TETON ENERGY CORP
Form 10-K
March 19, 2007

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2006

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 1-31679
TETON ENERGY CORPORATION
(Exact name of registrant as specified in its charter)

DELAWARE	**84-1482290**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
410 17th Street Suite 1850 Denver, Colorado	**80202**
(Address of principal executive offices)	(Zip Code)

Registrant s telephone number, including area code: **(303) 565-4600**
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	**Name of each exchange on which registered**
Common Stock, par value $0.001	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 Act). Yes o No þ
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No þ
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter periods that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ 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 or 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 (as defined in Rule 12b-2 of the Act).
Large accelerated filer o Accelerated filer o Non-accelerated filer þ
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o No þ
As of December 31, 2006, approximately 15,180,649 shares of common stock were outstanding. The aggregate market value of the common stock held by non-affiliates of the issuer, as of December 31, 2006, was approximately $72,553,048 based on the closing bid of $4.99 for the issuer s common stock as reported on the American Stock Exchange. Shares of common stock held by each director, each officer named in Item 12, and each person who owns

10% or more of the outstanding common stock have been excluded from this calculation in that such persons may be deemed to be affiliates. The determination of affiliate status is not necessarily conclusive.

As of March 12, 2007 the issuer had 15,693,229 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE   NONE

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Forward-Looking Statements

This Annual Report on Form 10-K contains both historical and forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements, written, oral or otherwise made, represent the Company s expectation or belief concerning future events. All statements, other than statements of historical fact, are or may be forward-looking statements. For example, statements concerning projections, predictions, expectations, estimates or forecasts, and statements that describe our objectives, future performance, plans or goals are, or may be, forward-looking statements. These forward-looking statements reflect management s current expectations concerning future results and events and can generally be identified by the use of words such as may, will, should, could, would, likely, predict, p continue, future, estimate, believe, expect, anticipate, intend, plan, foresee, and other similar words o as statements in the future tense.

Forward-looking statements involve known and unknown risks, uncertainties, assumptions, and other important factors that may cause our actual results, performance, or achievements to be different from any future results, performance and achievements expressed or implied by these statements. The following important risks and uncertainties could affect our future results, causing those results to differ materially from those expressed in our forward-looking statements:

- general economic conditions;
- the market price of, and demand for, oil and natural gas;
- our ability to service future indebtedness;
- our success in completing development and exploration activities;
- expansion and other development trends of the oil and gas industry;
- our present company structure;
- our accumulated deficit;
- acquisitions and other business opportunities that may be presented to and pursued by us;
- reliance on outside operating companies for drilling and development of our oil and gas properties;
- our ability to integrate our acquisitions into our company structure;
- changes in laws and regulations; and
- other Risk Factors described in Item 1A of this Annual Report.

These factors are not necessarily all of the important factors that could cause actual results to differ materially from those expressed in any of our forward-looking statements. Other factors, including unknown or unpredictable ones could also have material adverse effects on our future results.

The forward-looking statements included in this Annual Report on Form 10-K are made only as of the date of this Annual Report. We expressly disclaim any intent or obligation to update any forward-looking statements to reflect new information, subsequent events, changed circumstances, or otherwise.

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Glossary of Commonly Used Terms, Abbreviations, and Measurements

Within this report, the following terms and conventions have specific meanings:

COMMONLY USED TERMS AND ABBREVIATIONS

AMI Area of Mutual Interest.

Barrels of oil equivalent (BOE) Gas volume that is expressed in terms of its energy equivalent in barrels of oil, which is calculated as 6,000 cubic feet of gas equals one barrel of oil equivalent (BOE); or 42 U.S. gallons of oil at 40 degrees Fahrenheit.

Basin A depressed sediment-filled area, roughly circular or elliptical in shape, sometimes very elongated. Regarded as a potentially good area to explore for oil and gas.

Basis When referring to natural gas, the difference between the futures price for a commodity and the corresponding sales price at various regional sales points. The differential commonly is related to factors such as product quality, location and contract pricing.

Btu One British thermal unit a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.

Cash flow hedge A derivative instrument that complies with Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended, and is used to reduce the exposure to variability in cash flows from the forecasted physical sale of gas production whereby the gains (losses) on the derivative transaction are anticipated to offset the losses (gains) on the forecasted physical sale.

Collar A financial arrangement that effectively establishes a price range for the underlying commodity. The producer bears the risk of fluctuation between the minimum (floor) price and the maximum (ceiling) price.

Denver-Julesburg (DJ) Basin A geologic depression encompassing Eastern Colorado, Southwest Wyoming, Northwest Kansas and Western Nebraska.

Development well A well drilled into a known producing formation in a previously discovered field.

Exploratory well A well drilled into a previously untested geologic formation to test for commercial quantities of oil or gas.

Farm tap Natural gas supply service in which the customer is served directly from a well or gathering pipeline.

Field A geographic region situated over one or more subsurface oil and gas reservoirs encompassing at least the outermost boundaries of all oil and gas accumulations known to be within those reservoirs vertically projected to the land surface.

Futures contract An exchange-traded legal contract to buy or sell a standard quantity and quality of a commodity at a specified future date and price.

Gas All references to gas in this report refer to natural gas.

Gross Gross natural gas and oil wells or gross acres equal the total number of wells or acres in which the Company has a working interest.

Hedging The use of derivative commodity and interest rate instruments to reduce financial exposure to commodity price and interest rate volatility.

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Net Net gas and oil wells or net acres are determined by summing the fractional ownership working interests the Company has in gross wells or acres.
Piceance Basin A geologic depression encompassing a 6,000 square mile area in Western Colorado encompassing portions of Garfield and Mesa counties, with portions extending northward into Rio Blanco County and south into Gunnison and Delta counties.
Productive Able to economically produce oil and/or gas.
Proved reserves Reserves that, based on geologic and engineering data, appear with reasonable certainty to be recoverable in the future from known oil and gas reserves under existing economic and operating conditions.
Proved developed reserves Proved reserves which can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved undeveloped reserves Proved reserves that are expected to be recovered from new wells on undrilled proved acreage or from existing wells where a relatively major expenditure is required for completion.
Reserves The estimated value of oil, gas and/or condensate, which is economically recoverable.
Reservoir A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.
Transportation Moving gas through pipelines on a contract basis for others.
Throughput Total volumes of natural gas sold or transported by an entity.
Williston Basin A geologic depression encompassing portions of North Dakota, South Dakota and Eastern Montana.
Working interest An interest that gives the owner the right to drill, produce and conduct operating activities on a property and receive a share of any production.

MEASUREMENTS

Barrel = Equal to 42 U.S. gallons.
Bbl = barrel
Bcf = billion cubic feet of natural gas
Bcfe = billion cubic feet of natural gas equivalents
Mcf = thousand cubic feet of natural gas
Mcfe = thousand cubic feet of natural gas equivalents
MMBtu = million British thermal units
MMcf = million cubic feet of natural gas
MMcfe = million cubic feet of natural gas equivalents

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PART I

ITEM 1. BUSINESS.

Background

Teton Energy Corporation (the Company, Teton, we or us) was formed in November 1996 and is incorporated in th State of Delaware. From our inception until 2004, we were primarily engaged in oil and gas exploration, development, and production in Western Siberia, Russia. In July 2004, our shareholders voted to sell our Russian operations to our Russian partner. The gross proceeds received by us in this transaction totaled $15,000,000. Since July 2004, we have actively pursued opportunities primarily in North America in order (1) to redeploy the cash generated in the sale of our Goloil asset and (2) to continue our growth.

We are an independent energy company engaged primarily in the development, production and marketing of natural gas and oil in North America. Our strategy is to increase shareholder value by profitably growing reserves and production, primarily through acquiring under-valued properties with reasonable risk-reward potential and by participating in or actively conducting drilling operations in order to exploit our properties. We seek high-quality exploration and development projects with potential for providing long-term drilling inventories that generate high returns. Our current operations are focused in three basins in the Rocky Mountain region of the United States.

Piceance Basin

In February 2005, we acquired 25% of the membership interests in Piceance Gas Resources, LLC, a Colorado limited liability company (Piceance LLC). Piceance LLC owned certain oil and gas rights and leasehold assets covering 6,314 gross acres in the Piceance Basin in Western Colorado. The properties owned by Piceance LLC carry a net revenue interest of 78.75%. During the first quarter of 2006, the members of Piceance LLC applied to and received the consent of the fee owner of the land on which Piceance LLC s oil and gas rights and leases are located for Piceance LLC to transfer the underlying interest directly to each of the members. As a result, on February 28, 2006, our 25% interest in the oil and gas rights and leases were transferred directly to Teton Piceance LLC, a wholly owned subsidiary of the Company. Through February 28, 2006 we accounted for our investment in Piceance LLC using pro rata consolidation.

DJ Basin

During 2005, we acquired approximately 195,252 undeveloped gross acres in the Eastern Denver-Julesburg Basin (the DJ Basin) located in Nebraska on the Nebraska-Colorado border. The properties carried a net revenue interest of approximately 81.0%. Effective December 31, 2005, we entered into an Acreage Earning Agreement (the Earning Agreement) with Noble Energy, Inc. (Noble), which closed on January 27, 2006. Under the terms of the Earning Agreement, Noble retains a 75% working interest in our DJ Basin acreage within the Area of Mutual Interest (AMI) after drilling 20 wells by March 1, 2007 at no cost to us. Pursuant to the Earning Agreement, we were entitled to receive 25% of any net revenues derived from the first 20 wells drilled and completed. The Earning Agreement also provides that after completion of the first 20 wells, we and Noble will split all costs associated with future drilling, operating and other project costs according to each party s working interest percentage. Noble paid us $3,000,000 under the Earning Agreement and we recorded the entire $3,000,000 (including $300,000, which was reflected as a deposit at December 31, 2005) as a reduction of the investment in our DJ Basin undeveloped property. On December 8, 2006, we received notification from Noble that the first 20 wells have been drilled and completed and thus Noble has now earned 75% working interest in all acreage within the AMI.

In 2006, we acquired an additional 14,932 gross acres in the DJ Basin bringing our total gross acreage in the DJ Basin to 210,184 gross acres. On December 15, 2006, we closed on an agreement to purchase an additional leasehold interest in the DJ Basin with an undisclosed third party. The agreement called for the acquisition of approximately 56,389 gross acres. Approximately 45,773 net acres were within the Teton / Noble AMI and approximately 10,616 gross acres outside the AMI. Noble agreed to accept its 75% interest in the acreage within the AMI. As of December 31, 2006, our total gross acreage in the DJ Basin is 266,572 acres, of which 255,956 gross acres is in the Teton / Noble AMI and 10,616 gross acres is outside of the AMI. As a result of these transactions we currently have a net acreage position of 57,834 net acres within the Teton / Noble AMI and 8,550 net acres outside the AMI. Our interests in the oil and gas rights and leases are recorded directly to Teton DJ Basin LLC, a wholly owned subsidiary.

Williston Basin

On May 5, 2006, we acquired a 25% working interest in approximately 87,192 gross acres in the Williston Basin located in Williams County, North Dakota. The target of this prospect is the oil rich Mississippian Bakken formation of the Williston Basin within an intense oil generating area. This shale produces from horizontal wells at a depth of approximately 10,500 feet. The lateral legs will vary from 3,000 to 9,000 feet in length. Although the primary area with notable production from the Bakken is in Richland County, Montana several wells have been recently completed directly to the east of the acreage block. Multiple stage fracture stimulation will be used to increase recoveries and 640 acre spacing could allow for at least 134 locations over the acreage if economic recoveries are confirmed by the initial test wells. Secondary horizons include the Madison, Duperow, Red River, Nisku, and Interlake formations.

We purchased this acreage position from American Oil and Gas Inc. (American) for a total purchase price of approximately $6.17 million. Evertson Energy Company (Evertson) is the operator and has a 25% working interest in the acreage block with American holding the remaining 50% working interest. Per the terms of the purchase and sale agreement with American we paid American $2.47 million in cash at closing and agreed to pay an additional $3.7 million in respect of American s 50% share of the costs of the first two planned wells through June 1, 2007. Any portion of the $3.7 million not paid to American by June 1, 2007 will be paid to American on that date. As of December 31, 2006, we have paid to American approximately $3.0 million of the initial obligation of $3.7 million resulting in a remaining accrued purchase consideration of $775,054, all in respect to their share of the first well as further described.

Evertson began drilling the first well on this acreage, the Champion 1-25H, a tri-lateral horizontal test on September 25, 2006. The estimated cost for the Champion 1-25H is approximately $6.8 million to drill, complete and test. As of the date of this report Evertson was testing the Champion 1-25H. In addition to the payments to American in respect to the acreage purchase and sale agreement we are paying our 25% working interest share of the drilling, completion and testing costs of the Champion 1-25H, and will so on subsequent wells that we participate in at this ownership level.

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Recent Events

On February 1, 2007, we executed an employment agreement with Dominic J. Bazile II to become our Executive Vice President and Chief Operating Officer. The contract provides for an initial salary for Mr. Bazile of $225,000 per year. Under the terms of the agreement, Mr. Bazile is entitled to 12 months severance pay in the event of a change of position or change in control of the Company. The agreement contains an evergreen provision, which automatically extends the term of Mr. Bazile s agreement for a two-year period if the agreement is not terminated by notice by either party during 60 days prior to the end of the initial stated two-year term. In addition, Mr. Bazile s contract includes an indemnification agreement.

On March 12, 2007, BNP Paribas increased the Company s borrowing base to $6 million from the initial June 15, 2006 borrowing base of $3 million.

On March 14, 2007, the Company announced that 5 of the 20 pilot wells in the DJ Basin were put on production by Noble in the Chundy area as part of a flow rate test to ascertain commercial viability. Additional wells will be connected during the near term as part of this test.

Business Strategy

The Company s objective is to expand its natural gas and oil reserves, production and revenues through a strategy that includes the following key elements:

Pursue Attractive Reserve and Leasehold Acquisitions. To date, acquisitions have been critical in establishing our asset base. We believe that we are well positioned, given our initial success in identifying and quickly closing on attractive opportunities in the Piceance, DJ, and Williston Basins, to effect opportunistic acquisitions that can provide upside potential, including long-term drilling inventories and undeveloped leasehold positions with attractive return characteristics. Our focus is to acquire assets that provide the opportunity for developmental drilling and/or the drilling of extensional step out wells, which we believe will provide us with significant upside potential while not exposing us to the risks associated with drilling new field wildcat wells in frontier basins.

Pursuit of Selective Complementary Acquisitions. We seek to acquire long-lived producing properties with a high degree of operating control, or oil and gas entities that are known to be competent in the area and that offer opportunities profitably to increase our natural gas and crude oil reserves.

Drive Growth through Drilling. We plan to supplement our long-term reserve and production growth through drilling operations. In 2006, we participated in the drilling of 18 gross wells in connection with our Piceance Basin project where we have a 25% non-operated working interest, 20 gross wells in the DJ Basin under the Noble Earning Agreement where we have a 25% non-operated working interest in the AMI and two gross wells in the Williston Basin (in one gross well we have a 25% non-operated working interest and the other gross well a 1.56% non-operated working interest). In 2007, we anticipate that we will participate in 36 gross wells in the Piceance Basin.

Maximize Operational Control. Except for 10,616 gross acres in the DJ Basin, we do not own any other assets where we are the operator. It is strategically important to our future growth and maturation as an independent exploration and production company to be able to serve as operator of our properties when possible in order to be able to exert greater control over costs and timing in and the manner of our exploration, development, and production activities.

Operate Efficiently, Effectively, and Maximize Economies of Scale Where Practical. Our objective is to generate profitable growth and high returns for our stockholders, and we expect that our unit cost structure will benefit from economies of scale as we grow and from our continuing cost management initiatives. As we manage our growth, we are actively focusing on reducing lease operating expenses, general and administrative costs and finding and development costs. In addition, our acquisition efforts are geared toward pursuing opportunities that fit well within existing operations or in areas where we are establishing new operations or where we believe that a base of existing production will produce an

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adequate foundation for economies of scale necessary to grow a business within a geographical area or business segment.

Governmental Regulation

Our business and the oil and natural gas industry in general are heavily regulated. The availability of a ready market for natural gas production depends on several factors beyond our control. These factors include regulation of natural gas production, federal and state regulations governing environmental quality and pollution control, the amount of natural gas available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. State and federal regulations generally are intended to prevent waste of natural gas, protect rights to produce natural gas between owners in a common reservoir and control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state, and local agencies.

We believe that we and our operating partners are in substantial compliance with such statutes, rules, regulations and governmental orders, although there can be no assurance that this is or will remain the case. Failure to comply with such laws and regulations can result in substantial penalties. The regulatory burden on our industry increases our cost of doing business and affects our profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted so we are unable to predict the future cost or impact of complying with such laws and regulations.

The following discussion of the regulation of the United States natural gas industry is not intended to constitute a complete discussion of the various statutes, rules, regulations and environmental orders to which our operations may be subject.

Regulation of Oil and Natural Gas Exploration and Production

Our oil and natural gas operations are subject to various types of regulation at the federal, state and local levels. Prior to commencing drilling activities for a well, we (or our operating subsidiaries, operating entities, or operating partners) must procure permits and/or approvals for the various stages of the drilling process from the applicable federal, state and local agencies in the state in which the area to be drilled is located. Such permits and approvals include those for drilling wells, and such regulation includes maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties on which wells are drilled, the plugging and abandoning of wells and the disposal of fluids used in connection with operations. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units and the density of wells which may be drilled and the unitization or pooling of oil and natural gas properties. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of lands and leases. In areas where pooling is voluntary, it may be more difficult to form units, and therefore, more difficult to develop a project, if an operator owns less than 100% of the leasehold. In addition, state conservation laws may establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production.

The effect of these regulations may limit the amount of oil and natural gas we can produce from our wells and may limit the number of wells or the locations at which we can drill. The regulatory burden on the oil and natural gas industry increases our costs of doing business and, consequently, affects our profitability. Inasmuch as such laws and regulations are frequently expanded, amended and reinterpreted, we are unable to predict the future cost or impact of complying with such regulations.

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Split Estate Regulation and Access Difficulties

Frequently, the mineral estate and the surface estate are owned by separate parties (the so-called split estate), so that the surface owner is not receiving the monetary benefit of production from minerals underlying his lands. Although the mineral owner and its lessee (such as Teton) is entitled to use so much of the surface as is reasonably necessary to explore for and produce the minerals, many states have laws which grant the surface owner increased control over the nature and extent of surface use which the oil and gas operator may exercise. Legislation to give the surface owner greater control over use of the surface by the oil and gas operator is pending in several states. In addition, due to the increasing value of surface estates in many areas, the costs to obtain access are increasing.

Natural Gas Marketing, Gathering, and Transportation

Federal legislation and regulatory controls have historically affected the price of natural gas and the manner in which production is transported and marketed. Under the Natural Gas Act of 1938, the Federal Energy Regulatory Commission (FERC) regulates the interstate sale for resale of natural gas and the transportation of natural gas in interstate commerce, although facilities used in the production or gathering of natural gas in interstate commerce are generally exempted from FERC jurisdiction. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act deregulated natural gas prices for all first sales of natural gas, which definition covers all sales of our own production. In addition, as part of the broad industry restructuring initiatives described below, FERC has granted to all producers such as us a blanket certificate of public convenience and necessity authorizing the sale of gas for resale without further FERC approvals. As a result, all natural gas that we produce in the future may now be sold at market prices, subject to the terms of any private contracts that may be in effect.

Natural gas sales prices nevertheless continue to be affected by intrastate and interstate gas transportation regulation, because the prices that companies such as Teton receives for our production are affected by the cost of transporting the gas to the consuming market. Through a series of comprehensive rulemakings, beginning with Order No. 436 in 1985 and continuing through Order No. 636 in 1992 and Order No. 637 in 2000, FERC has adopted regulatory changes that have significantly altered the transportation and marketing of natural gas. These changes were intended by FERC to foster competition by, among other things, transforming the role of interstate pipeline companies from wholesale marketers of gas to the primary role of gas transporters, and by increasing the transparency of pricing for pipeline services. FERC also has developed rules governing the relationship of the pipelines with their marketing affiliates, and implemented standards relating to the use of electronic data exchange by the pipelines to make transportation information available on a timely basis and to enable transactions to occur on a purely electronic basis. In light of these statutory and regulatory changes, most pipelines have divested their gas sales functions to marketing affiliates, which operate separately from the transporter and in direct competition with all other merchants, and most pipelines have also implemented the large-scale divestiture of their gas gathering facilities to affiliated or non-affiliated companies. Interstate pipelines thus now generally provide unbundled, open and nondiscriminatory transportation and transportation-related services to producers, gas marketing companies, local distribution companies, industrial end users and other customers seeking such services. Sellers and buyers of gas have gained direct access to the particular pipeline services they need, and are better able to conduct business with a larger number of counterparties.

Environmental Regulations

Our operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Public interest in the protection of the

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environment has increased dramatically in recent years. The trend of more expansive and stricter environmental legislation and regulations could continue. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes environmental protection requirements that result in increased costs to the oil and natural gas industry in general, our business and prospects could be adversely affected.

