Storm Cat Energy CORP
Form 424B3
May 23, 2008

Filed Pursuant to Rule 424(b)(3) and Rule 424(c)

Registration No. 333-147023

PROSPECTUS SUPPLEMENT NO. 1
(To Prospectus Dated February 7, 2008)

21,882,826 Shares

Common Shares

This prospectus supplement relates to the public offering of up to 21,882,826 common shares by some of our existing shareholders, as described in the prospectus dated February 7, 2008, which we refer to as the prospectus. This prospectus supplement should be read in conjunction with the prospectus. This prospectus supplement is qualified by reference to the prospectus except to the extent that the information in this prospectus supplement updates and supersedes the information contained in the prospectus.

Investing in our common shares involves risks. See "Risk Factors" beginning on page 6 of the prospectus.

NEITHER THE SECURITIES AND EXCHANGE COMMISSION NOR ANY STATE SECURITIES COMMISSION HAS APPROVED OR DISAPPROVED OF THESE SECURITIES OR DETERMINED IF THIS PROSPECTUS SUPPLEMENT IS TRUTHFUL OR COMPLETE. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

The date of this prospectus supplement is May 23, 2008.

Recent Developments

On March 17, 2008, we filed the following annual report on Form 10-K for the year ended December 31, 2007 with the Securities and Exchange Commission ("SEC"). On April 22, 2008, we filed the following current report on Form

8-K with the SEC. On April 29, 2008, we filed the following current report on Form 8-K with the SEC. On April 29, 2008, we filed the following definitive proxy statement on Schedule 14A with the SEC. On May 8, 2008, we filed the following quarterly report on Form 10-Q for the quarter ended March 31, 2008 with the SEC.

Selling Shareholders

The table appearing under the caption entitled, “The Selling Shareholders” in the prospectus is hereby amended by substituting the information for Investor Company, Nesbitt Burns ITF Millennium Partners L.P. and Investor Company, on lines 14, 15 and 16, respectively, of the selling shareholder table with the information below and by adding the additional selling shareholders set forth below to the bottom of such table.

	Shares Beneficially Owned Prior to the Offering (1)						Shares Beneficially Owne (3)		
Name of Selling Shareholder	Number	Number of Shares Underlying Series A Notes	Number of Shares Underlying Series B Notes	Number of Shares Underlying Warrants	Percent (2)	Number of Shares Offered	Number	Number of Shares Underlying Series A Notes	Nu S Un Se N
Investor Company (16) c/o TD Waterhouse Canada Inc. 22 St. Clair Ave East 18th Floor Toronto, ON M4T 2S3 Canada	9,203,737	2,538,462	7,171,794	0	20.83%	9,710,256	9,203,737	0	
Nesbitt Burns ITF Millennium Partners LP (17) 1 First Canadian Place 35th Floor Toronto, ON M5X 1HS Canada	0	0	1,231,624	0	1.50%	1,231,624	0	0	
Investor Company (17) c/o TD Waterhouse Canada Inc. 22 St. Clair Ave East 18th Floor Toronto, ON M4T 2S3 Canada	4,479,039	623,932	2,770,941	0	9.32%	3,394,873	4,479,039	0	
Penson Financial Services of Canada Inc. (16) 360 St-Jacques Quest Suite 1100 Montreal, Quebec H2Y 1P5 Canada	0	0	2,564	0	*	2,564	0	0	
Nesbitt Burns ITF Barbara Dalton (17) 1 First Canadian Place B-1 Level Toronto, ON M5X 1HS Canada	0	0	5,982	0	*	5,982	0	0	

(1) Beneficial ownership is determined under the rules of the SEC and includes voting or investment power with respect to the securities.

(2)

Percentages are based on there being 81,109,403 issued and outstanding common shares. The number of common shares outstanding used in calculating the percentage for each listed selling shareholder includes the common shares underlying warrants, options, the Series A Notes and/or the Series B Notes held by that person, but excludes common shares underlying warrants, options, the Series A Notes or the Series B Notes held by any other person.

(3) Assumes all of the common shares registered are sold.

(16) Trapeze Asset Management Inc. is the beneficial owner of these securities. Randall Abramson and Trapeze Asset Management Inc., 1346049 Ontario Limited have investment power and voting control over Trapeze Asset Management Inc. and has investment power and voting control over these securities.

