3 to the consolidated financial statements, the Company determined that revenues had been billed incorrectly under a certain contract during 2005. Accordingly, the 2004 consolidated financial statements have been restated to correct the error.

As discussed in Note 5 to the consolidated financial statements, the Company adopted Financial Accounting Standards Board Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations, effective December 31, 2005.

/s/Ehrhardt Keefe Steiner & Hottman PC

March 30, 2006
Denver, Colorado

PRB Gas Transportation, Inc.
Consolidated Balance Sheets
(In thousands except share amounts)

	December 31, 2005	December 31, 2004 (As restated, see Note 3)
Assets		
Current assets		
Cash and cash equivalents	$ 6,434	$ 320
Accounts receivable	789	424
Inventory, net	1,346	
Prepaid expenses	194	103
Total current assets	8,763	847
Property and equipment, net	6,024	8,136
Oil and gas properties accounted for under the successful efforts method of accounting		
Proved properties, net	314	
Unproved leaseholds	136	
Wells-in-progress	1,081	
Total oil and gas properties	1,531	
Other non-current assets		
Deferred costs of raising capital		267
Deposits	23	4
Contracts, net	1,099	2,145
Total other non-current assets	1,122	2,416
Total assets	$ 17,440	$ 11,399
Liabilities and Stockholders Equity		
Current liabilities		
Accounts payable	$ 1,652	$ 138
Other accrued expenses and current liabilities	97	44
Accrued TOP acquisition costs		200
Dividends payable		134
Note payable		1,500
Total current liabilities	1,749	2,016
Retail installment sale contract	27	
Deferred rent	20	
Asset retirement obligations	387	65
Total liabilities	2,183	2,081
Commitments and Contingencies		
Stockholders equity		
Capital, 50,000,000 shares authorized, par value $0.001, 5,639,000 shares undesignated		
Series A, B and C Convertible Preferred, 4,361,000 shares authorized; 40,000 and 4,361,000 issued and outstanding, respectively	*	4
Common stock, 40,000,000 shares authorized; 8,231,894 issued; 7,431,894 and 800,000 outstanding, respectively	8	2
Treasury stock	(800)	(800)
Additional paid-in-capital	21,325	10,763
Accumulated deficit	(5,276)	(651)
Total stockholders equity	15,257	9,318
Total liabilities and stockholders equity	$ 17,440	$ 11,399

* amounts less than one thousand

The accompanying notes are an integral part of these consolidated financial statements.

PRB Gas Transportation, Inc.
Consolidated Statements of Operations
(In thousands except share amounts)

	Years Ended December 31, 2005	**2004 (As restated, see Note 3)**
Gas gathering revenue:		
Related party	$	$ 692
Third party	2,834	1,840
Total gas gathering revenue	2,834	2,532
Management fee revenue	270	
Natural gas revenue	51	
Total revenue	3,155	2,532
Operating expenses:		
Gas gathering expense	1,755	1,314
Gas production costs	34	
Asset impairment charge	2,487	
Exploration expense	450	
Depreciation, depletion, amortization and accretion	1,067	656
General and administrative	2,029	1,184
Total operating expenses	7,822	3,154
Operating loss	(4,667)	(622)
Other income (expense):		
Interest and other income	167	29
Interest expense	(49)	(58)
Total other income (expense)	118	(29)
Net loss before cumulative effect of change in accounting principle	(4,549)	(651)
Cumulative effect of change in accounting principle	(76)	
Net loss	(4,625)	(651)
Convertible Preferred stock dividends and deemed dividends	(204)	(1,212)
Net loss applicable to common stockholders	$ (4,829)	$ (1,863)
Net loss per share of common stock before cumulative effect of change in accounting principle	$ (0.68)	$ (1.33)
Cumulative effect of change in accounting principle per share of common stock	(0.01)	0.00
Net loss per share basic and diluted	$ (0.69)	$ (1.33)
Basic and diluted weighted average shares outstanding	6,959,025	1,398,907

The accompanying notes are an integral part of these consolidated financial statements.

PRB Gas Transportation, Inc.
Consolidated Statement of Changes in Stockholders Equity
(In thousands except share amounts)

	Shares	Amount (As restated, see Note 3)
Series A 10% Convertible Preferred stock, 2,400,000 shares authorized, 0 and 2,400,000 issued and outstanding, respectively, at December 31, 2005 and 2004		
Balance, January 1, 2004		$
Shares issued for cash	2,400,000	2
Balance, December 31, 2004	2,400,000	2
Conversion to common stock	(2,400,000)	(2)
Balance, December 31, 2005		
Series B 5% Convertible Preferred stock, 1,550,000 shares authorized, 0 and 1,550,000 issued and outstanding, respectively, at December 31, 2005 and 2004		
Balance, January 1, 2004		
Shares issued for cash	1,550,000	2
Balance, December 31, 2004	1,550,000	2
Conversion to common stock	(1,550,000)	(2)
Balance, December 31, 2005		
Series C Convertible Preferred stock, 411,000 authorized, 40,000 and 411,000 issued and outstanding, respectively, at December 31, 2005 and 2004		
Balance, January 1, 2004		
Shares issued for cash	411,000	*
Balance, December 31, 2004	411,000	*
Conversion to common stock	(371,000)	*
Balance, December 31, 2005	40,000	*
Common stock, 40,000,000 shares authorized, 8,231,894 issued 7,431,894 and 800,000 outstanding, respectively, at December 31, 2005 and 2004		
Balance, January 1, 2004		
Shares issued for cash	1,600,000	2
Purchase of common shares for cash	(800,000)	*
Balance, December 31, 2004	800,000	2
Issuance of shares for initial public offering	2,300,000	2
Conversion of Series A Convertible Preferred stock	2,400,000	2
Conversion of Series B Convertible Preferred stock	1,550,000	2
Conversion of Series C Convertible Preferred stock	371,000	*
Exercise of warrants and options	10,894	*
Balance, December 31, 2005	7,431,894	8
Treasury stock		
Balance, January 1, 2004		
Purchase of Treasury stock	800,000	(800)
Balance, December 31, 2005 and 2004	800,000	(800)
Additional paid-in-capital		
Balance, January 1, 2004		
Common stock issued		18
Series A Preferred stock issued, net of offering costs		4,985
Series B Preferred stock issued, net of offering costs		4,639
Series C Preferred stock issued, net of offering costs		1,231
Deemed capital contribution related to Series A dividend		63
Deemed capital contribution related to Series C issuance		1,027
Issuance of warrants for consulting services		12
Series A dividends		(375)
Series B dividends		(116)
Series C deemed dividend		(587)
Accrued dividends on preferred stock		(134)
Balance, December 31, 2004		10,763
Series A Preferred stock dividends		(139)
Series B Preferred stock dividends		(65)
Proceeds from initial public offering, net of offering costs		10,738
Proceeds from exercise of warrants and options		28
Balance, December 31, 2005		21,325
Accumulated deficit		
Balance, January 1, 2004		
Net loss (As restated, see Note 3)		(651)
Balance, December 31, 2004		(651)

Net loss	(4,625)
Balance, December 31, 2005	(5,276)
Total stockholders equity	$ 15,257

* amount less than one thousand

The accompanying notes are an integral part of these consolidated financial statements.