The nature of our business operations results in the generation of wastes that may be subject to the Federal Resource Conservation and Recovery Act (RCRA) and comparable state statutes. The U.S. Environmental Protection Agency (EPA) and various state agencies have limited the approved methods of disposal for certain hazardous and non-hazardous wastes. Furthermore, certain wastes generated by our operations (including operations through our operating partners) that are currently exempt from treatment as hazardous wastes may in the future be designated as hazardous wastes, and therefore be subject to more rigorous and costly operating and disposal requirements. Stricter standards in environmental legislation may be imposed on the industry in the future. For instance, legislation has been proposed in Congress from time to time that would reclassify certain exploration and production wastes as hazardous wastes and make the reclassified wastes subject to more stringent handling, disposal and clean-up restrictions. If such legislation were to be enacted, it could have a significant impact on our operating costs, as well as on the industry in general. Compliance with environmental requirements generally could have a materially adverse effect on our capital expenditures, earnings or competitive position.

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as the Superfund law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the present or past owners or an operator of the disposal site or sites where the release occurred and the companies that transported or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damages allegedly caused by the release of hazardous substances or other pollutants into the environment. Furthermore, although petroleum, including natural gas and crude oil, is exempt from CERCLA, at least two courts have ruled that certain wastes associated with the production of crude oil may be classified as hazardous substances under CERCLA and thus such wastes may become subject to liability and regulation under CERCLA. State initiatives further to regulate the disposal of crude oil and natural gas wastes are also pending in certain states and these various initiatives could have adverse impacts on our business.

Our operations may be subject to the Clean Air Act (the CAA) and comparable state and local requirements. Amendments to the CAA were adopted in 1990 and contain provisions that may result in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. The EPA and states have been developing regulations to implement these requirements. We may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues.

The Federal Water Pollution Control Act (the FWPCA or the Clean Water Act) and resulting regulations, which are implemented through a system of permits, also govern the discharge of certain contaminants into waters of the United States. Sanctions for failure strictly to comply with the Clean Water Act are generally resolved by payment of fines and correction of any identified deficiencies.

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However, regulatory agencies could require us to cease construction or operation of certain facilities that are the source of water discharges and compliance could have a materially adverse effect on our capital expenditures, earnings, or competitive position. The Energy Policy Act of 2005 specifically exempted fracturing fluids from regulation as underground injection under the Safe Drinking Water Act, provided that diesel fuel is not used in the fracturing fluid. However, there is talk of repealing that exemption.

Our operations are subject to local, state and federal laws and regulations to control emissions from sources of air pollution. Payment of fines and correction of any identified deficiencies generally resolve penalties for failure strictly to comply with air regulations or permits. Regulatory agencies also could require us to cease construction or operation of certain facilities that are air emission sources. We believe that we substantially comply with the emission standards under local, state, and federal laws and regulations.

Operating Hazards and Insurance

Our exploration and production operations include a variety of operating risks, including the risk of fire, explosions, above-ground and underground blowouts, craterings, pipe failure, casing collapse, abnormally pressured formations, and environmental hazards such as gas leaks, ruptures and discharges of toxic gas, the occurrence of any of which could result in our suffering substantial losses due to injury and loss of life, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. Our pipeline, gathering and distribution operations are subject to the many hazards inherent in the natural gas industry. These hazards include damage to wells, pipelines and other related equipment, and surrounding properties caused by hurricanes, floods, fires and other acts of God, inadvertent damage from construction equipment, leakage of natural gas and other hydrocarbons, fires and explosions and other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

Any significant problems related to our facilities (including jointly owned facilities) could adversely affect our ability to conduct our operations. In accordance with customary industry practice, we maintain insurance against some, but not all, potential risks; however, there can be no assurance that such insurance will be adequate to cover any losses or exposure for liability. The occurrence of a significant event not fully insured against could materially adversely affect our operations and financial condition. We cannot predict whether insurance will continue to be available at premium levels that justify its purchase or whether insurance will be available at all.

Employees

As of December 31, 2006, we had 11 full time employees.

Our employees are not covered by a collective bargaining agreement.

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ITEM 1A. RISK FACTORS.

Risks Related to our Business

We have incurred significant losses. We expect future losses and we may never become profitable.

We have incurred significant losses in the past. For the years ended December 31, 2006, 2005, and 2004, we incurred net losses from continuing operations of $5,724,469, $3,777,449, and $5,193,281, respectively. In addition, we had an accumulated deficit of $30,224,195 at December 31, 2006. We may fail to achieve significant revenues or sustain profitability. There can be no assurance of when, if ever, we will be profitable or, if we do become profitable, will be able to maintain profitability.

Substantially all of our producing properties are located in the Rocky Mountains, making us vulnerable to risks associated with operating in one geographic area.

Our operations are focused on the Rocky Mountain region, which means our producing properties are geographically concentrated in that area. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production from these wells caused by significant governmental regulation, transportation capacity constraints, curtailment of production or interruption of transportation of natural gas produced from the wells in these basins.

If we are unable to obtain additional funding our business operations will be harmed.

We will require additional funding to meet increasing capital costs associated with our operations. Based on our operating partners current capital expenditure plans, we will be unable to participate in additional wells if we are unable to secure additional funding. Although we received approximately $10.8 million from a raise involving the sale of our common stock in July 2006, we cannot assure you that any future offerings will be successful, nor can we estimate when, if such offerings are successful, these offerings will close and capital will become available to us. In addition, although our revolving credit facility provides for availability of up to $50 million, our current borrowing base is only $6 million as of March 12, 2007 and there can be no assurance that our borrowing base will be increased or that additional advances will be made under the revolving credit facility. We do not know if additional financing will be available when needed, or if it is available, if it will be available on acceptable terms. The lack of available future funding may prevent us from implementing our business strategy.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition, or results of operations.

Our future success will depend on the success of our exploitation, exploration, development, and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop, or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Our cost of drilling, completing and operating wells are often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay, or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;

- pressure or irregularities in geological formations;

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- shortages of or delays in obtaining equipment, including drilling rigs, and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions;
- reductions in oil and natural gas prices;
- title problems; and
- limitations in the market for oil and natural gas.

Our business involves numerous operating hazards for which our insurance and other contractual rights may not adequately cover our potential losses.

Our operations are subject to certain hazards inherent in drilling for oil or natural gas, such as blowouts, reservoir damage, loss of production, loss of well control, punchthroughs, craterings, or fires. The occurrence of any one of these events could result in the suspension of drilling operations, equipment shortages, damage to or destruction of the equipment involved and injury or death to rig personnel.

Operations also may be suspended because of machinery breakdowns, abnormal drilling conditions, failure of subcontractors to perform or supply goods or services or personnel shortages. Damage to the environment could also result from our operations, particularly through oil spillage or extensive uncontrolled fires. We may also be subject to damage claims by other oil and gas companies.

Although we and/or our operating partners maintain insurance to cover our operations, pollution and environmental risks generally are not fully insurable. Our insurance policies and contractual rights to indemnity may not adequately cover our losses, and we do not have insurance coverage or rights to indemnity for all risks. If a significant accident or other event occurs and is not fully covered by insurance or contractual indemnity, it could adversely affect our financial position and results of operations.

Acquisitions are a part of our business strategy and are subject to the risks and uncertainties of evaluating recoverable reserves and potential liabilities.

Our business strategy includes a continuing acquisition program. During 2005 and 2006, we completed two separate leasehold acquisitions each year. In addition to the leaseholds, we are seeking to acquire producing properties including the possibility of acquiring a producing property through the acquisition of an entire company. Possible future acquisitions could result in our incurring additional debt, contingent liabilities, and expenses, all of which could have a material adverse effect on our financial condition and operating results. We could be subject to significant liabilities related to our acquisitions.

The successful acquisition of producing and non-producing properties requires an assessment of a number of factors, many of which are inherently inexact and may prove to be inaccurate. These factors include: evaluating recoverable reserves, estimating future oil and gas prices, estimating future operating costs, future development costs, the costs and timing of plugging and abandonment and potential environmental and other liabilities, assessing title issues, and other factors. Our assessments of potential acquisitions will not reveal all existing or potential problems, nor will such assessments permit us to become familiar enough with the properties fully to assess their capabilities and deficiencies. In the course of our due diligence, we may not inspect every well, platform, or pipeline. Inspections may not reveal structural and environmental problems, such as pipeline corrosion or groundwater contamination, when they are made. We may not be able to obtain contractual indemnities from a seller of a property for liabilities that we assume. We may be required to assume the risk of the physical condition of acquired properties in

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addition to the risk that the acquired properties may not perform in accordance with our expectations. As a result, some of the acquired businesses or properties may not produce revenues, reserves, earnings or cash flow at anticipated levels and in connection with these acquisitions, we may assume liabilities that were not disclosed to or known by us or that exceed our estimates.

Our ability to complete acquisitions could be affected by competition with other companies and our ability to obtain financing or regulatory approvals.

In pursuing acquisitions, we compete with other companies, many of which have greater financial and other resources to acquire attractive companies and properties. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our strategy of completing acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Our ability to pursue our acquisition strategy may be hindered if we are not able to obtain financing or regulatory approvals.

Our acquisitions may pose integration risks and other difficulties.

Increasing our reserve base through acquisitions is an important part of our business strategy. Our failure to integrate acquired businesses successfully into our existing business, or the expense incurred in consummating future acquisitions, could result in our incurring unanticipated expenses and losses. In addition, we may have to assume cleanup or reclamation obligations or other unanticipated liabilities in connection with these acquisitions. The scope and cost of these obligations may ultimately be materially greater than estimated at the time of the acquisition.

In addition, the process of integrating acquired operations into our existing operations may result in unforeseen operating difficulties and may require significant management attention and financial resources that would otherwise be available for the ongoing development or expansion of existing operations.

Possible future acquisitions could result in our incurring additional debt, contingent liabilities and expenses, all of which could have a material adverse effect on our financial condition and operating results.

Substantial acquisitions or other transactions could require significant external capital and could change our risk and property profile.

In order to finance acquisitions of additional producing properties, we may need to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of production payments, or other means. These changes in capitalization may significantly affect our risk profile. Additionally, significant acquisitions or other transactions can change the character of our operations and business. The character of the new properties may be substantially different in operating or geological characteristics or geographic location than our existing properties. Furthermore, we may not be able to obtain external funding for future acquisitions, other transactions, or on terms acceptable to us.

Competitive industry conditions may negatively affect our ability to conduct operations.

Competition in the oil and gas industry is intense, particularly with respect to the acquisition of producing properties and of proved undeveloped acreage. Major and independent oil and gas companies actively bid for desirable oil and gas properties, as well as for the equipment, supplies, labor and services required to operate and develop their properties. Some of these resources may be limited and have higher prices due to current strong demand. Many of our competitors have financial resources that are substantially greater than ours, which may adversely affect our ability to compete within the industry.

There is currently a shortage of available drilling rigs and equipment which could cause us to experience higher costs and delays that could adversely affect our operations.

Although equipment and supplies used in our business are usually available from multiple sources, there is currently a general shortage of drilling equipment, drilling supplies, and personnel or firms that provide such services on a contract basis. We believe that these shortages are likely to intensify. The costs of equipment and supplies are substantially greater now than in prior periods and are currently escalating. In addition, the delivery time associated with such equipment and supplies is substantially longer from the date of order until receipt and continues to increase. We and our joint venture partners are also attempting to establish arrangements with others to assure adequate availability of certain other necessary drilling equipment and supplies on satisfactory terms, but there can be no guarantee that we will be able to do so. Accordingly, we cannot assure you that we will not experience shortages of, or material price increases in, drilling equipment and supplies, including drill pipe, in the future. Any such shortages could delay and adversely affect our ability to meet our drilling commitments.

We have limited operating control over our properties.

All of our business activities are conducted through joint operating agreements under which we own partial non-operated interests in oil and natural gas properties. As we do not currently operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures, or future development of underlying properties. Consequently, our operating results are beyond our control. The failure of an operator of our wells to perform operations adequately, or an operator s breach of the applicable agreements, could reduce our production and revenues. In addition, the success and timing of our drilling and development activities on properties operated by others depends upon a number of factors outside of our control, including the operator s timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells, and use of technology. Since we do not have a majority interest in our current properties, we may not be in a position to remove the operator in the event of poor performance. Further, significant cost overruns of an operation in any one of our current projects may require us to increase our capital expenditure budget and could result in some wells becoming uneconomic.

We have no long-term contracts to sell oil and gas.

We do not have any long-term supply or similar agreements with governments or other authorities or entities for which we act as a producer. We are therefore dependent upon our ability to sell oil and gas at the prevailing wellhead market price. There can be no assurance that purchasers will be available or that the prices they are willing to pay will remain stable.

Oil and gas prices fluctuate widely, and low prices for an extended period of time are likely to have a material adverse impact on our business, results of operations and financial condition.

Our revenues, profitability and future growth and reserve calculations depend substantially on reasonable prices for oil and gas. These prices also affect the amount of our cash flow available for capital expenditures, working capital and payments on our debt and our ability to borrow and raise additional capital. The amount we can borrow under our senior unsecured revolving credit facility (see Note 6 to the financial statements) is subject to periodic asset redeterminations based in part on changing expectations of future crude oil and natural gas prices. Lower prices may also reduce the amount of oil and gas that we can produce economically.

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Among the factors that can cause fluctuations are:

- domestic and foreign supply, and perceptions of supply, of oil and natural gas;
- level of consumer demand;
- political conditions in oil and gas producing regions;
- weather conditions;
- world-wide economic conditions;
- domestic and foreign governmental regulations; and
- price and availability of alternative fuels

We have multiple hedges placed on our oil and gas production. See Item 7A Quantitative and Qualitative Disclosures About Market Risk.

Our use of oil and natural gas price hedging contracts involves credit risk and may limit future revenues from price increases and result in significant fluctuations in our net income and shareholders equity.

We enter into hedging transactions for our oil and natural gas production to reduce our exposure to fluctuations in the price of oil and natural gas. Our only hedging transaction to date has consisted of a so-called costless collar, which in a hedging transaction that limits both our downside loss and our upside gain between a certain price range over a defined period of time. See Item 7 Management s Discussion and Analysis of Financial Condition of Operations Cash Flows and Expenditures .

We may in the future enter into these and other types of hedging arrangements to reduce our exposure to fluctuations in the market prices of oil and natural gas. Hedging transactions expose us to risk of financial loss in some circumstances, including if production is less than expected, the other party to the contract defaults on its obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. Hedging transactions may limit the benefit we otherwise would have received from increases in the price for oil and natural gas. Furthermore, if we do not engage in hedging transactions, then we may be more adversely affected by declines in oil and natural gas prices than our competitors that engage in hedging transactions. Additionally, hedging transactions may expose us to cash margin requirements.

The marketability of our production depends mostly upon the availability, proximity and capacity of gas gathering systems, pipelines and processing facilities, which are owned by third parties.

The marketability of our production depends upon the availability, operation, and capacity of gas gathering systems, pipelines and processing facilities, which are owned by third parties. The unavailability or lack of capacity of these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. We currently own an interest in several wells that are capable of producing but may be curtailed from time to time at some point in the future pending gas sales contract negotiations, as well as construction of gas gathering systems, pipelines, and processing facilities. United States federal, state, and foreign regulation of oil and gas production and transportation, tax and energy policies, damage to or destruction of pipelines, general economic conditions and changes in supply and demand could adversely affect our ability to produce and market oil and natural gas. If market factors change dramatically, the financial impact on us could be substantial. The availability of markets and the volatility of product prices are beyond our control and represent a significant risk.

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Our credit facility has substantial restrictions and financial covenants and we may have difficulty obtaining additional credit, which could adversely affect our operations.

Our revolving credit facility limits the amounts we can borrow to a borrowing base amount, determined by our lenders in their sole discretion, based upon, among other things, our level of proven reserves and the projected revenues from the oil and natural gas properties securing our loan. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under the revolving credit facility. Any increase in the borrowing base requires the consent of all of the lenders. If the lenders do not agree on an increase, then the borrowing base will be the lowest borrowing base acceptable to the required number of lenders.

Outstanding borrowings in excess of the borrowing base must be repaid immediately, or we must pledge other oil and natural gas properties as additional collateral. Upon a downward adjustment of the borrowing base, if borrowings in excess of the revised borrowing base are outstanding, we could be forced to repay our indebtedness under the revolving credit facility if we do not have any substantial unpledged properties to pledge as additional collateral.

We may not have sufficient funds to make repayments under our revolving credit facility. We cannot assure you that we will be able to generate sufficient cash flow to pay the interest on our debt, or will be able to refinance such debt through equity financings or by selling assets. The terms of our revolving credit facility also may prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions and our market value and operating performance at the time of such offering or other financing. We cannot assure you that any such offering, refinancing or sale of assets can be successfully completed.

Our debt level and the covenants in the agreements governing our debt could negatively impact our financial condition, results of operations and business prospects.

Our level of indebtedness, and the covenants contained in the agreements governing our debt, could have important consequences for our operations, including:

- increasing our vulnerability to general adverse economic and industry conditions and detracting from our ability to withstand successfully a downturn in our business or the economy generally;
- requiring us to dedicate a substantial portion of our cash flow from operations to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate and other activities;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- placing us at a competitive disadvantage relative to other less leveraged competitors; and
- making us vulnerable to increases in interest rates, because borrowings under our credit facility may be at rates prevailing at the time of each borrowing.

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The instruments governing our indebtedness contain various covenants limiting the discretion of our management in operating our business.

Our revolving credit facility contains various restrictive covenants that limit our management s discretion in operating our business. In particular, these agreements will limit our and our subsidiaries ability to, among other things:

- pay dividends on, redeem or repurchase our capital stock or redeem or repurchase our subordinated debt, if any;
- make loans to others;
- make investments;
- incur additional indebtedness or issue preferred stock;
- create certain liens;
- sell assets;
- enter into agreements that restrict dividends or other payments from our subsidiaries to us;
- consolidate, merge or transfer all or substantially all of the assets of us and our subsidiaries taken as a whole;
- engage in transactions with affiliates;
- enter into hedging contracts;
- create unrestricted subsidiaries; and
- enter into sale and leaseback transactions.

In addition, our revolving credit facility also requires us to maintain a certain working capital ratio and a certain debt to EBITDAX (as defined in the revolving credit facility as earnings before interest, taxes, depreciation, amortization and exploration expense) ratio. If we fail to comply with the restrictions in the revolving credit facility (or any other subsequent financing agreements), a default may allow the creditors (if the agreements so provide) to accelerate the related indebtedness as well as any other indebtedness to which a cross-acceleration or cross-default provision applies. In addition, lenders may be able to terminate any commitments they had made to make available further funds.

Our development and exploration operations require substantial capital and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our natural gas and oil reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration for and development, production and acquisition of oil and natural gas reserves. To date, we have financed capital expenditures primarily with equity financings as well as from cash generated from the sale of our Russian operations. We anticipate being able to finance our future capital expenditures with a combination of cash flow from operations, our existing financing arrangements, and equity financings. Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- the prices at which oil and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

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If our revenues or the borrowing base under our revolving credit facility decrease as a result of lower oil and natural gas prices, operating difficulties, declines in reserves or for any other reason, then we may have limited ability to obtain the capital necessary to sustain our operations at current levels. We may, from time to time, need to seek additional financing. We cannot assure you of the availability or terms of any additional financing.

If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our natural gas and oil reserves.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in our financial statements.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We also must analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and natural gas reserves are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves in our financial statements. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those presented using the present value estimate.

Seasonal weather conditions and lease stipulations can adversely affect the conduct of drilling activities on our properties.

Oil and natural gas operations can be adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife, particularly in the Rocky Mountain region where we currently operate. In certain areas, drilling and other oil and natural gas activities can only be conducted during the spring and summer months. This may limit operations in those areas and can intensify competition during those months for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. Resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

Unless we replace our oil and natural gas reserves, our level of reserves and production will decline, which would adversely affect our cash flows and income.

Unless we conduct successful development, exploitation, and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and, therefore our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire additional reserves to replace our current and future production.

The loss of key personnel could adversely affect our business.

We currently have four employees that serve in senior management roles. In particular, our Chief Executive Officer, Karl F. Arleth, our Chief Operating Officer, Dominic J. Bazile II, and our Vice President of Production, Andrew N. Schultz, are responsible for the operation of our oil and gas business and Bill I. Pennington, our Executive Vice President, Treasurer, and Chief Financial Officer, oversees our finance and administrative organizations. The loss of any one of these employees could severely harm our business. Although we have a life insurance policy on Mr. Arleth, of which we are a beneficiary, we do not currently maintain key man insurance on the lives of any of the other three individuals. Furthermore, competition for experienced personnel is intense. If we cannot retain our current personnel or attract additional experienced personnel, our ability to compete could be adversely affected.

Rising inflation and price increases could have a negative effect on our value and increase our costs.

