TETON ENERGY CORP
Form 10-K
March 13, 2008

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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, 2007

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, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer o	Accelerated filer þ	Non-accelerated filer o	Smaller reporting company o
		(Do not check if a smaller reporting company)	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o No þ

The aggregate market value of the common stock held by non-affiliates of the issuer, as of June 29, 2007, was approximately $79,889,000 based on the closing bid of $5.20 for the issuer s common stock as reported on the American Stock Exchange. Shares of common stock held by each director, each officer 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 10, 2008 the issuer had 17,810,534 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Certain information required by Items 10, 11, 12, 13 and 14 of Part III is incorporated by reference from portions of the registrant s definitive proxy statement relating to its 2008 annual meeting of stockholders to be filed within 120 days after December 31, 2007.

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The terms Teton , Company , we , our and us refer to Teton Energy Corporation and its subsidiaries, as a consolidated entity, unless the context suggests otherwise. We have included technical terms important to an understanding of our business under Glossary and in Items 1 and 2, Business and Properties , of this Form 10-K.

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 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 and political conditions, including governmental energy policies, tax rates or policies and inflation rates;
- The market price of, and demand for, oil and natural gas;
- Our ability to service current and future indebtedness;
- Our success in completing development and exploration activities;
- Reliance on outside operating companies for drilling and development of our oil and gas properties;
- Expansion and other development trends of the oil and gas industry;
- Acquisitions and other business opportunities that may be presented to and pursued by us;
- 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 on Form 10-K.

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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PART I

ITEMS 1. and 2. BUSINESS and PROPERTIES.

Background

We are an independent energy company engaged primarily in the development, production and marketing of oil and natural gas in North America. Our current operations are focused in four basins in the Rocky Mountain region of the United States: the Piceance, DJ, Williston and Big Horn Basins.

Teton Energy was formed in November 1996 and is incorporated in the State of Delaware. Our common shares are publicly traded on the American Stock Exchange under the symbol TEC.

Our principal executive offices are located at 410 Seventeenth Street, Suite 1850, Denver, CO 80202, and our telephone number is (303) 565-4600. Our web site is *www.teton-energy.com*.

Overview and Strategy

Our objective is to increase stockholder value by pursuing our corporate strategy of:

- economically growing reserves and production, by acquiring under-valued properties with reasonable risk-reward potential and by participating in, or actively conducting, drilling operations in order further to exploit our existing properties;

- seeking high-quality exploration and development projects with potential for providing operated, long-term drilling inventories; and

- selectively pursuing strategic acquisitions that may expand or complement our existing operations.

The pursuit of our strategy 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, Williston and Big Horn 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.

Drive Growth through Drilling

We plan to supplement our long-term reserve and production growth through drilling operations. In 2007, we participated in the drilling of 41 gross wells in connection with our Piceance Basin project where we have a 12.5% non-operated working interest, 81 gross wells in the DJ Basin under the Noble Earning Agreement where we have a 25% non-operated working interest in the AMI and 3 gross wells in the Williston Basin (in one gross well, we have a 25% non-operated working interest and, in the other two gross wells, a 5.95% and 1.56% non-operated working interest). In 2008, we anticipate that we will participate in the drilling of 52 gross wells in the Berry Petroleum Company (Berry) operated properties in the Piceance Basin, in the drilling of 163 gross wells in the Noble-operated properties in the Teton Noble AMI, and in the drilling of 4 gross wells in the Evertson-operated properties in the Williston Basin. During 2008 we also anticipate that we will drill 21 gross wells on properties operated by us, including 17 gross wells in the DJ Basin (Frenchman Creek, South Frenchman Creek and Washco), and 4 gross wells in the Big Horn Basin properties.

Maximize Operational Control

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. In 2007, we acquired 499,904 gross acres (413,786 net) in the DJ Basin Washco properties, including about 1.0 MMcfd of production, 111,872 gross acres (109,688 net) in the DJ Basin South Frenchman Creek properties, 28,204 gross acres (11,689 net) in the DJ Basin Frenchman Creek properties and 16,417 gross acres (15,132 net) in the Big Horn Basin properties, all of which are properties operated by us.

Operate Efficiently and 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 and finding and development costs. In addition, our acquisition efforts are geared toward pursuing opportunities that fit well within existing operations, in areas where we are establishing new operations or in areas where we believe that a base of existing production will produce an adequate foundation for economies of scale.

Pursuit of Selective Complementary Acquisitions

We seek to acquire long-lived producing properties with a high degree of operating control, or oil and gas concerns that enjoy good business reputations and that offer economical opportunities to increase our natural gas and crude oil reserves.

Operations, Properties and Recent Events

As of December 31, 2007, we had estimated proved reserves of 13.3 Bcf of natural gas and 129 MBbl of oil, or a total of 14.1 Bcfe, with a PV-10 value of $28.0 million (see reconciliation, and our definition, of the PV-10 non-GAAP financial measure to the standardized measure under Reserves on page 7). Of these reserves, 60% was proved developed and 95% was natural gas. This represents a net increase in reserve volumes of 99% and a 222% increase in the PV-10 value from the prior year, due to the increased reserve volumes and a pricing increase for reserve calculation purposes of $1.58 per Mcf of natural gas. Our reserve estimates change continuously and are evaluated by us annually. Changes in the market price of natural gas and oil, as well as the effects of production, acquisitions, dispositions and exploratory development activities may have a significant effect on the quantities and future values of our reserves.

During 2007, we invested $35.6 million in capital expenditures related to exploration and development. For 2008, we have budgeted approximately $36 million for ongoing development programs in the Piceance, DJ and Williston Basins. The 2008 budget estimate of $36 million does not include the impact of any future exploration or development projects in the Big Horn Basin, where we expect to drill 4 wells in 2008. We are seeking an industry partner for the Big Horn Basin project and will not know our budget amount for that area until we find a partner and determine its percentage ownership interest. We continually evaluate new opportunities, and if an additional opportunity is identified that complements our business objectives we will pursue the opportunity if we believe the economics are favorable and its pursuit will not compromise our financial and human resources.

We expect to fund our budgeted capital expenditures with cash provided by operating activities, cash on hand and funds made available through our $50 million credit facility.

As of December 31, 2007, we owned interests in a total of 132 producing wells and had an interest in 1,081,335 gross acres (642,740 net) with over 2,500 prospective locations in what we believe are hydrocarbon prone basins of the Rocky Mountains.

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As of December 31, 2007, our estimated acreage holdings by basin are:

Basin	Gross Acres	Net Acres
Piceance	6,314	789
DJ		
Noble AMI	330,152	75,310
Frenchman Creek*	28,204	11,689
S. Frenchman Creek*	111,872	109,688
Washco*	499,904	413,786
Williston	88,472	16,346
Bighorn*	16,417	15,132
Total	1,081,335	642,740

* Represents properties that are either currently operated by us or which are expected to be operated by us when development commences on the properties.

We intend to grow our reserves and production through our current areas of exploration and development, which are as follows:

Piceance Basin

Teton s properties in the Piceance Basin originally consisted of a 25% working interest (19.69% net revenue interest) in a 6,314-acre block located in Garfield County, Colorado, 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).

On October 1, 2007, we completed the sale of one-half of the 25% working interest in the Piceance assets for $38 million total consideration (prior to post-closing adjustments), including $33 million of cash, and $5 million worth of acreage (504,000 gross acres) and production (1 MMcfd) in the DJ Basin (see further discussion of DJ Basin assets below). We purchased the original acreage for approximately $4,000 per acre and realized approximately $48,000 per acre on this sale. After the sale, we have a 12.5% working interest in the 6,314 gross acres (789 net). 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 past drilling experience, that drilling and completion costs for a Williams Fork well will range between $2.1 million and $2.7 million. Based on currently approved field spacing rules (10 acre spacing), we and our partners in this acreage believe that as many as 559 additional wells may be drilled on the 6,314 acre block with an estimated average 1.1 1.3 Bcf ultimate recovery per well.

DJ Basin

Teton Noble AMI

We acquired our first interest in this play through a series of transactions between April 2005 and July 2005 that resulted in our accumulating in excess of 182,000 gross acres. In December 2005, we entered into an Acreage Earning Agreement (Earning Agreement) with Noble Energy, Inc. (Noble), under which Noble paid us $3 million and earned a 75% working interest in our DJ Basin acreage after drilling and completing 20 wells, at no cost to us. Pursuant to the Earning Agreement, we retained a 25% working interest in the AMI created by the Earning Agreement, and both parties share all costs at each individual s respective percentages. Through December 31, 2007, the parties have grown our acreage position to 330,152 gross acres (75,310 net) in the eastern DJ Basin located on the Nebraska-Colorado border in Chase, Dundy, Perkins, and Keith Counties, 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

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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 as well as past drilling experience, we and our operating partner anticipate that gross drilling and completion costs for a Niobrara well are approximately $220,000. Based on currently approved field spacing rules (40 acre spacing), we and our partners in this acreage believe that at least 1,300 additional wells may be drilled on the 330,152-acre block with an estimated average 200 MMcfe ultimate recovery per well.

Frenchman Creek

The Frenchman Creek acreage block, 28,204 gross acres (11,689 net), is located in Phillips County, Colorado, in the eastern DJ Basin. In 2007, we entered into an agreement with Targe Energy Exploration and Production, LLC (Targe) whereby Targe will carry us on two pilot wells and Targe s proportionate share of 3-D seismic to earn its 50 percent interest in the acreage block. Teton will operate the project and will utilize coiled tubing drilling and completion technology. Coiled tubing is being successfully used by other operators in the area, and it is expected to offer improved drilling time, lower costs and other advantages gained by economies of scale.

We have staked and permitted 11 locations for Niobrara test wells. Drilling is expected to commence when state approval has been received, which is anticipated to be late in the first quarter of 2008. If the first two wells are commercially successful, Teton and Targe expect to drill the remaining nine wells on 40 acre spacing during 2008.

Based on current service company rates as well as our past drilling experience in the Teton Noble AMI, we anticipate that gross drilling and completion costs for a Niobrara well at Frenchman Creek are approximately $220,000 at the present time. Based on currently approved field spacing rules (40 acre spacing), we believe we can drill at least 90 additional wells on the 28,204-acre block with an estimated average 200 MMcfe ultimate recovery per well.

The initial test wells will target the Niobrara Beecher Island Chalk Interval, which is gas-bearing in fields in close proximity to our new well locations, at a depth of about 2,500 feet. Teton believes that the Frenchman Creek prospect contains multiple Niobrara structures, which were identified by our 3-D seismic evaluations of the area.

South Frenchman Creek

In November 2007, we acquired bolt-on acreage (contiguous to our current acreage) in the DJ Basin that allowed us to establish a new operating area of 111,872 gross acres (109,688 net) in Yuma County, Colorado, southern Dundy County, Nebraska and northwestern Cheyenne County, Kansas. The acreage is in proximity to existing Niobrara gas production and deeper Lansing-Kansas City oil production.

Based on current service company rates as well as our past drilling experience in the Teton Noble AMI, we anticipate that gross drilling and completion costs for a Niobrara well at South Frenchman Creek are approximately $220,000 at the present time. Based on currently approved field spacing rules (40 acre spacing), we believe we can drill at least 638 wells on the 111,872-acre block with an estimated average 200 MMcfe ultimate recovery per well.

Washco

As part of the sale of a one-half interest in our Piceance properties (see comments under Piceance Basin above), we acquired a large, contiguous block of acreage in the DJ Basin of 499,904 gross acres (413,786 net) primarily in Washington and Yuma Counties, Colorado. The acreage is southwest of our existing acreage in the DJ Basin the Teton Noble AMI and Frenchman Creek Prospect areas. There was also approximately 1 MMcfed of production net to Teton associated with this acreage acquisition. This production breaks down as follows: 125 bopd net, primarily from the Spotted Dog Field, a J sand producer, and 300 Mcfd net, from Niobrara reservoirs.

The drilling targets of this play are the Niobrara formation for gas, and the J and D sands for oil. The gas is contained in shallow structural traps at depths ranging from 1,700-2,500 feet. The oil is contained either in four-way structural traps or stratigraphic traps with depths ranging from 4,300-4,500 feet. Based on current service company rates as well as our past drilling experience in the Teton Noble AMI, we anticipate that gross drilling and completion costs for a Niobrara well at Washco are approximately $220,000. Additionally, we anticipate that gross drilling and completion costs for a J and D sands well at Washco are approximately $450,000.

Williston Basin

On May 5, 2006, we acquired a 25% working interest from American Oil and Gas, Inc. (American) in approximately 87,192 gross acres in the Williston Basin located in Williams County, North Dakota, which has grown to 88,472 gross acres (16,346 net). In addition to our 25% working interest and American s 50% working interest, we have two other partners in the acreage: Evertson Energy Company (Evertson), which is the operator and has a 20% working interest, and Sundance Energy, Inc., which has a 5% working interest.

The targets of this prospect are the Mississippian Bakken (oil) formation of the Williston Basin and the natural gas of the Red River formation. This Bakken 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 completed directly to the east of the acreage block. Multiple stage fracture stimulation is used to increase recoveries. We participated in a Red River test well in November 2007 and in a 3D seismic survey in the Red River lead area in January 2008 and believe there are as many as 10 gross future locations for Red River wells. Secondary horizons in this area include the Madison, Duperow, Nisku, and Interlake formations.

Based on current service company rates as well as past drilling experience in the Williston Basin Bakken and Red River formations, we anticipate that gross drilling and completion costs for a Bakken well are approximately $3.8 million and for a Red River well are approximately $3.7 million. Based on currently approved field spacing rules (640 acres for Bakken, 320 acres for Red River), we believe we could drill possibly 135 additional Bakken wells and approximately 10 additional Red River wells on the 88,472-acre block with an estimated average 258 MBO ultimate recovery per Bakken well and an estimated average 3.9 Bcfe ultimate recovery per Red River well.

Big Horn Basin

In 2007, we acquired 16,417 gross acres (15,132 net) in the Big Horn Basin of Wyoming that will allow us to further add to our growing operating presence. The Greybull and Peay Sand formations are conventional oil and gas targets for this play and the Mowry Shale is an unconventional horizontal gas target. We intend to permit our first Greybull test well in this area in the first quarter 2008 and plan to drill two Greybull wells and two Mowry wells in 2008. Based on current service company rates, we anticipate that gross drilling and completion costs for a Greybull well are approximately $2.7 million and for a Mowry well are $4.0 million. Based on currently approved field spacing rules (160 acre spacing for Greybull and 640 acre spacing for Mowry), we believe we could drill approximately 68 Greybull and Mowry wells on the 16,417-acre block with an estimated average 1.5 Bcf of natural gas and 100,000 Bbl of oil in the Greybull wells and an estimated average 2.5 Bcf of natural gas in the Mowry wells of ultimate recovery per well.

Other Recent Developments

On May 16, 2007, we closed on a financing consisting of $9.0 million face value of 8% senior subordinated Convertible Notes (the Notes) due May 16, 2008, and warrants to purchase 3,600,000 shares of the Company s common stock at a $5.00 strike price with a term of five years and a cashless exercise provision. The Notes are also convertible into shares of our common stock when the price of the common stock, as listed on the American Exchange, is at or above $5 per share. Net proceeds from the sale of the Convertible Notes and warrants were $8.3 million after fees and expenses.

On July 25, 2007, we completed a registered direct offering of 964,060 shares of our common stock, at a price of $5.05 per share, to a select group of institutional investors for gross proceeds of $4.9 million. The offering included 337,421 warrants to purchase 337,421 shares of common stock at an exercise price of $6.06 per share with a term of five years.

Central Kansas Uplift

On February 26, 2008, we announced the signing of a Letter of Intent to acquire reserves, production and certain oil and gas properties in the Central Kansas Uplift of Kansas from a group of approximately 14 working interest owners (Sellers) for approximately $53.4 million before adjustments. The purchase price is expected to be funded with $40.1 million in cash and $13.3 million in Teton common stock. Terms also include warrant coverage of 625,000

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shares at a $6.00 strike price with a two-year term. The Company expects its bank credit facility s available borrowing base to grow to approximately $35 to $40 million as a result of the added reserves from this transaction. The transaction is anticipated to be funded from the increased bank credit facility and cash on hand. Closing is expected to occur on or before April 25, 2008 with an effective date of March 1, 2008.

The purchase price includes an estimated 11.3 billion cubic feet equivalent (Bcfe) or 1.89 million barrels of oil equivalent (MMboe) of proved reserves and an estimated 4.25 million cubic feet equivalent per day (MMcfed) or 710 barrels of oil equivalent (Boe) of daily production as of March 1, 2008. The Sellers proved reserves are approximately 92 percent oil and 92 percent of their reserves are developed (PDP or PDNP), located on approximately 1,571 gross (1,518 net) acres. When combined with Teton s existing reserves, Teton will have proved reserves of approximately 52 percent natural gas and 48 percent oil. In addition, the ratio of Teton s developed reserves in the proved category will increase from 61 percent to 75 percent.

Production from the Sellers assets is approximately 92 percent oil and eight percent natural gas. When combined with Teton s existing production, Teton will have production of approximately 43 percent natural gas and 57 percent oil. Teton anticipates hedging the commodity price of at least 80 percent of the oil PDP production related to this transaction at time of closing for five years in order to lock in base case economics.

The purchase price includes 50 producing wells, 22 wells with production behind pipe, five wells drilling or waiting on completion and 31 identified undeveloped locations. The proved assets to be acquired have a 92 percent working interest and a 76 percent net revenue interest to Teton. This acquisition will nearly double Teton s 2007 year-end proved reserves of 14.1 Bcfe and Teton s 2007 exit production rate of 4.3 MMcfed. In addition, the purchase price includes 52 square miles of 3-D seismic with additional seismic to be acquired in 2008. It also includes 54,000 gross (32,000 net) undeveloped acres where Teton operates, at 60 percent working interest to Teton and 40 percent working interest to Sellers. The Company believes the undeveloped acreage could yield additional upside potential to Teton. Teton and Sellers have also agreed to a go-forward 30-month area of mutual interest to pursue additional acreage and resource opportunities where Teton will operate under the same 60/40 working interest split with Sellers as described on the existing undeveloped acreage.

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Reserves

The reserve estimates at December 31, 2007, 2006 and 2005 presented below were reviewed by the independent petroleum engineering firm Netherland, Sewell and Associates, Inc. All reserves are located within the continental United States. For the periods presented, Netherland, Sewell and Associates, Inc. evaluated 100% of the properties included in our reserves. The PV-10 values shown in the following table are not intended to represent the current market value of the estimated proved oil and gas reserves owned by Teton. Reserve estimates are inherently imprecise and are continually subject to revisions based on production history, results of additional exploration and development, prices of oil and gas, and other factors. For more information regarding the inherent risks associated with estimating reserves, see Item 1A, Risk Factors.

	As of December 31,		
	2007	2006	2005
		(dollars in thousands)	
Proved developed oil reserves (Bbls)	112,173		
Proved undeveloped oil reserves (Bbls)	16,396		
Total proved oil reserves (Bbls)	128,569		
Proved developed gas reserves (Mcf)	7,929,988	4,927,429	852,849
Proved undeveloped gas reserves (Mcf)	5,377,520	2,165,629	3,156,300
Total proved gas reserves (Mcf)	13,307,508	7,093,058	4,009,149
Total proved gas equivalents (Mcfe) (1)	14,078,922	7,093,058	4,009,149
Present value of estimated future net cash flows before income taxes, discounted at 10%(2)	$ 27,992	$ 8,705	$ 8,716
Reconciliation of non-GAAP financial measure:			
PV-10 (3)	$ 27,992	$ 8,705	$ 8,716
Less: Undiscounted income taxes			
Plus: 10% discount factor			
Discounted income taxes			
Standardized measure of discounted future cash flows	$ 27,992	$ 8,705	$ 8,716

(1) Oil is converted to Mcfe of gas equivalent at six Mcfe per barrel.

(2) The present value of estimated future net cash flows

as of each date shown was calculated using oil and gas prices being received by each respective property as of that date.

(3) Our standardized measure of discounted future cash flows assumes no future income taxes will be paid as a result of our cumulative net operating loss carryforwards. As a result, the normal reconciling items between the non-GAAP financial measure of PV-10 and our standardized measure of discounted future net cash flows are zero.

The average prices utilized for December 31, 2007, 2006, and 2005, respectively, were $6.04 per Mcf and $82.50 per barrel of oil; $4.46 per Mcf; and $7.62 per Mcf.