PRB Gas Transportation, Inc.
Consolidated Statements of Cash Flows
(In thousands except share amounts)

	Years Ended December 31, 2005	2004 (As restated, see Note 3)
Cash flows from operating activities		
Net loss	$ (4,625)	$ (651)
Adjustments to reconcile net loss to net cash (used in) provided by operating activities:		
Asset impairment charge	2,487	
Exploration expense	450	
Depreciation, depletion, amortization and accretion	1,067	656
Inventory write down	27	
Cumulative effect of change in accounting principle	76	
Deemed compensation		441
Gain on sale of assets	(2)	
Changes in assets and liabilities:		
Accounts receivable	(366)	(423)
Inventory	(1,373)	
Prepaid expenses	(90)	(104)
Deposits	(19)	(4)
Accounts payable	1,514	157
Accrued expenses and other	73	
Net cash (used in) provided by operating activities	(781)	72
Cash flows from investing activities		
Capital expenditures	(1,979)	(41)
Purchase of TOP system		(2,960)
BPE asset purchase		(7,646)
Reduction in accrued TOP acquisition costs	(200)	
Leasehold acquisition payments	(136)	
Sale of fixed assets	17	
Net cash used in investing activities	(2,298)	(10,647)
Cash flows from financing activities		
Proceeds from IPO, net of issuance costs	11,007	
Deferred costs of raising capital		(255)
Proceeds from issuance of Series A Convertible Preferred stock, net of issuance costs		4,987
Proceeds from issuance of Series B Convertible Preferred stock, net of issuance costs		4,641
Proceeds from issuance of Series C Convertible Preferred stock, net of issuance costs		1,231
Repurchase of treasury stock		(800)
Proceeds from issuance of common stock	28	20
Borrowings under bank loan and financing agreement	50	
(Repayment of) proceeds from bank loan	(1,550)	1,500
Dividends	(338)	(429)
Repayment of retail installment sale contract	(4)	
Net cash provided by financing activities	9,193	10,895
Net increase in cash	6,114	320
Cash beginning of year	320	
Cash end of year	$ 6,434	$ 320
Supplemental disclosure of cash flow activity		
Cash paid for interest	49	58
Supplemental schedule for non-cash activity		
Issuance of warrants in connection with public offering	571	
Conversion of Series A, B and C Convertible Preferred stock	4	
Asset retirement obligations	318	60
Retail installment sale contract used to purchase vehicle	31	

The accompanying notes are an integral part of these consolidated financial statements.

PRB GAS TRANSPORTATION, INC.
Notes to Consolidated Financial Statements
December 31, 2005

Note 1 Description of Business and Rocky Mountain Gas Agreements

Description of Business

PRB Gas Transportation, Inc. (the Company) is an energy company with both oil and gas exploration and development and mid-stream operations in the Rocky Mountain states.

The Company was incorporated in December 2003. The Company was capitalized and commenced operations in January 2004 when it acquired certain gas gathering and related assets of TOP Gathering, LLC (TOP). In August 2004, the Company acquired certain gas gathering and related assets of Bear Paw Energy, LLC (BPE). Both the TOP and BPE gas gathering systems are located in the Powder River basin of Wyoming. The Company utilizes these assets to provide gas gathering, processing and compression services (the Company s gathering and processing segment) to third parties.

During the third quarter of 2005, the Company expanded the scope of its operations into a new segment (the Company s exploration and production segment) that includes exploring for, developing, producing and marketing coal-bed methane natural gas. In July 2005, the Company formed PRB Energy, Inc. a 100% wholly-owned subsidiary established to conduct the Company s exploration and production activities.

During September 2005, the Company entered into a Farm-In and Development Agreement, a Management Services Agreement and an Operating Agreement with Enterra Energy Trust and its wholly-owned subsidiary Rocky Mountain Gas (Rocky Mountain Gas). The Farm-In and Development Agreement provided the Company an opportunity to earn interests in Rocky Mountain Gas undeveloped leaseholds located in an area of mutual interest by making acquisition and development expenditures during the term of the agreement. In addition, the Company earned a 50% interest in the wells that it drilled and/or completed in the area of mutual interest. Through December 31, 2005, the Company made $2.070 million in acquisition and development expenditures and drilled and/or completed 28 wells in the area of mutual interest. As a result, the Company earned an approximate 4.7% interest in Rocky Mountain Gas undeveloped leaseholds in the area of mutual interest and a 50% interest in the 28 wells as of December 31, 2005. Once completed wells are productive, future operations are controlled by the Operating Agreement and this agreement also controls future operations in the case of termination of the Farm-In and Development Agreement.

The Management Services Agreement provided for the Company to earn management fees by operating certain Rocky Mountain Gas properties and by providing technical and administrative support on a cost-plus basis. During the year ended December 31, 2005, the Company earned $270 thousand in management fees under the Management Services Agreement.

Currently, the Company is expanding its operations to include projects located outside of the Powder River Basin and to include crude oil projects and projects involving conventional natural gas and natural gas liquids. These projects are in various stages of evaluation and or negotiation.

On March 20, 2006, the Company elected to terminate the Farm-In and Development Agreement and Management Services Agreement (referred to above) and agreed to continue to operate the Rocky Mountain Gas properties and provide management services for at least 60 days from the termination date. The Company agreed to continue to drill certain wells that had previously been approved by the State of Wyoming and Rocky Mountain Gas under the terms of the Operating Agreement.

On March 21, 2006, the Company notified its customers served by the TOP system that it was raising its rates to cover cash costs plus 15% for a 2-month period. The Company also advised these customers that it was planning to shut down the TOP system after the two month period has elapsed. These customers have the right to purchase the TOP system from the Company on terms to be negotiated, as per the related gas gathering agreements.

Restatement of Results

During June 2005, the Company determined that it had incorrectly invoiced a customer for the period August 2004 through April 2005. The Company invoiced the customer in June 2005 for the difference between the original invoices and the corrected invoices of approximately $304 thousand. The customer paid the Company the difference due in December 2005. For further information on this restatement, see Note 3 Restatement of Results.

Note 2 Summary of Significant Accounting Policies

Basis of Presentation

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiary PRB Energy, Inc. All material intercompany transactions have been eliminated.

Certain prior period amounts have been reclassified to conform to the current financial statement presentation.

Revenue Recognition

The Company recognizes gas gathering revenue at the time when the service is rendered. The Company recognizes revenue from the sale of natural gas during the period the sale of the product occurs and title transfers to the buyer. The Company recognizes management services revenue when the service is provided.

Property, Equipment and Contracts Gas Gathering and Other

Property and equipment is stated at estimated fair value for the TOP and BPE assets. The Company periodically reviews carrying values of long-lived assets for impairment. For information on the TOP impairment see Note 5 Property, Equipment and Contracts. Other property and equipment, such as office furniture, computer and related software and equipment, automobiles and leasehold improvements are recorded at cost. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets or underlying leases in respect to leasehold improvements, ranging from 3 to 10 years.

Amortization of contracts is calculated using the straight-line method over the term of the underlying contracts or the estimated life of production which ranges from four to ten years.

Oil and Gas Producing Properties

The Company has elected to follow the successful efforts method of accounting for its oil and gas properties. Under this method of accounting, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred. If an exploratory well does not find proved reserves, the costs of drilling the unsuccessful exploratory well are charged to expense. Exploratory dry hole costs are included in cash flows from investing activities as part of capital expenditures in the consolidated statements of cash flows. The cost of development wells, whether productive or not, is capitalized. Geological and geophysical costs and the cost of carrying and retaining unproved properties are expensed as incurred. Depreciation, depletion and amortization (DD&A) of capitalized costs of proved oil and gas properties is determined on a field-by-field basis using the units-of-production method based upon proved reserves. The computation of DD&A takes into consideration restoration, dismantlement and abandonment costs and the anticipated proceeds from equipment salvage. The Company has adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations (SFAS No. 143) which provides guidance on accounting for dismantlement and abandonment costs and FASB Interpretation 47, Accounting for Conditional Asset Retirement Obligations (FIN No. 47) which provides guidance in determining estimated dismantlement and abandonment costs in situations where the method and timing of settlement are uncertain. See Note 7 Asset Retirement Obligations.

Exploration Expense

The Company accounts for exploration and development activities utilizing the successful efforts method of accounting. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and gas leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found proved reserves in commercial quantities. The application of the successful efforts method of accounting requires managerial judgment to determine that proper classification of wells designated as developmental or exploratory is made to determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive but actually deliver oil and gas in quantities insufficient to be economic. This may result in the abandonment of the wells at a later date. Wells are drilled that have targeted geologic structures that are both developmental and exploratory in nature and an allocation of costs is required to properly account for the results. The evaluation of oil and leasehold acquisition costs requires managerial judgment to estimate the fair value of these costs with reference to drilling activity in a given area.