We may experience increased costs during 2007 and 2008 due to increased demand for oil and gas field products and services. The oil and natural gas industry is cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry can place extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Historically in the oil and gas industry, material changes in prices also impact the current revenue stream, estimates of future reserves, borrowing base calculations of bank loans and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and natural gas companies and their ability to raise capital, borrow money and retain personnel. While we do not currently expect business costs materially to increase, continued high prices for oil and natural gas could result in increases in the costs of materials, services and personnel.

Our inability to meet operating and financial obligations could adversely affect our business.

We have obligations and commitments related to our operations as well as our general and administrative activities. Our partners in our various projects have expectations that we will fund our proportionate share of drilling and related capital costs each year. Our commitments are expected to increase significantly as our operating partners increase their drilling activities and we incur additional cash calls in respect of these projects. In the event that we are unable to maintain our funding obligations in respect of our projects, we may be deemed to have gone non-consent, which will result in a project s other partners funding a well s operating costs without us. If we go non-consent on a well, the consequences to us likely will enable the consenting partners to recover their costs plus an agreed-upon percentage (typically 300% to 400%) before we will be entitled to participate in any of the future economics of the

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well, if at all. Our general and administrative commitments principally include our office lease, under which we are contractually obligated until 2009.

Risks Relating To Our Common Stock

Our stock price and trading volume may be volatile, which could result in losses for our stockholders.

The equity trading markets may experience periods of volatility, which could result in highly variable and unpredictable pricing of equity securities. The market price of our common stock could change in ways that may or may not be related to our business, our industry, or our operating performance and financial condition. In addition, the trading volume in our common stock may fluctuate and cause significant price variations to occur. Some of the factors that could negatively affect our share price or result in fluctuations in the price or trading volume of our common stock include:

- actual or anticipated quarterly variations in our operating results;
- changes in expectations as to our future financial performance or changes in financial estimates, if any, of public market analysts;
- announcements relating to our business or the business of our competitors;
- conditions generally affecting the oil and natural gas industry;
- the success of our operating strategy; and
- the operating and stock price performance of other comparable companies.

Many of these factors are beyond our control, and we cannot predict their potential effects on the price of our common stock.

Our insiders beneficially own a significant portion of our stock.

As of December 31, 2006 our executive officers, directors and affiliated persons beneficially own approximately 14.55 % of our common stock. As a result, our executive officers, directors and affiliated persons will have significant influence to:

- elect or defeat the election of our directors;
- amend or prevent amendment of our articles of incorporation or bylaws;
- effect or prevent a merger, sale of assets or other corporate transaction; and
- affect the outcome of any other matter submitted to the stockholders for vote.

In addition, sales of significant amounts of shares held by our directors and executive officers, or the prospect of these sales, could adversely affect the market price of our common stock. Management s stock ownership may discourage a potential acquirer from making a tender offer or otherwise attempting to obtain control of us, which in turn could reduce our stock price or prevent our stockholders from realizing a premium over our stock price.

We do not expect to pay dividends in the foreseeable future. As a result, holders of our common stock must rely on stock appreciation for any return on their investment.

We do not anticipate paying cash dividends on our common stock in the foreseeable future. Our existing credit agreement prohibits the payment of cash dividends without lender consent. Any payment of cash dividends also will depend on our financial condition, results of operations, capital requirements and other factors and will be at the discretion of our board of directors. Further, our current business strategy calls for the reinvestment of cash flow from operations back into our business. Accordingly, holders of our common stock will have to rely on capital appreciation, if any, to earn a return on their investment in our common stock.

The anti-takeover effects of provisions of our charter, by-laws, and shareholder rights plan, and of certain provisions of Delaware corporate law, could deter, delay, or prevent an acquisition or other change in control of us and could adversely affect the price of our common stock.

Our amended certificate of incorporation, our by-laws, our shareholder rights plan and Delaware General Corporation Law contain various provisions that could have the effect of delaying or preventing a change in control of us or our management which shareholders may consider favorable or beneficial. These provisions include the following:

- We are authorized to issue blank check preferred stock, which is preferred stock that can be created and issued by the board of directors without prior shareholder approval, with rights senior to those of our common shareholders;

- We have a shareholder rights plan that could make it more difficult for a third party to acquire us without the support of our board of directors and principal shareholders.

- We are subject to Section 203 of the Delaware General Corporation Law, or the DGCL. In general, Section 203 of the DGCL prohibits a publicly held Delaware corporation from engaging in a business combination with an interested stockholder for a period of three years after the date of the transaction in which the person became an interested stockholder. A business combination includes a merger, sale of 10% or more of our assets and certain other transactions resulting in a financial benefit to the stockholder. For purposes of Section 203, an interested stockholder includes any person that is:

  - the owner of 15% or more of the outstanding voting stock of the corporation;

  - an affiliate or associate of the corporation and was the owner of 15% or more of the outstanding voting stock of the corporation, at any time within three years immediately prior to the relevant date; and

  - an affiliate or associate of the persons defined as an interested shareholder.

Any one of these provisions could discourage proxy contests and make it more difficult for our shareholders to elect directors and take other corporate actions. These provisions also could limit the price that investors might be willing to pay in the future for shares of our common stock.

ITEM 2. DESCRIPTION OF PROPERTIES.

We currently operate in three basins in the Rocky Mountain region of the United States: the Piceance Basin, which is located in northwestern Colorado, Denver-Julesburg (DJ) Basin, which is located in eastern Colorado and western Nebraska and the Williston Basin, which is located in Williams County, North Dakota.

Piceance Basin

Teton s properties in the Piceance Basin consist of a 25% working interest (19.69% net revenue interest) in a 6,314-acre block located in Garfield County, Colorado, townships T5S-96W and T6S-96-97W, immediately to the northwest of Grand Valley gas field, the westernmost of the four gas fields that comprise the continuous, basin-centered, tight gas sand accumulation (the Piceance Fairway).

These properties are in the vicinity of major gas production from continuous basin-centered, tight gas sand accumulations within the Williams Fork formation of the Upper Cretaceous Mesaverde group and the shallower Lower Tertiary Wasatch formation. The primary targets for drilling on this large acreage position are the 1,500 -2,500 thick, gas-saturated sands of the middle and lower Williams Fork formation at approximately 6,000 -9,000 in depth. In addition, the subject acreage is surrounded on the west, east, and southeast by completed gas wells. To the northwest of the block is the Trail Ridge gas field (Wasatch and Mesaverde). To the west, south, and east are gas wells of the greater Grand Valley field.

We estimate, based on current service company costs as well as our past drilling experience, that drilling and completion costs for a Williams Fork well will range between $1.8 million and $2.5 million. Based on currently approved field spacing rules, we and our partners in this acreage believe we can drill as many as 628 wells on the 6,314-acre block with an estimated average 1.3 BCF ultimate recovery per well. Our natural gas production in this area is gathered by the gathering system owned by us and our partners and is currently delivered to markets through a pipeline owned by Encana, another operator in this area.

Eastern DJ Basin

We acquired our first interest in this play between April 2005 and July 2005 through a series of transactions that resulted in our accumulating an excess of 182,000 gross acres with a net revenue interest of approximately 81.0%. At the end of 2005 our undeveloped acreage position was approximately 195,252 gross acres in the Eastern Denver-Julesburg Basin (the DJ Basin) located in Nebraska on the Nebraska-Colorado border which is located on the eastern flank of the DJ basin in Chase, Dundy, Perkins, and Keith counties in Nebraska.

The drilling target of this play is primarily the Niobrara formation, within which is trapped biogenic gas in the Beecher Island chalk of the Upper Cretaceous Niobrara formation. The gas is contained in shallow structural traps at depths ranging from 1,700-2,500 feet. The acreage is located approximately 20 to 30 miles to the east of the main Niobrara gas productive trend that has been established to the west in Yuma, Phillips, and Sedgwick counties, Colorado and in Duell and Garden counties, Nebraska. Based on current service company rates, we and our operating partner anticipate that gross drilling and completion costs for a Niobrara well are approximately $200,000.

In 2006, we acquired an additional 14,932 gross acres in the DJ Basin through Nebraska state acreage sales bringing our total gross acreage in the DJ Basin to 210,184 gross acres. On December 15, 2006, we closed on an agreement to purchase an additional leasehold interest in the DJ Basin with an undisclosed third party. The agreement called for the acquisition of approximately 56,389 gross acres. Approximately, 45,773 net acres were within the Teton / Noble AMI and approximately 10,616 gross acres outside the AMI. Noble agreed to accept its 75% interest in the acreage within the AMI. As of December 31, 2006, our total gross acreage in the DJ Basin is 266,572 acres, of which 255,956 gross acres is in the Teton / Noble AMI and 10,616 gross acres is outside of the AMI. At December 31, 2006, we have a net acreage position of 57,834 net acres within the Teton / Noble AMI and 8,550 net acres outside the AMI. Our interests in the oil and gas rights and leases are recorded directly to Teton DJ Basin LLC, a wholly owned subsidiary of the Company.

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Williston Basin

On May 5, 2006, we closed a definitive agreement with American Oil and Gas, Inc. (American) acquiring a 25% working interest in approximately 87,192 gross acres in the Williston Basin located in North Dakota for a total purchase price of approximately $6.17 million, as further described below.

Per the terms of the agreement, we paid American approximately $2.47 million in cash at closing and would pay an additional $3.7 million in respect of American s 50% share of the drilling and completion costs of the first two planned wells through June 1, 2007. Any portion of the $3.7 million not paid to American for drilling and completion costs by June 1, 2007, will be paid to American on that date. In addition to our obligation to fund American s share, we are also obligated to pay costs in respect of our own 25% working interest of drilling and completion costs of such wells during the same time period. As of December 31, 2006, we have paid to American approximately $3.0 million of the initial obligation of $3.7 million resulting in a remaining accrued purchase consideration of $775,054.

In addition to our 25% working interest and American s 50% working interest, we have one other partner in the acreage: Evertson Energy Company (Evertson), who is the operator and has a 25% working interest. Evertson began drilling the Champion 1-25H well, a tri-lateral horizontal test that was drilled to the Mississippian Bakken Formation (at a depth of about 10,500 feet), on September 25, 2006. The estimated cost for the Champion 1-25H is approximately $6.8 million to drill, complete and test. As of the date of this report Evertson was testing the Champion 1-25H.

If economic recoveries are confirmed by the initial test well, a revised capital spending program will be announced later in 2007. If full field development occurs, the Company estimates that there may be up to 134 additional unrisked drilling locations on 640 acre spacing.

Production Data

The chart below sets forth certain production data for the fiscal years ended December 31, 2006 and 2005, for the period ended June 30, 2004, prior to the sale of our Russian operations. There was no oil and gas production activity from July 1, 2004 through December 31, 2004. Additional oil and gas disclosures can be found in Note 12 of the Financial Statements. Production data with respect to 2004 represents results of discontinued operations from our former operations in the western Siberian region of the Russian Federation. We sold our interest in these assets effective as of July 1, 2004.

	2006	2005	2004
Total gross oil production, barrels			1,393,616
Total gross gas production, MCF	3,744,379	457,331	
Net oil production, barrel[(1)]			348,404
Net gas production, MCF[(1)]	737,175	90,037	
Average oil sales price, $/Bbl[(2)]			$ 18.98
Average gas sales price, $/MCF[(3)]	$ 4.78	$ 7.86	
Average production cost per barrel[(4)]			$ 16.12
Average production cost per MCF including production taxes	$ 0.78	$ 1.10	
Gross productive wells			
Oil			24.0
Gas	20.0	3.0	
Total	**20.0**	**3.0**	**24.0**
Net productive wells			
Oil			12.0
Gas	5.00	0.75	
Total	**5.00**	**0.75**	**12.00**

(1) Net production and net well count is based on Teton s effective net interest as of the end of each year.

(2) Average oil sales price is a combination of domestic (Russian) and export price.

(3) Average gas sales price excludes fuel, gathering, transportation

and marketing fees.

(4) Excludes production payment to Limited Liability Company Energosoyuz-A.

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Net Wells Drilled

The following chart sets forth the number of productive wells and dry exploratory and productive wells drilled and completed during the last three fiscal years. For the year ended December 31, 2004, the wells are in respect of our former Russian operations (our Goloil license) prior to the sale of our interest in such license, effective July 1, 2004:

	Year Ended December 31,					
	2006		2005		2004	
	Gross	Net (1)	Gross	Net (1)	Gross	Net (1)
Number of Wells Drilled						
Exploratory						
Productive			3.00	0.75		
In progress (2)	18.00	4.27	7.00	1.75		
Dry (3)	4.00	1.00				
Total	**22.00**	**5.27**	**10.00**	**2.50**		
Development (4)						
Productive	20.00	5.00			3.00	1.50
In progress	8.00	2.00				
Dry						
Total	**28.00**	**7.00**			**3.00**	**1.50**
Total						
Productive	20.00	5.00	3.00	0.75	3.00	1.50
In progress	26.00	6.27	7.00	1.75		
Dry	4.00	1.00				
Total	**50.00**	**12.27**	**10.00**	**2.50**	**3.00**	**1.50**

(1) Net well count is based on Teton s effective net interest as of the end of each year.

(2) The 18 exploratory gross wells in progress as of December 31, 2006 are 16 gross wells in the DJ Basin and 2 gross wells in the

Williston Basin (1 gross well at 25% working interest and 1 gross well at 1.56% working interest).

(3) The 4 gross dry holes are in the DJ Basin as of December 31, 2006.

(4) The 28 development gross productive wells and in progress wells as of December 31, 2006 are in the Piceance Basin.

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Developed and Undeveloped Acreage

The following table sets forth the total gross and net developed acres and total gross and net undeveloped acres of the Company as of December 31, 2006:

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
Piceance Basin, Colorado	200	50	6,114	1,529
Eastern DJ Basin, Nebraska			256,749	58,627
Eastern DJ Basin, Colorado			9,823	7,757
Williston Basin, North Dakota			87,192	16,024
Total	**200**	**50**	**359,878**	**83,937**

Our offices are located in Denver, Colorado. We lease our offices from an unaffiliated third party. The term of our lease is three years, and the lease expires on April 30, 2009.

ITEM 3. LEGAL PROCEEDINGS.

We are not a party to any legal proceedings.

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

No matters were submitted to a vote of our security holders during the fourth quarter of 2006.

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PART II

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

Our common stock is listed and principally traded on the American Stock Exchange, under the symbol TEC. Our common stock is also listed for trading on the Frankfurt Stock Exchange (Germany) under the symbol TP9.

The following table sets forth, on a per share basis, the high and low closing price on the American Stock Exchange:

	High	Low
2006 period		
First quarter	$8.75	$6.01
Second quarter	$7.49	$5.06
Third quarter	$5.84	$4.34
Fourth quarter	$5.30	$4.20
2005 period		
First quarter	$3.81	$1.32
Second quarter	$4.53	$2.06
Third quarter	$8.00	$4.45
Fourth quarter	$7.20	$4.90

As of December 31, 2006, there were approximately 149 holders of record of our common stock.

Dividends: We have not paid any dividends on our common stock since inception, and we do not anticipate the declaration or payment of any dividends at any time in the foreseeable future.

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Performance Graph

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

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among Teton Energy Corporation, The Russell 2000 Index
And A Peer Group

* $100 invested on 12/31/01 in stock or index-including reinvestment of dividends. Fiscal year ending December 31.

Recent Issuances of Unregistered Securities

During the fourth quarter of 2006, there were no issuances of unregistered securities to unaffiliated third parties.

On December 31, 2006, 65,001 shares were issued as a result of the partial vesting of a previously granted restricted stock award to an officer and two directors.

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Equity Compensation Plan Information

The following table sets forth information about our equity compensation plans at December 31, 2006:

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted Avg. Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance
Equity compensation plans approved by security holders:			
2003 Employee Stock Compensation Plan(1)	2,088,545	$ 3.56	
2005 Long-term Incentive Plan:			
Performance Share Units(2)	1,911,000	(3)	(4)
Restricted Common Stock Grants(5)	193,999	$ 5.98	

(1) The 2003 Employee Stock Compensation Plan was terminated upon the adoption of the LTIP. See Note 8 to the financial statements.

(2) The total 1,911,000 stretch performance share units consists of 355,000 and 1,556,000 stretch performance share units for the 2005 and 2006 grant years, respectively, and are available for future

performance awards under the Company s LTIP. See Note 8 to the financial statements for description of the 2005 and 2006 grants and the Company s LTIP.

(3) Not applicable.

(4) The Company s Long-Term Incentive Plan (the LTIP) provides for the issuance of a maximum number of shares of common stock equal to 20% of the total number of shares of Common Stock outstanding as of the effective date for the LTIP s first year and for each subsequent LTIP year (i) that number of shares equal to 10% of the total number of shares of Common Stock outstanding as of the first day of each respective LTIP year, plus (ii) that number of shares of Common Stock reserved and

available for issuance but unissued during any prior plan year during the term of the LTIP; provided, however, that in no event shall the number of shares of Common Stock available for issuance under the LTIP as of the beginning of any year plus the number of shares of Common Stock reserved for outstanding awards under the LTIP exceed 35% percent of the total number of shares of Common Stock outstanding at that time, based on a three-year period of grants.

(5) Represents restricted stock shares made pursuant to the Company s LTIP which vest over a 3 year period from date of grant.

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ITEM 6. SELECTED FINANCIAL DATA.

The following table sets forth selected financial data, derived from the financial statements, regarding our financial position and results of operations as of the dates indicated. This selected financial data should be read in conjunction with our financial statements and notes to the financial statements.

	As of and for the Year Ended December 31,				
	2006	**2005**	**2004**	**2003**	**2002**
Summary of Operations					
Oil and gas sales	$ 3,528,558	$ 707,420	$	$	$
Loss from continuing operations	(5,724,469)	(3,777,449)	(5,193,281)	(4,036,164)	(10,191,307)
Discontinued operations, net of tax		(255,000)	12,383,582	(1,598,680)	(782,616)
Net income (loss)	$ (5,724,469)	$ (4,032,449)	$ 7,190,301	$ (5,634,844)	$(10,973,923)
Income (loss) per share for:					
Continuing operations	$ (0.44)	$ (0.38)	$ (0.64)	$ (1.00)	$ (3.28)
Discontinued operations		$ (0.02)	$ 1.37	$ (0.23)	$ (0.25)
Net income	$ (0.44)	$ (0.40)	$ 0.73	$ (1.23)	$ (3.53)
Balance Sheet					
Total assets	$41,243,707	$22,131,495	$17,611,565	$20,718,375	$ 10,012,395
Notes payable					$ 507,001
Cash dividends per common share					

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

The following discussion and analysis of our plan of operation should be read in conjunction with the financial statements and the related notes. This management s discussion and analysis of financial condition and results of operations is intended to provide investors with an understanding of our past performance, financial condition, and prospects.

Overview

We are an independent oil and gas exploration and production company with operations in the Rocky Mountain region of the U.S. We generate revenues by the production of oil and gas (principally natural gas at this time) from properties which we own independently or with other parties. Currently we have interests in three different plays: We own a 25% working interest in a drilling program in the Piceance Basin in western Colorado on 6,314 gross acres (1,579 net to the Company), a separate acreage play of 266,572 gross acres (66,384 net to the Company) in the eastern DJ Basin in eastern Colorado and western Nebraska and a separate acreage play of over 87,192 gross acres (16,024 net to the Company) in the Williston Basin in North Dakota. Prior to July 1, 2004, our primary focus was oil and gas exploration, development and production in the Russian Federation and former Commonwealth of Independent States

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(CIS) (see Note 4 to the financial statements). Since the sale of our Russian assets, our focus has been on acquiring and developing assets in North America, with a particular emphasis on the Rocky Mountain Region in the United States. At December 31, 2006, our Piceance program had 20 wells on production. There was no production at December 31, 2006 with respect of the acreage in the DJ and Williston Basins.

Financial highlights for the year ended December 31, 2006 include the following:

We sold 737,175 mcf of natural gas from our Piceance Basin properties at an average wellhead price of $5.45 per mcf. Actual price realization after fuel, gathering, marketing, and transportation averaged $4.78 per mcf, resulting in revenues net to us of $3,528,558.

Our net loss from continuing operations increased to $5,724,469 in 2006 ($0.44 per share) from $3,777,449 in 2005 ($0.38 per share).

On August 2, 2006, we closed on a public offering of 2,300,000 shares of our common stock, which was priced on July 27, 2006, at $5.20 per share. Petrie Parkman & Co., served as the sole underwriter and book-running manager for the offering. Total shares delivered at closing included the underwriter s over-allotment option to purchase 300,000 additional common shares, which was exercised at closing. As a result of the underwriter s exercise of its over-allotment option, net proceeds of the offering were $10.8 million.

The following summarizes our operational highlights during 2006:

We participated in the drilling of 18 gross wells (4.5 net to us) in 2006 in the Piceance Basin. As of December 31, 2006, we had 20 gross wells (5 net to us) on production and drilled another 8 gross wells of which 6 gross wells have been drilled to the total depth (1.50 net to us), of which all 8 gross wells are planned to be on production in 2007.