The table above also shows our reconciliation of our PV-10 to our standardized measure of discounted future net cash flows (the most directly comparable measure calculated and presented in accordance with GAAP). PV-10 is our estimate of the present value of future net revenues from estimated proved oil and natural gas reserves after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of future income taxes. The estimated future net revenues are discounted at an annual rate of 10% to determine their present value. We believe PV-10 to be an important measure for evaluating the relative significance of our oil and natural gas properties and that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating our company. We believe that most other companies in the oil and gas industry calculate PV-10 on the same basis. PV-10 should not be considered as an alternative to the standardized measure of discounted future net cash flows as computed under GAAP. Reference should also be made to the Supplemental Oil

and Gas Information included in Item 8, Note 12 to the Consolidated Financial Statements for additional information.

Production Data

The table below sets forth certain production data for the fiscal years ended December 31, 2007, 2006 and 2005. Additional oil and gas disclosures can be found in Item 8, Note 12 of the Consolidated Financial Statements.

	Years Ended December 31,		
	2007	**2006**	**2005**
Total gross oil production, Bbls	40,528		
Total gross gas production, Mcf	6,745,225	3,744,379	457,331
Net oil production, Bbls	16,575		
Net gas production, Mcf	1,127,568	737,175	90,037
Average oil sales price after realized hedging results, $/Bbl	$ 74.81	$	
Average gas sales price after realized hedging results, $/Mcf	$ 5.49	$ 5.46	$ 8.85
Average production cost ($/Mcfe)	$ 1.44	$ 1.45	$ 2.10

The following table summarizes our ownership interest in productive wells:

	As of December 31,		
	2007	**2006**	**2005**
Gross productive wells			
Oil	12.00		
Gas	120.00	20.00	3.00
Total	132.00	20.00	3.00
Net productive wells (1)			
Oil	9.37		
Gas	35.13	5.00	0.75
Total	44.50	5.00	0.75

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

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Wells Drilled

The following table sets forth the number of wells drilled and completed during the last three fiscal years:

	Years Ended December 31,					
	2007		2006		2005	
	Gross	Net (1)	Gross	Net (1)	Gross	Net (1)
Exploratory						
Oil	3	0.33				
Gas	13	3.25			3	0.75
Dry Holes			4	1.00		
Total	16	3.58	4	1.00	3	0.75
Development						
Oil						
Gas	90	18.38	20	5.00		
Dry Holes	13	3.13				
Total	103	21.51	20	5.00		
Total						
Oil	3	0.33				
Gas	103	21.63	20	5.00	3	0.75
Dry Holes	13	3.13	4	1.00		
Total	119	25.09	24	6.00	3	0.75

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

Finding and Development Costs

During the year ended December 31, 2007, we increased our gross proved reserves by 14.7 Bcfe from the level at December 31, 2006. During the same period, we expended $33.3 million in finding and development costs, defined as development and exploration costs incurred by the Company during 2007. This activity resulted in a one year finding and development cost in 2007 of $2.27 per Mcfe. Finding and development costs per Mcfe is determined by dividing our annual development costs incurred and exploration costs incurred on projects completed during the year by gross proved reserve additions, including both developed and undeveloped reserves added during the current year (gross amounts, not net of production and sales of properties). We use this measure as one indicator of the overall effectiveness of exploration and development activities. Proved reserves were added in each of 2007, 2006 and 2005 through our development drilling activities

Our finding and development cost per Mcfe measure has certain limitations. Consistent with industry practice, our finding and development costs have historically fluctuated on a year-to-year basis based on a number of factors including the extent and timing of new discoveries and property acquisitions. Due to the timing of proved reserve additions and timing of the related costs incurred to find and develop our reserves, our finding and development costs per Mcfe measure often includes quantities of reserves for which a majority of the costs of development have not yet been incurred. Conversely, the measure also often includes costs to develop proved reserves that had been added in earlier years. Finding and development costs, as measured annually, may not be indicative of our ability economically to replace oil and natural gas reserves because the recognition of costs may not necessarily coincide with the addition of proved reserves. Our finding and development costs per Mcfe may also be calculated differently than the comparable measure for other oil and gas companies.

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Acreage

The following table sets forth the total gross and net acres of developed and undeveloped oil and gas leases in which Teton had working interests as of December 31, 2007:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Piceance Basin	690	86	5,624	703	6,314	789
DJ Basin						
Noble AMI	4,040	922	326,112	74,388	330,152	75,310
Frenchman Creek*			28,204	11,689	28,204	11,689
S. Frenchman Creek*			111,872	109,688	111,872	109,688
Washco*	1,080	894	498,824	412,892	499,904	413,786
Williston Basin	1,600	296	86,872	16,050	88,472	16,346
Big Horn Basin*			16,417	15,132	16,417	15,132
Total	7,410	2,198	1,073,925	640,542	1,081,335	642,740

* Represents properties that are either currently operated by us or which are expected to be operated by us when development commences on the properties.

Hedge Contracts

We have entered into various contracts to hedge our exposure to the fluctuating cash flows due to changing oil and natural gas prices. The duration of our current and future hedging contracts depends on our view of the market conditions, available contract prices and our operating strategy at the time the contracts are initiated. As of December 31, 2007, we had hedging contracts in place for approximately 31% of our current daily production:

Type of Contract	Volume	Fixed Price	Price Index (1)	Contract Period	
Natural Gas Fixed Rate Swap Contract	30,000 MMBtu per month	$5.78/MMBtu	CIGRM	08/01/07	10/31/08
Oil Fixed Rate Swap Contract	60Bbls per day	$80.70/Bbl	WTI	11/01/07	12/31/08

(1) CIGRM refers to Colorado Interstate Gas Rocky Mountains price as quoted in Platt s for Inside

FERC on the first business day of each month. WTI refers to the West Texas Intermediate price as quoted on the New York Mercantile Exchange.

On February 1, 2008 we entered into an additional natural gas hedging agreement as summarized below:

Type of Contract	Volume	Floor	Ceiling	Price Index (1)	Contract Period	
Natural Gas Costless Collar	2,000 MMBtu per day	$6.00/MMBtu	$7.10/MMBtu	CIGRM	02/01/08	01/31/09

(1) CIGRM refers to Colorado Interstate Gas Rocky Mountains price as quoted in Platt s for Inside FERC on the first business day of each month.

Title to Properties

Substantially all of our working interests are held pursuant to leases from third parties. A title opinion is usually obtained prior to the commencement of drilling operations on properties. We have obtained title opinions or conducted a thorough title review on substantially all of our producing properties and believe that we have satisfactory title to such properties in accordance with standards generally accepted in the oil and gas industry. The majority of the value of our properties is subject to a mortgage under our credit facility, customary royalty interests, liens for current taxes and other burdens that we believe do not materially interfere with the use of or affect the value of such properties. We also perform a title investigation before acquiring undeveloped leasehold interests.

Seasonality

Generally, but not always, the demand and price levels for natural gas increase during the colder winter months and warmer summer months but decrease during the spring and fall months (shoulder months). Pipelines, utilities, local distribution companies and industrial users utilize natural gas storage facilities and purchase some of their anticipated winter and summer requirements during the shoulder months, which can lessen seasonal demand fluctuations.

We have entered into various hedging contracts for a portion of our production, which reduces our overall exposure to seasonal demand and resulting commodity price fluctuations. The duration of our current and future hedging contracts depends on our view of market conditions, available contract prices and our operating strategy at the time the contracts are initiated. As of December 31, 2007, we had sales delivery contracts in effect for approximately 31% of our current daily production (78% at February 1, 2008).

Marketing and Major Customers

The principal products produced by us are natural gas and crude oil, which products are marketed and sold primarily by the third party operators of the wells and a third party marketing company. Typically, oil is sold at the wellhead at field-posted prices and natural gas is sold under contract at negotiated prices based upon factors normally considered in the industry (such as distance from well to pipeline, pressure and quality).

The sale of most of our products was to Berry during the years ended December 31, 2007, and 2006, accounting for 77% and 92%, respectively, of our total oil and gas sales. 100% of our sales during the year ended December 31, 2005 were to Williams Production RMT Company. The only other company that accounted for more than 10% of our oil and gas sales during this period was Plains Marketing, L.P., which accounted for 16% of our oil and gas sales in the year ended December 31, 2007. Although a substantial portion of our production is purchased by two customers, we do not believe the loss of any one customer, or both customers, would have a material adverse effect on our business as other customers would be readily accessible to us.

Competition

The oil and gas industry is extremely competitive, particularly in the acquisition of prospective oil and natural gas properties and oil and gas reserves. Our competitive position also depends on our geological, geophysical and engineering expertise, and our financial resources. We believe that the location of our leasehold acreage, our exploration, drilling and production expertise and the experience and knowledge of our management and industry partners enable us to compete effectively in our current operating areas.

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.

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The following discussion of the regulation of the United States oil and 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, it may be 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.

Split Estate Regulation and Access Difficulties

Frequently, the mineral estate and the surface estate are owned by separate parties (the 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) are 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 over such surfaces 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 their 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

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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 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 or 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.

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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.

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 are in substantial compliance 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 and Office Space

As of December 31, 2007, we had eight full time employees. Our employees are not covered by a collective bargaining agreement. We lease 6,422 square feet of office space in Denver, Colorado, from an unaffiliated third party. The term of our lease is three years, and the lease expires on April 30, 2009.

Available Information

Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, and amendments to reports filed or furnished pursuant to Sections 13(a) and 15(d) of the Securities Exchange Act of 1934, as amended, are available on our website at *http://www.teton-energy.com*, as soon as reasonably practicable after we electronically file such reports with, or furnish those reports to, the Securities and Exchange Commission. Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q and amendments to reports are available free of charge by writing to:

Teton Energy Corporation
Ron Wirth, Director of Investor Relations and Administration
410 17th Street, Suite 1850
Denver, CO 80202

We maintain a code of ethics applicable to our Board of Directors, principal executive officer and principal financial officer, as well as all of our other employees. A copy of our Code of Business Conduct and Ethics and our

Whistleblower Policy may be found on our website at *http://www.teton-energy.com*, under the Corporate Governance section. These documents are also available in print to any stockholder who requests them. Requests for these documents may be submitted to the above address.

Glossary Terms

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

3-D seismic Seismic data that are acquired and processed to yield a three-dimensional picture of the subsurface.

AMI Area of Mutual Interest.

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.

Big Horn Basin A geologic depression in North Central Wyoming approximately 100 miles wide located in Big Horn, Washakie, Park and Hot Springs counties.

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 oil or 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.

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.

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.

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.

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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 quantities of oil, gas and/or condensate, which is economically recoverable.

Transportation Moving gas through pipelines on a contract basis for others.

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 of oil

Bcf = billion cubic feet of natural gas

Bcfe = billion cubic feet of natural gas equivalents

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.

MBbl = thousand barrels of oil

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

ITEM 1A. RISK FACTORS.

Investing in our securities involves risk. In evaluating the Company, careful consideration should be given to the following risk factors, in addition to the other information included or incorporated by reference in this annual report. Each of these risk factors could materially adversely affect our business, operating results or financial condition, as well as adversely affect the value of an investment in our common stock. In addition, the Forward-Looking Statements located in this Form 10-K, and the forward-looking statements included or incorporated by reference herein describe additional uncertainties associated with our business.

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, 2007, 2006, and 2005, we incurred net income (losses) from operations of $2.4 million, ($5.7 million), and ($4.1 million), respectively. In addition, we had an accumulated deficit of $27.8 million at December 31, 2007. There can be no assurance that we 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 current 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 oil and natural gas produced from the wells in these basins.

We may be unable to fund our planned capital expenditures.

We spend and will continue to spend a substantial amount of capital for the acquisition, exploration, exploitation, development and production of oil and gas reserves. We have historically addressed our short and long-term liquidity needs through the use of cash flow provided by operating activities, borrowing under bank credit facilities and the issuance of equity. Without adequate financing we may not be able successfully to execute our operating strategy. The availability of these sources of capital will depend upon a number of factors, some of which are beyond our control. These factors include:

- general economic and financial market conditions;
- oil and natural gas prices; and
- our market value and operating performance.

We may be unable to execute our operating strategy if we cannot obtain adequate capital. If low oil and natural gas prices, lack of adequate gathering or transportation facilities, operating difficulties or other factors, many of which are beyond our control, cause our revenues and cash flows from operating activities to decrease, we may be limited in our ability to spend the capital necessary to complete our capital expenditures program.

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 exploration, exploitation, 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.

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. In addition to the leaseholds, we are seeking to acquire producing properties including the possibility of acquiring producing properties 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.

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, estimating future development costs, estimating 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 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 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.

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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 adequate financing and, in some cases, 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 acquisitions, could result in our incurring unanticipated expenses and losses.

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.

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

Competition in the oil and gas industry is intense and 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 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.

We have limited operating control over our current production.

Most of our current production comes through joint operating agreements under which we own partial non-operated interests in oil and natural gas properties. As we do not currently operate a large portion of the production in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of underlying properties. Consequently, a portion of 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 non-operated 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 non-operated projects may require us to increase our capital expenditure budget and could result in some wells becoming uneconomic.

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, future growth and reserve calculations depend on reasonable prices for oil and natural gas. These prices also affect the amount of our cash flow available for capital expenditures and payments on our debt, and our ability to borrow and raise additional capital. The amount we can borrow under our senior secured revolving credit facility (see Note 6 to the Consolidated Financial Statements) is subject to periodic borrowing base re-determinations 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.

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;

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- 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 to attempt to mitigate this problem to some extent. 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 while not hedging may result in significant fluctuations in our net income and stockholders equity.

We enter into hedging transactions for our oil and natural gas production to reduce our exposure to fluctuations in the prices of oil and natural gas. We may in the future enter into additional 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 or the other party to the contract defaults on its obligations. Hedging transactions may limit the benefit we otherwise would have received from increases in the price for oil and natural gas, when the respective price goes above our hedged price.

The marketability of our production depends 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.

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 lender in its sole discretion, based upon, among other things, our level of proved reserves and the projected revenues from the oil and natural gas properties securing our loan. The lender 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 the lender.

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 in excess of the borrowing base 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 provide assurance 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 additional debt arrangements, or by selling assets. The terms of our revolving credit facility also may prohibit us from taking such actions without the consent of the lender. 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:

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 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 floating interest rates which are subject to change from time to time, based on LIBOR or U.S. prime rates.

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;

make loans to others;

make investments;

incur additional indebtedness;

create certain liens;

sell assets;

enter into agreements that allow 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 occur which might 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.

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.

Our reserves and future net revenues may differ significantly from our estimates.

The estimates of reserves and future net revenues are not exact and are based on many variable and uncertain factors; therefore, the estimates may vary substantially from the actual amounts depending, in part, on the assumptions made and may be subject to adjustment either up or down in the future. The actual amounts of production, revenues, taxes, development expenditures, operating expenses, and quantities of recoverable oil and gas reserves to be encountered may vary substantially from the estimated amounts. In addition, estimates of reserves are extremely sensitive to the market prices for oil and gas.

The loss of key personnel could adversely affect our business.

We currently have key employees that serve in senior management roles. The loss of any one of these employees could severely harm our business. Although we have a life insurance policy on our Chief Executive Officer, of which we are a part beneficiary, we do not currently maintain key man insurance on the lives of any of the other key employees. 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.

We may incur non-cash charges to our operations as a result of current and future financing transactions.

Under current accounting rules, we have incurred $2.6 million of non-cash charges for the year ended December 31, 2007, and may incur additional non-cash charges to future operations beyond the stated contractual interest payments required under our current and potential future financing arrangements. While such charges are generally non-cash, they impact our results of operations and earnings per share and have been and may be material.

Risks Relating To Our Common Stock

Our insiders beneficially own a significant portion of our stock.

As of March 10, 2008 our executive officers, directors and affiliated persons beneficially own approximately 14.44% 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.

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 stockholders may consider favorable or beneficial. These provisions include the following:

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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 stockholder approval, with rights senior to those of our common stockholders;

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 (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 stockholder.

Any one of these provisions could discourage proxy contests and make it more difficult for our stockholders 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 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

Information required under Item 2 Properties in included in Item 1 Business.

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 2007.

PART II

ITEM 5. MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Market Information

Our common stock is currently traded on the American Stock Exchange, under the symbol TEC.

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The following table sets forth, on a per share basis, the high and low prices for our common stock for each quarterly period from January 1, 2006 through December 31, 2007:

	High	Low
Year Ended December 31, 2007:		
First quarter	$5.52	$4.31
Second quarter	5.98	3.86
Third quarter	5.56	4.09
Fourth quarter	4.99	3.75
Year Ended December 31, 2006:		
First quarter	$8.95	$5.80
Second quarter	7.50	4.90
Third quarter	5.97	3.92
Fourth quarter	5.46	4.10

Holders

As of March 10, 2008, there were approximately 154 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.

Equity Compensation Plan Information

The following table sets forth information about our equity compensation plans at December 31, 2007:

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted Average 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]	1,415,844	$ 3.55	
2005 Long Term Incentive Plan:			
Performance Share Units	703,500	(2)	3,310,894(3)
Performance-vesting restricted common stock	540,000	(2)	3,310,894(3)
Restricted common stock grants	121,732	(2)	3,310,894(3)

(1) The 2003 Employee Stock Compensation Plan was terminated upon the adoption of the 2005 Long Term Incentive

Plan (the LTIP).

(2) Not applicable.

(3) The Company s 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.

Recent Issuances of Unregistered Securities

During the fourth quarter of 2007, there were no issuances of unregistered securities to unaffiliated third parties. On December 31, 2007, 376,126 shares were issued as a result of the vesting of a previously granted LTIP awards.

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Performance Graph

The graph below matches the cumulative five year total return of holders of Teton Energy Corporation s common stock with the cumulative total returns of the Russell 2000 index and a customized peer group of seventy companies listed in footnote (1) below. The graph assumes that the value of the investment in the company s common stock, in the peer group and the index (including reinvestment of dividends) was $100 on December 31, 2002 and tracks it through December 31, 2007.

Total Return Analysis

	12/31/02	12/31/03	12/31/04	12/31/05	12//3106	12/31/07
Teton Energy Corporation	100.00	115.28	35.19	136.57	115.51	113.43
Russell 2000	100.00	147.25	174.24	182.18	215.64	212.26
Peer Group	100.00	268.66	283.55	336.01	259.65	108.23

(1) The seventy companies included in the peer group are: Altex Industries Inc, American Resource Technologies Inc, Apollo Resources International Inc, Austin Chalk Oil Gas Limited, Avalon Oil And Gas Inc, Baseline Oil & Gas Corp, Basic Earth Science Systems Inc, Bayou City Exploration Inc, Big Sky Energy Corp., Capco Energy Inc,

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China North East Petroleum Holdings Limi, Consolidated Medical Management Inc, Credo Petroleum Corp., Crimson Exploration Inc, Cygnus Oil & Gas Corp., Daleco Resources Corp., Delek Resources Inc, Drucker Inc, Eden Energy Corp., Endevco Inc, Energas Resources Inc, Energytec Inc, Eurogas Inc, Falcon Natural Gas Corp., Fellows Energy Limited, Fieldpoint Petroleum Corp., Finmetal Mining Limited, Galaxy Energy Corp., Galton Biometrics Inc, GNC Energy Corp., Gulf Western Petroleum Corp., Hallador Petroleum Company, Hiko Bell Mining & Oil Company, Houston American Energy Corp., Ignis Petroleum Group Inc, Imperial Petroleum Inc, Interline Resources Corp., Intermountain Refining Inc, KAL Energy Inc, Lexaria Corp., Lions Petroleum Inc, Lucas Energy Inc, Mexco Energy Corp., Monument Resources Corp. Inc, Morgan Creek Energy Corp., Mountains West Exploration Inc, Ness Energy International Inc, New Frontier Energy Inc, Oakridge Energy Inc, Omega Commercial Finance Corp., Pangea Petroleum Corp., Petro Resources Inc, Petrohunter Energy Corp., Petrol Oil And Gas Inc, Petrominerals Corp., Petrosearch Energy Corp., Pluris Energy Group Inc, Pyramid Oil Company, Rancher Energy Corp., Sonoran Energy Inc, Spindletop Oil & Gas Company, Stallion Group, Star Energy Corp., Texas Vanguard Oil Company, Torrent Energy Corp., Trans Energy Inc, True North Energy Corp., United Heritage Corp., Victory Energy Corp. and XCL Limited

The stock price performance included in this graph is not necessarily indicative of future stock price performance.

ITEM 6. SELECTED FINANCIAL DATA.

The following selected financial data should be read in conjunction with our financial statements and the accompanying notes.