Impairment of Long-Lived Assets

The Company reviews its long-lived assets and other intangible assets with long lives for impairment whenever events or changes in circumstances indicate that the carrying amount of the asset may not be recovered. An impairment loss is recognized only if the carrying value of the asset is not recoverable and exceeds its fair market value. The Company estimates the fair market value of its long-lived assets using expected future discounted cash flows. See Note 5 Property, Equipment and Contracts in respect to the impairment of the TOP gas gathering system.

Stock-Based Compensation

At December 31, 2005, the Company has a stock-based employee compensation plan that includes stock options issued to employees and non-employee Directors as more fully described in Note 12 Compensation Plans. The Company has historically accounted for stock-based compensation using the intrinsic value recognition and measurement principles detailed in Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees and related interpretations. No stock-based compensation expense relating to stock options has been reflected in the Company s statements of operations for any period presented as all options granted under the plans had an exercise price equal to the market value of the underlying common stock on the date of grant. The Company currently uses the Black-Scholes option valuation model to calculate required disclosures under SFAS No. 123, Accounting for Stock Based Compensation (SFAS No. 123). As of January 1, 2006, the Company has adopted the provisions of SFAS No. 123R, Share-Based Payment (SFAS No. 123R). This statement requires the Company to record compensation expense associated with the fair value of stock-based compensation. As a result of the adoption of SFAS No. 123R, the Company expects to record compensation expense associated with unvested stock options totaling $432 thousand in future periods under the modified-prospective adoption method.

The following table illustrates the pro forma effect on net loss and loss per share if the Company has applied the fair value recognition provisions of SFAS No. 123 to stock-based employee compensation:

	For the Year Ended December 31, 2005	2004 (As restated, see Note 3)
	in thousands, except per share amounts	
Net loss applicable to common stockholders:		
As reported	$ (4,829)	$ (1,863)
Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	534	38
Pro forma net loss	$ (5,363)	$ (1,901)
Net loss per share, basic and diluted:		
As reported:		
Net loss per share of common stock before cumulative effect of change in accounting principle	$ (0.68)	$ (1.33)
Cumulative effect of change in accounting principle per share of common stock	(0.01)	(0.00)
Total, as reported	$ (0.69)	$ (1.33)
Pro forma:		
Net loss per share of common stock before cumulative effect of change in accounting principle	$ (0.76)	$ (1.36)
Cumulative effect of change in accounting principle per share of common stock	(0.01)	(0.00)
Total, pro forma	$ (0.77)	$ (1.36)

In respect to the pro forma disclosures herein the options are amortized to expense over the options vesting periods. Future actual amounts may differ from the pro forma disclosures.

Net Loss Per Share

The Company accounts for earnings (loss) per share (EPS) in accordance with SFAS No. 128, Earnings per Share (SFAS No. 128). Under SFAS No. 128, basic EPS is computed by dividing the net loss attributable to common stockholders by the weighted average common shares outstanding without including any potentially dilutive securities. Diluted EPS is computed by dividing the net loss for the period by the weighted average common shares outstanding plus, when their effect is dilutive, common stock equivalents.

Potentially dilutive securities, which have been excluded from the determination of diluted earnings per share because their effect would be anti-dilutive, are as follows:

	For the years ended December31, 2005	2004
Series A Convertible Preferred		2,400,000
Series B Convertible Preferred		1,550,000
Series C Convertible Preferred	40,000	411,000
Warrants (See Note 11)	230,000	45,000
Options	463,250	220,000
Total potentially dilutive shares excluded	733,250	4,626,000

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Subsequent to December 31, 2005 the Company issued the following dilutive securities, which would have increased the number of potentially dilutive shares excluded (above), if these securities were issued prior to December 31, 2005:

	Potential Common Shares
Convertible subordinated debt (See Note 17)	3,137,857
Warrants (See Note 17)	40,000
Options	217,500
Total	3,395,357

Use of Estimates

The preparation of 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, disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Income Taxes

In accordance with SFAS No. 109, Accounting for Income Taxes (SFAS No. 109), the Company recognizes deferred tax liabilities and assets based on the differences between the tax basis of assets and liabilities and their reported amounts in the consolidated financial statements that will result in taxable or deductible amounts in future years. In evaluating the realizability of net deferred tax assets, the Company will take into account a number of factors, primarily relating to the Company s ability to generate taxable income. The Company has not recorded a deferred tax asset attributable to the net operating loss for the years ended December 31, 2005 and December 31, 2004 as it is not more likely than not that a deferred asset will be realized.

Cash and Cash Equivalents

The Company considers all highly liquid instruments purchased with an original maturity of three months or less to be cash equivalents. The Company continually monitors its positions with, and the credit quality of, the financial institutions with which it invests. As of the balance sheet date, and periodically throughout the year, the Company has maintained balances in various operating accounts in excess of federally insured limits.

Concentrations of Credit Risk

The Company grants credit in the normal course of business to customers in the United States. The Company periodically performs credit analysis and monitors the financial condition of its customers to reduce credit risk. Management periodically reviews accounts receivable aging reports to assess credit risks, and if appropriate, also reviews updated credit information to assess credit risk. In the event that management assesses the customers accounts receivable collectibility as less than probable, management reduces the carrying amount by a valuation allowance that reflects management s best estimate of the amount that may not be collectible. Allowances for uncollectible accounts receivable are based on information available and historical experience. As of December 31, 2005 and December 31, 2004, the Company had not recorded an allowance for doubtful accounts receivable.

Sales to customers which represented 10% or more of the Company s sales for the year ended December 31, 2004 were as follows (as a percentage of total sales):

Customer	Percent of total sales
A	34.0 %
B	32.6 %
C	17.5 %

Customer A above represents two contracts. From January 1, 2004 through September 30, 2004, these contracts were with a related party whose president was a stockholder of the Company until September 30, 2004. Revenue under these two contracts while they were with a related party was $692 thousand which was 27.3% of total sales for the year ended December 31, 2004. See Note 15 Related Party Transactions.

One individual customer accounted for 53.91% of total sales and no other individual customer accounted for 10% or more of total sales for the year ended December 31, 2005.

Inventory

Inventory is recorded at the lower of cost or market. The Company periodically reviews the carrying cost of its inventories as compared to current market value for those inventories and adjusts its carrying value to the lower of cost or market.

Asset Retirement Obligations

The Company follows SFAS No. 143 and FIN No. 47. Estimated future asset abandonment costs are discounted to present values using a risk-adjusted rate over the estimated economic life of the assets. Such costs are capitalized as part of the cost of the related asset and amortized over the related asset s estimated useful life. The associated liability is classified as a long-term liability and is adjusted when circumstances change and for the accretion of expense which is recorded as a component of depreciation, depletion and amortization.

Off-Balance Sheet Arrangements

As part of its ongoing business, the Company has not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities (SPEs), or SPEs which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. As of December 31, 2005, the Company has not been involved in any unconsolidated SPE transactions.

Recent Accounting Pronouncements

In December 2004, the FASB issued SFAS No. 123R. SFAS No. 123R requires that compensation costs relating to share-based payment transactions be recognized in financial statements based on the fair value of the equity or liability instruments issued. SFAS No. 123R covers a wide range of share-based compensation arrangements including share options, restricted share plans, performance-based awards, share appreciation rights and employee share purchase plans. Effective April 2005, the Securities and Exchange Commission extended the implementation date to the beginning of a registrant s next fiscal year beginning after June 15, 2005. The provisions of SFAS No. 123R were adopted by the Company effective January 1, 2006. As a result of the adoption of SFAS No. 123R, the Company expects to record compensation expense associated with unvested stock options totaling $432 thousand in future periods under the modified-prospective adoption method.

In March 2005, the FASB issued FIN No. 47 which clarifies that the term conditional asset retirement obligation refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. This Interpretation is effective for years ended December 15, 2005 or later. The Company adopted this Interpretation effective December 31, 2005. See Note 7 Asset Retirement Obligations.

In May 2005, the FASB, as part of an effort to conform to international accounting standards, issued SFAS No. 154, Accounting Changes and Error Corrections (SFAS No. 154), which is effective for the Company beginning on January 1, 2006. SFAS No. 154 requires that all voluntary changes in accounting principles be retrospectively applied to prior financial statements as if that principle had always been used, unless it is impracticable to do so. When it is impracticable to calculate the effects on all prior periods, SFAS No. 154 requires that the new principle be applied to the earliest period practicable. The adoption of SFAS No. 154 is not anticipated to have a material effect on the Company s financial position or results of operations.

SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, specifies that drilling costs for completed exploratory wells should be expensed if the related reserves cannot be classified as proved within one year unless certain criteria are met. In April 2005, the FASB issued FASB Staff Position 19-1, Accounting for Suspended Well Costs (FSP 19-1). FSP 19-1 provides guidance for evaluating whether sufficient progress is being made to determine whether reserves can be classified as proved. FSP 19-1 is effective for all reporting periods beginning after April 4, 2005, and the Company adopted FSP 19-1 upon incurrence of its initial exploratory drilling costs during the fourth quarter of 2005.

We have disclosed our accounting policy for capitalization of exploratory drilling costs in the Exploration Expense accounting policy discussed above. We have disclosed capitalized exploratory drilling cost amounts in Note 13 Disclosures about Oil and Gas Producing Activities.

Note 3 Restatement of Results

The Company acquired a contract effective August 2004. During June 2005, the Company determined that it had incorrectly invoiced this customer for the period August 2004 through April 2005. The original invoices for this period did not take into account that the agreement includes a minimum contract billing provision. The Company invoiced the customer for the difference between the original invoices and the corrected invoices in June 2005. The Company was not able to determine whether the customer would pay the difference due and as such did not restate its financial statements until collection was assured. The customer paid the Company for the difference due (approximately $304 thousand) during December 2005, including approximately $142 thousand and $162 thousand in respect to the years ended December 31, 2005 and December 31, 2004, respectively. Accordingly, the Company has restated its financial statements as summarized below.

The effect of this restatement on the Company s previously issued financial statement of operations, balance sheet, statement of cash flows and stockholders equity for the year ended December 31, 2004 is as follows:

Year ended December 31, 2004	**As reported**	**Adjustment**	**As restated**
	(In thousands, except per share amounts)		
Revenue	$ 2,370	$ 162	$ 2,532
Net loss	$ (813)	$ 162	$ (651)
Net loss attributable to common stock	$ (2,025)	$ 162	$ (1,863)
Net loss per share basic and diluted	$ (1.45)	$ 0.12	$ (1.33)
Accounts receivable	$ 262	$ 162	$ 424
Accumulated deficit	$ (813)	$ 162	$ (651)

Other line items in the financial statements such as operating loss, total current assets etc. have been restated similarly. The aforementioned restatement adjustments do not affect cash flows used in operating activities, net cash flow used in investing activities and net cash provided by financing activities, although certain components of cash flows from operating activities have been restated.

Note 4 Acquisitions

Top Gas Gathering System

Effective January 1, 2004, the Company purchased the gas gathering assets of TOP, located in Campbell County Wyoming, for $3.185 million, including direct costs of $66 thousand, cash of $2.774 million, a compressor disposal liability assumed of $145 thousand (of that amount $120 thousand was paid during 2004) and acquisition costs payable to TOP of $200 thousand. The Company recorded the acquisition using the purchase method of accounting as per SFAS No. 141, Business Combinations (SFAS No. 141). In conjunction with the purchase accounting, the Company recorded the fair value of the liability for the asset retirement obligations, estimated at $60 thousand, in accordance with SFAS No. 143. The purchase consideration, including legal fees and other professional fees incurred, was allocated to the following asset categories based on the estimated fair value of the assets acquired:

Asset category	**In thousands**
Compressor site	$ 1,240
Pipeline and interconnect	984
Gathering contracts	1,021
Asset retirement obligations	(60)
Total	$ 3,185

The Company reviewed its carrying value of the TOP gas gathering system during the year ended December 31, 2005 and recorded an impairment charge of $2.487 million in its statement of operations. See Note 5 Property, Equipment and Contracts.

Bear Paw Gas Gathering System

Effective August 1, 2004, the Company purchased certain gas gathering assets from BPE, located in Campbell County Wyoming, for $7.646 million, including direct costs of $146 thousand. The Company paid $5.5 million in cash and provided a note payable of $2.0 million. The Company paid the note in full on December 15, 2004, see Note 10 Borrowings. The purchase was recorded using the purchase method of accounting under SFAS No. 141. The purchase price, including legal fees and other professional fees incurred, was allocated to the asset categories as outlined in the following table based on the estimated fair value of the assets acquired:

Asset category	**In thousands**
Pipeline	$ 5,578
Compressor sites	788
Gathering contracts	1,280
Total	$ 7,646

The Company had not recorded an asset retirement obligation at the date of the BPE acquisition relating to obligations under certain of these contracts as a reasonable determination of the timing of the asset retirement obligations could not be made at the time. Effective December 31, 2005, the Company recorded an asset retirement obligation in respect to the BPE assets, in accordance with FIN No. 47. See also Note 7 Asset Retirement Obligations.

Note 5 Property, Equipment and Contracts

Property and equipment consists of the following:

	Useful Lives (in thousands)	**December 31, 2005**	**December 31, 2004**
Compressor sites, pipelines and interconnect	1-10 year	$ 6,806	$ 8,591
Computer equipment	3 years	29	11
Office furniture and equipment and related	5-7 years	98	30
Automobiles	3 years	60	
		6,993	8,632
Less accumulated depreciation and amortization		(969)	(496)
Total		$ 6,024	$ 8,136

The Company s compressor sites, pipeline and equipment are in respect to gas gathering operations. Depreciation expense in respect to property and equipment totaled $843 thousand and $496 thousand for the years ended December 31, 2005 and 2004, respectively.

The Company reviewed the carrying value of the TOP system as associated revenue had declined due to decreasing producer volumes as well as the loss of a customer. Based on this review, the Company recorded an asset impairment charge of $2.487 million relative to the TOP gas gathering system during the year ended December 31, 2005. The impairment charge included $1.645 million for property and equipment and $842 thousand for contracts. The Company based its impairment on an independent evaluation of the fair market value of the TOP system.

The Company initially recorded an estimated impairment of $2.372 million for the TOP system during the period ended September 30, 2005. The Company estimated the system s fair market value based on management s evaluation of several potential scenarios based on estimated fair market values, using a probabilistic assessment of estimated future cash flows for those scenarios.

The Company subsequently engaged the services of an independent appraisal firm to estimate the system s fair market value as of December 31, 2005. Based on the evaluation of the independent appraisal firm, and the resulting estimated fair market value, the Company recorded an additional impairment charge of $115 thousand during the fourth quarter of 2005. The estimated fair market value at December 31, 2005 was based on the review of three potential scenarios. The first included estimated future cash flows determined by assigning probabilities to potential ranges of equipment disposition proceeds and contract cancellation costs in respect to the shut down and sell remaining asset scenario. The second and third scenarios included a similar probability weighted evaluation performed in respect to scenarios that assumed the Company would continue to operate the system for two different lengths of time. The estimated future cash flows that were evaluated for the three scenarios were assigned a probability of occurrence to determine the estimated fair market value. The probabilities of occurrence were assigned based on management s plans and knowledge as of December 31, 2005. These estimates may change as facts and circumstances change.

In accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, the estimated fair value of the assets becomes the new cost basis for the assets, and, as such, accumulated depreciation and amortization of $589 thousand related to these assets, including contracts, was eliminated in connection with the Company s accounting for this impairment. As a result of the Company s initial impairment review during the period ended September 30, 2005, the Company reduced the estimated useful life of the TOP system to four years effective October 1, 2005. Previously a ten-year life was used to calculate the TOP system s depreciation expense. Based on the Company s plans to continue to run or shut down the system at December 31, 2005, the Company has further reduced its estimated useful life of the system to one year. The effect of this reduced useful life will be to increase depreciation expense by $133 thousand per year compared to the revised useful life determined in the third quarter of 2005, and to reduce annual depreciation and amortization by $103 thousand compared to the Company s original useful life of 10 years. The Company will continue to assess the affect of the TOP system impairment on its asset retirement obligation accretion expense.

On March 21, 2006, the Company advised its customers served by the TOP system of a temporary price increase and the Company s plans to shut-down the site. See Note 17 Subsequent Events.