(17) Trapeze Capital Corp. is the beneficial owner of these securities. Randall Abramson and Trapeze Capital Corp., 1346049 Ontario Limited have investment power and voting control over Trapeze Capital Corp. and have investment power and voting control over these securities.

INDEX OF ATTACHMENTS

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-K

(Mark One)

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

For The Fiscal Year Ended December 31, 2007

OR

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 No. 001-32628

STORM CAT ENERGY CORPORATION
(Exact name of registrant as specified in its charter)

British Columbia, Canada	06-1762942
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1125 17th Street, Suite 2310 Denver, Colorado	80202
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (303) 991-5070

Securities registered under Section 12(b) of the Act: Common Shares, without par value

Securities registered under to Section 12(g) of the Act: None

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

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

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

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

As of June 29, 2007, the aggregate market value of voting stock held by non-affiliates of the registrant was approximately $76,325,387, based on the closing price of the Common Shares on the American Stock Exchange of $1.14 per share. As of March 13, 2008, 81,087,320 shares of registrant’s Common Shares, without par value, were issued and outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Pursuant to Instruction G (3) to Form 10-K, Items 10, 11, 12, 13 and 14 are omitted because the Company will file a definitive proxy statement (the “Proxy Statement”) pursuant to Regulation 14A under the Securities Exchange Act of 1934, as amended (the “Exchange Act”) not later than 120 days after the close of the fiscal year. The information required by such items will be included in the Proxy Statement to be so filed for the Company’s annual meeting of shareholders to be held on or about June 18, 2008 and is hereby incorporated by reference.

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PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

We use the terms "Storm Cat", the "Company", "we", "us" and "our" to refer to Storm Cat Energy Corporation and subsidiaries in this Annual Report on Form 10-K.

BUSINESS

General

Storm Cat Energy Corporation and its subsidiaries are engaged in the exploitation, development and production of crude oil and natural gas with specific focus on unconventional natural gas resources from coal seams, fractured shales and tight sand formations. For a description of the meanings of some of the natural gas and oil industry terms used in this Annual Report on Form 10-K, a glossary of terms is provided at the end of this section.

We report to the Securities and Exchange Commission (the "SEC") information, including the Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports pursuant to Section 13(a) or 15(d) of the Exchange Act. Copies of any materials the Company files with the SEC can be obtained at www.sec.gov or at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Information on the operation of the Public Reference Room is available by calling the SEC at 1-800-SEC-0330.

Our corporate internet web site is www.stormcatenergy.com. We make available free of charge, on or through the Financial Reports / Investors section of our web site, our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, all SEDAR filings with the British Columbia Securities Commission and all amendments to those reports as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC or British Columbia Securities Commission. We also provide corporate presentations made at recent industry gatherings. In addition, our Code of Ethics is available on our website. No content of our web site is incorporated by reference herein.

Our corporate headquarters are located at 1125 Seventeenth Street, Suite 2310, Denver, Colorado 80202. Our telephone number is (303) 991-5070.

We have grown primarily through the acquisition of undeveloped properties and development drilling on those properties. Our acquisition and development activities are concentrated in the following areas:

- Powder River Basin ("PRB") in northeast Wyoming;
- Arkoma Basin / Fayetteville Shale in north-central Arkansas;
- Elk Valley Region in southeast British Columbia;
- Western Canadian Sedimentary Basin ("WCSB") in Alberta, Canada; and
- Cook Inlet Region of Alaska.

Our estimated proved reserves at December 31, 2007 were 44.5 Bcf of natural gas based on an average December 31, 2007 price of $6.06/Mcf. Our December 31, 2007 proved reserves represent an increase of 78% over our December 31, 2006 proved reserves. Proved developed reserves constitute 62% of our proved reserves as of December 31, 2007. We produced 3.154 Bcf of natural gas during 2007, for an average daily production rate of 8.641 MMcf/d. This represents a 96% increase over our average daily production in 2006. Fourth quarter average daily production was 9.959 MMcf/d, a 32.0% increase over the fourth quarter 2006 average daily production rate. Our 2007 reserve replacement was 718% of our 2007 production.

As of December 31, 2007, we owned interests in 473 gross (360 net) wells and we operated 404 gross (344 net) wells. We operate 97% of the PV-10 value of our estimated net cash flow from our estimated proved developed reserves. The high proportion of operated properties allows us to exercise more control over our expenses, capital allocation and timing of our development and exploitation activities in our fields.

As of December 31, 2007, we owned interests in 193,094 gross acres and 169,748 net acres.