	Year Ended December 31,				
	2007	**2006**	**2005**	**2004**	**2003**
	(in thousands, except per share data)				
Statement of Operations Data:					
Total operating revenues	$23,694	$ 4,022	$ 797	$	$
Net income (loss) from continuing operations	$ 2,377	$ (5,724)	$ (4,032)	$ (5,193)	$ (4,036)
Discontinued operations	$	$	$	$12,384	$ (1,599)
Net income (loss)	$ 2,377	$ (5,724)	$ (4,032)	$ 7,190	$ (5,635)
Basic income (loss) per share:					
Continuing operations	$ 0.14	$ (0.44)	$ (0.40)	$ (0.64)	$ (1.00)
Discontinued operations	$	$	$	$ 1.37	$ (0.23)
Net income	$ 0.14	$ (0.44)	$ (0.40)	$ 0.73	$ (1.23)
Fully diluted income (loss) per share:					
Continuing operations	$ 0.13	$ (0.44)	$ (0.40)	$ (0.64)	$ (1.00)
Discontinued operations	$	$	$	$ 1.37	$ (0.23)
Net income	$ 0.13	$ (0.44)	$ (0.40)	$ 0.73	$ (1.23)
Balance Sheet Data:					
Total assets	$78,299	$41,244	$22,131	$17,612	$20,718
Long-term debt	$ 8,000	$	$	$	$
Total long-term liabilities	$ 8,529	$ 78	$ 4	$	$ 127

We have never declared cash dividends on our common shares.

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.

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Business Overview

We are an independent energy company engaged primarily in the development, production and marketing of oil and natural gas in North America. Our current operations are focused in four basins in the Rocky Mountain region of the United States: the Piceance, DJ, Williston and Big Horn Basins.

As of December 31, 2007, we had estimated proved reserves of 13.3 Bcf of natural gas and 129 MBbl of oil, or a total of 14.1 Bcfe, with a PV-10 value of $28.0 million (see reconciliation of the PV-10 non-GAAP financial measure to the standardized measure under Reserves on page 7). Of these reserves, 61% were proved developed reserves. Estimated proved reserves are 95% natural gas. At December 31, 2007, we controlled approximately 550,295 net acres, representing approximately 86% of our total net acreage position.

We intend economically to grow reserves and production, primarily by (1) acquiring under-valued properties with reasonable risk-reward potential and by participating in, or actively conducting, drilling operations in order further to exploit our existing properties; (2) seeking high-quality exploration and development projects with potential for providing operated, long-term drilling inventories; and (3) selectively pursuing strategic acquisitions that may expand or complement our existing operations.

Developments since December 31, 2006:

During 2007, we continued to grow oil and gas production and reserves, while participating in an active development program within the four basins, which we expect to continue in 2008:

Our non-operated Piceance Basin property had proved reserves of 7.1 Bcf at December 31, 2006. On October 1, 2007, we sold 50% of our 25% working interest in the property, leaving us with a 12.5% working interest in the Piceance Basin property. For the divested interest, we received $33 million in cash (prior to post-closing adjustments) plus 1 MMcfed of production and 504,000 gross acres in the DJ Basin. After the divestiture of one-half of our interest, after production and after drilling during 2007, at December 31, 2007, our interest in the Piceance Basin property had proved reserves of 11.9 Bcfe. Piceance Basin production for the year ended December 31, 2007, was 976 MMcf of natural gas, and we participated in the drilling of an additional 41 gross wells, bringing the total number of gross producing wells to 53 at December 31, 2007. There are currently 13 wells waiting on completion and two in process of drilling, as part of the planned 52 well, $15.3 million Piceance drilling program in 2008.

Fiscal year 2007 saw growth in our acreage position in the DJ Basin of 164% gross and 725% net. At December 31, 2006, we held interests in approximately 267,000 gross acres (approximately 66,000 net). During the year ended December 31, 2007, we added approximately 703,600 gross acres (approximately 544,100 net) in the DJ Basin. Of the 2007 growth in acreage, approximately 63,600 gross acres (approximately 8,900 net) are in the non-operated Teton Noble AMI, approximately 28,200 gross acres (approximately 11,700 net) are in our operated Frenchman Creek area, approximately 111,900 gross acres (approximately 109,700 net) are in our operated South Frenchman Creek area and approximately 499,900 gross acres (approximately 413,800 net) are in our operated Washco properties. At December 31, 2007 we have 50 producing wells in the non-operated Teton Noble AMI and 27 producing wells in our operated Washco properties. DJ Basin production for the year ended December 31, 2007, was 78 MMcf of natural gas and 12,467 Bbls of oil, and our total number of gross producing wells is 77 at December 31, 2007. There are currently 35 wells waiting on completion as part of the 180 well, $17 million DJ Basin drilling program in 2008 (163 planned in the non-operated DJ Basin Noble AMI and 17 planned in our operated Frenchman Creek area).

We participated in the drilling of two Bakken test wells and a Red River test well in the Williston Basin of North Dakota in the year ended December 31, 2007. The operator is preparing to stake and permit a second Red River test well, and we expect to participate in 2 additional Bakken wells and 2 additional Red River wells in 2008.

During the year ended December 31, 2007, we acquired a 100% working interest in 16,417 gross acres (15,132 net) in the Big Horn Basin of Wyoming. We are seeking a partner to share in this acreage and the future drilling in the Greybull and Mowry formations in the Big Horn Basin. We expect to drill 2 wells in the Greybull and 2 wells in the Mowry in 2008.

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Financial highlights for the year ended December 31, 2007 include the following:

Our net income was $2.4 million in 2007 as compared to a net loss of $5.7 million in 2006.

We raised $8.3 million after fees and expenses by issuing 8% senior subordinated convertible notes and warrants to purchase 3.6 million shares of our common stock with a cashless exercise provision.

We raised $4.5 million after fees and expenses by issuing 964,060 shares of common stock and warrants to purchase an additional 337,421 shares.

We completed a capital expenditure program totaling $35.6 million in 2007 as compared to $20.4 million in 2006.

The following summarizes our operational highlights during 2007:

We increased our oil and gas sales volumes to 1.2 Bcfe in 2007 from 737 MMcfe in 2006.

Our oil and gas revenues increased to $6.3 million at an average realized wellhead price of $5.10 per Mcfe ($6.06 after realized hedging results) in 2007 from revenues of $4.0 million and an average realized wellhead price of $5.46 per Mcfe in 2006.

We sold half of our 25% working interest in the Piceance Basin non-operated properties for $36.7 million in cash, after post-closing adjustments, plus oil and gas properties and related production valued at $4.7 million, after post-closing adjustments, for a gain on sale of assets totaling $17.4 million.

We increased proved reserves to 14.1 Bcfe on December 31, 2007 as compared to 7.1 Bcfe on December 31, 2006.

We participated in the drilling and completion of 106 gross producing wells (22.0 net) in 2007 as compared to 20 gross producing wells (5.0 net to us) in 2006.

We increased total gross producing wells to 132 (44.5 net) at December 31, 2007 as compared to 20 gross producing wells (5.0 net to us) at December 31, 2006.

We acquired 721,257 gross acres (558,753 net) in 2007 , comprised of the following:

	Acres Acquired in 2007	
	Gross	**Net**
Piceance Basin		(790)
DJ Basin		
Noble AMI	63,580	8,926
Frenchman Creek	28,204	11,689
S. Frenchman Creek	111,872	109,688
Washco	499,904	413,786
Williston Basin	1,280	322
Big Horn Basin	16,417	15,132
Total	721,257	558,753

The exploration for, and the acquisition, development, production, and sale of, natural gas and crude oil is highly competitive and capital intensive. As in any commodity business, the market price of the commodity produced and the costs associated with finding, acquiring, extracting, and financing the operation are critical to profitability and long-term value creation for stockholders. Generating reserve and production growth while containing costs represents an ongoing focus for management and is made particularly important in our business by the natural production and reserve decline associated with oil and gas properties. In addition to developing new reserves, we compete to acquire additional reserves, which involve judgments regarding recoverable reserves, future oil and gas prices, operating costs and potential environmental and other liabilities, title issues and other factors. During periods of historically high oil and gas prices, third party contractor and material cost increases are more prevalent due to increased competition for goods and services. Other challenges we face include attracting and retaining qualified personnel, gaining access to equipment and supplies and maintaining access to capital on sufficiently favorable terms.

We have taken the following steps to mitigate the challenges we face:

We attempt to reduce our overall exposure to commodity price fluctuations through the use of various hedging contracts for some of our production. The duration of our various hedging contracts depends on our view of market conditions, available contract prices and our operating strategy. Use of such contracts may limit the risk of fluctuating cash flows. As of December 31, 2007, we had hedging contracts in effect for approximately 31% of our current daily production (increased to approximately 78% when we added 2,000 MMBtus per day of production via costless collars at February 1, 2008).

We have an inventory of drilling locations that we believe will allow us to grow reserves and replace and expand production organically without having to rely solely on acquisitions. We estimate in excess of 2,500 prospective drilling opportunities in the Piceance, DJ, Williston and Big Horn Basins are expected to last for more than 10 years.

On April 3, 2006, we announced that our universal shelf registration statements on Forms S-3 and S-4 with the Securities and Exchange Commission were declared effective. The universal shelf on Form S-3 now permits, but does not obligate, Teton to sell, in one or more public offerings, shares of newly issued common stock, shares of newly issued preferred stock, warrants, stock purchase contracts, stock purchase units or debt securities, or any combination of such securities, for proceeds in an aggregate amount of up to $50 million. There is approximately $33 million remaining available under the Form S-3 shelf registration at December 31, 2007.

The acquisition shelf registration statement on Form S-4 permits Teton to issue up to $50 million of its common stock and warrants in one or more acquisition transactions that the Company may make from time to time. These transactions may include the acquisition of assets, businesses or securities, whether by purchase, merger or any other form of business combination.

We have no immediate plans, commitments or agreements to offer any securities pursuant to either registration statement at December 31, 2007 (see discussion directly below related to Developments since December 31, 2007 for possible use of S-4 shelf registration if acquisition closes), but believe each of the shelf registrations provides flexibility to quickly respond to opportunities in the future. The terms of any future offerings would be established at the time of the offerings and described in a prospectus supplement filed with the SEC.

Developments since December 31, 2007:

On February 26, 2008, we announced the signing of a Letter of Intent to acquire reserves, production and certain oil and gas properties in the Central Kansas Uplift of Kansas from a group of approximately 14 working interest owners (Sellers) for approximately $53.4 million before adjustments. The purchase price is expected to be funded with $40.1 million in cash and $13.3 million in Teton common stock (to be issued under the shelf registration statement on Form S-4 discussed above). Terms also include warrant coverage of 625,000 shares at a $6.00 strike price with a two-year term. The Company expects its bank credit facility s available borrowing base to grow to approximately $35 to $40 million as a result of the added reserves from this transaction. The transaction is anticipated to be funded from the increased bank credit facility and cash on hand. Closing is expected to occur on or before April 25, 2008 with an effective date of March 1, 2008.

The purchase price includes an estimated 11.3 billion cubic feet equivalent (Bcfe) or 1.89 million barrels of oil equivalent (MMboe) of proved reserves and an estimated 4.25 million cubic feet equivalent per day (MMcfed) or 710 barrels of oil equivalent (Boe) of daily production as of March 1, 2008. The Sellers proved reserves are approximately 92 percent oil and 92 percent of their reserves are developed (PDP or PDNP), located on approximately 1,571 gross (1,518 net) acres. When combined with Teton s existing reserves, Teton will have proved reserves of approximately 52 percent natural gas and 48 percent oil. In addition, the ratio of Teton s developed reserves in the proved category will increase from 61 percent to 75 percent.

Production from the Sellers assets is approximately 92 percent oil and eight percent natural gas. When combined with Teton s existing production, Teton will have production of approximately 43 percent natural gas and 57 percent oil. Teton anticipates hedging the commodity price of at least 80 percent of the oil PDP production related to this transaction for five years in order to lock in base case economics.

The purchase price includes 50 producing wells, 22 wells with production behind pipe, five wells drilling or waiting on completion and 31 identified undeveloped locations. The proved assets to be acquired have a 92 percent working interest and a 76 percent net revenue interest to Teton. This acquisition will nearly double Teton s 2007 year-end proved reserves of 14.1 Bcfe and Teton s 2007 exit production rate of 4.3 MMcfed. In addition, the purchase price includes 52 square miles of 3-D seismic with additional seismic to be acquired in 2008. It also includes 54,000 gross (32,000 net) undeveloped acres where Teton operates, at 60 percent working interest to Teton and 40 percent working interest to Sellers. The Company believes the undeveloped acreage could yield additional upside potential to Teton. Teton and Sellers have also agreed to a go-forward 30-month area of mutual interest to pursue additional acreage and resource opportunities where Teton will operate under the same 60/40 working interest split with Sellers as described on the existing undeveloped acreage.

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Results of Operations

	Year Ended December 31,			Percent Change Between Years	
	2007	2006	2005	2006 to 2007	2005 to 2006
	(revenues and expenses in thousands)				
Net production volumes					
Oil (Bbl)	16,575			nm	nm
Gas (Mcf)	1,127,568	737,175	90,037	53%	719%
Total (Mcfe)	1,227,021	737,175	90,037	66%	719%
Realized price pre hedging					
Oil (per Bbl)	$ 76.32	$	$	nm	nm
Gas (per Mcf)	$ 4.42	$ 5.46	$ 8.85	-19%	-38%
Total (per Mcfe)	$ 5.10	$ 5.46	$ 8.85	-7%	-38%
Realized price net of hedging					
Oil (per Bbl)	$ 74.81	$	$	nm	nm
Gas (per Mcf)	$ 5.49	$ 5.46	$ 8.85	1%	-38%
Total (per Mcfe)	$ 6.06	$ 5.46	$ 8.85	11%	-38%
Oil and gas sales					
Oil sales	$ 1,265	$	$	nm	nm
Gas sales	4,988	4,022	797	24%	405%
Total	$ 6,253	$ 4,022	$ 797	55%	405%
Oil and gas operating expenses					
Lease operating expense	$ 705	$ 325	$ 51	117%	537%
Transportation expense	652	493	90	32%	448%
Production taxes	412	251	48	64%	423%
Total	$ 1,769	$ 1,069	$ 189	65%	466%
Data on a per Mcfe basis					
Realized price net of hedging	$ 6.06	$ 5.46	$ 8.85	11%	-38%
Lease operating expense	0.57	0.44	0.57	30%	-23%
Transportation expense	0.53	0.67	1.00	-21%	-33%
Production taxes	0.34	0.34	0.53	0%	-36%
Total production costs	1.44	1.45	2.10	-1%	-31%
Gross margin	$ 4.62	$ 4.01	$ 6.75	15%	-41%

Gross margin percentage		76%		74%		76%			
General and administrative									
Stock-based compensation	$	3,288	$	2,928	$			12%	nm
Other compensation		2,175		2,086		1,278		4%	63%
Professional fees		2,373		967		1,686		145%	-43%
Other general and administrative		1,145		1,167		1,298		-2%	-10%
Total general and administrative	$	8,981	$	7,148	$	4,262		26%	68%
Other operating expenses									
Exploration expense	$	1,847	$	448	$	444		312%	1%
DD&A oil and gas	$	3,751	$	1,697	$	161		121%	954%
DD&A other	$	81	$	52	$	20		56%	160%
Other income (expense)									
Realized gain hedging	$	1,181	$		$			nm	nm
Unrealized gain (loss) hedging		(857)		403				nm	nm
Loss on derivative contracts		(2,624)						nm	nm
Interest (expense) income, net		(2,588)		265		247		nm	nm
Total	$	(4,888)	$	668	$	247		nm	nm

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Results of Operations 2007 Compared to 2006

We had net income from continuing operations for the year ended December 31, 2007 of $2.4 million compared to a net loss of $5.7 million for the same period in 2006. Factors contributing to the $8.1 million increase in net income from 2006 to 2007 included the following:

We sold half of our 25% working interest in the Piceance Basin non-operated properties for $36.7 million in cash, including purchase price adjustments, and oil and gas properties and related production valued at $4.7 million, for a gain on sale of assets totaling $17.4 million.

Oil and gas production net to our interest in 2007 was 1.2 Bcfe resulting in $6.3 million in oil and gas sales, at an average wellhead price of $5.10 per Mcfe for the year. In 2006 our net production was 737 MMcfe resulting in $4.0 million in oil and gas sales, at an average wellhead price of $5.46. The 63% increase in production volumes resulted from additional wells being put on line in 2007. The lower 2007 average price per Mcfe resulted from prices in 2006 being higher than normal due largely to the severity of the hurricane season in late 2005; the effects of which lasted into the first half of 2006. Additionally, Rocky Mountain natural gas traded at a higher than normal discount to natural gas in the rest of the country during parts of 2007 due to pipeline capacity constraints limiting the ability to move gas that was produced in the Rocky Mountain region into other areas of the country. The completion of the Rocky Mountain Express Pipeline (REX), which is ultimately projected to move up to 1.8 Bcfd of natural gas out of the Rocky Mountain region, is expected to help alleviate the capacity constraints. The first sections of REX began operation in early 2008, and the final completion is scheduled for 2009.

Our lease operating expenses, transportation costs and production taxes for 2007 increased to $705,000 (117% over 2006), $652,000 (32% over 2006) and $412,000 (64% over 2006), respectively, due largely to the 55% increase in oil and gas sales in 2007 compared to 2006. Lease operating expense increased by an additional 54% over the increase in production resulting from the fact that the new production in each of the Piceance, DJ and Williston Basins caused some operating inefficiencies while the outside operators were learning the best approaches to operating in new locations, and due to severe weather in early 2007 resulting in some additional lease operating expenses. As the outside operators are adding more wells and becoming more familiar with the operating areas, the lease operating expenses are beginning to decrease from the higher levels associated with new producing areas.

General and administrative expenses increased from $7.1 million for the year ended December 31, 2006 to $9.0 million for the year ended December 31, 2007, due largely to:

- a net increase in compensation expense of approximately $1.2 million due to approximately $550,000 of non-cash compensation expense increase from stock-based grants as a result of meeting performance milestones associated with our long-term incentive plan and an increase in salaries of approximately $620,000;

- a net increase of approximately $800,000 in consulting and related expenses associated with SOX compliance, oil and gas accounting services, investor relations, compensation benchmarking reports and study, and financial and legal services related to acquisitions, financings and the divestiture of part of the Piceance properties.

Exploration expenses for 2007 of $1.8 million relate largely to delay rentals, geological and geophysical expenses incurred by us in the eastern DJ and Williston Basins and the reclassification of general and administrative expense noted directly above. We use 3D seismic studies to locate potential drilling sites in each basin.

Depletion and depreciation expense increased from $1.7 million in 2006 to $3.8 million in 2007 due to the higher gas production volumes in 2007 compared to 2006.

During 2007 we recognized an unrealized derivative loss of $857,000 related to derivative contracts (natural gas and crude oil fixed price swaps). The loss represents marking the contracts to market at December 31, 2007, based on the future expected prices of the related commodities. Actual results from the contracts will be booked as realized gains (losses) as the production volumes being hedged are actually produced.

Interest income ($425,000) and interest expense ($3.0 million) in 2007 include interest income from the cash balances maintained and interest expense on our line of credit combined with amortization of deferred debt issuance costs. We maintained higher cash balances late in 2007 resulting from the partial sale of interest in the Piceance property.

Results of Operations 2006 Compared to 2005

We had a net loss from continuing operations for the year ended December 31, 2006 of $5.7 million compared to a net loss of $4.1 million 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 737,000 Mcfe resulting in $4.0 million in oil and gas sales, at an average wellhead price of $5.46 per Mcfe for the year. In 2005 our net production began in July 2005. Oil and gas production net to us in 2005 was 90,000 Mcfe resulting in $797,000 in oil and gas sales, at an average wellhead price of $8.85 per Mcfe for the year. The increased production resulted from additional wells being put on line in 2006. The higher 2005 average price per Mcfe resulted largely from the extreme hurricane season that occurred in late 2005, putting Gulf of Mexico production out of service and increasing the price for natural gas from other areas of the country being used to fill demand.

Our lease operating expenses, transportation costs and production taxes for 2006 increased to $325,000 (537% over 2005), $493,000 (448% over 2005) and $251,000 (423% over 2005), respectively, due largely to the 405% increase in oil and gas sales in 2006 compared to 2005. Additionally, bringing new operations on line in the oil and gas business often entails a learning curve on how to best operate the wells, which further increased our lease operating expenses for 2006.