Contracts valued at $1.28 million (on the date of acquisition, August 2004) in respect to the BPE assets are being amortized over 10 years which is the estimated life of the contracts and the natural gas reserves underlying the contracts. Amortization expense in respect to contracts totaled $213 thousand and $155 thousand for the years ended December 31, 2005 and 2004, respectively. The amortization expense for the year ended December 31, 2005 included amortization of the TOP contracts through September 30, 2005, when the TOP contracts were impaired in full.

Future period amortization expense in respect to the BPE contracts is as follows:

Year ending December 31,	**In thousands**
2006	$ 128
2007	128
2008	128
2009	128
2010	128
Thereafter	459
Total	$ 1,099

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Note 6 Inventory

Inventory consists of approximately 32 miles of 8-inch steel pipe that was purchased for an oil and gas pipeline project that was being planned to transport a customer s oil and gas production. This project has been suspended pending the final evaluation of the commercial reserves and the project s development plan. As the pipe is not required for current operations, the customer and the Company are jointly pursuing the disposition of this pipe. The customer agreed to share, on an equal basis, all costs in respect to holding and selling this inventory. See Note 17 Subsequent Events and Note 15 Related Party Transactions. The Company has recorded a reserve of approximately $27 thousand in respect to this inventory for the period ended December 31, 2005. The Company will continue to review the carrying value of this inventory until it is sold.

Note 7 Asset Retirement Obligations

Property and equipment includes platforms for the leased compressors at the Company s TOP gas gathering facilities. The Company is required to dismantle these compressor platforms at the end of their useful lives. In accordance with SFAS No. 143, the Company recognized the fair value of a liability for an asset retirement obligation (ARO) in the amount of $60 thousand as part of the purchase accounting at the time of the acquisition. The Company capitalized that cost as a part of the carrying value of the compressor site which is depreciated over the estimated life of the compressors use. See Note 5 Property, Equipment and Contracts for discussion of the impairment of the TOP assets.

During the year ended December 31, 2005, the Company reviewed its asset retirement obligations in respect to its BPE assets and determined an estimate of those future liabilities as determined in accordance with FIN No. 47. The Company was previously unable to determine a reasonable estimate of the timing of future period estimated dismantlement liabilities in accordance with SFAS No. 143. Those future liabilities include the removal of pipelines and compressor stations per the associated contracts. The Company estimated its future obligations in respect to the BPE assets based on estimated probabilities that the surface-use agreement based obligation would occur and also assigned probabilities as to potential settlement dates. The agreements with the lessors include provisions allowing the lessor to decide at a future date whether the lessor requires that the Company dismantle its sites and lines. Accordingly, the Company recorded its estimated asset retirement obligation liabilities of $259 thousand in respect to the BPE systems effective December 31, 2005, upon adoption of FIN No. 47. This included $76 thousand of accretion and depreciation expense that has been recorded as a cumulative effect of change in accounting principle in the Company s statement of operations for the year ended December 31, 2005. The $76 thousand cumulative effect of change in accounting principle included $30 thousand for the year ended December 31, 2004 and $46 thousand for the year ended December 31, 2005. The changes to the Company s asset retirement obligation liabilities and the pro forma effect of adopting FIN No. 47 are detailed in the following tables.

The following table details the effect on net loss, and net loss per share and asset retirement obligation liabilities as if the Company had adopted the provisions of FIN No.47 on August 1, 2004:

For the year ended	December 31, 2005 In thousands, except per share amounts	December 31, 2004 (as restated)
Net loss applicable to common stockholders:		
As reported	$ (4,829)	$ (651)
Pro forma	$ (4,799)	$ (681)
Net loss per share:		
As reported	$ (0.69)	$ (1.33)
Pro forma	$ (0.69)	$ (1.35)
Asset retirement obligations, end of period:		
As reported	$ 387	$ 65
Pro forma	$ 387	$ 299

During the year ended December 31, 2005, the Company established an asset retirement obligation of $59 thousand in respect to its oil and gas properties. The Company recognizes an estimate of the liability associated with the abandonment of its oil and gas properties at the time the well is completed. The Company estimated its asset retirement obligation liabilities for these wells based on estimated costs to plug and abandon the wells and the Company s respective ownership percentage in the wells.

The following table details all changes to the Company s estimated asset retirement obligation liabilities during the years ended December 31, 2005 and 2004:

	For the Year Ended December 31, 2005 (in thousands)	2004
Asset retirement obligations, beginning of period	$ 65	$
Acquisition of TOP assets		60
Cumulative effect of change in accounting principle BPE assets	259	
Proved properties	59	
Accretion expense	4	5
Asset retirement obligations, end of period	$ 387	$ 65

The Company will continue to review its asset retirement obligations and will adjust its estimates when facts and circumstances warrant.

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Note 8 Income Taxes

Income tax benefit for the years ended December 31, 2005 and December 31, 2004 are as follows:

	December 31, 2005 In thousands	December 31, 2004 (As restated, see Note 3)
Current:		
Federal	$	$
State		
Total current income tax benefit		
Deferred:		
Federal	1,883	71
Valuation allowance	(1,883)	(71)
Total deferred income tax benefit		
Total income tax benefit	$	$

The reconciliation between tax benefit computed by applying the estimated effective tax rate of 35% to loss before income taxes at December 31, 2005 and December 31, 2004 and the reported amount of income tax benefit is as follows:

	December 31, 2005 In thousands	December 31, 2004 (As restated, see Note 3)
Computed at the estimated effective tax rate	$ 1,619	$ 228
Permanent differences	(14)	(157)
Valuation allowance	(1,605)	(71)
Income tax benefit	$	$

The components of the net deferred income tax assets (liabilities) are as follows:

	December 31, 2005 In thousands	December 31, 2004 (As restated, see Note 3)
Non-current assets (liabilities):		
Property and equipment	$ (215)	$ (276)
Oil and gas properties	(372)	
Contracts	331	18
Organization costs	15	2
Asset retirement obligations	135	23
Net operating loss carryforwards	1,987	304
Bonus accrual	2	
Valuation allowance	(1,883)	(71)
Net deferred tax asset (liability)	$	$

At December 31, 2005, the Company had net operating loss carryforwards, for federal income tax purposes, of approximately $1.987 million. These net operating loss carryforwards, if not utilized to reduce taxable income in future periods, will expire in various amounts beginning in 2024 through 2025. This net operating loss carryforward may be subject to U.S. Internal Revenue Code Section 382 limitations.

The Company has established a valuation allowance for deferred taxes that reduces its net deferred tax assets as management currently believes that these losses will not be utilized in the near term. The allowance recorded was $1.883 million and $71 thousand for 2005 and 2004, respectively. The Company will continue to review the valuation allowance recorded as of December 31, 2005 and will record a net deferred tax asset if and when the realization of the deferred tax asset is more likely than not.

Note 9 Commitments and Contingencies

Possible Rescission of Series C Convertible Preferred Stock Sale

In December 2004, the Company received $1.233 million from the sale of 411,000 shares of Series C Convertible Preferred stock. The Company paid no cash or other commissions or finders fees in connection with this offering. In the view of the Securities and Exchange Commission, this placement might not have been eligible for an exemption from registration under the Securities Act of 1933. In the absence of such an exemption, investors could bring suit against the Company to rescind their stock purchases, in which event the Company could be liable for rescission payments to these investors of up to $1.233 million exclusive of interest and costs. In August 2005, the Company filed a registration statement on Form S-1 to register the underlying shares of common stock issuable upon conversion of the Series C Convertible Preferred stock. The SEC declared the S-1 effective on August 16, 2005. As of December 31, 2005, 371,000 Series C Convertible Preferred shares had been converted to common shares and 40,000 shares remained outstanding. See Note 17 for discussions of subsequent conversions.

Commitments

As a normal course of the Company s business operations, the Company enters into operating leases for office space, office equipment, vehicles and compression equipment. In addition, the Company has entered into service agreements that provide compression equipment and related services on a bundled basis. These agreements, which pertain to the Company s TOP and BPE gas gathering systems, expire in 2006. The Company is in the process of renewing its BPE service agreement which expires in July 2006.