In May 2006, we acquired from American a 25% working interest in approximately 87,192 gross acres (16,024 net to us) in the Williston Basin for a total purchase price of approximately $6.17 million. We are participating with American and Evertson (the operator) in the drilling of one tri-lateral horizontal well, the Champion 1-25H. Currently, the Champion 1-25H is being tested for production. The estimated cost for the Champion 1-25H well is approximately $6.8 million to drill, complete and test.

We participated in the drilling of 20 wells as part of the initial pilot program with Noble Energy, Inc. on our acreage block in the DJ Basin, which includes approximately 266,572 gross acres. We were carried for our 25 % working interest on the first 20 wells with Noble. Ten of the 20 wells were drilled in the Chundy prospect area located in Chase and Dundy Counties, Nebraska, and 7 of those wells have been logged, cased and fracture stimulated and are currently awaiting sales connection. One well has been logged and cased, and awaiting completion, and 2 wells were dry holes. The other 10 wells were drilled in the Grant prospect area located in Grant County, Nebraska of which 6 wells were logged, cased and are waiting on completion, 2 wells were perforated and fracture stimulated, and 2 wells were plugged and abandoned. On March 14, 2007, the Company announced that 5 of the 20 pilot wells in the Chundy area were put on production by Noble as part of a flow rate test to ascertain commercial viability. Additional wells will be connected during the near term as part of this test.

During 2006, we also concentrated on identifying opportunities to acquire additional properties primarily in the Rocky Mountain region of the United States. We are concentrating on close-in exploration and/or extension development projects involving resource plays in basins deemed to be prolific.

Results of Operations 2006 Compared to 2005

We had a net loss from continuing operations for 2006 of $5,724,469 compared to a net loss of $3,777,449 for the same period in 2005. Factors contributing to the larger net loss for the year included the following:

Oil and gas production net to our interest in 2006 was 737,175 mcf resulting in $3,528,558 in oil and gas sales, at an average wellhead price of $5.45 per mcf for the year. Our price per mcf, net of fuel, gathering, transportation and marketing fees totaled $493,548 which equates to $4.78 per mcf. In 2005 our net production began in July 2005. Oil and gas production net to us in 2005 was 90,037 mcf resulting in $707,420 in oil and gas sales, at an average wellhead price of $8.90 per mcf for the year. Our price net of fuel, gathering, transportation and marketing fees totaled $89,209 or $7.86 per mcf.

After taking into account lease operating expenses and production taxes for 2006 ($325,057 and $250,528, respectively, which costs represent 16% of revenues combined), our 2006 operating income from oil and gas activities equates to $2,952,973 before depletion and depreciation, exploration costs, general and administrative expenses, accretion expense, and other income. Including lease operating expenses and production taxes for 2005 ($50,932 and $48,196, respectively, which costs represent 14% of revenues combined), operating income from oil and gas activities for 2005 equates to $608,292 before depletion and depreciation, exploration costs, general and administrative expenses, accretion expense, and other income.

During 2006, general and administrative expenses increased from $4,006,747 during 2005 to $7,147,792, a $3,141,045 increase which is primarily due to an increase in non-cash charges associated with our stock-based compensation with implementation of SFAS 123R as described in greater detail below. Significant increases to general and administrative expenses for the year ended December 31, 2006 compared to 2005 include:

An increase in compensation expense of $3,138,842, which increase was due primarily to $2,623,830 of non-cash compensation expense of stock-based grants as a result of the actual performance milestones associated with our long-term incentive plan and our adoption of Statement of Financial Accounting Standard 123R Share-Based Payment, effective as of January 1, 2006 and a non-cash expense of $486,518 associated with restricted stock grants. In addition, compensation expense increased $787,707 as a result of an increase in the number of full time employees (from 6 employees in 2005 to 11 employees in 2006) and a cash bonus expense increase of approximately $610,000 from 2005 to 2006. A full-time CFO was hired to replace an outside contractor CFO, which increased salary and bonus costs, but reduced outside contractor fees as described below.

Consulting expenses associated with engineering, marketing, investor relations and financial services rendered increased $201,666 in 2006 from 2005.

Office expense increased $160,788 in 2006 from 2005 due to the increased administrative and computer support as well as additional office space leased.

During the year ended December 31, 2006; certain general and administrative expenses were lower than in the prior year period:

Legal and accounting costs decreased by $1,059,484 from the prior year period in 2005. Of the $1,059,484 decrease, $795,375 was due to non-cash issuance of common stock for accounting and legal services rendered in 2005. In 2006 we received back 50,000 shares of common stock as a refund of accounting services (that reduced our general and administrative expenses in 2006) valued at $157,500. The remaining

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decrease in 2006 of approximately $105,000 is primarily due to the replacement of a part-time, contract CFO with a full-time, in-house CFO in 2006.

Exploration expenses for 2006 relate to delay rentals and geological and geophysical expenses incurred by us primarily on the eastern DJ Basin leases, which were acquired in 2005.

Depletion and depreciation expense increased from $181,276 in 2005 to $1,724,854 in 2006 due to the higher gas production volumes in 2006 compared to 2005.

During 2006 we recognized an unrealized derivative gain of $402,867 in respect to a derivative contract (natural gas costless collar). In 2005 we did not have any derivative contracts.

Other income in 2006 includes interest income from the cash balances maintained.

Results of Operations 2005 Compared to 2004

During 2005 we sold 90,037 mcf of natural gas from our Piceance Basin properties at an average wellhead price of $8.90. Actual price realization after fuel, gathering, marketing, and transportation averaged $7.86 per mcf, resulting in revenues net to us of $707,420.

Our net loss from continuing operations decreased to $3,777,449 in 2005 ($0.38 per share) from $5,193,281 in 2004 ($0.64 per share).

The improved results between 2005 and 2004, were largely based on a combination of the commencement of revenues for our Piceance operations coupled with a reduced staff and infrastructure associated with the closing of our Russian-related operations, which occurred at the beginning of 2005.

The following summarizes our operational highlights during 2005:

On February 15, 2005, we acquired a 25% interest in Piceance LLC, which owned 6,314 acres in the Piceance Basin, for a total purchase price, including the fair value of stock and warrants issued, of approximately $6.4 million.

During the second quarter of 2005, we acquired an interest in an estimated 182,000 gross acres in the Eastern DJ Basin for a total investment, including the fair value of stock and warrants issued of approximately $4.2 million.

Piceance LLC drilled and completed three wells in 2005 and drilled to total depth an additional seven wells, which seven wells came on production in the first half of 2006.

We had a net loss from continuing operations for 2005 of $3,777,449 compared to a net loss of $5,193,281 for the same period in 2004. Factors contributing to the smaller net loss for the year included the following:

Oil and gas production net to our interest in 2005 was 90,037 mcf resulting in $707,420 in oil and gas sales, at an average wellhead price of $8.90 per mcf for the year. Our price net of fuel, gathering, transportation and marketing fees totaling $89,209 or $7.86 per mcf. Our net production began in July 2005. Oil and gas production net to us in 2004 was 384,404 bbls. Revenues between 2005 and 2004 are not comparable, as effective July 1, 2004 we sold our Russian oil production.

Lease operating expenses for the year were $50,932 and production taxes were $48,196 (or 7% of revenues) net to us resulting in operating income from oil and gas activities from Piceance LLC of $608,292 before depreciation and depletion, exploration costs, general and administrative expenses and other income. Lease operating expenses include $30,909 incurred directly by us for consultants working directly on the Piceance Basin properties.

During 2005, general and administrative expense decreased from $5,332,991 during 2004 to $4,006,747 for 2005. General and administrative expenses include the non-cash expense of $795,375 recorded in conjunction with the issuance of common stock to certain individuals affiliated with the Company. Factors contributing to the decrease in administrative expense in 2005 included reduced due diligence costs associated with the pursuit of acquisitions (including acquisitions that failed to close), elimination of our Moscow, Steamboat Springs, and Houston offices (which were associated with our former Russian operations), reduction in investor relations-related expenses, and reduction of corporate personnel associated with our overseas operations.

Significant changes in general and administrative expenses, exclusive of the $795,375 non-cash charge relating to the issuance of stock for the year ended December 31, 2005 compared to 2004 include:

Advertising and public relations and related consulting expenses decreased $457,820 in 2005 primarily due to the fact that we eliminated several consulting contracts in the second quarter of 2004 and expensed the costs to terminate such contracts during such quarter.

We expensed $415,494 in due diligence costs in 2004 compared to $28,886 in 2005 related to acquisitions that were not completed.

Our public company compliance expense and related legal and accounting expenses decreased $251,476 in 2005. Significant costs were incurred in 2004 related to the sale of our Russian operations, legal and accounting expense incurred on acquisitions that did not close and costs to prepare the proxy to solicit votes for the sale of our Russian operations. Components of our compliance and legal costs incurred in 2005 include costs incurred in respect to the establishment of the shareholders rights plan, the Long Term Incentive Plan, the preparation of three registration statements, and legal costs associated with the departure of one of our former officers and directors.

Franchise taxes, included in general and administrative expenses decreased $64,483 in 2005.

Travel and entertainment expenses decreased $217,581 in 2005 relative to 2004 as we no longer incur the significant costs of traveling to Russia.

Compensation paid to employees decreased $572,911 in 2005 relative to 2004 because we reduced our number of employees from 11 to 6, partially offset by an increase in severance paid to employees of $222,000, primarily related to the severance costs recorded for a former officer and director.

Exploration expenses for 2005 relate to delay rentals and geological and geophysical expenses incurred by us primarily on the eastern DJ Basin leases that were acquired in April.

Outlook for 2007

The following summarizes our goals and objectives for 2007:

Continue to develop the Piceance Basin acreage.

Increase our liquidity through increases in our senior credit facility borrowing base and consummation with other capital market transactions.

Determine the commerciality of our DJ Basin play with Noble and continue to develop the acreage as appropriate.

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Determine the commerciality of our Williston Basin play with Evertson/American and continue to develop the acreage as appropriate.

Pursue additional oil and gas asset and project acquisitions including an operated property.

Continue to build up our operating staff and related capabilities.

Liquidity and Capital Resources

At December 31, 2006, we had a cash balance of $4,324,784 and a working capital deficit of $1,118,993.

We currently estimate the cost of our Piceance development program to be approximately $20.4 million for the year ending December 31, 2007. In addition, we are planning on additional development projects in the DJ basin, conditioned on our evaluation of performance of the first test wells, that would increase our overall 2007 development plan by as much as $6.9 million, including seismic, gathering lines and development drilling and completion/facility costs. Our planned 2007 development and exploration expenses also could increase if any of the operations associated with our properties experience cost overruns. In addition, our 2007 capital budget could be substantially increased if: (1) Berry, as operator for the Piceance play, increases the drilling program, (2) Noble, as operator for the DJ Basin play, increases the drilling program, and (3) Evertson, as operator for the Williston play, increases the drilling program.

We anticipate that we will utilize working capital generated from our ongoing operations to meet some of our 2007 commitments. In addition, in March 2006, we filed S-3 and S-4 shelf registration statements for $50 million each in financing capacity, which registration statements have been declared effective by the SEC. As discussed above, we closed on a public offering of 2,300,000 shares of our common stock; net proceeds of the offering were $10.8 million. As a result of the offering, we have $39 million of financing capacity remaining on our S-3 shelf registration. We have not utilized any of our $50 million S-4 shelf registration.

We also may receive proceeds from the exercise of outstanding warrants and/or options as we did during the years ended December 31, 2006 and 2005. At March 1, 2007, warrants to purchase 867,819 shares of common stock were outstanding. These warrants have a weighted average exercise price of $3.14 per share and expire between April 2008 and December 2012. At March 1, 2007, options to purchase 2,088,545 shares of common stock were outstanding. These options have a weighted average exercise price of $3.56 per share and expire between July 2007 and May 2015.

In June 2006, we established a $50 million revolving credit facility with BNP Paribas (the Credit Facility). The Credit Facility had an initial borrowing base of $ 3 million, redetermined as follows, and matures on June 15, 2010. The Credit Facility provides for as much as $50 million in borrowing capacity, depending upon a number of factors, such as the projected value of our proven oil and gas assets. The borrowing base for the Credit Facility at any time will be the loan value assigned to the proved reserves attributable to our subsidiaries direct or indirect oil and gas interests. The borrowing base will be redetermined on a semi-annual basis, based upon an engineering report delivered by us from an approved petroleum engineer. The Credit Facility is available for working capital requirements, capital expenditures, acquisitions, general corporate purposes and to support letters of credit. The borrowing base as redetermined by BNP Paribas is $6 million as of March 12, 2007.

We expect that our current cash balances, combined with expected positive operating cash flow, amounts available from existing and anticipated increases in our senior debt facility, proceeds from the exercise of warrants and options and the use of our S-3 and S-4 shelf registrations will provide us with adequate resources to meet our capital needs for 2007.

There can be no assurances that we will be successful in raising capital from either the debt or equity markets in the future or increasing our borrowing base from the Credit Facility.

Sources and Uses of Funds

Historically, our primary source of liquidity has been cash provided by equity offerings. These offerings may continue to play an important role in financing our business. Cash raised from third parties or generated through operations will be used for additional acquisitions or in connection with drilling programs associated with our current properties. In addition, our Credit Facility has established a borrowing facility that will be used primarily for our developmental drilling and other capital expenditures. As a result of our developmental drilling program progress, we expect that cash flow from operating activities also will contribute to our cash requirements during 2007 and for the foreseeable future thereafter.

Cash Flows and Capital Expenditures

During the year ended December 31, 2006, we used $1,779,316 of cash in our operating activities. This amount compares to $2,796,088 of cash used in our operating activities for the year 2005. The decrease of $1,016,772 of net cash used in operating activities was primarily due to the growth in revenue in 2006 as compared to 2005, partially offset by increased operating expenses. Our cash used in operating activities during 2006 increased by $364,532 due to higher accounts receivable balances attributed to revenue growth and one time cost recoveries due from Noble under our Average Earning Agreement. Our cash used in operating activities decreased by $340,600 during 2006 as a result of increased accounts payable and other accrued liability balances associated with the growth of the Company. In addition, during 2006 cash used in operating activities increased by $148,628 in respect to inventory and $255,000 in respect to discontinued operations, as compared to 2005.

In respect to our investing activities, during the year ended December 31, 2006, we received cash of $2,700,000 in connection with the entering into the Acreage Earning Agreement with Noble involving our DJ Basin acreage. During the same period, we incurred costs of $20,355,252 related to our drilling and completion operations in the Piceance and the Williston Basin projects.

In respect to our financing activities during the year ended December 31, 2006, holders of 760,957 warrants exercised these warrants and purchased an equivalent number of common shares in us for net proceeds to us of $3,538,246, and holders of 770,039 stock options exercised these options and purchased an equivalent number of our common shares for net proceeds to us of $2,697,173. For the year ended December 31, 2005, we raised $3,497,501 from the exercised warrants to purchase common shares.

On October 24, 2006, we entered into a International Swap Dealers Association Inc., Master Agreement with BNP Paribas to allow us to hedge our commodity pricing risk relative to our future oil and gas production. In addition, we have a Company hedging policy in place, if necessary, to protect a portion of our production against future pricing fluctuations. Although we have not yet hedged any of our future production beyond December 31, 2007, we will consider this strategy for future oil and gas production and future acquisitions.

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Our outstanding hedges as of December 31, 2006 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)	CIG Floor/Ceiling
Natural Gas	01/2007	30,000	$6.00/$7.25
Natural Gas	02/2007	30,000	$6.00/$7.25
Natural Gas	03/2007	30,000	$ 6.00/$725
Natural Gas	04/2007	30,000	$6.00/$7.25
Natural Gas	04/2007	30,000	$6.00/$7.25
Natural Gas	05/2007	30,000	$6.00/$7.25
Natural Gas	06/2007	30,000	$6.00/$7.25
Natural Gas	07/2007	30,000	$6.00/$7.25
Natural Gas	08/2007	30,000	$6.00/$7.25
Natural Gas	09/2007	30,000	$6.00/$7.25
Natural Gas	10/2007	30,000	$6.00/$7.25
Natural Gas	11/2007	30,000	$6.00/$7.25
Natural Gas	12/2007	30,000	$6.00/$7.25

The collared hedges shown above have the effect of providing a protective floor while allowing us to share in upward pricing movements. Consequently, while these hedges are designed to decrease our exposure to price decreases, they also have the effect of limiting the benefit of price increases beyond the ceiling. For the 2007 natural gas contracts listed above, a hypothetical $0.10 change in the Colorado interstate gas, or CIG, price above the ceiling price or below the floor price applied to the notional amounts would cause a change in the gain (loss) on hedging activities in 2007 of $36,000. The Company plans to continue to enter into derivative contracts to decrease exposure to commodity price decreases.

Commitments

Mr. Arleth, our President and Chief Executive Officer, signed a new employment agreement on August 30, 2006, which employment agreement became effective as of September 1, 2006. Mr. Arleth s employment agreement is for a three-year term, with a base salary of $250,000 per year. Under the terms of his employment agreement, Mr. Arleth is entitled to 24 months severance pay in the event of a change of position or change in control of the Company or, if his employment is terminated without cause. Mr. Arleth s employment agreement contains an evergreen provision, which automatically extends its term for a two-year period if the employment agreement is not terminated by notice by either party at least 60 days prior to the end of the stated term which is 2 years. In addition, Mr. Arleth will be entitled to a bonus based on his performance against objectives established by our compensation committee each year. Mr. Arleth s employment agreement requires us to maintain a split term life insurance policy providing for no less than $3,000,000 in benefits, with any such paid benefit to be distributed equally between us and a beneficiary of Mr. Arleth s choosing. During the first quarter of 2007, we purchased the split term life insurance policy for the $3,000,000 benefit level as described. In addition, Mr. Arleth s employment agreement includes an indemnification agreement.

Mr. Pennington, our Executive Vice President and Chief Financial Officer, signed an employment agreement on June 1, 2006. The employment agreement provides for an initial salary for Mr. Pennington of $190,000 per year. Under the terms of the employment agreement, Mr. Pennington is entitled to 12 months severance pay in the event of a change of position or change in control of the Company or if his employment is terminated without cause. Mr. Pennington s employment agreement contains an evergreen provision, which automatically extends the term of Mr. Pennington s employment agreement for a two-year period if the employment agreement is not terminated by notice by either party during

60 days prior to the end of the initial stated term which is one year. In addition, Mr. Pennington s employment agreement includes an indemnification agreement.

Mr. Schultz, our Vice President of Production, signed an employment agreement on April 1, 2006. Under the terms of the employment agreement, Mr. Schultz is entitled to an initial salary is $165,000 per year. The employment agreement also provides that Mr. Schultz is entitled to six months severance pay in the event of a change of position or change in control of the Company or if his employment is terminated without cause. The employment agreement contains an evergreen provision, which automatically extends the term of Mr. Schultz s employ for a two-year period if the employment agreement is not terminated by notice by either party during 60 days prior to the end of the initial stated term, which is one year. In addition, Mr. Schultz s employment agreement includes an indemnification agreement.

Mr. Bosher, our Vice President Business Development, signed an employment agreement on October 1, 2006. Under the terms of the employment agreement, Mr. Bosher is entitled to an initial salary is $150,000 per year. The employment agreement also provides that Mr. Bosher is entitled to six months severance pay in the event of a change of position or change in control of the Company or if his employment is terminated without cause. The employment agreement contains an evergreen provision, which automatically extends the term of Mr. Bosher s employ for a one-year period if the employment agreement is not terminated by notice by either party during 60 days prior to the end of the initial stated term, which is one year. In addition, Mr. Bosher s employment agreement includes an indemnification agreement.

Mr. Brand, our Controller and Chief Accounting Officer, signed an employment agreement on December 1, 2006. Under the terms of the employment agreement, Mr. Brand is entitled to an initial salary is $110,000 per year. The employment agreement also provides that Mr. Brand is entitled to six months severance pay in the event of a change of position or change in control of the Company or if his employment is terminated without cause. The employment agreement contains an evergreen provision, which automatically extends the term of Mr. Brand s employ for a one-year period if the employment agreement is not terminated by notice by either party during 60 days prior to the end of the initial stated term, which is one year. In addition, Mr. Brand s employment agreement includes an indemnification agreement.

Subsequent to December 31, 2006, we entered into an agreement with Dominic J. Bazile II. See Subsequent Events below.

The following outlines our contractual commitments that are not recorded on our consolidated balance sheet:

	For the Year Ended December 31,				
	2007	**2008**	**2009**	**Thereafter**	**Total**
Operating lease for office space	$123,000	$129,000	$44,000	$	$296,000

Income Taxes, Net Operating Losses and Tax Credits

At December 31, 2006, we had net operating loss carryforwards, for federal income tax purposes, of approximately $27 million. These net operating loss carryforwards, if not utilized to reduce taxable income in future periods, will expire in various amounts beginning in 2018 through 2026. Approximately $19 million of such net operating loss is subject to U.S. Internal Revenue Code Section 382 limitations. As a result of these limitations, utilization of this portion of the net operating loss is limited to approximately $900,000 per annum plus any loss attributable to any built in gain assets sold within 5 years of the ownership change. 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 $11.5 million and $8.8 million for 2006 and 2005 respectively.