General and administrative expenses increased from $4.3 million for the year ended December 31, 2005 to $7.1 million for the year ended December 31, 2006, due largely to:

- compensation expense increasing due to (1) $2.6 million of non-cash compensation expense from stock-based grants as a result of meeting performance milestones associated with our long-term incentive plan, (2) a non-cash expense of approximately $490,000 associated with restricted stock grants, and (3) approximately $788,000 resulting from an increase in the number of full time employees (from six employees in 2005 to 11 employees in 2006;

- consulting expenses associated with engineering, marketing, investor relations and financial services increasing approximately $200,000 in 2006 from 2005 due to the increased operations of Teton resulting in additional needs that were not met with hiring of additional staff;

- office expense increasing approximately $160,000 in 2006 from 2005 due to increased administrative and computer support as well as additional office space leased.

However, certain components of general and administrative expenses decreased during the period, which include:

- legal and accounting costs decreasing by $1.1 million from the prior year, due to non-cash issuance of common stock for accounting and legal services rendered in 2005 of $795,000, for which we also received a refund of 50,000 shares of common stock for accounting services valued at $158,000 (which reduced our general and administrative expenses) in 2006 and approximately $105,000 due to the replacement of a part-time, contract CFO with a full-time, in-house CFO.

Exploration expenses for 2006 of $448,000 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 $181,000 in 2005 to $1.7 million in 2006 due to the higher gas production volumes in 2006 compared to 2005.

During 2006 we recognized an unrealized derivative gain of $403,000 related to a derivative contract (natural gas costless collar). In 2005 we did not have any derivative contracts.

Interest income and interest expense in 2006 include interest income from the cash balances maintained and interest expense on our line of credit.

Outlook for 2008

The following summarizes our goals and objectives for 2008:

- Increase production by at least 60% to 2.0 Bcfe from the properties in which we own interests at December 31, 2007.
- Achieve material increase in reserves.
- Continue to develop the Piceance, DJ and Williston Basin acreage.
- Begin the development of the Big Horn Basin acreage.
- Maintain liquidity through increases in our senior credit facility borrowing base and increased cash flow provided by operations.
- Pursue additional operated oil and gas asset and project acquisitions.
- Continue to build our operating staff and related capabilities.

Liquidity and Capital Resources

Historically, our primary sources of liquidity have been cash provided by equity offerings and borrowings under our bank credit facility. In the past, these sources have been sufficient to meet the needs of the business. As a result of our developmental drilling program progress (added more than 100 producing wells in 2007), we expect that cash flow from operating activities will also contribute to our cash requirements during 2008 and for the foreseeable future thereafter. We can give no assurances that the historical sources of liquidity and capital resources, or cash flow from operating activities, will be available for future development projects, and we may be required to seek additional or alternative financing sources. Product prices and volumes, as well as the timely collection of receivables and the availability of oil field services and supplies such as concrete, pipe and compression equipment are all expected to have a significant influence on our future net cash provided by operating activities. Additionally, our future growth will be dependent upon the success and timing of our exploration and production activities, new project development, efficient operation of our facilities and our ability to obtain financing at favorable terms.

We believe that the amounts available under our $50.0 million bank credit facility ($10.0 million borrowing base at December 31, 2007) and the $24.6 million of cash in the bank at December 31, 2007, together with the anticipated net cash provided by operating activities during 2008, will provide us with sufficient funds to develop new reserves, maintain our current facilities and complete our current capital expenditure program through 2008. Depending on the timing and amount of future projects, as well as the amount of the increase we receive in our borrowing base related to the reserves we intend to purchase in the Central Kansas Uplift (see additional discussion above on page 28), we may be required to seek additional sources of capital. While we believe that we would be able to secure additional financing if required, we can provide no assurance that we will be able to do so or as to the terms of any additional financing.

We may also receive proceeds from the exercise of outstanding warrants and/or options as we did during the years ended December 31, 2007, 2006 and 2005. At March 1, 2008, warrants to purchase 5,240,866 shares of common stock were outstanding. These warrants have a weighted average exercise price of $4.78 per share and expire between April 2008 and December 2012. At March 1, 2008, options to purchase 1,415,844 shares of common stock were outstanding. These options have a weighted average exercise price of $3.55 per share and expire between April 2013 and May 2015.

Credit Facility

In June 2006, we established a $50.0 million revolving credit facility with BNP Paribas (the Credit Facility). The Credit Facility had an initial borrowing base of $3.0 million, was redetermined to $6.0 million on March 12, 2007, and had an original maturity of June 15, 2010. The Credit Facility with BNP Paribas was replaced on August 9, 2007 by an amended and restated Credit Facility with JPMorgan Chase Bank, N.A. The amended and restated Credit Facility provides for as much as $50.0 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. At December 31, 2007, the Credit Facility had a borrowing base of $10.0 million with $8.0 million outstanding.

Cash Flows and Capital Expenditures

Our capital budget for 2008 is currently estimated at $36.0 million for the planned drilling in the Piceance, DJ and Williston Basins. In addition, we are planning to drill four wells in the Big Horn Basin that are not currently in our 2008 budget. The amounts to be included for those properties will be determined when we have added a partner to the operation. Our planned 2008 development and exploration expenses could also increase if any of the operations associated with our properties experience cost overruns, or if: (1) Berry, as operator for the Piceance Basin play, increases the drilling program, (2) Noble, as operator for the Teton Noble AMI play, increases the drilling program, or (3) Evertson, as operator for the Williston Basin play, increases the drilling program.

Our primary capital needs for the three years ended December 31, 2007, 2006 and 2005 were:

	As of December 31,		
	2007	**2006**	**2005**
		(in thousands)	
Property acquisition costs	$ 6,807	$ 3,323	$ 10,636
Exploration	2,712	1,823	445
Development	32,900	17,163	3,944
Total	$ 42,419	$ 22,309	$ 15,025

Operating Activities

During the year ended December 31, 2007, we used $2.1 million of net cash for operating activities, an increase of $289,000 over 2006. Our net income of $2.4 million for 2007 was adjusted for non-cash items to arrive at the net cash used in operating activities. The non-cash depreciation, depletion and accretion increased by $2.1 million due the addition of approximately 22 new net wells drilled in 2007, resulting in a larger base to deplete and more production. We had $4.8 million of non-cash debt issuance costs and debt discount amortization, as well as non-cash loss on derivative contract liabilities related to our issuance of 8% Convertible Notes (see item 8, Note 4 to the Consolidated Financial Statements for a full discussion of this item), all related to debt activity in 2007. Our non-cash stock based compensation and stock issued for outside services remained relatively level from year to year, largely because non-cash employee stock based compensation was reduced by withholding taxes of approximately $700,000. The $17.4 million gain on the sale of a partial interest in our Piceance properties (as more fully discussed above under *Developments since December 31, 2006*) is an adjustment to net income to arrive at net cash used in operating activities because it is the result of an investing activity with the proceeds from the transaction being shown in that section of the Consolidated Statement of Cash Flows. The $1.0 million increase in cash provided by net changes in working capital items (mainly due to accrued liabilities increasing during 2007 due largely to increased drilling activity, somewhat offset by the increases in trade accounts receivable resulting from increased sales) are largely due to the growth of the operations of the Company experienced during 2007.

During the year ended December 31, 2006, we used $1.8 million of cash in our operating activities. This amount compares to $2.8 million of cash used in our operating activities for the year 2005. The decrease of $1.0 million of net cash used in operating activities was primarily due to the growth in revenue in 2006 as compared to 2005, offset by increased operating expenses related to early stage development of the properties brought on line in 2006 by outside operators. Our cash used in operating activities during 2006 increased by $365,000 due to higher accounts receivable balances attributed to revenue growth and one time cost recoveries due from Noble under our Acreage Earning Agreement. Our cash used in operating activities decreased by $341,000 during 2006 as a result of increased accounts payable and other accrued liability balances associated with the growth of the Company, offset by a $255,000 accrual for a contract termination in 2005. In addition, during 2006, cash used in operating activities increased by $149,000 with respect to tubular inventory purchased in preparation for upcoming drilling operations in the Williston Basin that was subsequently postponed until 2008.

Investing Activities

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During the year ended December 31, 2007, we received cash proceeds of $35.1 million in connection with the sale of oil and gas properties, $34.9 million of which was related to our sale of one-half of our Piceance assets (net of transaction costs and amounts in accounts receivable at December 31, 2007). During the same period we spent $35.6 million related to our drilling and completion programs in the Piceance, Williston and DJ Basins.

With respect to our investing activities, during the year ended December 31, 2006, we received cash of $2.7 million in connection with the entering into the Acreage Earning Agreement with Noble in the DJ Basin. During the same period, we incurred costs of $20.4 million related to our drilling and completion operations in the Piceance and the Williston Basin projects.

Financing Activities

During the year ended December 31, 2007, we raised $9.0 million through the issuance of 8% senior subordinated Convertible Notes and borrowed $8.0 million under our $50.0 million credit facility. We paid $950,000 in debt issuance costs associated with these borrowings. On July 25, 2007, we completed a registered direct offering of 964,060 shares of common stock, at a price of $5.05 per share, to a selected group of institutional investors for gross proceeds of $4.9 million and paid $368,000 in offering costs. In addition, during 2007, holders of 672,701 stock options and 1,500 warrants exercised to purchase an equivalent number of common shares for proceeds of $2.4 million.

With 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 for net proceeds of $3.5 million, 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 $2.7 million. For the year ended December 31, 2005, we raised $3.5 million from exercised warrants to purchase common shares.

Contractual Obligations

We have a Company hedging policy in place, if necessary, to protect a portion of our production against future pricing fluctuations. Our outstanding hedges as of December 31, 2007 are summarized below:

Type of Contract	Volume	Fixed Price	Price Index (1)	Contract Period	
Natural Gas Fixed Price Swap Contracts	30,000 MMBtu per month	$5.78/MMBtu	CIGRM	08/01/07	10/31/08
Oil Fixed Price Swap Contracts	60Bbls per day	$80.70/Bbl	WTI	11/01/07	12/31/08

(1) CIGRM refers to Colorado Interstate Gas Rocky Mountains price as quoted in Platt s for Inside FERC on the first business day of each month. WTI refers to the West Texas

Intermediate price as quoted on the New York Mercantile Exchange.

On February 1, 2008 we entered into a new hedging agreement as summarized below:

Type of Contract	Volume	Floor	Ceiling	Price Index (1)	Contract Period	
Natural Gas Costless Collar	2,000 MMBtu per day	$6.00/MMBtu	$7.10/MMBtu	CIGRM	02/01/08	01/31/09

(1) CIGRM refers to Colorado Interstate Gas Rocky Mountains price as quoted in Platt s for Inside FERC on the first business day of each month.

The collared hedges shown above have the effect of providing a protective floor while allowing us to share in upward pricing movements to a fixed point. 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

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2008 and 2009 natural gas contracts listed above, a hypothetical $0.10 change in the CIGRM price above the ceiling price or below the floor price applied to the notional amounts would cause a change in the unrealized gain or loss on hedging activities in 2008 of $67,000. The Company plans to continue to enter into derivative contracts to decrease exposure to commodity price volatility.

The impact that our contractual obligations at December 31, 2007 are expected to have on our liquidity and cash flow in future periods is:

	One Year or Less	2 3 Years	4 5 Years	More than 5 Years
		(in thousands)		
Operating lease for office space	$ 129	$ 44	$	$
Senior bank facility line of credit (a) (b)			8,000	
Interest on line of credit (c)	516	1,032	311	
8% convertible notes (d)	9,000			
Interest on 8% convertible notes	268			
Total contractual cash commitments	$ 9,913	$ 1,076	$ 8,311	$

(a) The amount listed reflects the balance outstanding at December 31, 2007. Any balance outstanding at August 9, 2011 is due at that time.

(b) The entire line of credit balance outstanding was paid off on February 11, 2008.

(c) The interest rate assumed on the credit facility is 6.45% per annum, the rate in effect at December 31, 2007.

(d) The 8% convertible note is due in its entirety on May 16, 2008.

Income Taxes, Net Operating Losses and Tax Credits

At December 31, 2007, we had net operating loss carryforwards, for federal income tax purposes, of approximately $32.1 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 2027. Approximately $5.8 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 $3.6 million and $2.2 million for the years ended December 31, 2008 and 2009, respectively, plus any loss attributable to any built-in gain assets sold within five years of the ownership change. Under current income tax law, active drilling for oil and gas reserves generates tax deductions that are expected to offset any taxable income for the foreseeable future. Thus, we have established a valuation allowance for deferred taxes equal to our entire net deferred tax assets as management currently believes that it is more likely than not that these losses will not be utilized. The allowance recorded was $10.0 million and $11.5 million for 2007 and 2006, respectively.

Off-Balance Sheet Arrangements

We do not participate in transactions that generate relationships with unconsolidated entities or financial partnerships. Such entities are often referred to as structured finance or special purpose entities (SPEs) or variable interest entities (VIEs). SPEs and VIEs can be established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. We were not involved in any unconsolidated SPEs or VIEs at any time during any of the periods presented in this Form 10-K.

From time to time, we enter into contracts that might be construed as off-balance sheet obligations but are normal in the day-to-day course of business in the oil and gas industry. Those contracts could include the contracts discussed directly above under Contractual Obligations. We do not believe we will be affected by these contracts materially differently than other similar companies in the energy industry.

Critical Accounting Policies and Estimates

This discussion and analysis of our financial condition and results of operations are based on the consolidated financial statements prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of our financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Our significant accounting policies are described in

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Note 1 to the Consolidated Financial Statements, included in Item 8 of this Annual Report on Form 10-K. In the following discussion, we have identified the accounting estimates which we consider as the most critical to aid in fully understanding and evaluating our reported financial results. Estimates regarding matters that are inherently uncertain require difficult, subjective or complex judgments on the part of our management. We analyze our estimates, including those related to oil and gas reserves, oil and gas properties, income taxes, contingencies and litigation, and base our estimates on historical experience and various other assumptions that we believe reasonable under the circumstances. Actual results may differ from these estimates.

Derivative Financial Instruments

We use derivative financial instruments to hedge exposures to oil and gas production cash-flow risks caused by fluctuating commodity prices. All derivatives are initially, and subsequently, measured at estimated fair value and recorded as liabilities or assets on the balance sheet. For oil and gas derivative contracts that do not qualify as cash flow hedges, changes in the estimated fair value of the contracts are recorded as unrealized gains and losses under the other income and expense caption in the consolidated statement of operations. When oil and gas derivative contracts are settled, we recognize realized gains and losses under the other income and expense caption in its consolidated statement of operations.

We also use various types of financing arrangements to fund our business capital requirements, including convertible debt and other financial instruments indexed to the market price of our common stock. Teton evaluates these contracts to determine whether derivative features embedded in host contracts require bifurcation and estimated fair value measurement or, in the case of free-standing derivatives (principally warrants) whether certain conditions for equity classification have been achieved. In instances where derivative financial instruments require liability classification, we initially and subsequently measure such instruments at estimated fair value. Accordingly, Teton adjusts the estimated fair value of these derivative components at each reporting period through a charge to earnings until such time as the instruments are exercised, expire or are permitted to be classified in stockholders equity.

Successful Efforts Method of Accounting

We account for our 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 oil and gas leases are charged to expense as incurred. Exploratory drilling costs are initially capitalized but charged to expense if and when the well is determined not to have found 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 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 the 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 oil and gas in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. Wells are drilled which have targeted geologic structures which are both developmental and exploratory in nature and an allocation of costs is required to properly account for the results. The evaluation of oil and gas leasehold acquisition costs may require 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 we are entering a new exploratory area in hopes of finding an oil and gas field that will be the focus of future development drilling activity. The initial exploratory wells may be unsuccessful and will be expensed.

Reserve Estimates

Estimates of oil and gas 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 oil and gas 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 oil and natural gas 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 oil and natural gas prices, future operating costs, severance taxes, development costs and workover costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas 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 oil and gas properties and/or the rate of depletion of the oil and gas properties. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material.

Impairment of Oil and Gas Properties

We review the carrying values of our long-lived assets whenever events or changes in circumstances indicate that such carrying values may not be recoverable. If, upon review, the sum of the undiscounted pretax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets, generally on a field-by-field basis. The fair value of impaired assets is determined based on quoted market prices in active markets, if available, or upon the present values of expected future cash flows using discount rates commensurate with the risks involved in the asset group. The long-lived assets of the Company, which are subject to periodic evaluation, consist primarily of oil and gas properties and undeveloped leaseholds.

Stock-Based Compensation

Stock and stock-based grants are charged to earnings over the period services are provided, which is generally equivalent to the vesting period.

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, 2007, we recorded stock-based compensation expense of $3.6 million based on the degree of progress we made in achieving each of the performance objectives established by our Compensation Committee. Our stock-based compensation expense increases or decreases in each quarter during the course of the year based on an assessment of 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 stock-based compensation expense for the year will be based on our actual performance and the associated vesting of the particular LTIP tranche.

The portion of the stock-based compensation expense pertaining to Performance Share Units under our LTIP for the year ended December 31, 2007 was $2.7 million. We recorded expense for the nine months ended September 30, 2007 of $1.5 million based upon estimated annual expense of $2.0 million. We increased the amount of the annual expense to $2.7 million during the fourth quarter as a result of achieving higher than anticipated performance objectives.

Asset Retirement Obligations

Legal obligations associated with the retirement of long-lived assets result from the acquisition, construction, development and normal use of the asset. The Company s asset retirement obligations relate primarily to the

retirement of oil and gas properties and related production facilities, lines and other equipment used in the field operations. The fair value of a liability for an asset retirement obligation is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The estimated fair value of the liability is added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability increases due to the passage of time based on the time value of money until the obligation is settled.

Recently Adopted Accounting Pronouncements

In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes an Interpretation of SFAS No. 109 (FIN 48). The interpretation creates a single model to address accounting for uncertainty in tax positions. Specifically, the pronouncement prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition of certain tax positions.

The Company adopted the provisions of FIN 48 effective January 1, 2007. The adoption of this accounting principle did not have an effect on the Company s financial statements as of December 31, 2007.

Recently Issued Accounting Pronouncements

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (SFAS No. 157). SFAS No. 157 establishes a single authoritative definition of fair value, sets out a framework for measuring fair value and requires additional disclosures about fair value measurements. This standard requires companies to disclose the fair value of their financial instruments according to a fair value hierarchy. SFAS No. 157 does not require any new fair value measurements, but will remove inconsistencies in fair value measurements between various accounting pronouncements. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years (fiscal 2008 for the Company). The adoption of SFAS No. 157 is not expected to have a material effect of the Company s financial position, results of operations or cash flows.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (SFAS No. 159) 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. SFAS No. 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007 (fiscal 2008 for the Company). The adoption of SFAS No. 159 is not expected to have a material effect of the Company s financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations (SFAS No. 141R), which replaces FASB Statement No. 141. SFAS No. 141R will change how business acquisitions are accounted for and will impact financial statements both on the acquisition date and in subsequent periods. SFAS No. 141R is effective as of the beginning of an entity s fiscal year that begins after December 15, 2008 (fiscal 2009 for the Company). The Company is in the process of evaluating the impacts, if any, of adopting this pronouncement.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statement, an amendment of ARB No. 51 (SFAS No. 160). SFAS No. 160 will change the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests and classified as a component of equity. This statement is effective as of the beginning of an entity s first fiscal year beginning after December 15, 2008 (fiscal 2009 for the Company). The Company is in the process of evaluating the impacts, if any, of adopting this pronouncement.

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

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in oil and natural gas prices, interest rates and the market price of our common stock. The disclosures are not meant to be precise indicators of expected future gains and losses, but rather indicators of reasonably possible gains and losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our U.S. natural gas production. Pricing for oil production and natural gas has been volatile and unpredictable for several years. The prices we receive for production depend on many factors outside of our control. For the year ended December 31, 2007, our net income would have changed by approximately $524,000 for each $0.50 change per Mcf in natural gas prices and approximately $16,600 for each $1.00 change per Bbl in crude oil prices.

We have entered into oil and natural gas derivative contracts to manage our exposure to oil and natural gas price volatility. At December 31, 2007 our oil and gas derivative contracts consist of fixed price oil and natural gas SWAPS.

Our outstanding oil and gas derivative contracts as of December 31, 2007 are summarized below:

Type of Contract	Volume	Fixed Price	Price Index (1)	Contract Period	
Natural Gas Fixed Rate Swap Contracts	30,000 MMBtu per month	$5.78/MMBtu	CIGRM	11/01/07	10/31/08
Oil Fixed Rate Swap Contracts	60Bbls per day	$80.70/Bbl	WTI	11/01/07	12/31/08

(1) CIGRM refers to Colorado Interstate Gas Rocky Mountains price as quoted in Platt s for Inside FERC on the first business day of each month. WTI refers to the West Texas Intermediate price as quoted on the New York Mercantile Exchange.