In addition, the Company is party to surface-use agreements in respect to the TOP and BPE gathering systems that are cancelable when gas volumes decline to a level where the contract is uneconomic to the Company. The Company has estimated that future minimum lease commitments under these agreements will expire in 2014 based on estimated reserves in place.

Rental payments under these operating leases and service agreements totaled $1.781 million and $452 thousand for the periods ended December 31, 2005 and 2004, respectively.

Future payments, by year, under these operating leases and service agreements are as follows:

	(in thousands)
2006	$ 1,085
2007	254
2008	236
2009	235
2010	215
Thereafter	514
Total	$ 2,539

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Note 10 Borrowings

Note Payable to BPE

In August 2004, the Company signed a promissory note for $1.944 million as part of the purchase consideration paid for the gas gathering assets acquired from BPE. See Note 4 Acquisitions. The interest rate on the note was 8%. The note was paid in full on December 15, 2004 including accrued interest of $30 thousand, with proceeds from the bank line of credit discussed below being used to repay this note.

Retail Installment Sale Contract

On August 3, 2005, the Company purchased a vehicle using a 0% retail installment sale contract for a total of $31 thousand.

Promissory Note

On December 14, 2004, the Company signed a promissory note with the Bank of Oklahoma (BOK) for a $1.75 million revolving line of credit that was due on the earlier of March 31, 2005 or upon funding of the Company s initial public offering. The note included accrued interest, calculated at prime, that was payable monthly. The note was secured by the Company s gas gathering assets, associated contracts and a $1.0 million certificate of deposit pledged by a preferred stockholder as described below. The Company drew down $1.5 million upon signing and the proceeds were used in the payment of the BPE note. The Company drew down an additional $50 thousand for working capital purposes in April 2005. This promissory note was paid in full in April 2005 from proceeds from the Company s initial public offering and the line of credit was withdrawn.

Stockholder Pledge of Certificate of Deposit

On December 14, 2004, a preferred stockholder (Pledgor) pledged a certificate of deposit in the amount of $1.0 million as collateral for the BOK line of credit, as discussed above. The Company paid the stockholder a monthly fee of .529% of the collateral value for this pledge. The Company paid $18 thousand and $3 thousand of fees to the Pledgor for the years ended December 31, 2005 and 2004. The pledge was withdrawn upon payment of the BOK note in April 2005.

Note Payable to Preferred Stockholder

On October 1, 2004 the Company borrowed $800 thousand from the above preferred stockholder. The unsecured note accrued interest at 12% per annum, payable monthly. The principal and any unpaid, accrued interest were payable in one year or upon the closing of the Company s initial public offering, whichever occurred earlier. As of December 31, 2004, the Company had paid $19 thousand of interest in respect to this note. Proceeds from the issuance of Series C Convertible Preferred shares were used to pay off the note on December 10, 2004. See Note 11 Stockholders Equity.

Note 11 Stockholders Equity

Initial Public Offering

On April 12, 2005, the Company s registration statement on Form S-1 was declared effective by the Securities and Exchange Commission and the Company s stock began trading on the American Stock Exchange under the trading symbol PRB. The Company sold 2,300,000 shares of common stock, including 300,000 shares pursuant to the underwriter s exercise of its over-allotment option. In conjunction with the offering, holders of Series A and Series B preferred stock converted their shares into an equal number of registered common shares. The Company recorded proceeds of $10.169 million net of underwriter s discounts, commissions and expenses, including warrants valued at $583 thousand.

Series C Preferred Stock

In December 2004, the Company issued 411,000 shares of the convertible preferred series C shares at a price of $3.00 per share resulting in proceeds of approximately $1.231 million, net of offering costs of approximately $2 thousand. See Note 9 Commitments and Contingencies for further discussion on the convertible preferred series C shares.

Dividends

Both the Convertible Preferred Series A and Series B shares included dividend rights that stated that dividends would accrue from the date of issuance until the date paid, whether or not earned or declared. All of the Series A and B preferred stockholders converted to common shares during April 2005 and all of the related dividends were paid through the date of conversion. The Series C Convertible Preferred stock does not pay dividends.

Warrants

On June 28, 2004, the Company granted 45,000 warrants to consultants as compensation for their work on the Company s initial public offering. These warrants have a 5 year term with immediate vesting and an exercise price of $5.50. The estimated fair value of the warrants at December 31, 2004 was $12 thousand based on the Black-Scholes option pricing model.

The Company entered into an underwriting agreement on April 12, 2005. The agreement called for the underwriter to purchase the shares on a firm commitment basis at an 8% discount to the offering price. The Company s underwriter also received a 3% non-accountable expense allowance of the aggregate offering price of the shares offered, excluding the 300,000 over-allotment shares. At the closing of the underwriting, the Company sold warrants to the underwriter to purchase 200,000 shares of common stock at a price of $0.0001 per warrant. The warrants have an exercise price of $6.875 (125% of the initial offering price) and are exercisable for 4 years from the first anniversary of their issuance. The estimated fair value of the warrants at issuance was $571 thousand based on the Black-Scholes option pricing model.

During the year ended December 31, 2004, the Company recorded deferred offering costs of raising capital, with a corresponding increase in additional paid-in-capital in respect to the 45,000 warrants issued during that period, of $12 thousand. In respect to the 200,000 warrants issued during April 2005, the fair value of the warrants of $571 thousand was also charged against additional paid-in-capital.

The following assumptions were used in determining the fair values of the warrants as described above:

Risk-free interest rate (%)	3.89
Expected life (years)	5
Expected volatility (%)	25
Expected dividends	

Through December 31, 2005, cumulative activity in respect to warrants is as follows:

	December 31, 2005	December 31, 2004
Balance, beginning of year	45,000	
Issued	200,000	45,000
Exercised	(15,000)	
Balance, end of year	230,000	45,000

The warrants exercised during the year ended December 31, 2005 were exercised under the cashless exercise provision.

Note 12 Compensation Plans

The Company has an Equity Compensation Plan (Option Plan). The Plan grants options to purchase shares of the Company s common stock to eligible employees, contractors and current and former members of the Board of Directors. There are 743,000 shares of the Company s common stock reserved for issuance under the Plan.

All options granted to date under the Plan have been granted at exercise prices equal to or greater than the respective market prices of the Company s common stock on the grant dates. There were 279,939 shares available for grant under the Plan as of December 31, 2005.

The following table summarizes activity for options:

	For the Year Ended December 31, 2005 Number of ShareS	Weighted Avg. Exercise Price	For the Year Ended December 31, 2004 Number of ShareS	Weighted Avg. Exercise Price
Outstanding, beginning of year	220,000	$ 5.50		
Granted	299,000	$ 7.59	220,000	$ 5.50
Forfeitures	(50,750)	$ 6.51		
Exercised	(5,000)	$ 5.50		
Outstanding, end of year	463,250	$ 6.74	220,000	$ 5.50
Exercisable, end of year	227,500	$ 6.39	70,000	$ 5.50
Weighted-average fair value of options granted during the year		$ 3.19		$ 0.82

The weighted average remaining contractual life for the options outstanding at December 31, 2005 is 7.4 years. The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model. The weighted average fair value of options outstanding at December 31, 2005 is $2.16. The weighted average fair value of options granted and exercisable at December 31, 2005 is $1.63.

SFAS No. 123 establishes a fair value method of accounting for stock-based compensation plans through either recognition or disclosure. The Company accounts for stock-based compensation under the intrinsic value method pursuant to Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees (APB No. 25) and has elected to adopt SFAS No. 123 through compliance with the disclosure requirements set forth in the Statement. Because the exercise price of the Company s stock options equals the market price of the underlying stock on the date of the grant, no compensation expense is recognized under APB No. 25. Pro forma information regarding net loss and loss per share is required by SFAS No. 123 and has been determined as if the Company had accounted for its employee stock options under the fair value method of that Statement. See Note 2 Summary of Significant Accounting Policies for pro forma information.