Subsequent Events

On February 1, 2007, we executed an employment agreement with Dominic J. Bazile II to become our Executive Vice President and Chief Operating Officer. The employment agreement provides for an initial salary for Mr. Bazile of $225,000 per year. Under the terms of the employment agreement, Mr. Bazile is entitled to 12 months severance pay in the event of a change of position or change in control of the Company or if his employment is terminated without cause. The employment agreement contains an evergreen provision, which automatically extends the term of Mr. Bazile s employ for a two-year period if the agreement is not terminated by notice by either party during 60 days prior to the end of the initial stated term which is two years. In addition, Mr. Bazile s contract employment agreement has an indemnification agreement.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations was based upon our 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 us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Significant accounting policies are described in Note 2 to our financial statements. In response to SEC Release No. 33-8040, Cautionary Advice Regarding Disclosure About Critical Accounting Policies, we have identified certain of these policies as being of particular importance to the portrayal of the financial position and results of operations and which require the application of significant judgment by management. We analyze our estimates, including those related to oil and gas reserves, asset retirement obligations, oil and gas properties, marketable securities, income taxes, derivatives and contingencies, and base those estimates on historical experience and various other assumptions that our management believes are reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect the more significant judgments and estimates used in the preparation of our financial statements.

Revenue Recognition

Oil and natural gas revenue is recognized monthly based on production and delivery. We follow the sales method of accounting for our natural gas and crude oil revenue, so that we recognize sales revenue on all natural gas or crude oil sold to our purchasers at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectibility of the revenue is probable. Processing costs for natural gas that are paid in-kind are deducted from our revenues.

The volume of natural gas sold may differ from the volume to which we are entitled based on our working interest. When this occurs, a gas imbalance is deemed to exist. An imbalance is recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the under-produced owner(s) to recoup its entitled share through future production. Natural gas imbalances can arise on properties for which two or more owners have the right to take production in-kind. In a typical gas balancing arrangement, each owner is entitled to an agreed-upon percentage of a property s total production; however, at any given time, the amount of natural gas sold by each owner may differ from its allowable percentage. Two principal accounting practices have evolved to account for natural gas imbalances. These methods differ as to whether revenue is recognized based on the actual sale of natural gas (sales method) or an owner s entitled share of the current period s production (entitlement method).

If we used the entitlement method, our future reported revenues may be materially different than those reported under the sales method.

At December 31, 2006, there were no gas imbalances in respect of our gas balancing arrangements.

Oil and Gas Hedging

We have and plan to enter into commodity derivative contracts to manage our exposure to oil and natural gas price volatility. To date, our hedging has been limited to the utilization of costless collars, which are generally placed with major financial institutions. The oil and natural gas reference prices of these commodity derivatives contracts are based upon crude oil and natural gas futures, which have a high degree of historical correlation with actual prices we receive. Under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activity, all derivative instruments are recorded on the consolidated balance sheet at fair value. Changes in the derivative s fair value are recognized currently in earnings unless specific hedge accounting criteria are met. For qualifying cash flow hedges, the gain or loss on the derivative is deferred in accumulated other comprehensive income (loss) to the extent the hedge is effective and is reclassified to the Gain (loss) on oil and gas hedging activities line item in our consolidated statements of income in the period that the hedged production is delivered. Hedge effectiveness is measured at least quarterly based on the relative changes in the fair value between the derivative contract and the hedged item over time. We currently do not have any derivative contracts in place that qualify as cash flow hedges.

We have established the fair value of all derivative instruments using estimates determined by our counterparties and subsequently reviewed internally. The fair value is calculated as the present value of the difference between then current future period prices and the floor and ceiling value of our costless collar contracts.

Our results of operations each period can be impacted by our ability to estimate the level of correlation between future changes in the fair value of the hedge instruments and the transactions being hedged, both at the inception and on an ongoing basis. This correlation is complicated since energy commodity prices, the primary risk we hedge, have quality and location differences that can be difficult to hedge effectively. The factors underlying estimates of fair value and our assessment of correlation of our hedging derivatives are impacted by actual results and changes in conditions that affect these factors, many of which are beyond our control.

Successful Efforts Method of Accounting

We account for natural gas and crude oil exploration and development activities utilizing the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Oil and gas lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for gas and oil 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 reserves in commercial quantities. The sale of a partial interest in a proved property is accounted for as a cost recovery and no gain or loss is recognized as long as this treatment does not significantly affect the

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unit-of-production amortization rate. A gain or loss is recognized for all other sales of producing properties.

The application of the successful efforts method of accounting requires managerial judgment to determine that proper classification of wells designated as developmental or exploratory which will ultimately 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 and actually deliver gas and oil in quantities insufficient to be economic, which 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 properly to account for the results. Delineation seismic data acquisition and analysis costs, which are performed to select development locations within an oil and gas field are typically considered a development cost and capitalized, but often these seismic programs extend beyond the reserve area considered proved and management must estimate the portion of the seismic costs to expense. The evaluation of gas and oil leasehold acquisition costs requires managerial judgment to estimate the fair value of these costs with reference to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

The successful efforts method of accounting can have a significant impact on the operational results reported when entering a new exploratory area in hopes of finding a gas and oil field that will be the focus of future development drilling activity. The initial exploratory wells may be unsuccessful and will be expensed. Seismic costs can be substantial which will result in additional exploration expenses when incurred.

Reserve Estimates

Estimates of gas and oil reserves, by necessity, are projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of gas and oil that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable gas and oil reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies and assumptions governing future gas and oil prices, future operating costs, severance taxes, development costs and workover costs, all of which may in fact vary considerably from actual results. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to an extent that these reserves may be later determined to be uneconomic. For these reasons, estimates of the economically recoverable quantities of gas and oil attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected there from may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of gas and oil properties and/or the rate of depletion of the gas and oil properties. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material.

Depreciation, Depletion and Amortization

Our rate of recording depreciation, depletion and amortization (DD&A) is dependent upon our estimates of total proved and proved developed reserves, which incorporate assumptions regarding future

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development and abandonment costs as well as our level of capital spending. If the estimates of total proved or proved developed reserves decline, the rate at which we record DD&A expense increases, reducing our net income. This decline may result from lower market prices, which may make it uneconomic to drill for and produce higher cost fields. We are unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of our exploitation and development program, as well as future economic conditions.

Impairment of Oil and Gas Properties

We review oil and gas properties for impairment whenever events and circumstances indicate a decline in the recoverability of their carrying value. We estimate the expected future cash flows of the developed proved properties and compare such future cash flows to the carrying amount of the proved properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, an adjustment will be made to the carrying amount of the oil and gas properties to their fair value. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and a discount rate commensurate with the risk associated with realizing the expected cash flows projected.

We review the carrying values of our undeveloped leasehold interests as compared to comparable sales values.

Given the complexities associated with gas and oil reserve estimates and the history of price volatility in the gas and oil markets, events may arise that would require us to record an impairment of the recorded book values associated with gas and oil properties. We did not record an impairment during the years ended December 31, 2006, 2005 or 2004.

Stock-Based Compensation

Effective January 1, 2006, we adopted the provisions of SFAS 123R to account for stock-based compensation. Previously, we accounted for this compensation under the provisions of APB 25. Under APB 25, stock options did not result in any charge to earnings if the exercise price on the date of grant equaled or exceeded fair value (market price) on the grant date. Stock grants were charged to earnings on the vesting date based upon the market price of the stock on the date of the grant.

We accrue for anticipated vesting of stock grants in interim reporting periods based upon our best estimates at the time of the interim period of the conditions and criteria under which the options will vest. These conditions and criteria include service through the vesting date, announced future terminations, performance criteria based upon most recent forecasts and market conditions where appropriate. The estimates used are subjective and based upon management s judgment and may change over time as experience emerges. Changes to the interim accruals due to changes in the estimates of the conditions and criteria are recorded in the period in which the estimate changes occur.

During the year ended December 31, 2006, we recorded current compensation of $3,138,842 based on our Compensation Committee s final assessments of the progress made in the satisfaction of performance and service conditions for these awards that could vest at year end 2006, provided that certain milestones were achieved. The annual performance assessment is scored based on an evaluation of the degree of progress made in achieving each of Threshold, Base, and Stretch objectives established by our Compensation Committee. Our compensation expense will increase or decrease in subsequent quarters based on management s progress toward the achievement of these objectives. Improved performance during the subsequent quarters of the year will increase compensation expense in those quarters whereas diminished performance will reduce compensation expense in subsequent quarters. The ultimate compensation expense for the year will reflect our actual performance and its associated vesting of the particular LTIP tranche. The portion of the stock compensation expense pertaining to Performance Share Units under our LTIP for the year ended December 31, 2006 was $3,138,842. We recorded expense for the nine months ended September 30, 2006 of $1,137,447 based upon estimated annual expense of $1,516,596. We increased the amount of the estimated annual expense by $1,622,246 during the fourth quarter as a result of higher estimates of expected achievement of performance objectives. Under SFAS 123R, we amortize the unvested portion of stock option grants over the vesting period at the fair value of the option, as described in Note 8 to the financial statements. At December 31, 2006, there were 13,333 option grants unvested and during the year ended December 31, 2006 we amortized $28,494 to expense in respect to the unvested stock options.

Income Taxes

We provide for income taxes in accordance with Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes. We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess the realizability of our deferred tax assets. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, the tax asset would be reduced by a valuation allowance. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and natural gas prices). Currently, we are providing a 100% valuation allowance against the tax benefits of our net operating loss carry forward, because of the uncertainty of its realization.

Asset Retirement Obligations

Our asset retirement obligations (ARO) consist primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with its oil and natural gas properties. SFAS No. 143 requires that the discounted fair value of a liability for an ARO be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and natural gas asset. The recognition of an ARO requires that management make numerous estimates, assumptions and judgments regarding such factors as the estimated amounts and timing of settlements; the credit-adjusted risk-free rate to be used; inflation rates, and future advances in technology. In periods subsequent to initial measurement of the ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A.

Recently Adopted Accounting Pronouncements

In September 2006, the SEC issued Staff Accounting Bulletin No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements, or SAB 108. SAB 108 was effective for us beginning with our fiscal year ended on December 31, 2006. SAB 108 did not have a material effect on our financial position or results of operations for the year ended December 31, 2006.

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Effective January 1, 2006, we adopted SFAS No. 123R which revises SFAS No. 123, Accounting for Stock-Based Compensation. See Note 3 Accounting Change to our consolidated financial statements in Item 8 of this report for additional information.

Recently Issued Accounting Pronouncements

In July 2006 the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109, (FIN 48), which clarifies the accounting for uncertainty of tax positions. FIN 48 will require the Company to recognize the impact of a tax position in its financial statements only if the technical merits of that position indicate that the position is more likely than not of being sustained upon audit. The Company has evaluated the impact of FIN 48 as of the January 1, 2007 adoption date and determined there will be no impact to its financial statements.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements, which is effective for us beginning January 1, 2008 and provides a definition of fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements for future transactions. We do not expect the adoption of this pronouncement to have a material impact on our financial position or results of operations.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, which permits an entity to measure certain financial assets and financial liabilities at fair value. The objective of SFAS No. 159 is to improve financial reporting by allowing entities to mitigate volatility in reported earnings caused by the measurement of related assets and liabilities using different attributes, without having to apply complex hedge accounting provisions. Under SFAS No. 159, entities that elect the fair value option (by instrument) will report unrealized gains and losses in earnings at each subsequent reporting date. The fair value option election is irrevocable, unless a new election date occurs. SFAS No. 159 establishes presentation and disclosure requirements to help financial statement users understand the effect of the entity s election on its earnings, but does not eliminate disclosure requirements of other accounting standards. Assets and liabilities that are measured at fair value must be displayed on the face of the balance sheet. This statement is effective beginning January 1, 2008 and we are evaluating this pronouncement.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS.

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile, and these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control. Based on our 2006 production, our income before income taxes for 2006 would have moved up or down approximately $69,000 for every $0.10 change in natural gas prices.

We have begun entering into derivative contracts to manage our exposure to oil and natural gas price volatility. To date, our derivative contracts have been costless collars, although we evaluate other forms of derivative instruments as well.

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On October 24, 2006, we entered into certain ISDA agreements with BNP Paribas to allow us to hedge our commodity pricing risk relative to our future oil and gas production. In addition, we have a Company hedging policy in place, if necessary, to protect a portion of our production against future pricing fluctuations. Although we have not yet hedged any of our future production beyond December 31, 2007, we will consider this strategy for oil and gas production and future acquisitions.

Our outstanding hedges as of December 31, 2006 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)	CIG Floor/Ceiling
Natural Gas	01/2007	30,000	$6.00/$7.25
Natural Gas	02/2007	30,000	$6.00/$7.25
Natural Gas	03/2007	30,000	$ 6.00/$725
Natural Gas	04/2007	30,000	$6.00/$7.25
Natural Gas	04/2007	30,000	$6.00/$7.25
Natural Gas	05/2007	30,000	$6.00/$7.25
Natural Gas	06/2007	30,000	$6.00/$7.25
Natural Gas	07/2007	30,000	$6.00/$7.25
Natural Gas	08/2007	30,000	$6.00/$7.25
Natural Gas	09/2007	30,000	$6.00/$7.25
Natural Gas	10/2007	30,000	$6.00/$7.25
Natural Gas	11/2007	30,000	$6.00/$7.25
Natural Gas	12/2007	30,000	$6.00/$7.25

The collared hedges shown above have the effect of providing a protective floor while allowing us to share in upward pricing movements. Consequently, while these hedges are designed to decrease our exposure to price decreases, they also have the effect of limiting the benefit of price increases beyond the ceiling. For the 2007 natural gas contracts listed above, a hypothetical $0.10 change in the CIG price above the ceiling price or below the floor price applied to the notional amounts would cause a change in the gain (loss) on hedging activities in 2007 of $36,000. The Company plans to continue to enter into derivative contracts to decrease exposure to commodity price decreases.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Consolidated Financial Statements
and
Independent Auditors Report
December 31, 2006, 2005 and 2004

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Teton Energy Corporation
Denver, Colorado

We have audited the accompanying consolidated balance sheets of Teton Energy Corporation (formerly Teton Petroleum Company) and subsidiaries (the Company) as of December 31, 2006 and 2005, and the related consolidated statements of operations and comprehensive (loss) income, changes in stockholders equity and cash flows for each of the years in the three year period ended December 31, 2006. 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 consolidated 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 audits 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 consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated 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 Teton Energy Corporation and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 3, the Company has changed its accounting method for stock-based compensation by adopting SFAS No. 123 (R) Share-Based Payment effective January 1, 2006.

/s/ Ehrhardt Keefe Steiner & Hottman PC
Ehrhardt Keefe Steiner & Hottman PC

Denver, Colorado
March 16, 2007

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TETON ENERGY CORPORATION AND SUBSIDIARIES
Consolidated Balance Sheets
December 31, 2006 and 2005

	December 31, 2006	December 31, 2005
Assets		
Current assets		
Cash	$ 4,324,784	$ 7,064,295
Trade accounts receivable	860,070	247,769
Advances to operators	401,491	224,429
Tubular inventory	148,628	
Fair value of derivatives	402,867	
Prepaid expenses and other assets	142,163	137,729
Total current assets	6,280,003	7,674,222
Non-current assets		
Property and equipment		
Oil and gas properties (using successful efforts method of accounting)		
Proved	11,635,699	1,717,213
Producing facilities	690,244	
Unproved	13,959,480	10,636,279
Wells in progress	8,492,150	2,105,884
Facilities in progress	1,363,644	120,554
Land	300,000	
Fixed assets	242,691	71,045
Total property and equipment	36,683,908	14,650,975
Less accumulated depletion and depreciation	(1,911,889)	(193,702)
Net property and equipment	34,772,019	14,457,273
Debt issuance costs net	191,685	
Total non-current assets	34,963,704	14,457,273
Total assets	$ 41,243,707	$ 22,131,495

See notes to consolidated financial statements.

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TETON ENERGY CORPORATION AND SUBSIDIARIES
Consolidated Balance Sheets
December 31, 2006 and 2005

	December 31, 2006	December 31, 2005
Liabilities and Stockholders Equity		
Current liabilities		
Accounts payable	$ 1,506,873	$ 1,281,457
Accrued liabilities	4,195,674	297,351
Accrued payroll and severance	890,877	396,589
Accrued royalties		94,403
Accrued franchise taxes payable	30,518	62,025
Deposit on sale of assets		300,000
Accrued liability of discontinued operations		255,000
Accrued purchase consideration	775,054	
Total current liabilities	7,398,996	2,686,825
Non-current liabilities		
Asset retirement obligations	78,115	3,851
Total non-current liabilities	78,115	3,851
Total liabilities	7,477,111	2,690,676
Commitments and contingencies		
Stockholders equity		
Common stock, $.001 par value, 250,000,000 shares authorized, 15,180,649 shares issued and outstanding at December 31, 2006 and 11,329,652 shares issued and outstanding at December 31, 2005	15,180	11,329
Additional paid-in capital	60,836,839	43,929,216
Stock based compensation	3,138,772	
Accumulated deficit	(30,224,195)	(24,499,726)
Total stockholders equity	33,766,596	19,440,819
Total liabilities and stockholders equity	$ 41,243,707	$ 22,131,495

See notes to consolidated financial statements.

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TETON ENERGY CORPORATION AND SUBSIDIARIES
Consolidated Statements of Operations and Comprehensive (Loss) Income

	For the Years Ended December 31,		
	2006	2005	2004
Oil and gas sales	$ 3,528,558	$ 707,420	$
Cost of sales and expenses:			
Lease operating expense	325,057	50,932	
Production taxes	250,528	48,196	
General and administrative	7,147,792	4,006,747	5,332,991
Depletion, depreciation and amortization	1,724,854	181,276	
Accretion expense from asset retirement obligations	24,329		
Exploration expense	448,054	445,108	
Total cost of sales and expenses	9,920,614	4,732,259	5,332,991
Loss from operations	(6,392,056)	(4,024,839)	(5,332,991)
Other income (expense):			
Unrealized derivative gain	402,867		
Other income	292,733	247,390	139,710
Financing charges	(28,013)		
Total other income (expense)	667,587	247,390	139,710
Loss from continuing operations	(5,724,469)	(3,777,449)	(5,193,281)
Discontinued operations, net of tax		(255,000)	12,383,582
Net (loss) income	(5,724,469)	(4,032,449)	7,190,301
Imputed preferred stock dividends for inducements and beneficial conversion charges			(521,482)
Preferred stock dividends		(61,455)	(105,949)
Net (loss) income applicable to common shares	(5,724,469)	(4,093,904)	6,562,870
Other comprehensive loss, net of tax effect of exchange rates			(898,756)
Comprehensive (loss) income	$ (5,724,469)	$ (4,093,904)	$ 5,664,114
Basic and diluted weighted average common shares outstanding	13,092,741	10,282,394	9,028,967
	$ (0.44)	$ (0.38)	$ (0.64)

Basic and diluted loss per common share for continuing operations						
Basic and diluted weighted average (loss) income per common shares for discontinued operations	$		$	(0.02)	$	1.37
Basic and diluted (loss) income per common share	$	(0.44)	$	(0.40)	$	0.73

See notes to consolidated financial statements.

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TETON ENERGY CORPORATION AND SUBSIDIARIES
Consolidated Statements of Changes in Stockholders Equity

	Preferred Stock Shares	Preferred Stock Amount	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Stock Based Compensation	Unamortized Preferred Stock Dividends	Foreign Currency Translation Adjustment	Accumulated Deficit	To Stock Eq
December 31,	618,231	$ 618	8,584,068	$ 8,583	$ 37,073,367	$	$ (118,610)	$ 898,756	$ (27,657,578)	$ 10,2
n Stock issued ment of iabilities			13,750	14	58,686					
n Stock issued ces			32,175	33	101,296					1
s issued for					149,061					1
l stock issued net issions of (cash)	126,436	126			499,872					4
l stock d to common	(463,207)	(463)	500,264	500	(37)					
ation of l Stock s					(118,610)		118,610			
l stock s					(105,949)					(1
currency on adjustment								(898,756)		(8
me for year									7,190,301	7,1
December 31,	281,460	281	9,130,257	9,130	37,657,686				(20,467,277)	17,1
n stock issued ment of iabilities			12,828	13	10,487					
n stock issued ces			298,276	298	944,726					9
n stock issued acquisitions			862,963	863	1,467,143					1,4
s issued for uisitions					413,872					4
s exercised net X			743,868	744	3,496,757					3,4
l stock d to common	(281,460)	(281)	281,460	281						

l stock s				(61,455)					(
for year								(4,032,449)	(4,0
December 31,		11,329,652	11,329	43,929,216				(24,499,726)	19,4
s and options d		1,530,996	1,531	6,233,888					6,2
of common t		2,300,000	2,300	10,831,185					10,8
f common		(50,000)	(50)	(157,450)					(1
sed ation		70,001	70		3,138,772				3,1
for year								(5,724,469)	(5,7
December 31,	$	15,180,649	$ 15,180	$ 60,836,839	$ 3,138,772	$	$	$ (30,224,195)	$ 33,7

See notes to consolidated financial statements.