On February 1, 2008 we entered into a new hedging agreement as summarized below:

Type of Contract	Volume	Floor	Ceiling	Price Index (1)	Contract Period

Natural Gas Costless Collar	2,000 MMBtu per day	$6.00/MMBtu	$7.10/MMBtu	CIGRM	02/01/08	01/31/09

(1) CIGRM refers to Colorado Interstate Gas Rocky Mountains price as quoted in Platt s for Inside FERC on the first business day of each month.

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 2008 and 2009 natural gas contracts listed above, a hypothetical $0.10 change in the CIGRM price above the ceiling price or below the floor price applied to the notional amounts would cause a change in the unrealized gain or loss on hedging activities in 2008 of $67,000. We plan to continue to enter into derivative contracts to decrease exposure to commodity price decreases.

At December 31, 2007 our oil and gas derivative contract liabilities balance was $455,000. Each period, we adjust this liability to fair value and recognize an unrealized gain or loss on oil and gas derivative contracts in our consolidated statement of operations.

Market Price of Common Stock Risk

Our gain or loss on derivative contract liabilities is subject to wide fluctuations each reporting period. The amount of gain or loss is largely dependent upon assumptions underlying valuation techniques we apply. In addition, our derivative contract liabilities balance is also highly susceptible to changes in the market price of our common stock. At December 31, 2007 a $1.00 increase in the market price of our common stock would result in a $2.8 million increase in loss on derivative contract liabilities.

At December 31, 2007 our derivative contract liabilities balance was $9.5 million. Each period, we adjust this liability to estimated fair value and recognize a gain or loss on derivative contract liabilities in our consolidated statement of operations.

Interest Rate Risk

At December 31, 2007, we had $8.0 million outstanding on our credit facility. Under the credit facility, each loan bears interest at a Eurodollar rate or a base rate, as requested by us, plus an additional margin based on the amount of our total outstanding borrowings relative to the total borrowing base. The Eurodollar rate is based on the London Interbank Offered Rate (LIBOR). The base rate is the higher of the Prime Rate or the Federal Funds Rate plus one-half of one percent. At December 31, 2007, the interest rate on the credit facility borrowings, calculated in accordance with the agreement at 1.50% above the three month LIBOR, was 6.45%. Assuming no change in the amount outstanding as of December 31, 2007, a one hundred basis point (1.0%) increase in each of the average LIBOR rate and federal funds rate would result in additional interest expense to us of $80,000 per year.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Stockholders and Board of Directors
Teton Energy Corporation:

We have audited the accompanying consolidated balance sheets of Teton Energy Corporation and subsidiaries (the Company) as of December 31, 2007 and 2006, and the related consolidated statements of operations, stockholders equity and cash flows for each of the three years in the period ended December 31, 2007. We also have audited the Company s internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control over Financial Reporting included in Item 9A. Our responsibility is to express an opinion on these financial statements and an opinion on the Company s internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audit of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company s assets that could have a material effect on the financial statements.

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

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 at December 31, 2007 and 2006, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, Teton Energy Corporation and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

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

Denver, Colorado
March 12, 2008

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TETON ENERGY CORPORATION
Consolidated Balance Sheet

	December 31, 2007	December 31, 2006
	(in thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$ 24,616	$ 4,325
Trade accounts receivable	2,686	860
Advances to operator		401
Tubular inventory	149	149
Fair value of oil and gas derivative contracts		403
Prepaid expenses and other assets	131	142
Deferred debt issuance costs net	1,419	
Total current assets	29,001	6,280
Oil and gas properties (using successful efforts method of accounting)		
Proved	35,708	12,326
Unproved	13,411	13,959
Wells and facilities in progress	3,230	9,856
Land	153	300
Fixed assets	332	243
Total property and equipment	52,834	36,684
Less accumulated depreciation and depletion	(3,695)	(1,912)
Net property and equipment	49,139	34,772
Deferred debt issuance costs net	159	192
Total assets	$ 78,299	$ 41,244
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable	$ 400	$ 1,506
Accrued liabilities	7,833	4,227
Accrued payroll	902	891
Accrued purchase consideration		775
8% senior subordinated convertible notes, net of discount of $7,370	1,630	
Fair value of oil and gas derivative contracts	455	
Derivative contract liabilities	9,522	
Total current liabilities	20,742	7,399

Long-term liabilities:		
Long-term debt senior secured bank debt	8,000	
Asset retirement obligations	529	78
Total long-term liabilities	8,529	78
Total liabilities	29,271	7,477
Commitments and contingencies (see Note 11)		
Stockholders equity:		
Preferred stock, $.001 par value; 25,000,000 shares authorized; none outstanding		
Common stock, $.001 par value; 250,000,000 shares authorized; 17,652,889 and 15,607,167 shares issued and outstanding as of December 31, 2007 and 2006, respectively	18	16
Additional paid-in capital	76,857	63,975
Accumulated deficit	(27,847)	(30,224)
Total stockholders equity	49,028	33,767
Total liabilities and stockholders equity	$ 78,299	$ 41,244

The accompanying notes are an integral part of the financial statements

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TETON ENERGY CORPORATION
Consolidated Statement of Operations

	Years Ended December 31,		
	2007	2006	2005
	(in thousands, except per share amounts)		
Operating revenues:			
Oil and gas sales	$ 6,253	$ 4,022	$ 797
Gain on sale of oil and gas properties	17,441		
Total operating revenues	23,694	4,022	797
Operating expenses:			
Lease operating expense	705	325	51
Transportation expense	652	493	90
Production taxes	412	251	48
Exploration expense	1,847	448	444
General and administrative	8,981	7,148	4,262
Depreciation, depletion and accretion expense	3,832	1,749	181
Total operating expenses	16,429	10,414	5,076
Operating income (loss)	7,265	(6,392)	(4,279)
Other income (expense):			
Realized gain on oil and gas derivative contracts	1,181		
Unrealized (loss) gain on oil and gas derivative contracts	(857)	403	
Loss on derivative contract liabilities	(2,624)		
Interest income	425	293	247
Interest expense	(3,013)	(28)	
Total other income (expense)	(4,888)	668	247
Net income (loss)	2,377	(5,724)	(4,032)
Preferred stock dividends			(61)
Net income (loss) applicable to common shares	$ 2,377	$ (5,724)	$ (4,093)
Basic income (loss) per common share	$ .14	$ (.44)	$ (.40)

Fully diluted income (loss) per common share	$ .13	$ (.44)	$ (.40)
Basic weighted-average common shares outstanding	16,545	13,093	10,282
Fully diluted weighted-average common shares outstanding	18,061	13,093	10,282

The accompanying notes are an integral part of the financial statements

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TETON ENERGY CORPORATION
Consolidated Statement of Cash Flows

	Years Ended December 31, 2007	2006 (in thousands)	2005
Operating activities:			
Net income (loss)	$ 2,377	$ (5,724)	$ (4,032)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation, depletion and accretion	3,832	1,749	181
Debt issuance cost amortization	586		
Debt discount amortization	1,630		
Stock-based compensation expense, exclusive of cash withheld for payroll taxes	2,588	2,928	
Stock issued for outside services, net	264	53	835
Non-cash loss on derivative contract liabilities	2,624		
Unrealized loss (gain) oil and gas derivative contracts	857	(403)	
Gain on sale of oil and gas properties	(17,441)		
Changes in current assets and liabilities:			
Trade accounts receivable	(1,173)	(612)	(248)
Advances to operator		(177)	(224)
Tubular inventory		(149)	
Prepaid expenses and other current assets	10	(4)	(37)
Accounts payable and accrued liabilities	1,767	66	441
Accrued payroll	11	494	288
Net cash used in operating activities	(2,068)	(1,779)	(2,796)
Investing activities:			
Proceeds from sale of oil and gas properties	35,125	2,700	300
Acquisition of corporate fixed assets	(89)	(182)	(6)
Development of oil and gas properties	(35,635)	(20,355)	(11,303)
Net cash used in investing activities	(599)	(17,837)	(11,009)
Financing activities:			
Proceeds from sale of common stock, net of offering costs of $368	4,500	10,834	
Proceeds from exercise of options/warrants	2,408	6,235	3,497
Proceeds from 8% senior subordinated convertible notes	9,000		
Net borrowings from senior bank credit facility	8,000		
Debt issuance costs	(950)	(192)	
Payment of preferred dividends			(61)
Net cash provided by financing activities	22,958	16,877	3,436

Increase (decrease) in cash and cash equivalents	20,291	(2,739)	(10,369)
Cash and cash equivalents beginning of period	4,325	7,064	17,433
Cash and cash equivalents end of period	$ 24,616	$ 4,325	$ 7,064

The accompanying notes are an integral part of the financial statements

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TETON ENERGY CORPORATION
Consolidated Statement of Cash Flows (continued)

	Years Ended December 31, 2007	2006	2005
		(in thousands)	
Supplemental disclosure of cash and non-cash transactions:			
Cash paid for interest, net of amounts capitalized	$ 694	$	$
Capitalized interest	121		
Stock-based compensation, exclusive of cash withheld for payroll taxes	2,588	2,928	
Stock issued for outside services, net of stock returned (in 2005)	264	53	845
Sales of oil and gas properties included in accounts receivable	652		
Deposits and advances applied to oil and gas properties	401	300	
Accrued purchase consideration recorded as oil and gas properties		775	
Capital expenditures included in accounts payable and accrued liabilities	5,667	4,933	1,256
Asset retirement obligation additions and revisions associated with oil and gas properties	241	50	4
Placement agent warrants recorded as equity issuance costs	190		
Placement agent warrants recorded as debt issuance costs	1,022		
Derivative liabilities reclassified to stockholders equity, net	3,124		
Issuance of common stock and warrants acquisition of oil and gas properties			1,882

The accompanying notes are an integral part of the financial statements

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TETON ENERGY CORPORATION
Consolidated Statement of Changes in Stockholders Equity

	Preferred Stock Shares	Preferred Stock Amount	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Accumulated Deficit	Total Stockholders Equity
	(in thousands)						
Balance-December 31, 2004	281	$	9,130	$ 9	$ 37,658	$ (20,468)	$ 17,199
Common stock issued for settlement of accrued liabilities			13		11		11
Common stock issued for services			298		945		945
Common stock issued for asset acquisitions			863	1	1,467		1,468
Warrants issued for asset acquisitions					414		414
Warrants exercised net of AMEX fees			744	1	3,496		3,497
Preferred stock converted to common stock	(281)		281				
Preferred stock dividends					(61)		(61)
Net loss for year						(4,032)	(4,032)
Balance-December 31, 2005			11,329	11	43,930	(24,500)	19,441
Warrants and options exercised			1,531	2	6,234		6,236
Sale of common stock, net			2,300	2	10,831		10,833
Return of common stock			(50)		(158)		(158)
Stock-based compensation			463	1	2,927		2,928
Common stock issued for services			34		211		211
Net loss for year						(5,724)	(5,724)
Balance-December 31, 2006			15,607	16	63,975	(30,224)	33,767
Options exercised			673	1	2,404		2,405
Warrants exercised			2		3		3
Sale of common stock, net of offering costs of $368			964	1	4,499		4,500
Stock-based compensation, exclusive of amounts withheld for			364		2,588		2,588

payroll taxes					
Common stock issued for services	43		264		264
Reclassification of derivative liabilities			3,124		3,124
Net income for year				2,377	2,377
Balance-December 31, 2007	$ 17,653	$ 18	$ 76,857	$ (27,847)	$ 49,028

The accompanying notes are an integral part of the financial statements

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TETON ENERGY CORPORATION
Notes to Consolidated Financial Statements

Note 1 Business Description and Summary of Significant Accounting Policies

Teton Energy Corporation (Teton or the Company) was formed in November 1996 and is incorporated in the State of Delaware. Teton is an independent energy company engaged primarily in the development, production, and marketing of oil and natural gas in North America. The Company s current operations are focused in four basins in the Rocky Mountain region of the United States; the Piceance, DJ, Williston and Big Horn Basins.

Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Teton and its wholly owned subsidiaries Teton North America LLC, Teton Piceance LLC, Teton DJ LLC, Teton DJCO LLC, Teton Williston LLC, and Teton Big Horn LLC. All inter-company accounts and transactions have been eliminated in consolidation.

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.

The Company has no interests in any unconsolidated entities, nor does it have any unconsolidated special purpose entities.

Certain reclassifications have been made to amounts reported in previous years to conform to 2007 presentation, including, but not limited to, presenting revenues on a gross basis before gathering and transportation expenses which are now included in transportation expense on the Consolidated Statement of Operations.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities and disclosure on contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Estimates of oil and gas reserve quantities provide the basis for calculation of depreciation and depletion, and impairment, each of which represents a significant component of the consolidated financial statements.

Revenue Recognition

Revenues are recognized when oil and natural gas is sold to a purchaser at a fixed or determinable price, when delivery has occurred, title has transferred and collectibility of the revenue is probable. Revenues are recorded gross of the related gathering, transportation and fuel charges, and those costs are included in transportation expense in the Consolidated Statement of Operations.

Gas Balancing

Teton uses the sales method of accounting for gas revenue whereby natural gas revenue is recognized on all gas sold to purchasers, regardless of whether the sales are proportionate to the Company s ownership in the property. A liability is recognized to the extent that there is an imbalance in excess of the remaining gas reserves on the underlying properties. The Company did not have any gas imbalances at December 31, 2007 and 2006.

Oil and Gas Producing Activities

Teton uses the successful efforts method of accounting for its oil and gas producing activities. Under this method of accounting, all property acquisition costs and costs of exploration and development wells are capitalized when

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TETON ENERGY CORPORATION
Notes to Consolidated Financial Statements

incurred, pending determination of whether the well has found proved reserves. If an exploratory well does not find proved reserves, the costs of drilling the well are charged to expense. The costs of development wells are capitalized whether productive or nonproductive. The Company had no exploratory well costs that had been suspended for one year or more as of December 31, 2007 or 2006.

Geological and geophysical costs, and the costs of carrying and retaining unproved leaseholds are expensed as incurred. The Company limits the total amount of unamortized capitalized costs for each proved property to the value of future net revenues, based on current prices and costs.

Depletion of capitalized costs for producing oil and gas properties is provided on a field-by-field basis using the units-of-production method, based on proved oil and gas reserves. Depletion takes into consideration restoration, dismantlement and abandonment costs and the anticipated proceeds for equipment salvage. Some of the Company s producing facilities, consisting of natural gas pipelines and water disposal wells, are depreciated utilizing the straight-line method over lives of 15 to 30 years.

Depreciation and depletion of oil and gas properties for the years ended December 31, 2007, 2006 and 2005, was $3.7 million, $1.7 million and $161,000, respectively.

Teton invests in unevaluated oil and gas properties for the purpose of exploration and subsequent development of proved reserves. The costs of unproved leases which become productive are reclassified to proved properties when proved reserves are discovered on the property. Unproved oil and gas properties are carried at the lower of cost or estimated fair market value and are not subject to amortization.

The sale of a partial interest in a proved or an unproved 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 unit-of-production depletion rate. A gain or loss is recognized for all other sales of proved or unproved properties.

Derivative Financial Instruments

The Company uses derivative financial instruments to mitigate exposures to oil and gas production cash-flow risks caused by fluctuating commodity prices. All derivatives are initially, and subsequently, measured at estimated fair value and recorded as liabilities or assets on the balance sheet. For oil and gas derivative contracts that do not qualify as cash flow hedges, changes in the estimated fair value of the contracts are recorded as unrealized gains and losses under the other income and expense caption in the consolidated statement of operations. When oil and gas derivative contracts are settled, the Company recognizes realized gains and losses under the other income and expense caption in its consolidated statement of operations. At December 31, 2007 and 2006, and for the three year period ended December 31, 2007, the Company did not have any derivative contracts that qualify as cash flow hedges.

The Company also uses various types of financing arrangements to fund its business capital requirements, including convertible debt and other financial instruments indexed to the market price of the Company s common stock. Teton evaluates these contracts to determine whether derivative features embedded in host contracts require bifurcation and fair value measurement or, in the case of free-standing derivatives (principally warrants) whether certain conditions for equity classification have been achieved. In instances where derivative financial instruments require liability classification, the Company initially and subsequently measures such instruments at estimated fair value. Accordingly, the Company adjusts the estimated fair value of these derivative components at each reporting period through a charge to earnings until such time as the instruments are exercised, expire or are permitted to be classified in stockholders equity.

Cash and Cash Equivalents

Cash and cash equivalents includes all cash balances and any highly liquid investments with an original maturity of 90 days or less.

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TETON ENERGY CORPORATION
Notes to Consolidated Financial Statements

Accounts Receivable

The Company records estimated oil and gas revenue receivable from third parties at its net revenue interest. The Company also reflects costs incurred on behalf of joint interest partners in accounts receivable. Management periodically reviews accounts receivable amounts for collectibility. No allowance for doubtful accounts was considered necessary at December 31, 2007, 2006 and 2005.

Deferred Debt Issuance Costs

Deferred debt issuance costs are amortized to interest expense over the life of the related debt instrument or credit facility using the effective interest method.

Capitalized Interest

Interest incurred on funds borrowed to finance certain acquisition and development activities is capitalized. To qualify for interest capitalization, the costs incurred must relate to the acquisition of unproved reserves, drilling of wells to prove up the reserves and the installation of the necessary pipelines and facilities to make the property ready for production. Such capitalized interest is included in oil and gas properties. Capitalized interest is amortized over the estimated life of the respective project.

Fixed Assets

Fixed assets are stated at cost. Depreciation is provided utilizing the straight-line method over the estimated useful lives ranging from five to seven years.

Impairment of Long-Lived Assets

The Company reviews the carrying values of its long-lived assets whenever events or changes in circumstances indicate that such carrying values may not be recoverable. If upon review the sum of the estimated undiscounted pretax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets, generally on a field-by-field basis. The fair value of impaired assets is determined based on quoted market prices in active markets, if available, or upon the present values of expected future cash flows using discount rates commensurate with the risks involved in the asset group. The long-lived assets of the Company, which are subject to periodic evaluation, consist primarily of oil and gas properties including undeveloped leaseholds. The Company has not incurred an impairment expense during the years ended December 31, 2007, 2006 and 2005.

Asset Retirement Obligations

Legal obligations associated with the retirement of long-lived assets result from the acquisition, construction, development and normal use of the asset. The Company s asset retirement obligations relate primarily to the retirement of oil and gas properties and related production facilities, lines and other equipment used in the field operations. The estimated fair value of a liability for an asset retirement obligation is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The estimated fair value of the liability is added to the carrying amount of the associated asset. This additional carrying amount is then depreciated over the life of the asset. The liability increases due to the passage of time based on the time value of money until the obligation is settled.

For the years ended December 31, 2007, 2006 and 2005, an expense of $43,000, $24,000 and $0, respectively, was recorded as accretion expense on the liability and included in depreciation, depletion and accretion. During 2007 and 2006, the Company recorded an additional $189,000 and $50,000, respectively, in oil and gas properties and asset retirement obligation liability to reflect the present value of plugging liability on new wells.

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TETON ENERGY CORPORATION
Notes to Consolidated Financial Statements

A reconciliation of the Company s asset retirement obligation liability:

	Year Ended December 31, 2007	2006
	(in thousands)	
Asset retirement obligation beginning of period	$ 78	$ 4
Additional liabilities incurred	189	50
Revisions in estimated cash flows	52	
Obligations settled		
Accretion expense	43	24
Obligations acquired	239	
Obligations sold	(72)	
Asset retirement obligation end of period	$ 529	$ 78

Income (Loss) per Common Share

Basic income (loss) per common share is computed by dividing net income (loss) applicable to common shares by the weighted average number of basic common shares outstanding during each period. The shares represented by vested restricted stock and vested performance share units under the Company s Long Term Incentive Plan (see Note 8) are considered issued and outstanding at December 31, 2007 and 2006, respectively, and are included in the calculation of the weighted average basic common shares outstanding. Diluted income (loss) per common share reflects the potential dilution that would occur if securities or other contracts to issue common stock were exercised or converted into common stock.

Stock-Based Compensation Expense

Effective January 1, 2006, Teton adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 123R Share-Based Payment (revised 2004) (SFAS No. 123R), which requires the measurement and recognition of compensation expense for all share-based payment awards (including stock options) made to employees and directors based on estimated fair value. Compensation expense for equity-classified awards is measured at the grant date based on the fair value of the award and is recognized as an expense in earnings over the requisite service period. The Company adopted SFAS No. 123R using the modified prospective transition method. Under this transition method, compensation cost recognized during the year ended December 31, 2007 and 2006 included the cost for options which were granted prior to January 1, 2006, as determined under the provisions of SFAS No. 123. See Note 8 below.