History of the Company

Storm Cat was incorporated under the laws of British Columbia, Canada on May 15, 2000 under the name "Toby Ventures Inc." We conducted an initial public offering in Canada and our shares began trading under the symbol "SME" on the TSX Venture Exchange on November 15, 2001 (listing graduated to the Toronto Stock Exchange ("TSX") on June 29, 2006). Since incorporation, we have been involved in the development and exploration of natural resources. We commenced the acquisition and exploration of mineral properties in 2000. In late 2003, we disposed of, sold or abandoned our mineral exploration interests and focused our efforts on the exploitation, development and production of crude oil and natural gas with specific focus on unconventional natural gas resources from coal seams, fractured shales and tight sand formations.

Effective January 30, 2004, we changed our name to Storm Cat Energy Corporation and adopted new Articles of Incorporation under the Business Corporations Act of British Columbia on May 21, 2004. Prior to June 2004, our authorized capital was 20,000,000 common shares without par value. Beginning in June 2004, we were authorized to issue an unlimited number of common shares without par value. Effective March 31, 2005, we affected a two-for-one share split. All share and per share amounts included in this filing have been restated to give retroactive effect, as necessary, to the effect of the share split.

On October 3, 2005, we began trading our shares on the American Stock Exchange ("AMEX") under the symbol "SCU."

Business Strategy

Our business strategy is comprised of the following components:

- Deploying our capital resources in areas that create favorable rates of return;
- Increasing production and reserves through efficient management of operations;
- Acquiring additional undeveloped properties in our core areas;
- Retaining operational control wherever possible;
- Hedging a significant portion of our production to provide adequate cash flow to fund a portion of our capital development budget and protect the economic return on our development projects; and
- Retaining management and technical staff that have substantial expertise in our core operating areas.

PROPERTIES

Powder River Basin

Our growth in production and reserves from 2004 through mid 2007 has been focused primarily on our coal bed natural gas (“CBNG”) operations in the PRB. The PRB is located in northeast Wyoming and southeast Montana (see Figure 1).

Figure 1: Powder River Basin

Figure 2: CBNG Development in Powder River Basin

Our operations are concentrated within two areas in Wyoming; the Recluse area north of Gillette, Wyoming and the Sheridan area east of Sheridan, Wyoming (see Figures 2 and 3). Covering 12,000 square miles, the PRB CBNG play encompasses parts of seven counties in two states and targets natural gas contained in the Tertiary-age Fort Union Formation coal seams. Depths for the play range from 100 feet to over 3,000 feet, and include a series of distinct coal seams, such as the Wyodak and Big George. In our area of operations, these coal seams split into equivalent members, such as the Anderson, Canyon, Cook, Wall and Pawnee seams. Over the past ten years, development has increased dramatically. In 2007, the PRB CBNG play was producing in excess of one Bcf/d from over 22,000 producing wells.

Figure 3: Storm Cat Energy Leasehold and Wells in Powder River Basin

On December 31, 2007 we owned approximately 51,951 gross acres and 35,345 net acres in the PRB, operated 370 wells and owned interests in 51 non-operated wells. We added 107 wells on our acreage position in 2007 in our Sheridan, Ford Ranch, PeeGee and Marathon Joint Development operating areas (see Figure 3).

At December 31, 2007, our exit-rate production out of the PRB was 21.5 MMcf/d gross and 11.9 MMcf/d net.

Arkoma Basin / Fayetteville Shale

The Fayetteville Shale is an unconventional gas reservoir located on the Arkansas side of the Arkoma Basin, ranging in thickness from 50 to 550 feet and ranging in depth from 1,000 to 6,500 feet. The formation is a Mississippian-age shale that is the geologic equivalent of the Caney Shale found on the Oklahoma side of the Arkoma Basin and the Barnett Shale found in north Texas.

Driven by the activities of Southwestern Energy Company, XTO Energy Inc., Chesapeake Energy Corporation, PetroHawk Energy Corporation and other operators, the Fayetteville Shale play has developed rapidly since early 2006. Southwestern Energy Company, the early leader in the play, produced approximately 10 MMcf/d in January 2006 from the Fayetteville Shale and was producing 325 MMcf/d on December 31, 2007, a 3,150% increase in just twenty-four months.