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TETON ENERGY CORPORATION AND SUBSIDIARIES
Consolidated Statements of Cash Flows

	For the Years Ended December 31,		
	2006	2005	2004
Net (loss) income	$ (5,724,469)	$ (4,032,449)	$ 7,190,301
Adjustments to reconcile net (loss) income to net cash used in operating activities			
Depletion, depreciation, and amortization	1,724,854	181,276	11,380
Gain on sale of discontinued operations			(13,086,761)
Accretion expense from asset retirement obligations	24,329		
Stock, stock options and warrants issued for services and interest	2,981,342	834,774	250,390
Unrealized derivative gain	(402,867)		
Changes in assets and liabilities			
From discontinued operations	(255,000)	255,000	1,149,609
Trade accounts receivable	(612,301)	(247,769)	
Advances to operators	(177,062)	(224,429)	
Tubular inventory	(148,628)		
Prepaid expenses and other assets	(4,434)	(36,812)	(5,224)
Accounts payable and accrued liabilities	446,543	140,829	69,530
Accrued payroll and severance, royalties, and franchise taxes payable	368,378	333,492	
	3,945,154	1,236,361	(11,611,076)
Net cash used in operating activities	(1,779,316)	(2,796,088)	(4,420,775)
Cash flows from investing activities			
Sales deposit liability		300,000	
Proceeds from sale of oil and gas properties	2,700,000		
Proceeds from sale of discontinued operations			7,963,450
Repayments of loan from discontinued operating entity			6,040,000
Increase in deposits			(25,000)
Increase in oil and gas properties	(20,355,252)	(11,302,692)	
Increase in fixed assets	(182,163)	(6,395)	(45,420)
Increase in non-current assets of discontinued operating entity			(2,988,882)
Net cash (used in) provided by investing activities	(17,837,415)	(11,009,087)	10,944,148
Cash flows from financing activities			
From discontinued operations			3,258,378
Proceeds from issuance of common stock, net of underwriting fees and expenses of $1,126,515 and $50,000 commissions, respectively	10,833,485		499,998

Proceeds from exercise of warrants / options and issuance of common stock , net of AMEX fees of $48,462 in 2005	6,235,419	3,497,501	
Debt issuance costs from bank debt	(191,685)		
Payment of dividends		(61,455)	(81,463)
Net cash provided by financing activities	16,877,219	3,436,046	3,676,913
Effect of exchange rates of cash and cash equivalents			(282,856)
Net (decrease) increase in cash and cash equivalents	(2,739,511)	(10,369,129)	9,917,430
Cash and cash equivalents beginning of year	7,064,295	17,433,424	7,515,994
Cash and cash equivalents end of year	$ 4,324,784	$ 7,064,295	$ 17,433,424

(Continued on the following page.)

See notes to consolidated financial statements.

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TETON ENERGY CORPORATION AND SUBSIDIARIES
Consolidated Statements of Cash Flows (cont d)

Supplemental disclosure of non-cash activity:

During the year ended December 31, 2006, the Company had the following transactions:

Non-cash unrealized derivative gain of $402,867.

In connection with the resignation of our former contract Chief Financial Officer, effective March 31, 2006, 50,000 restricted shares of common stock were returned to us as an agreed-upon reduction in service fees charged. The return of such shares had been recorded as a reduction in accounting fees totaling $157,500 at March 31, 2006.

Deposit of $300,000 applied to oil and gas properties associated with the DJ Basin acquisition.

Capital expenditures included in accrued liabilities of $3,672,094.

Capital expenditures included in accounts payable of $1,261,361.

Accrued purchase consideration of $775,054 associated with the Williston Basin acquisition.

The Company recorded an asset retirement obligation in the amount of $49,935 with a corresponding increase to oil and gas properties.

During the year ended December 31, 2005, the Company had the following transactions:

The Company issued 12,828 shares of common stock to outside directors for settlement of accrued liabilities of $10,500 at December 31, 2004.

The Company issued 281,460 shares of common stock upon the conversion of 281,460 shares of preferred stock.

The Company issued 450,000 shares of common stock, valued at $837,000 and 200,000 warrants, valued at $251,949 in conjunction with the purchase of a 25% interest in Piceance Gas Resources, LLC.

The Company issued 412,962 shares of common stock, valued at $631,006 and 206,481 warrants, valued at $161,923, in conjunction with the purchase of acreage in the eastern Denver-Julesburg Basin.

The Company issued 287,500 shares to three consultants of the Company, valued at $905,624 for services, $110,250 of which has been capitalized in oil and gas properties.

The Company issued 10,776 shares of common stock valued at $39,400 for services rendered by the outside directors.

The Company recorded an asset retirement obligation in the amount of $3,851 with a corresponding increase to oil and gas properties.

$1,256,259 of capital expenditures are included in accounts payable at December 31, 2005.

During the year ended December 31, 2004, the Company had the following transactions:

The Company has issued warrants to consultants for services valued at $149,061.

13,750 shares of common stock were issued for the settlement of accrued liabilities at December 31, 2003 valued at $58,700.

The Company has issued 32,175 shares of common stock for services to consultants and outside directors valued at $101,329.

Approximately $1,317,000 of capital expenditures for discontinued operations were included in current liabilities of discontinued operations at June 30, 2004 and approximately $1,786,000 of capital expenditures were in accounts payable at December 31, 2003 for a decrease during the six months ended June 30, 2004 of $469,000.

Conversion of 463,207 shares of preferred stock, plus dividends of 37,057 shares converted into 500,264 shares of common stock.

The Company accrued dividends to preferred stockholders of $24,486 at December 31, 2004.

See notes to consolidated statements.

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TETON ENERGY CORPORATION AND SUBSIDIARIES
Notes to Consolidated Financial Statements

Note 1 Nature of Organization

Teton Energy Corporation (Teton or the Company) is an independent oil and gas exploration and production company with operations in the Rocky Mountain region of the U.S. which currently includes a drilling program in the Piceance Basin in western Colorado with 6,314 gross acres, an acreage play of 266,572 gross acres in the eastern DJ Basin and an acreage play of 87,192 gross acres in the Williston Basin located in North Dakota (see Note 5 to financial statements for further descriptions of all three projects). Prior to July 1, 2004 Teton s primary focus was oil and gas exploration, development and production in the Russian Federation and former Commonwealth of Independent States through ownership of a 35.30% interest in ZAO Goloil, a Russian closed joint-stock company (Goloil). The Company sold all of its interest in Goloil effective July 1, 2004 (see Note 4 to financial statements).

The United States dollar is the principal currency of the Company s business and, accordingly, these consolidated financial statements are expressed in United States dollars.

Note 2 Summary of Significant Accounting Policies

Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Teton; its wholly owned subsidiaries Teton Piceance LLC, Teton DJ LLC, Teton Williston LLC and through June 30, 2004, its wholly owned subsidiary, Goltech Petroleum, LLC (Goltech). Through February 28, 2006, the Company consolidated its investment in Piceance Gas Resources, LLC, a Colorado limited liability company (Piceance LLC), using pro rata consolidation, whereby the Company included its 25% pro rata share of Piceance LLC s assets, liabilities, revenues, expenses and oil and gas reserves in its financial statements. During the first quarter of 2006, the members of Piceance LLC applied to and received the consent of the fee owner of the land on which Piceance LLC s oil and gas rights and leases are located for Piceance LLC to transfer the underlying interest directly to each of the members. As a result, on February 28, 2006, the Company s 25% working interest in the oil and gas rights and leases were transferred directly to Teton Piceance LLC, a wholly owned subsidiary of the Company. All intercompany accounts and transactions have been eliminated in consolidation.

As of December 31, 2006, the Company has no investments in partnerships or LLCs that would require it to use pro rata consolidation.

Discontinued Operations

See Note 4 for a summary of the income (loss) from discontinued operations. The Company completed the sale of Goloil to be effective July 1, 2004. Accordingly, the operating activities of Goloil for the six months ended June 30, 2004 have been included in the results from discontinued operations. The Company accrued, at December 31, 2005, as part of its Goloil discontinued operations, $255,000 relating to a repayment of a grant from the U.S. Trade and Development Agency (TDA). The $255,000 was refunded on February 28, 2006.

Use of Estimates

The preparation of these financial statements requires the Company to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. In response to SEC Release No. 33-8040, Cautionary Advice Regarding Disclosure About Critical Accounting Policies, the Company has identified certain of these policies as being of particular importance to the portrayal of the financial position and results of operations and which require the application of significant judgment by management. The Company reviews those estimates, including those related to oil and gas reserves, asset retirement obligations, oil and gas properties, marketable securities, income taxes, derivatives and contingencies, and base those estimates on historical experience and various other assumptions that the Company s management believes are reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. The Company believes the following critical accounting policies affect the more significant judgments and estimates used in the preparation of our financial statements.

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 accounts in excess of federally insured limits. As of the balance sheet date, the Company had no cash equivalents.

Revenue Recognition

The Company recognizes crude oil or natural gas sales revenue at the point in time crude oil or natural gas quantities have been delivered to purchasers.

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TETON ENERGY CORPORATION AND SUBSIDIARIES
Notes to Consolidated Financial Statements

Oil and Gas Derivatives

On November 29, 2006, the Company entered into derivative contracts (costless collar) to hedge certain future natural gas production in order to mitigate the risk of market price fluctuations.

All derivatives are recognized on the balance sheet and measured at fair value. Realized and unrealized gains and losses on derivatives that are not designated as hedges, as well as the ineffective portion of hedge derivatives, if any, are recorded as a derivative fair value gain or loss in the consolidated statements of income. Unrealized gains and losses on cash flow hedge derivatives are recorded in earnings as unrealized derivative gains or losses. When the hedged transaction occurs, the realized gain or loss on the hedge derivative is transferred from accumulated other comprehensive income (loss) to earnings.

During the year ended December 31, 2006 the Company recorded an unrealized gain on derivative contracts of $402,867, representing the fair market value of the November 29, 2006 derivative contract. The Company determined that this contract did not qualify for hedge accounting as prescribed in SFAS 133. No derivative contracts had been entered into for the years ending December 31, 2005 and 2004.

For the years ended December 31, 2006, 2005 and 2004, the Company recognized no realized losses or gains on commodity derivative settlements.

Comprehensive Income

Comprehensive income is defined as the change in equity during a period from transactions and other events from non-owner sources. Comprehensive income is the total of net income or loss and other comprehensive income or loss. The Company has no other comprehensive income or loss for the years ended December 31, 2006 and 2005. During the year ending December 31, 2004, other comprehensive loss of $898,756 was recorded in respect to foreign currency translation adjustments.

Tubular Inventory

Tubular inventory consists primarily of tubular pipe and casing used in our operations and is stated at the lower of average cost or market value.

Debt Issuance Costs

Debt issuance costs are amortized to interest expense over the life of the related credit facility using the effective interest method. For the years ended December 31, 2006, 2005 and 2004, the Company recorded $28,013, $0 and $0 in debt issuance amortization included in interest expense, respectively.

Oil and Gas Properties

The Company uses the successful efforts method of accounting for oil and gas producing activities. Costs to acquire mineral interests in oil and gas properties, to drill and equip exploratory wells that find proved reserves and to drill and equip development wells are capitalized. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs and costs of carrying and retaining unproved properties are expensed. The Company also evaluates costs capitalized for exploratory wells, and if proved reserves cannot be determined within one year from drilling exploration wells, those costs are written-off and recorded as an expense. At December 31, 2006, the Company had $7,117,425 in 8 development wells in the Piceance Basin and $1,374,725 in one

TETON ENERGY CORPORATION AND SUBSIDIARIES
Notes to Consolidated Financial Statements

exploratory well in the Williston Basin. Of the 8 development wells in the Piceance Basin, six wells had been drilled to total depth. The one Williston Basin well also has been drilled to total depth. These wells are expected to be completed in the first half of 2007.

Unproved oil and gas properties that are individually significant are periodically assessed for impairment of value and a loss is recognized at the time of impairment by providing an impairment allowance. Other unproved properties are amortized based on the Company s experience of successful drilling and average holding period.

Capitalized costs of producing oil and gas properties are depreciated and depleted by the unit-of-production method using proved reserves. Significant development projects are excluded from the depletion calculation prior to assessment of the existence of proven reserves that are ready for commercial production. The Company did not have any significant development projects in process other than wells and facilities in progress at December 31, 2006 that were excluded from the calculation of depletion. Support equipment and other property and equipment are depreciated over their estimated useful lives.

The net carrying value of the Company s oil and gas properties is limited to an estimated net recoverable amount. The net recoverable amount is based on estimated undiscounted future net revenues and is determined by applying factors based on historical experience and other data such as primary lease terms of properties and average holding periods. For undeveloped leasehold properties, we compare our carrying values to estimated fair market values using sales values from recent comparable property sales. If it is determined that the net recoverable value is less than the net carrying value of the oil and gas properties, any impairment is charged to operations.

Property and Equipment

Property and equipment is stated at cost. Depreciation is provided utilizing the straight-line method over the estimated useful lives for owned assets, ranging from 5 to 7 years.

Impairment of Long-Lived Assets

The Company evaluates its long-lived assets for impairment, in accordance with the provisions established under Statement of SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, when events or changes in circumstances indicate that the related carrying amount may not be recoverable. An impairment is considered to exist if the estimated fair value (based upon market selling prices, if available), or the total estimated future cash flows on an undiscounted basis is less than the carrying amount of the related assets. An impairment loss, if applicable, is measured and recorded based on the difference between the carrying value of the asset and the estimated fair market value of the asset. Changes in significant assumptions underlying estimated fair values of assets may have a material effect on the Company s financial position and results of operations.

Asset Retirement Obligations

The Company follows the provisions of SFAS No. 143, Accounting for Asset Retirement Obligations , in respect to recognizing estimated future obligations for its long-lived assets. The estimated fair value of the future costs associated with the dismantlement, abandonment and restoration of wells and the related facilities and locations are estimated and 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 related accretion expense.

At December 31, 2006, the Company has recorded $78,115 related to the Company s estimated liability for the retirement of its oil and gas assets in the Piceance Basin of Colorado, the DJ Basin of Colorado and Williston Basin of North Dakota along with a corresponding increase of $53,786 in the carrying value of the related oil and gas properties.

Foreign Currency Translation

For the six months ended June 30, 2004, all assets and liabilities of the Company s subsidiary were translated into U.S. dollars using the prevailing exchange rates as of the balance sheet date. Income and expenses are translated using the weighted average exchange rates for the period. Stockholders investments are translated at the historical exchange rates prevailing at the time of such investments. Any gains or losses from foreign currency translation are included as a separate component of stockholders equity. The prevailing exchange rate at June 30, 2004 was

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TETON ENERGY CORPORATION AND SUBSIDIARIES
Notes to Consolidated Financial Statements

approximately one U.S. dollar to 29.03 Russian rubles. For the six months ended June 30, 2004, the average exchange rate for one U.S. dollar was 28.76 Russian rubles.

Basic Loss Per Share

The Company applies the provisions of Statement of Financial Accounting Standard No. 128, Earnings Per Share (SFAS 128). All dilutive potential common shares have an antidilutive effect on diluted per share amounts and therefore have been excluded in determining net loss per share and accordingly, basic and dilutive loss per share is the same.

The following table reflects the effects of dilutive securities as of the years ended December 31:

	2006	2005	2004
Dilutive effects of options	2,088,545	2,875,334	2,993,037
Dilutive effects of warrants	867,819	1,731,764	7,359,728
Dilutive effects of convertible preferred shares			281,460
Dilutive effects of restricted shares(1)	193,999	195,000	
Dilutive effects of performance share units(2)	1,911,000	596,000	
Dilutive effects of grants awarded during 2006(3)	426,517		
	5,487,880	5,398,098	10,634,225

(1) These shares vest in equal tranches over three years beginning with grants made in 2006.

(2) 800,000 performance share units were reserved in July 2005 for the 2005 Grant. As of December 31, 2006, after forfeitures and releases (such as the performance targets for 2005 not being met or certain participants leaving the Company s employ prior to vesting), there

were 177,500 Base and 355,000 Stretch performance share units available to vest in 2007, assuming time and performance vesting criteria are met. In March 2006, the Compensation Committee reserved 2,500,000 performance share units under the LTIP, awarding approximately 715,625 performance share units for Base objectives to executives, directors, certain employees and consultants on March 17, 2006. Throughout the balance of 2006, the Compensation Committee made additional awards in respect of new hires, with the result being that at December 31, 2006, 972,500 performance share units for Base objectives (net of forfeitures that occurred during 2006 as a result of employees who left the Company s employ during 2006) were awarded in respect of the 2006 objectives. As of December 31, 2006, there were 778,000 Base and 1,556,000 Stretch performance share units available to vest in 2007 and 2008, assuming time and performance vesting criteria are met. Amounts available to vest in future years represent performance share units that are net of awards certified by the Compensation Committee on March 13, 2007 and are deemed to have vested for purposes of this table on December 31, 2006. Please see Note 8, for a description of performance share units.

(3) On March 13, 2007 the Compensation Committee awarded

134,767 shares for the 2005 grant and 291,750 shares for the 2006 grant based on performance achievements for the respective 2005 and 2006 year s milestones.

Such securities have been excluded from the earnings per share calculation as their effect was anti-dilutive. However, such securities could dilute future earnings, if achieved.

Fair Value of Financial Instruments

The carrying amounts of financial instruments including cash and cash equivalents, accounts payable and accrued liabilities approximated fair value as of December 31, 2006 and 2005 because of the relatively short maturity of these instruments. In addition, fair market values of derivative contracts require discounted cash flow valuation estimates that will change over time due to changes in market conditions for those instruments as well as underlying commodity prices. Actual results could differ from those estimates.

Income Taxes

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 financial statements that will result in taxable or deductible amounts in future years. The measurement of deferred tax assets may be reduced by a valuation allowance based upon management s assessment of available evidence if it is deemed more likely than not some or all of the deferred tax assets will not be realizable. Currently, a valuation

TETON ENERGY CORPORATION AND SUBSIDIARIES
Notes to Consolidated Financial Statements

allowance of 100% is provided for the deferred tax asset resulting from the Company s net operating loss carry forward in each of the reporting years.

Recently Adopted Accounting Pronouncements

In September 2006, the SEC issued Staff Accounting Bulletin No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements, or SAB 108. SAB 108 was effective for the Company beginning with its fiscal year ended on December 31, 2006. The Company does not expect the adoption of this pronouncement to have a material impact on its financial position or results of operations.

Recently Issued Accounting Pronouncements

In July 2006 the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109, (FIN 48), which clarifies the accounting for uncertainty of tax positions. FIN 48 will require the Company to recognize the impact of a tax position in its financial statements only if the technical merits of that position indicate that the position is more likely than not of being sustained upon audit. In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements, which is effective for the Company beginning January 1, 2008 and provides a definition of fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements for future transactions. The Company is evaluating the impact of FIN 48 as of the January 1, 2007 adoption date, does not expect the adoption of this pronouncement to have a material impact on its financial position or results of operations.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements, which is effective for the Company beginning January 1, 2008 and provides a definition of fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements for future transactions. The Company does not expect the adoption of this pronouncement to have a material impact on its financial position or results of operations.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, which permits an entity to measure certain financial assets and financial liabilities at fair value. The objective of SFAS No. 159 is to improve financial reporting by allowing entities to mitigate volatility in reported earnings caused by the measurement of related assets and liabilities using different attributes, without having to apply complex hedge accounting provisions. Under SFAS No. 159, entities that elect the fair value option (by instrument) will report unrealized gains and losses in earnings at each subsequent reporting date. The fair value option election is irrevocable, unless a new election date occurs. SFAS No. 159 establishes presentation and disclosure requirements to help financial statement users understand the effect of the entity s election on its earnings, but does not eliminate disclosure requirements of other accounting standards. Assets and liabilities that are measured at fair value must be displayed on the face of the balance sheet. The Company does not expect the adoption of this pronouncement to have a material impact on its financial position or results of operations.

Note 3 Accounting Change

Prior to 2006, the Company accounted for its stock-based compensation plans under the recognition and measurement provisions of Accounting Principles Board Opinion No. 25 , Accounting for Stock Issued to Employees (APB 25), and related interpretations, as permitted by Statement of Financial Accounting Standard 123, Accounting for Stock Based Compensation (SFAS No. 123). Effective January 1, 2006, the Company adopted Statement of Financial Accounting Standard 123R, Share-Based Payment (SFAS No. 123R) which applies to all employee or consultant awards granted, modified, or settled after January 1, 2006. SFAS No. 123R establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods and services, focusing primarily on accounting for transactions in which an entity obtains employee services in share-based payment transactions. It also addresses transactions in which an entity incurs liabilities in exchange for goods and services that are based on the fair value of the entity s equity instruments or that may be settled by the issuance of those equity instruments.