Prior to the adoption of the provisions of SFAS No. 123R, Teton accounted for employee stock-based compensation expense under Accounting Principles Board Opinion (APB) No. 25, Accounting for Stock Issued to Employees (APB No. 25), and related interpretations, as permitted by SFAS No. 123, Accounting for Stock-Based Compensation APB No. 25 did not require any compensation expense to be recorded in the financial statements if the exercise price of the employee stock-based compensation award was equal to or greater than the market price of the stock on the date of grant. Prior to July 2005, the Company had only issued stock options as employee stock-based compensation 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. Had compensation cost for stock options been recognized in 2005 based on the estimated fair value at the date of grant, the Company would have recorded additional compensation expense of $20,000 for the year ended December 31, 2005.

Fair Value of Financial Instruments

The carrying amounts of financial instruments including cash and cash equivalents, accounts payable and accrued liabilities approximates their fair value because of the relatively short maturity of these instruments. The recorded value of the Company s long-term debt approximates its fair value as it bears interest at a floating rate. The Company s derivative financial instruments are recorded at estimated fair value as described above. The Company s

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8% senior subordinated convertible notes (Convertible Notes) are recorded at amortized cost as discussed in Note 5 below. The terms of the Convertible Notes provide that if not converted prior to maturity they are to be repaid in full ($9.0 million) in May 2008.

Income Taxes

The Company recognizes deferred tax assets and liabilities based on the differences between the tax basis of assets and liabilities and their reported amounts in the financial statements that may 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 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.

Significant Customers

The Company had oil and gas sales to two customers accounting for 77% and 16%, respectively, of total oil and gas revenues for the year ended December 31, 2007. The Company had oil and gas sales to one major customer (a different customer in each year) accounting for 92% and 100%, respectively, of total oil and gas revenues for the years ended December 31, 2006 and 2005. The Company believes that it is not dependent upon any of these customers due to the nature of its product. No other single customer accounted for 10% or more of revenues in 2007, 2006 or 2005.

Concentrations of Credit Risk

Substantially all of the Company s accounts receivable are due from purchasers of oil and natural gas or operators of the oil and gas properties. Oil and natural gas sales are generally unsecured. The Company has not experienced any meaningful credit losses in prior years and is not aware of any uncollectible accounts at December 31, 2007 or 2006. Derivative financial instruments that hedge the price of oil and gas are generally executed with major financial or commodities trading institutions which expose the Company to market and credit risks and may, at times, be concentrated with one counterparty. Although notional amounts are used to express the volume of these contracts, the amounts potentially subject to credit risk, in the event of non-performance by the counterparty, are substantially smaller. The credit worthiness of counterparties is subject to continuing review and full performance is anticipated. The Company s policy is to execute financial derivatives only with major financial institutions.

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.

Recently Adopted Accounting Pronouncements

In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes an Interpretation of SFAS No. 109 (FIN 48). The interpretation creates a single model to address accounting for uncertainty in tax positions. Specifically, the pronouncement prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition of certain tax positions.

The Company adopted the provisions of FIN 48 effective January 1, 2007. The adoption of this accounting principle did not have an effect on the Company s financial statements at, and for the three years ended December 31, 2007.

Recently Issued Accounting Pronouncements

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (SFAS No. 157). SFAS No. 157 establishes a single authoritative definition of fair value, sets out a framework for measuring fair value and requires additional disclosures about fair value measurements. This standard requires companies to disclose the fair value of their financial instruments according to a fair value hierarchy. SFAS No. 157 does not require any new fair value measurements, but will remove inconsistencies in fair value measurements between various accounting

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pronouncements. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years (fiscal 2008 for the Company). The adoption of SFAS No. 157 is not expected to have a material effect of the Company s financial position, results of operations or cash flows.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (SFAS No. 159) 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. SFAS No. 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007 (fiscal 2008 for the Company). The adoption of SFAS No. 159 is not expected to have a material effect of the Company s financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations (SFAS No. 141R), which replaces FASB Statement No. 141. SFAS No. 141R will change how business acquisitions are accounted for and will impact financial statements both on the acquisition date and in subsequent periods. SFAS No. 141R is effective as of the beginning of an entity s fiscal year that begins after December 15, 2008 (fiscal 2009 for the Company). The Company is in the process of evaluating the impacts, if any, of adopting this pronouncement.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51 (SFAS No. 160). SFAS No. 160 will change the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests and classified as a component of equity. This statement is effective as of the beginning of an entity s first fiscal year beginning after December 15, 2008 (fiscal 2009 for the Company). The Company is in the process of evaluating the impacts, if any, of adopting this pronouncement.

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Note 2 Income (Loss) per Common Share

The following table summarizes the calculation of basic and fully diluted income (loss) per common share:

	Years Ended December 31, 2007	2006	2005
	(in thousands, except per share data)		
Net income (loss) applicable to common shares	$ 2,377	$ (5,724)	$ (4,093)
Adjustments for dilution			
Net income (loss) adjusted for effects of dilution	$ 2,377	$ (5,724)	$ (4,093)
Weighted average common shares outstanding basic	16,545	13,093	10,282
Add dilutive effect of:			
LTIP performance share units 2006 Plan	445		
LTIP performance-vesting restricted common stock 2007 Plan	373		
LTIP restricted common stock	13		
Stock options	393		
Warrants	292		
Weighted average common shares outstanding diluted	18,061	13,093	10,282
Basic income (loss) per common share	$ 0.14	$ (0.44)	$ (0.40)
Fully diluted income (loss) per common share	$ 0.13	$ (0.44)	$ (0.40)

The following securities that could be potentially dilutive in future periods were not included in the computation of fully diluted income (loss) per common share because the effect would have been anti-dilutive for the periods indicated:

	Years Ended December 31, 2007	2006	2005
Securities in-the-money:			
LTIP performance share units 2005 Plan		355,000	596,000
LTIP performance share units 2006 Plan		1,556,000	
LTIP restricted common stock		193,999	195,000
Stock options		2,088,545	2,875,334
Warrants		867,819	1,368,773
Subtotal securities in-the-money		5,061,363	5,035,107
Securities out-of-the-money:			
Convertible Notes	1,800,000		
Warrants	4,374,547		362,991

Subtotal securities out-of-the-money	6,174,547		362,991
Total	6,174,547	5,061,363	5,398,098

Note 3 Acquisitions and Dispositions of Oil and Gas Properties

Subsequent Event

On February 26, 2008, the Company signed a letter of intent (the LOI) to acquire reserves, production and certain oil and gas properties in the Central Kansas Uplift of Kansas from a group of approximately 14 working interest owners (Sellers) for approximately $53.4 million before adjustments. Closing is expected to occur on or before April 25, 2008 with an effective date of March 1, 2008.

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The Company expects to pay approximately $40.1 million of the purchase price in cash and the remaining $13.3 million in shares of Teton s common stock. The number of shares of common stock to be issued will be based on the average price of Teton s common stock for the period from February 26, 2008 through the second day preceding the closing date. Teton also will issue to the Sellers warrants to purchase an additional 625,000 shares of Teton common stock for a period of two years at an exercise price of $6.00 per share.

Teton placed $1.0 million as a good faith deposit in escrow upon execution of the LOI, which will be applied towards the cash component of the purchase price, or will be refunded in the event that a mutually acceptable purchase and sale agreement is not executed by the parties within 60 days of the date of the LOI.

Prior to entering into the LOI, there was no material relationship between the Company or its affiliates and the Sellers.

2007 Acquisitions and Dispositions

In 2007, the Company acquired a 100% working interest in 16,417 gross acres (15,132 net) in the Big Horn Basin in the state of Wyoming for $1.0 million. The Company will serve as the operator for this project.

On October 1, 2007, the Company closed on an Asset Exchange Agreement (the Exchange Agreement) with Delta Petroleum Corporation (Delta). The Exchange Agreement provided for an economic effective date of July 1, 2007. Pursuant to the Exchange Agreement the Company sold to Delta a 12.5% working interest position, or one-half of its 25% working interest position, in certain oil and gas rights and leasehold assets covering 6,314 gross acres in the Piceance Basin in Western Colorado, for a sales price of $33.0 million in cash (before normal closing adjustments) and all of Delta s rights, title and interest in certain proved producing oil and gas properties and undeveloped acreage located in the DJ Basin, which Teton valued at $5.0 million at July 1, 2007 (net of asset retirement obligations assumed).

The Company included the revenues and expenses applicable to the properties sold in its results of operations through September 30, 2007. The Company also recorded capital expenditures applicable to the properties sold through September 30, 2007. Delta reimbursed the Company for capital expenditures and certain operating expenses, net of applicable revenues, that the Company incurred during the period July 1, 2007 through September 30, 2007 in the amount of approximately $3.0 million and approximately $700,000 of additional reimbursements are included in trade accounts receivable on the Consolidated Balance Sheet..

During the period July 1, 2007 through September 30, 2007, the Company reimbursed Delta for its capital expenditures and certain operating expenses, net of applicable revenues, associated with the oil and gas properties acquired in the amount of $482,000.

The purchase price of the DJ Basin properties acquired was allocated as follows:

	As of October 1, 2007 (in thousands)
Proved oil and gas properties	$ 4,343
Unproved oil and gas properties	362
Fixed assets	13
Less:	
Asset retirement obligation	239
Net purchase price	$ 4,479

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The gain on sale of oil and gas properties is as follows:

	For the Year Ended December 31, 2007 (in thousands)	
Cash component of initial sales price	$	33,000
Sales price adjustments applicable to oil and gas properties sold		3,682
Initial price of oil and gas properties acquired including asset retirement obligations		5,200
Sales price adjustments applicable to oil and gas properties acquired		(482)
Less:		
Transaction costs, net of $169,000 capitalized		1,287
Asset retirement obligation assumed with oil and gas properties acquired		239
Asset retirement obligation assumed by purchaser with properties sold		(72)
Carrying value of properties sold as of October 1, 2007		22,505
Gain on sale of oil and gas properties	$	17,441

In November 2007, the Company acquired an additional leasehold interest in the Denver-Julesburg Basin, in proximity to its current projects in Nebraska and eastern Colorado. Teton entered into an agreement to acquire the sellers interest in 168,197 gross acres (160,689 net). The purchase price is approximately $1.3 million gross and approximately $1.0 million net to Teton after all partners exercised their options within the two areas of mutual interest. At December 31, 2007, the Company had spent $984,000 toward the purchase price and received $188,000 from partners, and the remaining expenditures and receipts are scheduled to occur in early 2008.

At December 31, 2007, trade accounts receivable includes $652,000 applicable to the sale of oil and gas properties.

2006 Acquisitions and Dispositions

On January 27, 2006, the Company closed an Acreage Earning Agreement (the Earning Agreement) with Noble Energy, Inc. (Noble), with an effective date of December 31, 2005. Teton received $3.0 million from Noble and recorded this payment as a reduction to its investment in its DJ Basin oil and gas properties. Effective December 18, 2006, Noble earned a 75% working interest in these properties by drilling and completing 20 wells in the acreage covered by the Earning Agreement. Teton is entitled to 25% of the net revenues applicable to those first 20 wells. After completing the first 20 wells, the Earning Agreement provides that Teton and Noble will split all costs associated with future drilling and development activities in accordance with each party s working interest percentage.

On May 5, 2006, the Company acquired a 25% working interest in approximately 87,192 gross acres in the Williston Basin located in North Dakota for a total purchase price of $6.2 million from American Oil & Gas, Inc. (American). The Company paid American $2.5 million at closing and an additional $3.7 million prior to June 1, 2007 for American s 50% share of drilling and completion costs applicable to two new wells. In addition to the obligation to fund American s share, the Company was also obligated to pay its 25% share of drilling and completion costs of such wells.

2005 Acquisitions

On February 15, 2005, the Company acquired a 25% working interest in 6,314 gross acres in the Piceance Basin in western Colorado. The total purchase price was $6.4 million consisting of $5.3 million in cash, 450,000 shares of the Company s common stock valued at $837,000 and warrants to purchase 200,000 shares of the Company s common stock valued at $252,000.

During the first two quarters of 2005, the Company acquired a 100% working interest in 182,000 gross acres in the eastern Denver-Julesburg (DJ) Basin located in Nebraska. The purchase price was $3.7 million consisting of $2.9 million in cash, 412,962 shares of common stock valued at $631,000 and 206,481 warrants to purchase the

Company s common stock valued at $162,000. The Company incurred $630,000 of professional services fees which included the issuance of common stock valued at $110,000 in connection with the acquisition of this acreage, which were included in capitalized costs of the property.

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Note 4 Derivative Contract Liabilities

As of December 31, 2007, derivative financial instruments classified as a component of current liabilities consist of the fair value of financing warrants to purchase 3,600,000 shares of the Company s common stock that do not achieve all of the requisite conditions for equity classification. These free-standing derivative financial instruments arose in connection with the Company s financing transaction in May 2007 which consisted of the $9.0 million Convertible Notes and warrants to purchase 3,600,000 shares of the Company s common stock at a $5.00 strike price for a period of five years (the Warrants) as more fully discussed in Note 5.

Changes in estimated fair value of derivative contract liabilities

The Company incurred (gains) and losses from the valuation adjustments to derivative contract liabilities as follows:

	Year Ended December 31, 2007 (in thousands)
Derivative financial instruments:	
Financing warrants	$ (650)
Warrants issued to placement agents	106
Compound embedded derivative	306
Other warrants	561
	323
Day-one loss from derivative allocation	2,301
Loss on derivative contract liabilities	$ 2,624

The Company s derivative contract liabilities as of December 31, 2007, and the Company s loss on derivative contract liabilities arising from fair value adjustments during the year ended December 31, 2007 are significant to the Company s consolidated financial statements. The magnitude of the loss on derivative contract liabilities reflects the following:

(1) During the period from issuance (May 16, 2007) through December 31, 2007 in which our derivative financial instruments were classified as liabilities, the trading price of our common stock, which significantly affects the estimated fair value of our derivative contract liabilities, experienced a price increase from $4.66 to $4.90.

(2) During May 2007, the Company entered into the Convertible Notes and Warrants financing transaction, more fully discussed in Note 5. In connection with the Company s accounting for this financing transaction the Company recognized a day-one derivative loss related to the valuation of the derivative. The estimated fair value of the bifurcated compound embedded derivative financial instrument and Warrants exceeded the net proceeds that the Company received from the transaction, and the Company was required to recognize a loss of $2.3 million to record the derivative financial instruments at estimated fair value.

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Significant valuation assumptions:

The following tables set forth the significant assumptions, or ranges of assumptions, underlying the valuation of derivative financial instruments:

Free-standing Warrants:

	Inception Date (a)		Reclassification Date (a)		December 31, 2007
Trading market value	$4.66	$4.67	$5.11		$4.90
Strike prices	$1.75	$5.00	$1.75	$4.35	$5.00
Estimated term (years).	0.64	6.78	0.52	6.66	4.38
Estimated volatility	43.46%	85.04%	39.01%	80.07%	65.72%
Risk-free rates	4.62%	4.86%	4.95%	5.06%	3.45%

(a) See Note 5 for pertinent information regarding the origination of free-standing warrants that were classified or reclassified as derivative liabilities. The inception and reclassification date assumptions include those applied to certain other free-standing warrants that were reclassified from stockholders equity, see also Note 7.

Compound Embedded Derivative:

	Inception Date (b)(c)		Reclassification Date (b)(c)	
Trading market value	$4.66		$5.11	
Conversion price	$5.00		$5.00	
Estimated term (years)	1.00		0.885	
Equivalent volatility	43.46%	45.50%	43.43%	50.63%
Equivalent risk-adjusted interest rate	8.42%	9.00%	8.42%	9.00%
Equivalent credit-risk adjusted annual yield	13.67%	22.67%	13.67%	22.67%

(b) See Note 5 for pertinent information regarding the origination of compound embedded derivative financial instruments. On June 28, 2007, the compound embedded derivative financial instruments were reclassified to stockholders equity in accordance with EITF 06-07, Issuer s Accounting for a Previously Bifurcated Conversion Option in a Convertible Debt Instrument When the Conversion Option No Longer Meets the Bifurcation Criteria in SFAS No. 133 .

(c) Equivalent assumption amounts and percentages reflect the net results of multiple simulations that the Monte Carlo simulation valuation technique applies to multiple data points in the ranges of the underlying assumptions.

Note 5 8% Senior Subordinated Convertible Notes

On May 16, 2007, the Company closed on a financing consisting of $9.0 million face value of 8% Senior Subordinated Convertible Notes due May 16, 2008, which included Warrants to purchase 3,600,000 shares of the Company s common stock at a $5.00 strike price for a period of five years. The Warrants include a cashless exercise feature. Net proceeds from the sale of the Convertible Notes and Warrants amounted to $8.3 million after fees and expenses. The Convertible Notes bear interest at 8% per annum which is payable on a quarterly basis on July 1, October 1, January 1, and April 1, beginning July 1, 2007, either in cash or common stock at the Company s option. The Convertible Notes were initially convertible into common stock at a conversion price of $5.00 per share subject to adjustment at maturity to a then market-indexed rate. The conversion feature also provided full-ratchet anti-dilution protection in the event of sales of shares or other share-indexed instruments below the conversion price. The Convertible Notes are unsecured but provide for penalties in the event of default. In addition, on May 18, 2007, the Company issued to the placement agent, which acted in connection with this offering, warrants to purchase 360,000 shares of the Company s common stock at a $5.00 strike price with a term of five years. The fair value of the

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placement agent s warrants was $1.0 million using the Black-Scholes-Merton valuation technique and was recorded as deferred debt issuance costs in the Company s consolidated balance sheet.

The Company evaluated the terms and conditions embedded in the Convertible Notes for indications of features that were not clearly and closely related to debt-associated risk and concluded that the conversion feature, share-indexed interest feature, anti-dilution protections and certain default features required compounding and bifurcation as a derivative liability in accordance with SFAS No. 133. In addition, the financing and placement agent s warrants did not meet all the conditions for equity classification on their transaction inception dates and required liability classification. Since derivative financial instruments are initially and subsequently measured at estimated fair value, the Company allocated financing proceeds to those instruments plus other financing components, as follows:

		Allocation of Proceeds (in thousands)
Fair value of derivative financial instruments:		
Financing warrants	$	10,172
Warrants issued to placement agents		1,022
Compound embedded derivative		1,129
Day-one loss from derivative allocation		(2,301)
Direct financing costs		(1,732)
Net proceeds	$	8,290

On June 28, 2007, the Company amended the Convertible Notes with the holders to, among other things, change the conversion terms at maturity from a variable conversion price to a fixed $5.00 conversion price as the floor at maturity and to modify the anti-dilution protections to fix the $5.00 price as the floor. While the amendment did not give rise to an extinguishment of the original Convertible Notes, the Company concluded that the Convertible Notes met the Conventional Convertible Debt Exemption criteria which provides for classification of the compound embedded derivative in stockholders equity. In addition, the removal of the variable conversion price resulted in reclassification of the placement agents warrants and certain other warrants to stockholders equity. The Warrants continue to require classification as derivative contract liabilities in the Company s consolidated balance sheet. Subsequent to the amendment, the principal amount of the Convertible Notes is convertible into 1.8 million shares of the Company s common stock.

Accounting for the reclassifications in accordance with EITF 06-7 resulted in the Company adjusting the compound embedded derivative, warrants issued to placement agents and certain other warrants to estimated fair value on the amendment date and reclassifying the adjusted balances to stockholders equity without any adjustment to the carrying value or amortization of the host debt instrument. Details for these reclassifications are provided in Note 7.

The $9.0 million debt component of the Convertible Notes was initially recorded net of debt issuance discount of $9.0 million. The debt issuance discount is being amortized to interest expense over the one year life of the Convertible Notes using the effective interest method. The Company recorded $1.6 million of debt issuance discount amortization during the year ended December 31, 2007.

Deferred debt issuance costs of $1.4 million associated with the Convertible Notes are included in current assets as of December 31, 2007 and are being amortized to interest expense using the effective interest method. The Company recorded $314,000 of amortization during the year ended December 31, 2007.