Figure 4: Storm Cat Energy Leasehold and Wells in the Fayetteville Shale

We owned or controlled 24,178 gross and 18,265 net acres in the Fayetteville Shale at December 31, 2007 (see Figure 4). During 2007, we successfully drilled and completed three Company-operated horizontal wells. All of these wells are currently shut-in and awaiting pipeline completion. We placed our first completed well, the Kamalmaz 1-13H, on an extended two week flow test. The initial production rate was 1.75 MMcf/d and the well averaged 1.2 MMcf/d over the two week test period. Of our other two wells, the Files 1-12H has shown limited early time productivity similar to Kamalmaz 1-13H and the Vaughn 1-18H will not be conclusively production tested until the sales pipeline discussed below is completed.

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In the fourth quarter of 2007, we reached an agreement with an unaffiliated third party for the construction of field gathering, compression and a transportation lateral to the Ozark interstate pipeline. Pipeline construction was underway on December 31, 2007 and we anticipate that the pipeline could be completed and operational in the second quarter of 2008.

In addition to our operated acreage position, we have nominal interests in 16 non-operated wells in the play that were in various stages of production, drilling and completion through 2007. Production at year-end 2007 associated with our non-operated wells, eight of which were producing, was 0.3 MMcf/d net (10.5 MMcf/d gross).

Elk Valley / British Columbia

Our Elk Valley project in southeast British Columbia is a CBNG project targeting the Jurassic-aged Mist Mountain coals. The project is comprised of 76,960 gross (76,960 net) acres (see Figure 5). We earned our interest in the project in 2005 through a farm-in agreement. In 2006, we increased our ownership to a 100% working interest when the former operator elected to retain an overriding royalty interest only.

Figure 5: Elk Valley and Storm Cat Energy Land Position

The Mist Mountain coal section is comprised of up to fourteen separate coal seams totaling as much as 300 net feet of coal thickness underlying our acreage position. Our challenge is that tectonic activities associated with our geologic setting have significantly altered permeability. Commercial productivity is conditioned upon inducing or connecting permeable pathways into our wellbores to allow the extraction of water and resulting desorption of natural gas from the coal seams.

The prior operator of the property drilled 17 stratigraphic test and pilot wells. We drilled seven additional wells, two in 2005 and five in 2006. Of the 24 total wells, nine are currently producing at an aggregate rate as high as 1.3MMcf/d.

Western Canadian Sedimentary Basin of Alberta, Canada
The WCSB is a vast sedimentary basin underlying 540,000 square miles of western Canada including southwestern Manitoba, southern Saskatchewan, Alberta, northeast British Columbia and the southwest corner of the Northwest Territories (see Figure 6). The WCSB contains significant reserves of petroleum and natural gas and supplies the North American market. It also has extensive reserves associated with coal and shales.

Figure 6: Storm Cat Prospect Areas in Western Canadian Sedimentary Basin

In the WCSB, we owned or controlled approximately 15,680 gross (14,853 net) acres at December 31, 2007. As of December 31, 2007, we have drilled or participated in eight wells. We have two productive wells that are being evaluated for a pipeline connection and the others are in various stages of completion and production testing.

We continue to evaluate opportunities on our acreage and are actively reviewing potential prospects and strategic joint development opportunities.

Cook Inlet Alaska

We hold 24,325 gross (24,325 net) acres in the Cook Inlet region of Alaska (see Figure 7). The Cook Inlet region contains a thick sequence of inter-bedded coals and sandstones deposited in fluvial environments during Tertiary time creating both conventional and CBNG objectives and targets.

Figure 7: Storm Cat Leases in Cook Inlet, Alaska

In 2006, we drilled and cased one well on our acreage position. We are actively seeking an industry partner to complete and production test the well and assist in the development of the acreage position.
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Reserve Estimates

Netherland, Sewell & Associates, Inc. of Dallas, Texas estimated our proved reserves as of December 31, 2007.

The terms set forth below are used in our disclosures of oil and natural gas reserves. For the complete detailed definitions of proved, proved developed and proved undeveloped oil and gas reserves applicable to oil and gas registrants, reference is made to Rule 4-10(a)(2)(3)(4) of Regulation S-X of the SEC, available at its web site http://www.sec.gov/divisions/ corpfin/ecfrlinks.shtml.

Proved reserves. Estimated quantities of crude oil, natural gas and natural gas liquids which, upon analysis of geologic and engineering data, appear with reasonable certainty to be recoverable in the future from known oil and gas reservoirs under existing economic and operating conditions.

Proved developed reserves. Proved reserves which can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved undeveloped reserves. Proved reserves which are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required.