APB 25 did not require any compensation expense to be recorded in the financial statements if the exercise price of the award was not less than the market price on the date of grant. Prior to July 2005, the Company issued only stock options and since all options granted by the Company had exercise prices equal to or greater than the market price on the date of the grant, no compensation expense was recognized for stock option grants prior to January 1, 2006.

SFAS No. 123R requires measurement of the cost of share-based payment transactions to employees at the fair value of the award on the grant date and recognition of expense over the requisite service or vesting period. SFAS No. 123R requires implementation using a modified version of prospective application, under which compensation

TETON ENERGY CORPORATION AND SUBSIDIARIES
Notes to Consolidated Financial Statements

expense for the unvested portion of previously granted awards and all new awards will be recognized on or after the date of adoption. SFAS No. 123R also allows companies to adopt SFAS No. 123R by restating previously issued financial statements, basing the amounts on the expense previously calculated and reported in their pro forma footnote disclosures required under SFAS No. 123. The provisions of SFAS No. 123R were adopted by the Company effective January 1, 2006, using the modified prospective application method.

A summary of the stock-based compensation expense recognized in the results of operations is set forth below:

	Years Ended December 31,		
	2006	**2005**	**2004**
Stock options employees	$ 28,494	$	$
LTIP performance share units directors, employees and consultants	2,623,830		
Restricted common stock directors, employees and consultants	486,518		
Non-employee shares issued or awarded		795,375	250,390
Total	$ 3,138,842	$ 795,375	$ 250,390

The Company adopted the disclosure-only provisions of SFAS No. 123 prior to 2006. Accordingly, no compensation cost was recognized in 2005 and 2004 for stock options. Had compensation cost for stock options been recognized in 2005 and 2004 based on the fair value at the date of grant, consistent with SFAS No. 123, the Company would have recorded additional compensation expense of $19,725 and $3,512,305 for the years ended December 31, 2005 and 2004, respectively. During the years ended December 31, 2006 and 2005, the Company issued 33,888 shares under the 2005 LTIP and 252,500 common shares under the 2004 plan, respectively, to accounting and legal consultants for services rendered.

Note 4 Sale of Goloil

As described in Note 1, the Company completed the sale of Goloil effective July 1, 2004. Accordingly, the operating activities of Goloil for the six months ended June 30, 2004 has been included in the results from discontinued operations, summarized as follows, for the years ended December 31:

	2006	**2005**	**2004**
Sales	$	$	$ 6,552,138
Cost of sales and expenses		255,000	7,072,272
Loss from operations		(255,000)	(520,134)
Other income (expense)			
Interest expense			(166,216)
Net loss from discontinued operations, before tax		(255,000)	(686,350)
Income tax			(16,829)
Net loss from discontinued operations, before gain on disposal		(255,000)	(703,179)
Gain on sale of Goloil stock			13,086,761
Income (loss) from discontinued operations	$	$ (255,000)	$ 12,383,582

The gain on sale of Goloil stock is calculated as follows:

Sale price for Goloil shares	$ 8,960,229

Less direct transaction expenses:	
Investment banking fee	(750,000)
Net fees and expenses	(246,779)
Net proceeds	7,963,450
Net deficit of investment in Goloil at date of sale	5,123,311
Gain on disposal of ZAO Goloil	$ 13,086,761

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On September 20, 1999, Goloil entered into a Grant Agreement (the Agreement) with the U.S. Trade and Development Agency (TDA) in which the TDA agreed to grant to Goloil, subject to the satisfaction of certain conditions, up to $300,000 (the Grant) partially to fund the cost of goods and services required for a feasibility study (the Study) of the Eguriakhskiy License Territory Pipeline Project in Russia. In turn, Goloil contracted with the Company to perform the Study. During the fourth quarter of 1999, the Company received $255,000 of the $300,000. Such amount was recorded as a reduction of the Russian property expenditures. In conjunction with the finalization of the Company s discontinued Russian activities, the Company determined that certain criteria contained in the Agreement were met that would require it to refund the $255,000 to the TDA, and, accordingly, had recorded as a liability at December 31, 2005 the full amount received ($255,000) and included such amount as an expense of discontinued activities for the year ended December 31, 2005. On February 28, 2006, the Company provided the TDA with a final success fee report and refunded the amount of the Grant.

Note 5 Acquisitions and Sales of Oil and Gas Assets

Acquisition of Piceance Basin

On February 15, 2005, the Company signed a membership interest purchase agreement with PGR Partners, LLC (PGR) whereby the Company acquired 25% of the membership interest in Piceance LLC. Piceance LLC owned certain oil and gas rights and leasehold assets covering 6,314 gross acres in the Piceance Basin in western Colorado. The properties owned by Piceance LLC carried a net revenue interest of 78.75%.

The purchase price for the membership interest in Piceance LLC was $5.25 million in cash, the issuance of 450,000 shares of the Company s common stock, which had a fair market value of $837,000, and the issuance of warrants to purchase 200,000 shares of the Company s common stock, exercisable for a period of five years at an exercise price of $2.00 per share. Assuming a volatility of 85%,a risk free interest rate of 3.71% and $0 dividends, the warrants had a fair value, using the Black Scholes method of valuation, of approximately $252,000 at the date of issuance. Additional costs of approximately $48,000 associated with the purchase of the Piceance acreage were also capitalized.

Subsequent to December 31, 2005 the members of Piceance LLC applied to and received the consent of the fee owner of the land on which Piceance LLC s oil and gas rights and leases are located for Picenace LLC to transfer the underlying interest directly to each of the members. As a result, as of February 28, 2006, Teton s 25% working interest in the oil and gas rights and leases were transferred directly to Teton Piceance LLC, our wholly owned subsidiary.

Acquisition of Eastern Denver-Julesburg Basin Acreage and Noble Acreage Earning Agreement

The Company entered into a formal Purchase and Sale Agreement on January 10, 2005 with Apollo Energy, LLC and ATEC Energy Ventures, LLC to acquire certain undeveloped acreage in the eastern Denver-Julesburg (DJ) Basin located in Nebraska. During the second quarter of 2005 the Company closed, in three different tranches, on leasehold interests covering an estimated 182,000 gross acres. The properties carried a net revenue interest of approximately 81%. As of December 31, 2005, our undeveloped acreage position in the DJ was approximately 195,252 gross acres. The total consideration for the DJ acreage acquisition was $3,683,744, consisting of $2,890,744 in cash plus 412,962 in shares of common stock valued at $631,000 and warrants to purchase 206,481 shares of common stock, exercisable at $1.75 per share for a period of three years with a fair value, using Black Scholes of approximately $162,000 assuming a volatility of 82%, a risk-free interest rate of 3.21% and $0 dividends. Included in capitalized costs at December 31, 2005 were $367,000 in legal and due diligence costs incurred during the negotiation and acquisition of such properties and $110,250 which is the fair value of the shares issued to a consultant engaged to perform due diligence for the Company, as well as approximately $153,000 in other capitalized costs.

Effective December 31, 2005, the Company entered into an Acreage Earning Agreement (the Earning Agreement) with Noble Energy, Inc. (Noble), which closed on January 27, 2006. Under the terms of the Earning Agreement, Noble would earn a 75% working interest in Teton s DJ acreage in all acreage within the Area of Mutual Interest (AMI) after payment of the $3,000,000 and after drilling twenty wells by March 1, 2007 at no cost to Teton. Noble paid the Company $3,000,000 under the Earning Agreement and the Company recorded the entire $3,000,000 (including $300,000, which was reflected as a deposit at December 31, 2005) as a reduction of the investment in its DJ Basin property. Teton receives 25% of any revenues derived from the drilling and completion of the first

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20 wells. After completion of the first 20 wells, the Earning Agreement provides that Teton and Noble will split all costs associated with future drilling according to each party s working interest percentage.

On December 21, 2006, the Company received notification from Noble that the first 20 wells have been drilled and it had satisfied the earning criteria for completion for the Denver-Julesburg Basin Niobrara pilot project. Therefore as part of agreement, Noble earned 75% in all acreage within the AMI.

During 2006, the Company also acquired an additional 14,932 gross acres in the DJ Basin through Nebraska state acreage sales bringing its total gross acreage in the DJ Basin to 210,184 gross acres. On December 15, 2006, Teton closed on an agreement to purchase additional leasehold interest in the DJ Basin with an undisclosed third party. The agreement called for the acquisition of approximately 56,389 gross acres. Approximately, 45,773 net acres were within the Teton / Noble AMI and approximately 10,616 gross acres outside the AMI. Noble agreed to accept its 75% interest in the acreage within the AMI. As of December 31, 2006, the Company s total gross acreage in the DJ Basin is 266,572 acres of which 255,956 gross acres is in the Teton / Noble AMI and 10,616 gross acres is outside of the AMI. The Company has a net acreage position of 57,834 net acres within the Teton / Noble AMI and 8,550 net acres outside the AMI. Teton s interests in the oil and gas rights and leases are recorded directly to Teton DJ Basin LLC, a wholly owned subsidiary of the Company.

Acquisition of Williston Basin Acreage

On May 5, 2006, the Company closed a definitive agreement with American Oil & Gas, Inc. (American) acquiring a 25% working interest in approximately 87,192 gross acres in the Williston Basin located in North Dakota for a total purchase price of approximately $6.17 million.

Per the terms of the agreement, the Company paid American approximately $2.47 million in cash at closing and will pay an additional approximately $3.7 million in respect of American s 50% share for drilling and completion of the two planned wells through June 1, 2007. Any portion of the $3.7 million not expended in respect of American s 50% share of drilling and completion by June 1, 2007, will be paid directly to American on that date. In addition to the Company s obligation to fund American s share, it is also obligated to pay costs in respect of its own 25% share of drilling and completion costs of such wells during the same time period.

In addition to its 25% and American s 50% working interests in the acreage, the Company has one other partner in the acreage: Evertson Energy Company (Evertson) which is the operator and has a 25% working interest. Evertson began drilling one tri-lateral horizontal well, the Champion 1-25H on September 25, 2006. As of December 31, 2006, the Company has paid to American $3.0 million of the initial obligation of $3.7 million resulting in a remaining accrued purchase consideration of $775,054.

Note 6 Senior Bank Facility

On June 15, 2006, the Company entered into a $50 million revolving credit facility (the Credit Facility) with BNP Paribas as administrative agent, sole lead arranger, and sole book runner. The Credit Facility matures on June 15, 2010.

The Credit Facility provides for as much as $50 million in borrowing capacity, depending upon a number of factors, such as the projected value of the Company s proven oil and gas assets. The borrowing base for the Credit Facility at any time will be the loan value assigned to the proved reserves attributable to the Company s subsidiaries direct or indirect oil and gas interests. The Credit Facility had an initial borrowing base of $3 million. The borrowing base as redetermined by the BNP Paribas as of March 12, 2007 is $ 6 million. The borrowing base is redetermined on a semi-annual basis, based upon an engineering report delivered by the Company from an approved petroleum engineer. The Credit Facility is available for working capital requirements, capital expenditures, acquisitions, general corporate purposes and to support letters of credit.

Under the Credit Facility, each loan bears interest at a Eurodollar rate or a base rate, as requested by the Company, plus an additional margin based on the amount of the Company s total outstanding borrowings relative to the total borrowing base. The Eurodollar rate is based on the London Interbank Offered Rate. The base rate is the higher of the Prime Rate or the Federal Funds Rate plus one-half of one percent. In addition, under the terms of the Credit Facility, the Company is required to pay a commitment fee based on the average daily amount of the unused amount of the commitment of each lender. This fee accrues at a rate of 0.50% per annum and is paid quarterly in arrears on the last day of March, June, September, and December of each year and on the date on which the Credit Facility is terminated. Loans made under the Credit Facility are secured by a first mortgage against the Company s properties, a pledge of the equity of the Company s subsidiaries and a guaranty by those same subsidiaries.

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Debt issuance costs were incurred in connection with the Credit Facility and have been recorded as deferred debt issuance costs and are included in the Company s non-current assets. The remaining unamortized debt issuance costs at December 31, 2006 were $191,685. Those debt issuance costs are amortized to interest expense over the life of the related Credit Facility using the effective interest method.

The Credit Facility contains customary affirmative and negative covenants such as minimum/maximum ratios for liquidity and leverage. Under the terms of the Credit Facility, certain covenants are not immediately effective and are phased in beginning at the end of the first quarter of 2007 and are then gradually phased-in over the first three quarters of 2007. As of December 31, 2006, there were no outstanding balances associated with the Credit Facility.

Note 7 Stockholders Equity

Changes in Stockholders Equity during 2006

Placements of Common Stock

On August 2, 2006 the Company closed a public offering of 2,300,000 shares of its common stock at $5.20 per share. Total shares delivered at closing included the underwriter s over-allotment option to purchase 300,000 additional common shares, which was exercised at closing. Gross proceeds from the offering totaled $11.9 million. Offering costs including the underwriter s fees, legal, accounting and other related expenses totaled $1.1 million. The Company received net proceeds from the offering of $10.8 million.

During the year ended December 31, 2006, 1,530,996 warrants and options were exercised, purchasing 1,530,996 common shares of the Company for net proceeds of $6,235,419.

In connection with the resignation of the Company s former contract Chief Financial Officer, effective March 31, 2006, 50,000 restricted shares of common stock were returned to the Company as an agreed-upon reduction in service fees charged. The return of such shares had been recorded as a reduction in accounting fees totaling $157,500 at March 31, 2006.

On June 8, 2006, the Company issued 5,000 restricted shares of common stock for services rendered by an outside director (at a time prior to his becoming a director) valued at $31,695 based on the closing price of its stock on the date of issuance.

On December 31, 2006, 65,001 restricted shares partially vested to an officer and two directors pursuant to grants made under the Company s LTIP.

Changes in Stockholders Equity during 2005

Private Placements of Common Stock

During the year ended December 31, 2005, 311,104 common shares were issued for (i) the settlement of accrued liabilities of $10,500; (ii) services provided by accounting and legal consultants of $905,624 and (iii) services provided by its former advisory board of $39,400. The services were valued based upon the value of the shares issued, which management deemed to be the more readily determinable value.

The Company issued 450,000 shares of common stock, valued at $837,000 and 200,000 warrants, valued at $251,949 in conjunction with the purchase of a 25% interest in Piceance LLC.

The Company issued 412,962 shares of common stock valued at $631,006, and 206,481 warrants valued at $161,923, in conjunction with the purchase of acreage in the eastern DJ.

During the year ended December 31, 2005, 743,868 warrants were exercised, purchasing 743,868 common shares of the Company for net proceeds of $3,497,501, net of related AMEX fees of $48,862.

On June 2, 2005, the Board of Directors of the Company declared a dividend distribution of one Preferred Stock Purchase Right (each a Right and collectively the Rights) for each outstanding share of Common Stock, $0.001 par value (Common Stock), of the Company. The distribution was paid as of June 14, 2005 (the Record Date), to stockholders of record on that date. Each Right entitles the registered holder to purchase from the Company one one-hundredth of a share of the Company s Series C Preferred Stock, $0.001 par value at a price of $22.00, subject to adjustment on the occurrence of certain events which generally involve a person acquiring 15% of the Company s Common Stock without the permission of the Board of Directors. The description and terms of the Rights are set forth in the Rights Agreement dated as of June 3, 2005, between the Company and Computershare Investor Services, LLC, as Rights Agent.

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Convertible Preferred Stock

The terms of the certificate of designation for the Company s Series A and B Preferred Stock (the Preferred Stock) included automatic conversion to Common Stock once the Company s Common Stock averaged $6.00 per share for a period of 30 days. On September 23, 2005, the Company notified holders of its Preferred Stock that their shares of Preferred Stock would be automatically converted into shares of the Company s Common Stock effective September 30, 2005, as the automatic conversion trigger had been met. As a result, 281,460 outstanding shares of Preferred Stock were converted to 281,460 shares of Common Stock.

Changes in Stockholders Equity during 2004

Private Placements of Common Stock

During the year ended December 31, 2004, the Company issued 45,925 common shares for (i) the settlement of accrued liabilities of $58,700; (ii) services provided by consultants of $43,329; and (iii) services provided by its former advisory board of $58,000.

50,000 warrants were issued to settle a liability at December 31, 2003 valued at $46,967. The Company also issued 100,000 warrants to a consultant valued at $102,094 for services. The services were valued based upon the value of the shares issued, which management deemed to be the more readily determinable value.

Private Placements of Series A Convertible Preferred Stock

The Company received the following proceeds from the issuance of privately placed preferred stock at a price of $4.35 per share: Proceeds of $499,998 (net of cash costs of $50,000) from the issuance of 126,436 shares of 8% Series A Convertible Preferred Stock.

The Series A Preferred Stock carried an 8% dividend, payable quarterly commencing January 1, 2004 and was convertible into common stock at a price of $4.35 per share. The Series A Preferred Stock was entitled to vote on all matters presented to the Company s common stockholders, with the number of votes being equal to the number of underlying common shares. The Series A Preferred Stock also contained a liquidation preference of $4.35 per share plus accrued unpaid dividends. The Series A Preferred Stock could be redeemed by the Company after one year for $4.35 per share upon proper notice of redemption being provided by the Company.

The following table presents the activity for warrants outstanding:

	Shares	Weighted Average Exercise Price
Outstanding December 31, 2003	7,389,981	$ 5.63
Granted	4,496,142	6.00
Forfeited/canceled	(4,526,396)	5.98
Outstanding December 31, 2004	7,359,727	5.62
Granted	406,481	1.87
Exercised	(743,868)	4.77
Forfeited/canceled	(5,290,576)	6.00
Outstanding December 31, 2005	1,731,764	3.93
Granted		
Exercised	(760,959)	4.65
Forfeited/canceled	(102,986)	5.36

Outstanding	December 31, 2006	867,819	$	3.14

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On May 11, 2004, the Board of Directors voted to extend by one year the expiration date of 3,943,151 warrants issued during the period from April 1, 2002 to December 15, 2003, with no change in the exercise price of $6.00. The above table includes the extension as an expiration and grant of such warrants.

The following table presents the composition of warrants outstanding and exercisable as of December 31, 2006:

Range of Exercise Prices	Number	Price*	Life*
$1.75 - $3.24	861,819	$ 3.13	4.6
$3.48 - $4.35	6,000	3.81	1.6
Total shares outstanding and exercisable	867,819	$ 3.14	4.6

* Price and Life reflect the weighted average exercise price and weighted average remaining contractual life (in years), respectively.

Note 8 Stock-Based Compensation

At the Company s 2004 Annual Meeting, its shareholders approved a stock-based compensation plan for non-employees (the 2004 Plan). The maximum number of shares of Common Stock with respect to which awards could be granted was 1,000,000 shares. On April 5, 2005 the Board authorized the issuance of 140,000 restricted shares to the Company s contract Chief Financial Officer, 112,500 restricted shares to the Company s outside legal counsel and 35,000 restricted shares to an outside consultant providing land services on the Company s acquisitions. The shares were not formally issued to the consultants until the third quarter; however, the Company recorded such shares at their fair value on April 5, 2005 of $905,625. During the second quarter of 2005, the Company capitalized $110,250 of such amount and recorded the balance of $795,375 as general and administrative expenses.

Both the 2003 Plan and the 2004 Plans were terminated upon shareholder approval of the LTIP at the Company s 2005 Annual Meeting; however, grants made under these plans remain outstanding until exercised or terminated pursuant to each plan s terms.

At the Company s 2005 Annual Meeting the stockholders approved a Long Term Incentive Plan (the LTIP). The LTIP is a performance-based compensation plan whereby up to 10% of the outstanding shares at the beginning of each plan year, except for the first year wherein 20% of the outstanding shares are available (not to exceed, in any three year period, 35% of the outstanding shares of the Company) can be awarded to certain employees, directors and consultants. In most cases, awards will be linked to the performance of the Company as measured by performance metrics that, at the time of the grants, are deemed necessary by the Compensation Committee of the Board of Directors for the creation of shareholder value.

On July 26, 2005 the Compensation Committee finalized the award of 800,000 performance share units to certain Company employees and directors which vest during each of 2005, 2006 and 2007 provided the Company meets certain performance targets as established by the Committee. The vesting of the performance share units into common stock is conditioned on the participants remaining employed by the Company at each measurement date and will vest over one, two and three year periods. The performance share units will vest into common stock on a sliding scale from 50% to 200%, depending on the performance levels achieved by the Company. No LTIP shares were earned for 2005 as the objectives established by the Compensation Committee were not met.

During 2006 the Compensation Committee reserved 2,500,000 performance share units under the LTIP to executives, directors, certain employees and consultants which vest during each of 2006, 2007 and 2008 provided the Company meets certain performance targets as established by the Committee. The vesting of the performance share units into common stock is conditioned on the participants remaining employed by the Company at each measurement date and will vest over one, two and three year periods. The performance share units will vest into common stock on a sliding scale from 50% to 200%, depending on the performance levels achieved by the Company.

Each of the component categories of stock-based compensation is described more fully below.