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Note 6 Senior Bank Facility

Long-term debt consisted of the following:

	December 31, 2007	2006
	(in thousands)	
Senior bank credit facility	$ 8,000	$

BNP Paribas Credit Facility

On June 15, 2006, the Company entered into a $50.0 million senior revolving credit facility (the Credit Facility) with BNP Paribas. The original maturity date of the Credit Facility was June 15, 2010. The Credit Facility had an initial borrowing base of $3.0 million. The borrowing base was increased to $6.0 million on March 12, 2007, and further increased to $10.0 million on July 19, 2007.

Under the Credit Facility, each loan bore interest, at the Company s option, at a Eurodollar rate (London Interbank Offered Rate, or LIBOR) plus applicable margins of 1.5% to 2.25%, or a base rate (the higher of the Prime Rate or the Federal Funds Rate plus 0.5%) plus applicable margins of 0% to 0.75%. Teton was also required to pay a 0.5% per annum commitment fee based on the average daily amount of the unused amount of the commitment. Loans made under the Credit Facility were secured by a first mortgage against the Company s properties, a pledge of the equity of all subsidiaries and a guaranty by all subsidiaries.

The Credit Facility contained customary affirmative and negative covenants such as minimum/maximum ratios for liquidity and leverage. Those covenants are no longer applicable as a result of the amended and restated Credit Facility with JP Morgan Chase Bank, N.A. (JPMorgan Chase) as of August 9, 2007, described below.

JPMorgan Chase Amended and Restated Credit Facility

On August 9, 2007, the Company entered into an amended and restated $50.0 million revolving credit facility (the Amended Credit Facility) with JPMorgan Chase, as administrative agent. JPMorgan Chase assumed the Company s previous Credit Facility with BNP Paribas. The Amended Credit Facility matures on August 9, 2011. The Amended Credit Facility had an initial borrowing base of $14.0 million, which included an initial conforming borrowing base of $11.0 million. As a result of the Company s sale of part of its Piceance Basin properties that closed on October 1, 2007 as described in Note 3, JPMorgan reduced the borrowing base and the conforming borrowing base on the Amended Credit Facility to $8.0 million. The borrowing base (and, until November 1, 2008, the conforming borrowing base) is scheduled to be re-determined on a semi-annual basis, based on engineering reports delivered by the Company from an approved petroleum engineer. On November 1, 2008, the borrowing base will be automatically reduced to the amount of the conforming borrowing base, and at all times thereafter will be equal in amount to the conforming borrowing base. On November 9, 2007, there was a re-determination of the borrowing base and conforming borrowing base to $10.0 million.

Under the Amended Credit Facility, each loan bears interest at a Eurodollar rate (London Interbank Offered Rate, or LIBOR) plus applicable margins of 1.25% to 3.0% or a base rate (the higher of the Prime Rate or the Federal Funds Rate plus 0.5%) plus applicable margins of 0% to 1.5%, as requested by the Company. The Company is also required to pay a commitment fee of 0.375% or 0.5% per annum, based on the average daily amount of the unused amount of the commitment. Loans made under the Amended Credit Facility are secured primarily by a first mortgage against the Company s oil and gas assets and by a pledge of the Company s equity interests in its subsidiaries and a guaranty by its subsidiaries. The Amended Credit Facility contains customary affirmative and negative covenants such as minimum/maximum ratios for liquidity and leverage.

For the years ended December 31, 2007 and 2006, the Company recorded $272,000 and $28,000, respectively, of deferred debt issuance cost amortization in interest expense. During 2007, deferred debt issuance cost amortization included the write-off of $229,000 of unamortized deferred debt issuance costs applicable to the Company s original $50.0 million Credit Facility with BNP Paribus. Deferred debt issuance costs of $159,000 associated with the

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Amended Credit Facility are included in non-current assets on our consolidated balance sheet as of December 31, 2007.

On February 11, 2008, the Company repaid the entire $8.0 million balance outstanding under the Amended Credit Facility, leaving the entire $10 million available under the borrowing base.

Note 7 Stockholders Equity

Preferred Stock

The Company is authorized to issue up to 25,000,000 shares of $.001 par value preferred stock, the rights and preferences of which are to be determined by the Board of Directors at or prior to the time of issuance.

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.

Common Stock

On July 25, 2007, the Company completed a registered direct offering of 964,060 shares of its common stock, at a price of $5.05 per share, to a selected group of institutional investors for gross proceeds of $4.9 million. The offering included 337,421 warrants to purchase 337,421 shares of common stock at an exercise price of $6.06 per share with a term of five years. Offering costs, including underwriter s fees, legal, accounting and other related expenses, totaled $558,000 which includes the issuance of 77,126 warrants to purchase 77,126 shares of common stock to the Company s placement agent in the transaction, valued at $190,000.

Warrants

The following table presents the activity for warrants outstanding:

	Shares	Weighted Average Exercise Price
Outstanding December 31, 2004	7,359,727	$ 5.62
Issued	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
Issued		
Exercised	(760,959)	4.65
Forfeited/canceled	(102,986)	5.36
Outstanding December 31, 2006	867,819	3.14
Issued	4,374,547	5.10
Exercised	(1,500)	1.75
Forfeited/canceled		

Outstanding	December 31, 2007	5,240,866	$	4.78

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The following table presents the composition of warrants outstanding and exercisable as of December 31, 2007:

Range of Exercise Prices	Number	Weighted Average Remaining Contractual Life (years)
$1.75	60,748	0.3
$3.24	799,571	3.8
$3.48	3,700	0.5
$4.35	2,300	0.8
$5.00	3,960,000	4.4
$6.06	414,547	4.6
Total warrants outstanding and exercisable	5,240,866	4.3

Derivative Financial Instruments

Current accounting standards provide that the Company is required to evaluate existing derivative financial instruments for classification in stockholders equity or as derivative liabilities at the end of each reporting period, or upon the occurrence of any event that may give rise to a presumption that the Company could not share or net-share settle the derivatives. As discussed in Note 5, on May 16, 2007, the Company entered into a Convertible Note and Warrant financing that was initially convertible into common stock at a conversion price of $5.00 per share subject to adjustment at maturity to a then market-indexed rate. In this instance, it was concluded that the feature placed share settlement outside of the Company s control due to (without regard to probability) the potential of the trading market price declining to a level where the Company would have insufficient authorized shares with which to settle all of its share-indexed instruments. Accordingly, certain non-exempt warrants (or tainted warrants) required reclassification to derivative liabilities on the date of the financing. As further discussed in Note 5, on June 28, 2007, the Company amended the Convertible Note agreements such that liability classification for certain derivatives, including the tainted warrants, was no longer required. On that date certain of the derivatives were reclassified to stockholders equity.

The following table illustrates the reclassifications of derivatives at estimated fair values from (to) stockholders equity during 2007:

	Year Ended December 31, 2007 (in thousands)
Reclassifications of derivative liabilities from (to) stockholders equity:	
Existing warrants tainted to derivative liabilities	$ 4,951
Compound embedded derivative no longer requiring bifurcation	(1,435)
Financing warrants issued to placement agents no longer tainted	(1,128)
Existing warrants no longer tainted to stockholders equity	(5,512)
Net change in stockholders equity	$ (3,124)

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Note 8 Stock-Based Compensation

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

	For the Years Ended December 31,		
	2007	2006 (in thousands)	2005
Performance share units employees and directors	$ 2,421	$ 2,413	$
Performance-vesting restricted common stock employees and directors	278		
LTIP restricted common stock employees and directors	571	487	
Stock options employees	18	28	
Total stock-based compensation expense	3,288	2,928	
Performance share units non-employees	264	211	
Restricted common stock non-employees		(158)	796
Common stock non-employees			39
Total stock-based compensation expense	$ 3,552	$ 2,981	$ 835

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 performance share units, restricted stock units, restricted stock, stock options, stock appreciation rights, and other stock-based awards to employees, directors, consultants and advisors (Participants) as administered by the Compensation Committee of the Board of Directors (the Compensation Committee). Shares issued to participants under this plan are newly issued shares.

LTIP Performance Share Units

The Compensation Committee established a pool (Pool) of Performance Share Units (Units) under the LTIP for 2005 and 2006 and granted Units (each a Grant, collectively Grants) to Participants (each such year in which Units were granted becoming a Grant Year). The Grants vest solely as a result of the Company achieving performance goals established by the Compensation Committee. Each Grant vests in three tranches over a three-year period, and is conditioned on the Participant remaining employed by the Company at each measurement date, which is December 31 of each calendar year.

The Compensation Committee designated annual performance goals for each tranche as Threshold, Base, and Stretch. If the Company achieves the Threshold level of performance, 25% of the Units in that tranche will vest. If the Company achieves the Base level of performance, 50% of the Units in that tranche will vest. If the Company achieves the Stretch level of performance, 100% of the Units in that tranche will vest. If the Threshold performance level is not achieved, no Units in that tranche will vest. Once the performance results have been certified by the Compensation Committee the vested Units are issued to the Participants as common stock.

The fair value of each Unit is measured based on the market price of the Company s common stock on the date of Grant. Stock-based compensation expense is recognized based upon the number of Units granted to employees and directors that vest each year. During the years ended December 31, 2007, 2006 and 2005 the Company recorded $2.4 million, $2.4 million and $0, respectively, of stock-based compensation expense applicable to the vesting of Units granted to employees and directors as a component of general and administrative expense.

Other general and administrative expense is recognized based upon the market value of the Units granted to consultants, advisors and other non-employees that vest each year. During the years ended December 31, 2007, 2006 and 2005, the Company recorded $264,000, $211,000 and $0, respectively, of other general and administrative expense applicable to the vesting of Units granted to non-employees.

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On July 26, 2005, the Compensation Committee established a Pool of 800,000 Units for grant (the 2005 Grants). During 2005 and 2006, 895,000 Units were granted to Participants by the Compensation Committee (including Units re-granted out of forfeitures). The 2005 Grants vested in three tranches (20% in 2005, 30% in 2006 and 50% in 2007), provided the goals set forth by the Compensation Committee were met. The performance goals for the 2005 Grants were based upon attaining specific annual or year-end objectives, including: (a) achieving certain levels of oil and gas reserves, (b) achieving a certain level of oil and gas production, (c) achieving a certain level of stock price performance, (d) achieving finding and development costs goals and (e) achieving an overall management efficiency and effectiveness rating. During the years ended December 31, 2007, 2006 and 2005, 133,507, 134,767 and zero Units applicable to the 2005 Grants vested and the underlying common shares were considered issued and outstanding on those dates.

During 2006, the Compensation Committee initially established a pool of 2,500,000 Units for grant (the 2006 Grants). During 2006, 1,969,250 Units were granted to Participants by the Compensation Committee. 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 goals for the 2006 Grants are based upon attaining specific annual or year-end objectives, including: (a) increasing the Company s asset base through acquisitions, (b) achieving stock price goals relative to an index of comparable companies stock prices, and (c) achieving an overall management efficiency and effectiveness rating. 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 that the 2006 Grants vest. During the years ended December 31, 2007, 2006 and 2005, 177,619, 291,750 and zero Units applicable to the 2006 Grants vested and the underlying common shares were considered issued and outstanding on those dates.

A summary of the 2005 and 2006 Grant activity is below:

	Unvested 2005 Grants (shares)	Weighted Average Grant Date Market Price	Unvested 2006 Grants (shares)	Weighted Average Grant Date Market Price
Outstanding December 31, 2004		$		$
Granted	745,000	4.88		
Forfeited/returned	(149,000)	4.88		
Outstanding December 31, 2005	596,000	4.88		
Granted	150,000	5.23	1,969,250	6.71
Vested	(134,767)	4.95	(291,750)	6.71
Forfeited/returned	(256,233)	4.94	(121,500)	6.74
Outstanding December 31, 2006	355,000	4.95	1,556,000	6.71
Vested, net of shares withheld for payroll taxes	(133,507)	4.91	(177,619)	6.74
Forfeited/returned	(221,493)	4.98	(674,881)	6.68
Outstanding December 31, 2007		$	703,500	$ 6.72

LTIP Performance-Vesting Restricted Common Stock

LTIP performance-vesting restricted common stock is granted to Participants pursuant to the Company s LTIP, and shares generally vest in three tranches over three years based on the Company achieving certain results. Compensation expense is recorded at fair value based on the market price of the Company s common stock at the date of grant and is recognized over the related service period. During the years ended December 31, 2007, 2006 and 2005 the Company recorded $278,000, $0 and $0, respectively, of stock-based compensation expense applicable to LTIP performance-vesting restricted stock grants vesting as a component of general and administrative expense.

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During 2007, 540,000 shares were granted to Participants by the Compensation Committee (the 2007 Grants). The 2007 Grants vest in three tranches (20% in 2008, 30% in 2009 and 50% in 2010), provided the goals set forth by the Compensation Committee are met. The performance goals for the 2007 Grants are based upon attaining specific annual or period-end objectives, including: (a) achieving certain levels of oil and gas reserves, (b) achieving a certain level of oil and gas production, and (c) achieving an overall management efficiency and effectiveness rating.
A summary of the 2007 Grant activity is below:

	Unvested 2007 Grants (shares)	Weighted Average Grant Date Market Price
Outstanding December 31, 2006		
Granted in 2007	540,000	$ 5.15
Outstanding December 31, 2007	540,000	$ 5.15

On February 21, 2008, the Compensation Committee awarded a total of up to 2,500,000 Performance Share Units in the aggregate to certain participants under the Company s LTIP pursuant to 2008 Performance Share Unit Award Agreements and a 2008 grant administration document. The period being measured for the Performance Share Units is January 1, 2008 through December 31, 2010. The performance measure under this Award is based on increases in the Company s net asset value per share. The grants vest at 20%, 30% and 50% when the net asset value per share of the Company increases by 40%, 100% and 200%, respectively, from a base level set by the Compensation Committee as of December 31, 2007.

LTIP Restricted Common Stock

LTIP restricted common stock is granted to Participants pursuant to the Company s LTIP and shares generally vest over three years based solely on service. Compensation expense is recorded at fair value based on the market price of the Company s common stock at the date of grant and is recognized over the related service period. During the years ended December 31, 2007, 2006 and 2005 the Company recorded $571,000, $487,000 and $0, respectively of stock-based compensation expense applicable to LTIP restricted stock grants vesting as a component of general and administrative expense.
A summary of LTIP restricted common stock activity is below:

	Unvested LTIP - Restricted Common Stock (shares)	Weighted Average Grant Date Market Price
Outstanding December 31, 2004		$
Granted	195,000	6.06
Outstanding December 31, 2005	195,000	6.06

Granted	69,000		5.84
Vested	(70,001)		6.08
Outstanding December 31, 2006	193,999		5.98
Granted	57,400		5.07
Vested	(96,335)		5.99
Forfeited/canceled	(33,332)		6.18
Outstanding December 31, 2007	121,732	$	5.49

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Restricted Common Stock

On July 16, 2004, the Company s shareholders approved a stock-based compensation plan for non-employees (the 2004 Plan) authorizing a pool of 1,000,000 shares of common stock available to grant. On June 28, 2005, the 2004 Plan was terminated upon shareholder approval of the LTIP. Shares granted under the 2004 Plan vested immediately and are recorded at fair value based on the market price of the Company s common stock at the date of grant.

On April 5, 2005 the Board authorized the grant 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 Company recorded such shares at their fair value of $906,000, capitalized $110,000 of such amount and recorded the balance of $796,000 as general and administrative expenses.

Effective March 31, 2006, in connection with the resignation of the Company s former contract Chief Financial Officer, 50,000 shares of restricted common stock were returned to the Company as an agreed-upon reduction in service fees charged. The return of such shares was recorded as a reduction in accounting fees included in general and administrative expenses totaling $158,000.

A summary of restricted common stock activity is below:

	Restricted Common Stock (shares)	Weighted Average Grant Date Market Price
Year ended December 31, 2005:		
Granted	287,500	$ 3.15
Year ended December 31, 2006:		
Returned	(50,000)	$ 3.15

Stock Options

On March 19, 2003, the Company s shareholders approved an employee stock option plan (the 2003 Plan) authorizing a pool of 3,000,000 options available to grant. On June 28, 2005, the 2003 Plan was terminated upon shareholder approval of the LTIP; however options granted under the 2003 Plan remain outstanding until exercised, forfeited or expired pursuant to the terms of each grant.

During 2003 and 2004, 2,993,037 options were granted with no vesting requirements and expiration dates over various periods up to ten years from the date of grant.

During 2005, the Company granted 45,000 stock options under the 2003 Plan to certain employees. These options have ten year terms and vest over a three-year period, assuming the employees remain in the Company s employ.

In accordance SFAS No. 123R, effective January 1, 2006, the Company began recognizing compensation expense for unvested stock options over the period that the stock options vest. During the years ended December 31, 2007 and 2006, the Company recognized $18,000 and $28,000, respectively, of stock-based compensation expense applicable to stock option vesting as a component of general and administrative expense. As of December 31, 2007, there were 6,800 unvested stock options outstanding, and the total unrecognized compensation expense related to these options was $9,000 which will be recognized over the remaining vesting period of six months.

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A summary of stock option activity for the three years ended December 31, 2007 is below:

	Stock Options (shares)	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding December 31, 2004	2,993,037	$ 3.54	8.70	$
Granted	45,000	3.11		
Forfeited/expired	(162,703)	3.52		
Outstanding December 31, 2005	2,875,334	3.54	5.87	6,788
Exercised	(770,039)	3.50		1,648
Forfeited/expired	(16,750)	3.11		
Outstanding December 31, 2006	2,088,545	3.56	5.44	2,867
Exercised	(672,701)	3.57		935
Outstanding December 31, 2007	1,415,844	$ 3.55	5.77	$ 1,916
Exercisable at December 31, 2005	2,875,334	$ 3.54	5.87	$ 6,788
Exercisable at December 31, 2006	2,075,212	$ 3.56	5.42	$ 2,842
Exercisable at December 31, 2007	1,409,044	$ 3.55	5.76	$ 1,904

Note 9 Benefit Plans

During 2005, the Company established a SIMPLE IRA plan which provides retirement savings options for all eligible employees. The Company makes a matching contribution based on the participants eligible wages. The Company made matching contributions of approximately $35,000, $23,000 and $3,000 during the years ended December 31, 2007, 2006 and 2005, respectively.

Note 10 Income Taxes

For each of the three years in the period ended December 31, 2007, the current and deferred provisions for income taxes was zero.

Total income tax expense differed from the amounts computed by applying the federal statutory income tax rate of 35% to income (loss) before income taxes as a result of the following items:

	Year Ended December 31, 2007	2006 (in thousands)	2005
Federal statutory income tax provision (benefit)	$ 832	$ (2,004)	$ (1,322)
State income tax provision (benefit), net of federal income tax provision/benefit	77	(171)	(112)

Loss on derivative contract liabilities	991		
Debt issuance cost amortization	619	16	5
Other	129		
Change in valuation allowance	(2,648)	2,159	1,429
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 are as follows:

	December 31, 2007	December 31, 2006
	(in thousands)	
Current deferred tax assets (liabilities):		
Other receivables	$	$ (265)
Accounts payable and accrued liabilities		569
Oil and gas derivatives	173	(153)
Debt issuance costs	(221)	
Valuation allowance		(151)
Net current deferred tax assets (liabilities)	$ (48)	$
Non-current deferred tax assets (liabilities)		
Stock-based compensation	$ 1,108	$ 1,057
Oil and gas properties	(4,481)	(42)
Net operating loss	12,358	10,419
Valuation allowance	(8,937)	(11,434)
Net non-current deferred tax assets (liabilities)	$ 48	$
Net deferred tax assets (liabilities)	$	$

At December 31, 2007, the Company had net operating loss carryforwards (NOLs), for federal income tax purposes, of approximately $32.5 million. These NOLs, if not utilized to reduce taxable income in future periods, will expire in various amounts from 2018 through 2027. Approximately $5.8 million of such NOLs is subject to U.S. Internal Revenue Code Section 382 limitations. As a result of these limitations, utilization of this portion of the NOLs is limited to approximately $3.6 million and $2.2 million for the years ending December 31, 2008 and 2009, respectively plus any loss attributable to any built-in gain on assets sold within five years of the ownership change.

During 2006, the Company had $1.6 million of tax deductions from the exercise of nonqualified stock options; however, a valuation allowance has been provided for the entire amount. The Company has established a valuation allowance for deferred taxes equal to its entire net deferred tax assets as management currently believes that it is more likely than not that these losses will not be utilized.

On January 1, the Company adopted the provisions of FIN 48, which requires that the Company recognize in its consolidated financial statements only those tax positions that are more-likely-than-not of being sustained as of the adoption date, based on the technical merits of the position. As a result of the implementation of FIN 48, the Company performed a comprehensive review of its material tax positions in accordance with recognition and measurement standards established by FIN 48.