The fair value of options was measured at the date of grant using the Black-Scholes option-pricing model. The fair values of options granted and employee stock purchase plan shares issued were estimated using the following weighted-average assumptions:

Assumption	**December 31, 2005**		**December 31, 2004**	
Risk free interest rate (%)	3.9-4.5		3.89-4.73	
Volatility factor of the expected market price of the Company s common stock	25	%	25	%
Expected life of the options (in years)	5-10		5-10	
Expected dividend				

The Black-Scholes option valuation model was developed for use in estimating the fair value of traded options that have no vesting restrictions and are fully transferable. In addition, option valuation models incorporate highly subjective assumptions including the expected stock price volatility. The Company s stock options have characteristics significantly different from those of traded options and, as changes in the subjective input assumptions can materially affect the fair value estimate, it is management s opinion that the valuations as determined by the existing models are different from the value that the options would realize if traded in the market.

Note 13 Disclosures about Oil and Gas Producing Activities

Costs Incurred in Oil and Gas Producing Activities

The Company commenced its oil and gas activities during the year ended December 31, 2005. The Company has incurred the following costs, both capitalized and expensed, in respect to its oil and gas property acquisition, exploration and development activities during the year ended December 31, 2005:

	In thousands
Exploration	$ 1,531
Development	314
Unproved leasehold	136
Total	$ 1,981

Included in the above are capitalized asset retirement obligations of $59 thousand.

The following table details the net changes in capitalized exploratory well costs for the year ended December 31, 2005:

	In thousands
Beginning balance, January 1, 2005	$
Additions to capitalized exploratory well costs pending the determination of proved reserves	1,531
Capitalized exploratory well costs charged to exploration expense	(450)
Ending balance, December 31, 2005	$ 1,081

Capitalized exploratory well costs included $1.531 million of exploratory drilling costs. During 2005, the Company charged $450 thousand of these exploratory drilling costs, relating to 6 wells, to exploration expense. At December 31, 2005, $1.081 million of exploratory drilling costs, relating to 12 wells, remained capitalized as wells-in-progress pending the determination of proved reserves. None of these wells are in areas requiring major capital expenditures before production can begin, nor were any of these wells completed more than one year ago. These wells are currently undergoing de-watering and the Company believes that after these wells are de-watered it will be able to determine if proved reserves have been discovered. The Company estimates that in mid 2006 it will be able to make this determination.

Oil and Gas Reserve Quantities (Unaudited)

The Company engages Sproule Associates Inc. to determine its reserve information included herein. The Company reviews the reserve information in the report that Sproule prepares. The Company emphasizes that reserve estimates are imprecise by their nature, and that reserve estimates on new discoveries and developments are less precise than reserve estimates for existing fields. Accordingly, the Company expects these estimates to change as time passes and information as to actual well performance can be included in those future estimates.

Proved oil and gas reserves are estimates of recoverable quantities of oil, natural gas and natural gas liquids that are determined using engineering and geological data with reasonable certainty. The reserve estimates are based on existing economic and operating conditions and include only existing wells from known reservoirs with existing equipment and technology. All of the Company s proved reserves are located in the Powder River Basin area of Wyoming.

The following table summarizes estimated proved reserves as of December 31, 2005:

	Gas-MMcf s
Developed and undeveloped:	
Beginning of year, January 1, 2005	
Discoveries	402
Production	(6)
End of year, December 31, 2005	396

As of December 31, 2005, all of the Company s proved reserves are categorized as proved developed producing.

Standardized Measure of Discounted Future Net Cash Flows (Unaudited)

SFAS No. 69, Disclosures about Oil and Gas Producing Activities (SFAS 69) details guidelines of how to determine the standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The Company follows these guidelines that are summarized as follows:

- Future cash inflows, production and development costs are determined by applying oil and gas prices and costs in effect at year-end, including overhead expense allocable, transportation, quality and basis differentials to the year-end quantities of oil and gas to be produced in the future;

- Future income taxes are estimated using current income tax rates and estimated future statutory depletion;

- Future operating and development costs are based on estimates of expenditures in developing and producing proved oil and gas reserves in place at year-end, assuming continuity of year-end economic conditions;

- The resulting cash flows are reduced to present value using a ten percent discount rate; and

- The Company used $5.27 as the year end price for natural gas on an Mcf basis, as adjusted for transportation, quality and basis differentials.

The following summarizes the Company s standardized measure of future net cash flows relating to its proved reserves as prescribed in SFAS No. 69:

	In thousands
Future cash flows	$ 2,089
Future production costs	(878)
Future abandonment costs	(75)
Future income taxes	(316)
Future net cash flows	820
Ten percent discount	(132)
Standardized measure of discounted future net cash flows	$ 688

The Company initiated its oil and gas activities during the year ended December 31, 2005.

Note 14 Segment Information

During the third quarter of 2005, the Company entered into the oil and gas exploration and production segment and began producing and selling natural gas during the fourth quarter of 2005.

The Company s management, effective during the year ended December 31, 2005, monitors the performance of its segments described as follows.

Gas Gathering and Processing Segment

The Company operates in the gathering and processing segment and owns and operates gas gathering and processing systems it acquired from TOP and BPE as earlier described. The Company charges a fee to its customers for these services based on a rate per Mcf, and/or based on a monthly minimum fee and/or based on the level of compression services provided.

Oil and Gas Exploration and Production Segment

The Company, beginning in the third quarter of 2005, commenced operations in the exploration and production segment. The Company s operations in this segment include exploring for, developing and marketing natural gas from coal-bed methane wells. For the year ended December 31, 2005, the Company s exploration and production segment operated in the Powder River Basin area of Wyoming and Montana.

Through the Company s Management Services Agreement with Rocky Mountain Gas, the Company earned management fee revenue and has included that revenue under Corporate in the following table that details the performance of its segments.

	For the Year Ended December 31, 2005			
	Gathering and Processing	Exploration and Production	Corporate	Total
	In thousands			
Revenue	$ 2,834	$ 51	$ 270	$ 3,155
Operating expense	1,755	34		1,789
Asset impairment charge	2,487			2,487
Exploration expense		450		450
Depreciation, depletion, amortization and accretion	1,041	4	22	1,067
General and administrative			2,029	2,029
Operating loss	(2,449)	(437)	(1,781)	(4,667)
Interest and other-net			118	118
Cumulative effect of change in accounting principle	(76)			(76)
Net loss	(2,525)	(437)	(1,663)	(4,625)
Preferred stock dividends			204	204
Net loss attributable to common stockholders	$ (2,525)	$ (437)	$ (1,867)	$ (4,829)
Identifiable assets				
Property, plant and equipment	$ 5,747		$ 277	$ 6,024
Contracts	$ 1,099			$ 1,099
Oil and gas properties		$ 1,531		$ 1,531

The Company operated in only one segment during the year ended December 31, 2004 and the Company s management reviewed the results of its operations as a single segment during that period. Accordingly, segment information is not presented for the year ended December 31, 2004.

Note 15 Related Party Transactions

In October 2005, the Company and JMG Exploration, Inc. (JMG) entered into an agreement whereby the Company was to build and operate a 32 mile, 8-inch oil and gas pipeline in exchange for a cost-plus compensation arrangement negotiated on an arms length basis. Thomas J. Jacobsen, Joseph Skeehan and Reuben Sandler are Directors on the Company s Board and also serve on the Board of Directors of JMG. During October 2005, the Company, based on its agreements with JMG, ordered the manufacture of the 32 miles of 8-inch steel pipe at a cost of approximately $1.373 million that was intended to be used in an oil and gas pipeline the Company was planning to build to serve JMG s oil and gas production anticipated in North Dakota. See Note 6 Inventory for additional discussion regarding this transaction.

Susan Wright, the Company s Corporate Secretary and wife of the Company s CEO, provides Corporate Secretary services to the Company on a contract basis. During the years ended December 31, 2005 and December 31, 2004, Mrs. Wright was paid $19 thousand and $18 thousand, respectively, for contract services. In addition, during the year ended December 31, 2004, Mrs. Wright received deemed compensation of $208 thousand in respect to the purchase of the Company s Series C Convertible Preferred stock.

Officers of the Company purchased 171,500 shares, or 42%, of the Company s Series C Convertible Preferred shares, that were issued in December 2004.