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Stock Options

We granted 45,000 stock options during 2005 under the 2003 Employee Stock Option Plan. These options are exercisable at $3.11 per share and vest over a three-year period, assuming the employees remain in our employ. As of December 31, 2006, we estimated the unrecognized value of the stock options at $26,299 using the Black-Scholes option-pricing model with the following assumptions: volatility of 109.46%, a risk-free rate of 4%, zero dividend payments and a life of 10 years. The remaining unvested value of the stock options as of December 31, 2006 was revised to $54,791 during the second quarter of 2006, as adjusted for estimated forfeitures. As of December 31, 2006, there were 13,333 unvested stock options outstanding, and the total unrecognized compensation cost adjusted for estimated forfeitures related to non-vested options was $26,299, which is expected to be recognized over the remaining service period of 18 months.

A summary of stock option activity for the year ended December 31, 2006 is presented below:

	Number Outstanding	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value
Outstanding at December 31, 2005	2,875,334	$ 3.54		
Granted		$		
Exercised	(770,039)	$ 3.50		
Forfeited or expired	(16,750)	$ 3.11		
Outstanding at December 31 2006	2,088,545	$ 3.56	5.44	$ 2,867,126
Exercisable at December 31, 2006	2,075,212	$ 3.56	5.42	$ 2,842,059

Long Term Incentive Plan

On June 28, 2005, the Company s shareholders approved a long-term incentive plan (the LTIP) that permits the grant of stock options, stock appreciation rights, performance share units, and restricted share units to employees, directors, consultants and vendors as directed by the Compensation Committee of the Board of Directors, with management recommendations regarding consultants, vendors, and non-executive employees.

The Compensation Committee establishes a pool (Pool) of Performance Share Units (Units) under the LTIP each year (each year becoming a Grant Year), subject to limits set forth in the LTIP, and allocates the pool to officers, directors, employees and consultants, and grants units (Grants) to individual participants. The Grants vest over a period of time, typically over a three-year period. In addition to vesting based on a participant s continued employment with or service to the Company over the period of a Grant, the Units must be earned based on achieving performance goals set forth by the Compensation Committee. The Compensation Committee designates performance levels as Threshold, Base, and Stretch. If the Company achieves 100% of the Base level of performance, 100% of the Units vesting in that year will be earned. If the Company achieves the Threshold level of performance, 50% of the Units will be earned. If the Company achieves the Stretch level of performance, 200% of the Units will be earned. If the Threshold performance is not achieved, no Units are earned. Units may not be earned above the 200% Stretch level. Once the Units are vested and earned, they are released to the participants as common stock.

The value of each Unit is measured and determined based on the value of the Company s common stock at the date the Unit is granted. Annual compensation expense is calculated based upon the number of Units vested and earned each year. Each quarter the Company estimates the level of performance expected to be achieved by year-end and records an estimated expense accordingly.

During the third quarter of 2005 (the 2005 Grant Year) the Compensation Committee established a Pool of 400,000 Base Units and 800,000 Stretch Units (the 2005 Grants). During 2005, grants of 372,500 Base Unit awards were made. The Units vest in three tranches (20% in 2005, 30% in 2006 and 50% in 2007), provided the goals set forth by the Compensation Committee are met. The performance goals are based upon attaining specific objectives, including: (a) achieving certain levels of oil and gas

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reserves in each year of the grant, (b) achieving a certain level of oil and gas production in each year of the grant, (c) achieving a certain level of stock price performance in each year of the Grant, (d) maintaining finding and development costs within certain ranges during each year of the grant and (e) management s efficiency and effectiveness in its operations. The Threshold performance objectives were not achieved for 2005 and none of the initial tranche of 20% of the 2005 Grants (totaling 74,500) was earned in 2005. On March 13, 2007, based on the achievement of a 126.54% composite index in respect of the milestones established for 2006 under the 2005 Grants, 134,767 shares were earned and awarded. Accordingly, the Company has recorded 2006 LTIP compensation expense of $667,629 based on the milestone achievement through December 31, 2006. Pursuant to the Plan s terms, 79,149 shares have been returned to the Plan for future use as the 200% Stretch targets were met.

In December of 2005, the Compensation Committee reserved for 2006 (the 2006 Grant Year) 1,000,000 Base Units and 2,000,000 Stretch Units (the 2006 Grants). In March 2006, the Compensation Committee increased the Pool of Base Units being reserved to 1,250,000 and Stretch Units to 2,500,000 to accommodate anticipated executive hires. At December 31, 2006, a total of 984,625 Base Units and 1,969,250 Stretch Units had been granted, but not yet earned or vested. The remainder of Units in the 2006 Pool reverted to shares deemed available for future issuance, consistent with the terms of the LTIP.

The 2006 Grants vest in three tranches (20% in 2006, 30% in 2007 and 50% in 2008), provided the goals set forth by the Compensation Committee are met. The performance objectives established by the Compensation Committee for the 2006 Grants are based on the (a) value of completed acquisitions in each year of the Grant relative to the Company s market capitalization at the end of the previous calendar year, (b) stock price performance relative to an index of comparable companies over the period of the Grant established by an independent third party, and (c) management s efficiency and effectiveness in its operations. These objectives represent 100% of the goals for senior executives of the Company and varying but lesser percentages for other employees, whose vesting includes a combination of individual, team, and corporate objectives in each year of the 2006 Grant. On March 13, 2007, based on the achievement of a 150% composite index for the 2006 Grants under the 2006 Grant Year, 291,750 shares were earned and awarded. Pursuant to the Plan s terms, 97,250 shares have been returned to the Plan for future use as the 200% Stretch targets were not met. Accordingly, we have recorded 2006 LTIP compensation expense of $1,956,201 in respect to this milestone share achievement through December 31, 2006.

A summary of the Performance Units as for the year ended December 31, 2006 is set forth below:

	2005 Grant Year		2006 Grant Year		Total	
	Base Performance Share Units	Weighted Average Grant Date Fair Value	Base Performance Share Units	Weighted Average Grant Date Fair Value	Base Performance Share Units	Weighted Average Grant Date Fair Value
Total pool	400,000		1,250,000		1,650,000	
Grants outstanding at beginning of year	298,000	$ 4.88		$	298,000	$ 4.88
Grants during the period	60,000	$ 5.29	984,625	$ 6.71	1,044,625	$ 6.70
Vested and released	(106,500)	$ 4.97	(194,500)	$ 6.71	(301,000)	$ 6.09
Forfeited/cancelled	(74,000)	$ 4.88	(12,125)	$ 6.90	(86,125)	$ 6.21
	177,500	$ 4.95	778,000	$ 6.71	955,500	$ 6.38

Outstanding at end of period

Restricted Common Stock

In December 2005, grants of 195,000 restricted shares were made pursuant to the Company s LTIP, which vest equally over 3 years, beginning January 1, 2006, based solely on service and continued employment throughout the vesting period. Of the 195,000 restricted shares, 65,001 shares vested in 2006. An additional 69,000 share grants were made during the 2006 year of which 64,000 vest over three years and 5,000 vested immediately. Compensation expense was recorded during the year ended December 31, 2006 based on the market value of the common stock at the date of grant recorded over the related service period. There was no compensation expense for the year ended December 31, 2005 as no Restricted Stock grants were outstanding.

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A summary of the status of restricted stock activity granted under our LTIP for the year ended December 31, 2006, is summarized below:

	Restricted Stock Shares	Weighted Average Grant-Date Fair Value
Non-vested at December 31, 2005	195,000	$ 6.06
Granted	69,000	$ 5.82
Vested	(70,001)	$ 6.08
Forfeited		$
Non-vested at December 31, 2006	193,999	$ 5.98

Note 9 Income Taxes

The provision for income taxes from continuing operations consists of the following components for the years ended December 31:

	2006	2005	2004
Current:			
Federal	$	$	$
State			
Total current	$	$	$
Deferred:			
Federal	$	$	$
State			
Total Deferred	$	$	$

Total income tax expense from continuing operations differed from the amounts computed by applying the federal statutory income tax rate of 35% to earnings (loss) before income taxes as a result of the following items for the years ended December 31:

	2006	2005	2004
Federal statutory income tax benefit from continuing operations	$ (2,003,564)	$ (1,322,107)	$ (1,817,648)
State income tax benefit, net of federal income tax benefit from continuing operations	(171,233)	(112,282)	(154,367)
Other	16,320	4,546	16,703
Change in valuation allowance	2,158,477	1,429,843	1,955,312
Income tax expense	$	$	$

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The tax effects of temporary differences that give rise to significant components of the Company s deferred tax assets and liabilities at December 31, are as follows:

	2006	2005
Current Deferred Tax Assets (Liabilities)		
Other receivables	$ (264,560)	$ (7,441)
Prepaid expenses		(45,157)
Accounts payable and accrued liabilities	568,942	550,205
Hedge gain	(153,089)	
Valuation allowance	(151,293)	(497,607)
Net current deferred tax asset (liability)	$	$
Non-Current Deferred Tax Assets (Liabilities)		
Depletion, depreciation, amortization	$ 494,726	$ (3,053)
Stock-based compensation	1,057,478	
Oil and gas properties	(536,881)	(801,210)
Net operating loss	10,419,166	9,110,270
Valuation allowance	(11,434,489)	(8,306,007)
Net non-current deferred tax asset (liability)	$	$
Net Deferred Tax Asset (Liability)	$	$

At December 31, 2006, the Company had net operating loss carryforwards, for federal income tax purposes, of approximately $27 million. These net operating loss carryforwards, if not utilized to reduce taxable income in future periods, will expire in various amounts beginning in 2018 through 2026. Approximately $19 million of such net operating loss is subject to U.S. Internal Revenue Code Section 382 limitations. As a result of these limitations, utilization of this portion of the net operating loss is limited to approximately $900,000 per annum plus any loss attributable to any built in gain assets sold within 5 years of the ownership change.

During 2006 we recognized $1.6 million of tax deductions from the exercise of nonqualified stock options. Stockholders equity has been credited for $0.6 million for the benefit of these deductions; however a valuation allowance has been provided for the full amount. 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 $11.5 million and $8.8 million for 2006 and 2005 respectively.

Note 10 Commitments

On October 5, 2005, in connection with the resignation of a former officer and director of the Company, the existing consulting agreement between the Company and the officer was replaced with a severance agreement. The severance agreement provided that such former Officer and Director will receive a severance benefit equal to one-year s salary, paid monthly. The severance payments may be terminated by the Company under certain circumstances prior to the total severance being paid. This severance benefit, totaling $216,000, was accrued at September 30, 2005, as the Company and the former officer and director had agreed upon and were committed to all of the basic terms of such severance agreement as of such date. At December 31, 2006 no amounts remained payable in accordance with the terms of the severance agreement.

Mr. Arleth, the Company s President and Chief Executive Officer, signed a new employment agreement on August 30, 2006, which employment agreement became effective as of September 1, 2006. The employment agreement is for a three-year term, with a base salary of $250,000 per year. Under the terms of the agreement, Mr. Arleth is entitled to 24 months severance pay in the event of a change of position or change in control of the Company or if his employment is terminated without cause. The employment agreement contains an evergreen provision, which automatically extends the term of Mr. Arleth s employ for a two-year period if the employment agreement is not terminated by notice by either party at least 60 days prior to the end of the stated term which is 2 years. In addition, Mr. Arleth will

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be entitled to a bonus based on his performance against objectives established by our compensation committee each year, and a provision that provides for the Company to purchase a split term life insurance policy providing for no less than $3,000,000 in benefits, with any such paid benefit to be distributed equally between the Company and a beneficiary of Mr. Arleth s choosing. During the first quarter of 2007, the Company purchased the split term life insurance policy for the $3,000,000 benefit level as described. In addition, Mr. Arleth s contract includes an indemnification agreement.

Mr. Pennington, the Company s Executive Vice President and Chief Financial Officer, signed an employment agreement on June 1, 2006. The employment agreement provides for an initial salary for Mr. Pennington of $190,000 per year. Under the terms of the employment agreement, Mr. Pennington is entitled to 12 months severance pay in the event of a change of position or change in control of the Company or if his employment is terminated without cause. The employment agreement contains an evergreen provision, which automatically extends the term of Mr. Pennington s employ for a two-year period if the agreement is not terminated by notice by either party during 60 days prior to the end of the initial stated term which is one year. In addition, Mr. Pennington s employment agreement includes an indemnification agreement.

Mr. Schultz, the Company s Vice President of Production, signed an employment agreement on April 1, 2006. The employment agreement provides for an initial salary for Mr. Schultz of $165,000 per year. Under the terms of the employment agreement, Mr. Schultz is entitled to 6 months severance pay in the event of a change of position or change in control of the Company or if his employment is terminated without cause. The employment agreement contains an evergreen provision, which automatically extends the term of Mr. Schultz s employ for a two-year period if the agreement is not terminated by notice by either party during 60 days prior to the end of the initial stated term which is one year. In addition, Mr. Schultz s employment agreement includes an indemnification agreement.

Mr. Bosher, the Company s Vice President Business Development, signed an employment agreement on October 1, 2006. The employment agreement provides for an initial salary for Mr. Bosher of $150,000 per year. Under the terms of the employment agreement, Mr. Bosher is entitled to 6 months severance pay in the event of a change of position or change in control of the Company or if his employment is terminated without cause. The employment agreement contains an evergreen provision, which automatically extends the term of Mr. Bosher s employ for a one- year period if the agreement is not terminated by notice by either party during 60 days prior to the end of the initial stated term which is one year. In addition, Mr. Bosher s employment agreement includes an indemnification agreement.

Mr. Brand, the Company s Controller and Chief Accounting Officer, signed an employment agreement on December 1, 2006. The employment agreement provides for an initial salary for Mr. Brand of $110,000 per year. Under the terms of the employment agreement, Mr. Brand is entitled to 6 months severance pay in the event of a change of position or change in control of the Company or if his employment is terminated without cause. The employment agreement contains an evergreen provision, which automatically extends the term of Mr. Brand s employ for a one- year period if the agreement is not terminated by notice by either party during 60 days prior to the end of the initial stated term which is one year. In addition, Mr. Brand s employment agreement includes an indemnification agreement.

The following outlines the Company s contractual commitments that are not recorded on the Company s consolidated balance sheet:

	For the Year Ended December 31,				
	2007	**2008**	**2009**	**Thereafter**	**Total**
Operating lease for office space	$123,000	$129,000	$44,000	$	$296,000

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During 2005, the Company established a Simple IRA plan, allowing for the deferral of employee income. The plan provides for the Company to match employee contributions up to 3% of gross wages. For the years ended December 31, 2006 and 2005, the Company contributed $23,406 and $3,467, respectively to such plan.

Note 11 Subsequent Events

On February 1, 2007, the Company executed an employment agreement with Dominic J. II Bazile to become our Executive Vice President and Chief Operating Officer. The employment agreement provides for an initial salary for Mr. Bazile of $225,000 per year. Under the terms of the agreement, Mr. Bazile is entitled to 12 months severance pay in the event of a change of position or change in control of the Company or if his employment is terminated without cause. The employment agreement contains an evergreen provision, which automatically extends the term of Mr. Bazile s employment for a two-year period if the employment agreement is not terminated by notice by either party during 60 days prior to the end of the initial stated term which is two year. In addition, Mr. Bazile s contract includes an indemnification agreement.

Note 12 Unaudited Supplemental Oil and Gas Disclosures

The following is a summary of costs incurred in oil and gas producing activities:

Included below is the Company s investment and activity in oil and gas producing activities including the Piceance and DJ. For 2004 prior to the sale of Goloil, the Company includes a proportionate share of Goloil s oil and gas properties, revenues, and costs.

	For the Years Ended December 31,		
	2006	**2005**	**2004**
Property acquisition costs	$ 14,164,263	$ 10,778,408	$
Facilities in progress	1,363,644	120,554	
Wells in progress	8,492,150	2,105,884	
Development costs	12,121,160	1,575,084	2,988,882
Total	$ 36,141,217	$ 14,579,930	$ 2,988,882

The following reflects the Company s capitalized costs associated with oil and gas producing activities:

	For the Years Ended December 31,		
	2006	**2005**	**2004**
Property acquisition costs:			
Proved	$ 204,783	$ 142,129	$
Unproved	13,959,480	10,636,279	
Facilities in progress	1,363,644	120,554	
Wells in progress	8,492,150	2,105,884	
Development costs	12,121,160	1,575,084	
Subtotal	36,141,217	14,579,930	
Accumulated depletion and valuation allowances	(1,832,849)	(160,653)	
Net capitalized costs	$ 34,308,368	$ 14,419,277	$

Results of Operations from Oil and Gas Producing Activities

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Results of operations from oil and gas producing activities (excluding general and administrative expense, and interest expense) are presented as follows:

	For the Years Ended December 31,		
	2006	**2005**	**2004**
Oil and gas revenues	$ 3,528,558	$ 707,420	$ 6,552,138
Oil and gas production expenses	(325,057)	(50,932)	(1,331,273)
Taxes other than income taxes	(250,528)	(48,196)	(4,286,025)
Depletion, depreciation and amortization expense	(1,672,196)	(160,653)	(747,481)
Results of operations from oil and gas producing activities	$ 1,280,777	$ 447,639	$ 187,359

Reserves (Unaudited)

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved development oil and gas reserves are those reserves expected to be recovered through existing wells with existing equipment and operating methods. The proved reserve information as of December 31, 2006 and 2005 included herein is based on estimates prepared by Netherland Sewell & Associates, Inc., independent petroleum engineers. Proved reserve information for 2004 was based on estimates provided by Gustavson Associates, Inc., independent petroleum engineers. All proved reserves of natural gas for 2006 and 2005 are located in the Piceance Basin in Colorado. All proved reserves prior to July 1, 2004 were located in Russia.

	For the Years Ended December 31,		
	2006 MMCF	**2005 MMCF**	**2004 MBBLS**
Proved reserves, beginning of period	4,009		8,262
Production	(737)	(90)	(348)
Extensions and discoveries		4,099	
Sale of reserves in place			(7,914)
Revisions of previous estimates	3,821		
Proved reserves, end of period	7,093	4,009	
Proved developed reserves, beginning of period	853		3,816
Proved developed reserves, end of period	4,927	853	

Standardized Measure of Discounted Future Net Cash Flows (Unaudited)

SFAS No. 69 prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The Company has followed these guidelines, which are briefly discussed below.

Future cash inflows and future production and development costs are determined by applying year-end prices and costs to the estimated quantities of oil and gas to be produced. Estimated future income taxes are computed using current statutory income tax rates for those countries where production occurs. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

The assumptions used to compute the standardized measure are those prescribed by the Financial Accounting Standards Board and, as such, do not necessarily reflect the Company s expectations for actual revenues to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation

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process, as discussed previously, are equally applicable to the standardized measure computations since these estimates are the basis for the valuation process.

The following summarizes the standardized measure and sets forth the Company s future net cash flows relating to proved oil and gas reserves based on the standardized measure prescribed in Statement of Financial Accounting Standards No. 69.

	For the Years Ended December 31, (in thousands of dollars)		
	2006	2005	2004
Future cash inflows	$ 29,167	$ 30,514	$
Future production costs	(10,066)	(4,643)	
Future development costs	(3,419)	(5,900)	
Future income tax expense			
Future net cash flows (undiscounted)	15,682	19,971	
Annual discount of 10% for estimated timing of cash flows	(6,977)	(11,255)	
Standardized measure of future net discounted cash flows	$ 8,705	$ 8,716	$

Changes in Standardized Measure Base Case (Unaudited)

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

	For the Years Ended December 31, (in thousands of dollars)		
	2006	2005	2004
Standardized measure, beginning of period,	$ 8,716	$	$ 5,993
Net changes in prices and production costs	(10,798)		
Sales of oil and gas produced during period	(2,953)	(608)	(935)
Future development costs	2,481		
Revisions of previous quantity estimates	10,387		
Extensions and discoveries		9,324	
Accretion of discount	872		300
Sale of reserves in place			(5,358)
Changes in income taxes, net			
Standardized measure, end of period	$ 8,705	$ 8,716	$

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Note 13 Selected Quarterly Information (Unaudited)

The following represents selected quarterly financial information for the years ended December 31, 2006 and 2005. Certain amounts have been reclassified to conform to the presentation in this Form 10-K.

	For the Quarter Ended			
	March 31,	**June 30,**	**Sept 30,**	**Dec 31**
2006				
Oil and gas sales	$ 290,249	$ 650,234	$ 1,468,892	$ 1,119,183
Loss from continuing operations (2)	$ (1,262,625)	$ (1,526,345)	$ (796,964)	$ (2,138,535)
Net Loss	$ (1,262,625)	$ (1,526,345)	$ (796,964)	$ (2,138,535)
Basic and diluted loss per common share for continuing operations	$ (0.11)	$ (0.13)	$ (0.06)	$ (0.14)
Basic and diluted loss per common share	$ (0.11)	$ (0.13)	$ (0.06)	$ (0.14)
2005				
Oil and gas sales	$	$	$ 229,594	$ 477,826
Loss from continuing operations	$ (655,507)	$ (1,644,693)	$ (802,285)	$ (674,964)
Discontinued operations, net of tax,(1)	$	$	$	$ (255,000)
Net Loss	$ (655,507)	$ (1,644,693)		