The Company is subject to the following material taxing jurisdictions: U.S., Colorado and Nebraska. The tax years that remain open to examination by the Internal Revenue Service are 2004 through 2007. The tax years that remain open to examination by the Colorado Department of Revenue and the Nebraska Department of Revenue are 2003 through 2007. Our policy is to recognize interest and penalties related to uncertain tax benefits in income tax expense. We have no accrued interest or penalties related to uncertain tax positions as of January 1, 2007 or December 31, 2007.

Note 11 Commitments and Contingencies

To mitigate a portion of the potential exposure to adverse market changes in the prices of oil and natural gas, the Company has entered into various derivative contracts. The Company s derivative contracts in place at December 31, 2007 include fixed rate swap arrangements for the sale of oil and natural gas.

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Type of Contract	Volume	Fixed Price	Price Index (1)	Contract Period	
Natural Gas Fixed Rate Swap Contract	30,000 MMBtu per month	$5.78/MMBtu	CIGRM	08/01/07	10/31/08
Oil Fixed Rate Swap Contract	60Bbls per day	$80.70/Bbl	WTI	11/01/07	12/31/08

(1) CIGRM refers to Colorado Interstate Gas Rocky Mountains price as quoted in Platt s for Inside FERC on the first business day of each month. WTI refers to the West Texas Intermediate price as quoted on the New York Mercantile Exchange.

On February 1, 2008, the Company entered into a new hedging agreement as summarized below:

Type of Contract	Volume	Floor	Ceiling	Price Index (1)	Contract Period	
Natural Gas Costless Collar	2,000 MMBtu per day	$6.00/MMBtu	$7.10/MMBtu	CIGRM	02/01/08	01/31/09

(1) CIGRM refers to Colorado Interstate Gas Rocky Mountains price as quoted in Platt s for Inside FERC on the first business day of each month.

As of December 31, 2007, the Company has hedge contracts in place through 2008 for a total of approximately 21,960 Bbls of oil production and 300,000 MMbtu of natural gas production. As of February 1, 2008, the Company has hedge contracts remaining in place through 2008 for a total of approximately 20,100 Bbls of oil production and 940,000 MMbtu of natural gas production.

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

	For the Years Ending December 31,			
	2008	2009	Thereafter	Total
	(in thousands)			
Operating lease for office space	$ 129	$ 44	$	$ 173

Rent expense for the Denver office was approximately $120,000, $97,000 and $67,000 in 2007, 2006 and 2005, respectively.

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Notes to Consolidated Financial Statements

Note 12 Supplemental Oil and Gas Disclosures

Capitalized Costs Relating to Oil and Gas Producing Activities

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

	For the Years Ended December 31, 2007	2006	2005
		(in thousands)	
Oil and gas properties:			
Proved	$ 4,057	$ 259	$ 142
Unproved	13,411	13,959	10,636
Facilities in progress		1,364	121
Wells in progress	3,230	8,492	2,106
Development costs	31,804	12,367	1,575
Subtotal	52,502	36,441	14,580
Accumulated depletion and depreciation	(3,535)	(1,833)	(161)
Net capitalized costs	$ 48,967	$ 34,608	$ 14,419

Costs Incurred in Oil and Gas Property Acquisitions, Exploration and Development Activities

Costs incurred in property acquisitions, exploration and development activities (including asset retirement costs) are as follows:

	For the Years Ended December 31, 2007	2006	2005
		(in thousands)	
Property acquisition costs unproved properties	$ 2,465	$ 3,323	$ 10,636
Property acquisition costs proved properties	4,342		
Development costs	32,900	17,163	3,944
Exploration costs	2,712	1,823	445

The following table reflects the net changes in capitalized exploratory well costs and does not include amounts that were capitalized and either subsequently expensed or reclassified to proved properties or producing facilities in the same period. No exploratory well costs have been capitalized for a period greater than one year from the completion of exploratory drilling.

	2007	2006	2005
		(in thousands)	
Beginning Balance at January 1	$ 1,375	$ 2,106	$
Additions to capitalized exploratory well costs pending determination of proved reserves		1,375	2,106
Reclassification to proved properties and producing facilities based on the determination of proved reserves	(1,375)	(2,106)	
Capitalized exploratory well costs charged to expense			
Ending balance at December 31	$	$ 1,375	$ 2,106

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Results of Operations from Oil and Gas Producing Activities

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

	For the Years Ended December 31, 2007	2006	2005
		(in thousands)	
Oil and gas sales	$ 6,253	$ 4,022	$ 797
Operating expenses:			
Lease operating expense	705	325	51
Transportation costs	652	493	90
Production taxes	412	251	48
Exploration expense	1,847	448	444
Depletion, depreciation and accretion expense	3,751	1,697	161
Impairment expense			
Total operating expenses	7,367	3,214	794
Operating (loss) income	$ (1,114)	$ 808	$ 3

Oil and Gas Reserves (Unaudited)

Proved oil and gas reserves are the estimated quantities of crude oil and natural gas 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 developed oil and gas reserves are those reserves expected to be recovered through existing wells with existing equipment and operating methods. The reserve information presented below was prepared by Netherland Sewell & Associates, Inc., independent petroleum engineers. The Company did not have any oil reserves at December 31, 2006 and December 31, 2005.

Estimated net quantities

	For the Years Ended December 31, 2007		2006	2005
	Oil (MBbl)	Gas (MMcf)	Gas (MMcf)	Gas (MMcf)
Proved reserves, beginning of year		7,093	4,009	
Revisions of estimates	40	4,018	3,821	
Extensions and discoveries	43	14,505		4,099
Purchase of reserves in place	87	574		
Sales of reserves in-place	(24)	(11,754)		
Production	(17)	(1,128)	(737)	(90)
Proved reserves, end of year	129	13,308	7,093	4,009
Proved developed reserves, beginning of year		4,927	853	
Proved developed reserves, end of year	112	7,930	4,927	853

Standardized Measure of Discounted Future Net Cash Flows (Unaudited)

SFAS No. 69 Disclosures about Oil and Gas Producing Activities (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.

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

The resulting standardized measure is less than the net book value of the Company s proved properties as presented on the Consolidated Balance Sheet at December 31, 2007. However, the estimated undiscounted future net cash flows are in excess of the net book value. As noted under the caption Impairment of Long-lived Assets in Note 1 above, the Company has evaluated the proved properties and found no impairment is necessary at December 31, 2007.

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

	For the Years Ended December 31,		
	2007	2006	2005
		(in thousands)	
Future cash inflows	$ 88,297	$ 29,167	$ 30,514
Future production costs	(22,782)	(10,066)	(4,643)
Future development costs	(13,708)	(3,419)	(5,900)
Future income tax expense			
Future net cash flows (undiscounted)	51,807	15,682	19,971
10% annual discount	(23,815)	(6,977)	(11,255)
Standardized measure of discounted future net cash flows	$ 27,992	$ 8,705	$ 8,716

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

	For the Years Ended December 31,		
	2007	2006	2005
		(in thousands)	
Standardized measure, beginning of year	$ 8,705	$ 8,716	$
Net changes in prices and production costs	2,172	(10,798)	
Sales of oil and gas produced, net of production costs	(4,484)	(2,953)	(608)
Development costs incurred during the year	2,519		
Change in estimated future development costs	400	2,481	
Revisions of previous quantity estimates	8,433	10,387	
Extensions and discoveries	31,190		9,324
Accretion of discount	871	872	
Purchases of reserves in place	5,272		
Sales of reserves in place	(24,465)		
Changes in income taxes, net			

Changes in timing and other	(2,621)		
Aggregate change	19,287	(11)	8,716
Standardized measure, end of period	$ 27,992	$ 8,705	$ 8,716

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Notes to Consolidated Financial Statements

Note 13 Selected Quarterly Information (Unaudited)

The following represents selected quarterly financial information:

	For the Quarter Ended			
	March 31,	June 30,	Sept 30,	Dec 31,
	(In thousands, except per share amounts)			
2007				
Total operating revenues (1) (2)	$ 1,198	$ 990	$ 1,317	$20,189
Operating income (loss) (2)	$(1,779)	$(2,404)	$(2,564)	$14,012
Net income (loss) (2)	$(1,801)	$(7,246)	$ (951)	$12,375
Income (loss) per common share basic	$ (0.12)	$ (0.45)	$ (0.06)	$ 0.77
Income (loss) per common share diluted	$ (0.12)	$ (0.45)	$ (0.06)	$ 0.76
2006				
Total operating revenues	$ 331	$ 754	$ 1,628	$ 1,309
Operating loss	$(1,331)	$(1,587)	$ (882)	$ (2,592)
Net loss	$(1,263)	$(1,526)	$ (797)	$ (2,138)
Basic and diluted loss per common share	$ (0.11)	$ (0.13)	$ (0.06)	$ (0.14)

(1) Quarterly operating revenues have been reclassified to conform to presentation for the quarter ended December 31, 2007. The total operating revenues includes gross revenues before gathering and transportation expenses which are now included in transporation expense in the Consolidated Statement of Operations.

(2) The gain on sale of oil and gas properties of

$17,441 is included in the total operating revenues, operating income (loss) and net income (loss) amounts for the quarter ended December 31, 2007.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES.

(a) Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that are designed to ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and to ensure that such information is accumulated and communicated to our management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. Management necessarily applied its judgment in assessing the costs and benefits of such controls and procedures, which, by their nature, can provide only reasonable assurance regarding management s control objectives.

With the participation of management, our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of the design and operation of our disclosure controls and procedures at the conclusion of the period ended December 31, 2007. Based upon this evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective in ensuring that material information required to be disclosed is included in the reports that we file with the Securities and Exchange Commission.

(b) Management s Report on Internal Control over Financial Reporting

Our Company management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. The Company s internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. The Company s internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and

(iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company s assets that could have a material effect on the financial statements.

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

Management assessed the effectiveness of the Company s internal control over financial reporting as of December 31, 2007. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework. Management s assessment included an evaluation of the design of our internal control over financial reporting and testing of the operational effectiveness of these controls.

Based on this assessment, management has concluded that as of December 31, 2007, our internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

The Company s independent registered public accounting firm, Ehrhardt Keefe Steiner & Hottman PC (EKSH), has issued a report on the effectiveness of the Company s internal controls over financial reporting as of December 31, 2007, and EKSH s report is included under Item 8 of this Annual Report on Form 10-K.

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(c) Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during our fiscal quarter ended December 31, 2007 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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ITEM 9B. OTHER INFORMATION.

None.

PART III

Pursuant to instruction G(3) to Form 10-K, the following Items 10,11,12,13 and 14 are incorporated by reference to the information provided in the Company s definitive proxy statement for the 2008 annual meeting of stockholders to be filed within 120 days from December 31, 2007.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

ITEM 11. EXECUTIVE COMPENSATION

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

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

Exhibits.

Exhibit No.	Description
3.1.1	Certificate of Incorporation of EQ Resources Ltd incorporated by reference to Exhibit 2.1.1 of Teton s Form 10-SB (File No. 000-31170), filed July 3, 2001.
3.1.2	Certificate of Domestication of EQ Resources Ltd incorporated by reference to Exhibit 2.1.2 of Teton s Form 10-SB (File No. 000-31170), filed July 3, 2001.
3.1.3	Articles of Merger of EQ Resources Ltd. and American-Tyumen Exploration Company incorporated by reference to Exhibit 2.1.3 of Teton s Form 10-SB (File No. 000-31170), filed July 3, 2001.
3.1.4	Certificate of Amendment of Teton Petroleum Company incorporated by reference to Exhibit 2.1.4 of Teton s Form 10-SB (File No. 000-31170), filed July 3, 2001.
3.1.5	Certificate of Amendment of Teton Petroleum Company incorporated by reference to Exhibit 2.1.5 of Teton s Form 10-SB (File No. 000-31170), filed July 3, 2001.
3.1.6	Certificate of Amendment to Certificate of Incorporation, dated June 28, 2005, incorporated by reference to Exhibit 10.1 of Teton s Form 10-Q filed on August 15, 2005.
3.2	Bylaws, as amended, of Teton Petroleum Company incorporated by reference to Exhibit 3.2 of Teton s Form 10-QSB, filed August 20, 2002.
4.1	Certificate of Designation for Series A Convertible Preferred Stock, incorporated by reference to Exhibit 3.1.6 of Teton s Form SB-2 (File No. 333-112229), filed January 27, 2004.
4.2	Certificate of Designations, Preferences and Rights of the Terms of the Series C Preferred Stock, incorporated by reference to Exhibit 3.1 of Teton s 8-K filed on June 8, 2005.
4.3	Rights Agreement between Teton and Computershare Investors Services, LLC, dated June 3, 2005, incorporated by reference to Exhibit 4.1 of Teton s Form 8-K filed on June 8, 2005.
4.4	Form of Senior Subordinated Convertible Note in connection with Teton s May 2007 financing, incorporated by reference to Exhibit 4.1 of Teton s Form 10-Q filed on August 14, 2007.
4.5	Form of Common Stock Purchase Warrant issued to investors in connection with Teton s May 2007 financing, incorporated by reference to Exhibit 4.2 of Teton s Form 10-Q filed on August 14, 2007.
4.6	Form of Common Stock Purchase Warrant issued to investors and placement agents in connection with Teton s July 2007 financing, incorporated by reference to Exhibit 4.3 of Teton s Form 10-Q filed on August 14, 2007.
10.1	International Swap Dealers Association, Inc. Master Agreement, dated October 24, 2006, between BNP Paribas and Teton, incorporated by reference to Exhibit 10.18 of Teton s Form 10-K filed March 19, 2007.

10.2	Letter Agreement dated as of October 6, 2005, between H. Howard Cooper and Teton Energy Corporation, incorporated by reference to Exhibit 10.8 of Teton s Form 10-Q filed on November 14, 2005.
10.3	First Amendment to Purchase and Sale Agreement Niobrara Shallow Gas Project, dated January 2005, incorporated by reference to Exhibit 10.1 of Teton s Form 10-Q filed May 16, 2005.

Table of Contents

Exhibit No.	Description
10.4	Purchase and Sale Agreement Niobrara Shallow Gas Project, dated April 13, 2005, incorporated by reference to Exhibit 10.2 of Teton s Form 10-Q filed May 16, 2005.
10.5	Membership Interest Purchase Agreement between PGR Partners, LLC and Teton Petroleum Company, dated February 15, 2005, incorporated by reference to Exhibit 10.3 of Teton s Form 10-Q filed May 16, 2005.
10.6	Purchase and Sale Agreement, West Greybull Project, Big Horn County, Wyoming, dated as of April 25, 2007 between Teton, and Melange International LLC, Mike A. Tinker individually and Desert Moon Gas Company, and Hannon & Associates, Inc., as assignors, incorporated by reference to Exhibit 10.1 of Teton s Form 10-Q filed on August 14, 2007.
10.7	Purchase and Sale Agreement, Oil and Gas Leasehold Purchase, Big Horn County Wyoming, dated as of April 25, 2007 between Teton and Kirkwood Oil and Gas Company, incorporated by reference to Exhibit 10.2 of Teton s Form 10-Q filed on August 14, 2007.
10.8	Acreage Earning Agreement between Teton and Noble Energy, Inc., dated December 31, 2005, incorporated by reference to Exhibit 10.18 of Teton s Form 10-K filed on March 10, 2006.
10.9	First Amendment to Acreage Earning Agreement between Teton and Noble Energy, Inc., dated December 31, 2005, incorporated by reference to Exhibit 10.19 of Teton s Form 10-K filed on March 10, 2006.
10.10	Form of 2005 Long-Term Incentive Plan 2005 Performance Share Unit Award Agreement, Employees and Directors, incorporated by reference to Exhibit 10.5 of Teton s Form 10-Q filed November 14, 2005.
10.11	Form of 2005 Long-Term Incentive Plan 2005 Performance Share Unit Award Agreement, Patrick A. Quinn, incorporated by reference to Exhibit 10.6 of Teton s Form 10-Q filed November 14, 2005.
10.12	Form of 2005 Long Term Incentive Plan Performance-Based Restricted Stock Award Agreement, incorporated by reference to Exhibit 10.11 of Teton s Form 10-Q filed on November 13, 2007.
10.13	Employment Agreement, dated April 1, 2006, between Richard Bosher and Teton, incorporated by reference to Exhibit 10.14 of Teton s Form 10-K filed March 19, 2007.
10.14	Employment Agreement, effective as of September 1, 2006, between Teton and Karl F. Arleth, incorporated by reference to Exhibit 10.1 to Teton s Form 8-K filed September 1, 2006.
10.15	Employment Agreement, dated December 1, 2006, between Teton and William P. Brand, Jr., incorporated by reference to Exhibit 10.20 of Teton s Form 10-K filed March 19, 2007.
10.16	Employment Agreement, dated February 1, 2007, between Teton and Dominic J. Bazile II, incorporated by reference to Exhibit 10.21 of Teton s Form 10-K filed March 19, 2007.
10.17	

	Employment Agreement, dated January 1, 2008, between Teton Energy Corporation and Lonnie Brock, incorporated by reference to Exhibit 10.1 of Teton s Form 8-K filed December 12, 2007.
10.18	Amended and Restated Credit Agreement, dated as of August 9, 2007, between and among Teton, as Borrowers, each of the lenders party thereto, and JPMorgan Chase Bank, NA, as Administrative Agent for the lenders, incorporated by reference to Exhibit 10.1 to Teton s Form 8-K, filed on August 10, 2007.
10.19	Amended and Restated Guaranty and Pledge Agreement, dated as of August 9, 2007, made by Teton, in favor of JPMorgan Chase Bank, NA, incorporated by reference to Exhibit 10.2 to Teton s Form 8-K, filed on August 10, 2007.
10.20	Asset Exchange Agreement dated September 26, 2007, between Teton Energy Corporation, Teton Piceance LLC, a wholly owned subsidiary of Teton Energy Corporation and Delta

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Exhibit No.	Description
	Petroleum Corporation, incorporated by reference to Exhibit 10.1 of Teton s Form 8-K filed October 2, 2007.
10.21	Placement Agent Agreement, dated as of May 11, 2007, between Teton and Commonwealth Associates, LP, incorporated by reference to Exhibit 10.3 of Teton s Form 10-Q filed on August 14, 2007
10.22	Placement Agency Agreement dated as of July 19, 2007, between Teton, Commonwealth Associates, LP and Ferris, Baker Watts, Incorporated, incorporated by reference to Exhibit 10.4 to Teton s Quarterly Report on Form 10-Q filed August 14, 2007.
10.23	Form of Subscription Agreement in connection with Teton s July 25, 2007 financing. incorporated by reference to Exhibit 10.2 to Teton s Registration Statement on Form S-3/A (File No. 333-145164), filed September 5, 2007.
10.24	Advisory Services Agreement dated as of July 1, 2007, between Teton and Commonwealth Associates, L.P., incorporated by reference to Exhibit 10.4 to Teton s Registration Statement on Form S-3/A (File No. 333-145164), filed September 18, 2007.
14	Code of Ethics and Business Conduct, incorporated by reference to Exhibit 14.1 of Teton s 10-K filed on March 31, 2005.
21	List of Subsidiaries, incorporated by reference to Exhibit 21.1 of Teton s Form 10-K filed on March 31, 2005.
23.1	Consent of independent registered accounting firm, filed herewith.
23.2	Consent of Independent Petroleum Engineers and Geologists, filed herewith.
31.1	Certification by Chief Executive Officer pursuant to Sarbanes-Oxley Section 302, filed herewith.
31.2	Certification by Chief Financial Officer pursuant to Sarbanes-Oxley Section 302, filed herewith.
32	Certification by Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, filed herewith.

SIGNATURES

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

TETON ENERGY CORPORATION

By: /s/ Karl F. Arleth
Karl. F. Arleth,
Chief Executive Officer
Dated: March 13, 2008

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

Signature	Title	Date
/s/ James J. Woodcock James J. Woodcock	Chairman and Director	March 13, 2008
/s/ Karl F. Arleth Karl F. Arleth	President, CEO (principal executive officer) and Director	March 13, 2008
/s/ Thomas F. Conroy Thomas F. Conroy	Director	March 13, 2008
/s/ John T. Connor John T. Connor	Director	March 13, 2008
/s/ Bill I. Pennington Bill I. Pennington	Director	March 13, 2008
/s/ Robert Bailey Robert Bailey	Director	March 13, 2008
/s/ Lonnie R. Brock Lonnie R. Brock	Chief Financial Officer (principal financial officer)	March 13, 2008

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Exhibit No.	Description
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