Kevin P. Norris, a former Director from December 2003 to May 2004 and a former principal stockholder in the Company, is the Manager of TOP, a company from which the Company acquired certain assets in January 2004 for $3.185 million. In January 2004, Mr. Norris purchased 800,000 shares of the Company s common stock for $0.0125 per share or $10 thousand. On September 30, 2004, the Company repurchased Mr. Norris s 800,000 shares of common stock for $800 thousand. The Company provides gathering services that represented approximately 8.4% and 29.2% of its total revenue for the years ended December 31, 2005 and 2004, respectively, to e2 Business Services, Inc. Mr. Norris is also a stockholder of e2 Business Services, Inc.

In January 2004, the Company sold 2,400,000 shares of Series A Convertible Preferred stock to JMGG Partners, Ltd., a California limited partnership, of which John P. McGrain was the general partner. The Series A Convertible Preferred stock rights and preferences included the right to vote equally with common stock and the right to elect three of five Directors as a class with the Series B Convertible Preferred stockholders. In January 2004, the Series A Convertible Preferred stock owned by JMGG represented 60% of the Company s voting shares of stock. Mr. McGrain served as the Company s non-executive Chairman of the Board from January 2004 to June 2004. He resigned as the Company s non-executive Chairman of the Board in June 2004 when JMGG dissolved its operations and distributed its assets, consisting solely of shares of the Company s Series A Convertible Preferred stock, to its partners. The Company did not compensate Mr. McGrain for any of his services as the Company s non-executive Chairman. Mr. McGrain was a control person within the meaning of federal securities laws for the period from January 2004 through June 2004.

In June 2004, the Company issued Mr. McGrain warrants to purchase 15,000 shares of common stock at an exercise price of $5.50 per share, valued at $4 thousand, as consideration for consulting services in conjunction with the Company s initial public offering. See Note 17 Subsequent Events for information on warrants issued subsequent to December 31, 2005.

In October 2004, Mr. McGrain loaned the Company $800 thousand in connection with the Company s repurchase of 800,000 shares of common stock from Mr. Norris. The Company repaid Mr. McGrain in full in December 2004, plus interest at a rate of 12% per year.

In December 2004, the Company borrowed $1.5 million under a $1.75 million bank line of credit. In addition to a lien on all of the Company s gathering assets, security for this bank line of credit included a pledge to the bank of a $1.0 million certificate of deposit by Mr. McGrain. In consideration for this pledge, the Company agreed to pay Mr. McGrain a monthly fee of approximately $5 thousand until the pledge was released upon the repayment of the line of credit. The Company paid the bank line in full and the pledge was released following the Company s initial public offering.

Note 16 Quarterly Financial Information (Unaudited)

	First	Second	Third	Fourth	Total
	In thousands, except per share data				
2005					
Revenue	$ 841	$ 715	$ 724	$ 875	$ 3,155
Operating loss	$ (189)	$ (415)	$ (2,931)	$ (1,132)	$ (4,667)
Net loss before cumulative effect of change in accounting principle	$ (230)	$ (375)	$ (2,868)	$ (1,076)	$ (4,549)
Cumulative effect of change in accounting principle				$ (76)	$ (76)
Net loss	$ (230)	$ (375)	$ (2,868)	$ (1,152)	$ (4,625)
Net loss applicable to common stockholders	$ (412)	$ (397)	$ (2,868)	$ (1,152)	$ (4,829)
Net loss per share before cumulative effect of change in accounting principle	$ (0.52)	$ (0.06)	$ (0.40)	$ (0.15)	$ (0.68)
Cumulative effect of change in accounting principle per share of common stock	(0.00)	(0.00)	(0.00)	(0.01)	(0.01)
Net loss per share basic and diluted	$ (0.52)	$ (0.06)	$ (0.40)	$ (0.16)	$ (0.69)
2004 (As restated, see Note 3)					
Revenue	$ 399	$ 343	$ 841	$ 949	$ 2,532
Operating income (loss)	$ 8	$ (135)	$ (3)	$ (492)	$ (622)
Net income (loss)	$ 11	$ (126)	$ 13	$ (549)	$ (651)
Net loss applicable to common stockholders	$ (93)	$ (280)	$ (170)	$ (1,320)	$ (1,863)
Net loss per share basic and diluted	$ (0.06)	$ (0.17)	$ (0.11)	$ (1.65)	$ (1.33)

During the third quarter of 2005, the Company recorded an estimated impairment charge in respect to its TOP gas gathering system of $2.372 million, and during the fourth quarter of 2005 recorded an additional $115 thousand in respect to this impairment. See Note 5 Property, Equipment and Contracts. During the fourth quarter of 2005 the Company recorded a $76 thousand cumulative effect of change in accounting principle. See Note 7 Asset Retirement Obligations.

Note 17 Subsequent Events

During January 2006, the Company issued a convertible subordinated debt offering. The aggregate amount of the offering was $21.965 million, before expenses, that included commissions and professional fees totaling $1.045 million. The terms of the notes include 10% interest paid quarterly in arrears with maturity 30 months from date of closing. In addition, the holders have the right, after the shares have been registered, to convert the notes to the Company s common shares at a conversion price of $7 per share, which is subject to certain anti-dilution adjustments. The Company pledged certain gas gathering assets as collateral to the note holders. The terms of the Subscription Agreement provide that the Company will file a Registration Statement with the SEC within 90 days after the closing date of the offering. The Subscription Agreement includes 1% per month liquidated damages in the event the securities are not registered. In the event the common stock of the Company trades at $14 per share or above for 10 consecutive days, the Company has a call provision to convert these notes to its common shares at $7 per share. In addition, the Company is prohibited from declaring or paying cash dividends on its common stock during the period that any note is outstanding and unpaid. Future interest expense, assuming that the notes are held for the entire 30 months and the notes are registered per the terms of the subscription agreement, is projected to be $1.924 million, $2.227 million and $1.414 million for the years ending December 31, 2006, 2007 and 2008, respectively.

The Company is currently evaluating the accounting treatment applicable to the embedded conversion option contained in the recently issued convertible subordinated debt offering.

In January 2006, the Company issued 40,000 warrants to John McGrain, a related party, for services rendered in respect to its recent convertible debt offering. These warrants were issued at $7 per share and were valued at $59 thousand on the date of issuance as determined by the Black-Scholes model. See also Note 17, Related Party Transactions.

On January 17, 2006, the Termo Company informed the Company it was designated as the preferred gatherer for its Homestead Project containing 3,400 acres. The Company was offered a 9.25% working interesting in the project and paid $85,000 for the working interests in the undeveloped leaseholds that contain proved undeveloped reserves.

On January 25, 2006, the Company announced that it had purchased a gas gathering system from Storm Cat Energy Corporation (Storm Cat) for $1 million. The Company also has entered into a related gas gathering and compression services agreement with Storm Cat covering 6,600 acres.

On March 3, 2006, the Company entered into a farm-in agreement for a 15% working interest in leaseholds underlying its GAP and Bonepile gas gathering systems and plans to propose a drilling program during 2006. The leaseholds cover 5 counties and a total of approximately 3,400 net acres.

On March 3, 2006, the Company acquired a high pressure natural gas gathering line from Clear Creek Natural Gas, LLC for $450 thousand. The newly acquired 6.5 miles of 6 and 8-inch steel pipe ties into the gathering and compression assets the Company purchased in January 2006, from Storm Cat. The Company will deliver gas from this line to the Thunder Creek interstate pipeline system.

On March 20, 2006, the Company withdrew from its Farm-In and Development Agreement with Rocky Mountain Gas, as per the terms of the agreement. The Company will continue to provide operator and management services for at least a 60 day period as per the Management Services Agreement.

On March 21, 2006, the Company notified its 2 customers served by its TOP system that the Company was raising its rates to cover its cash costs plus 15% for a 2 month period. The Company also advised these customers that it was planning to shut down the TOP system after the two month period elapsed. The customers have the right to purchase the TOP system from the Company on to be negotiated terms, as per the related gas gathering agreements.

Subsequent to December 31, 2005, 30,000 shares of Series C Convertible Preferred stock were converted to common shares and as of March 30, 2006, 10,000 Series C Convertible Preferred shares remained outstanding.