Estimated future net revenues. Also referred to herein as "estimated future net cash flows." Computational result of applying current prices of oil and gas (with consideration of price changes only to the extent provided by existing contractual arrangements, other than hedge derivatives) to estimated future production from proved oil and gas reserves as of the date of the latest balance sheet presented, less estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves.

Present value of estimated future net cash flows. The computational result of discounting estimated future net cash flows at a rate of 10% annually. The present value of estimated future net cash flows after income tax is also referred to herein as "standardized measure of discounted future net cash flows" or "standardized measure."

The following table summarizes our proved natural gas reserves at the end of each year for 2005 through 2007. Amounts do not include estimates of future Federal and state income taxes.

Proved Reserves and Future Net Cash Flows

	Year Ended December 31,		
	2007	2006	2005
Proved reserves (MMcf)	44,487.9	25,015.3	10,010,0
Estimated net cash flow from proved reserves (in thousands)	$ 132,794.5	$ 41,944.7	$ 37,461.0
Estimated future net cash flow, discounted at 10% (in thousands)	$ 98,425.1	$ 32,036.4	$ 29,017.2
Percentage of total proved reserves classified as developed	61.8%	53.4%	38.7%
Price per Mcf used to calculate estimated future net cash flows	$ 6.06	$ 4.46	$ 7.72

All proved reserves and estimated future net cash flows are for our PRB and Fayetteville properties in the U.S. We have no proved reserves in Canada.

Productive Wells

As of December 31, 2007, we owned interests in 473 gross (360 net) wells and we operated 404 gross (344 net) wells, of which 415 gross (314 net) were producing and 58 gross (46 net) were shut-in. Productive wells are either producing wells or wells capable of commercial production although currently shut-in. One or more completions in the same wellbore are counted as one well. A well is categorized under state reporting regulations as an oil well or a gas well based upon the ratio of gas to oil produced when it first commenced production, and such designation may not be indicative of current production. The table below illustrates our gross/net productive wells at December 31, 2007:

	Year Ended December 31, 2007		
		Gross/Net	
United States	Producing	Shut-in	Total
Powder River Basin	398/305	23/21	421/326
Fayetteville Shale	8/0.2	11/2.5	19/2.7
Cook Inlet	0/0	1/1	1/1
Total U.S.	406/305	35/25	441/330
Canada			
Elk Valley	9/9	15/15	24/24
Alberta	0/0	8/6	8/6
Total Canada	9/9	23/21	32/30
Total Productive Wells	415/314	58/46	473/360

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Drilling Activity

All of our drilling activities are conducted on a contract basis with independent drilling contractors. We do not own any drilling equipment. The following table sets forth the wells drilled and recompleted in which we participated during each of the three years indicated:

	Year Ended December 31,					
	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	—	—	—	—	—	—
Gas	126	78	86	73	43	43
Non-productive	—	—	—	—	—	—
Total Development	126	78	86	73	43	43
Exploratory:						
Oil	—	—	—	—	—	—
Gas	2	2	11	9	2	2
Non-productive	—	—	3	1	1	1
Total Exploratory	2	2	14	10	3	3
Farm-out or non-consent	—	—	—	—	—	—
Total Wells Drilled	128	80	100	83	46	46

Acreage

A summary of our oil and gas leasehold position as of December 31, 2007 is as follows:

	Acreage					
Area:	Total		Developed		Undeveloped	
United States	Gross	Net	Gross	Net	Gross	Net
Powder River Basin, WY	51,951	35,345	20,303	18,390	31,648	16,955
Fayetteville Shale, AR	24,178	18,265	280	210	23,898	18,055
Cook Inlet, AK	24,325	24,325	160	160	24,165	24,165
Total U.S.	100,454	77,935	20,743	18,760	79,711	59,175
Canada						
Elk Valley, BC	76,960	76,960	800	800	76,160	76,160
Alberta, AB	15,680	14,853	800	800	14,880	14,053
Total Canada	92,640	91,813	1,600	1,600	91,040	90,213
Total Acreage	193,094	169,748	22,343	20,360	170,751	149,388

Undeveloped Acreage Expiring

The following table sets forth the number of undeveloped acres (primarily located in the PRB) that will expire during the next five years and thereafter unless production is established in the interim. Undeveloped acres "held-by-production" represents the undeveloped portions of producing leases that will not expire until commercial production ceases.

	As of December 31, 2007 Working Interest Acreage	
	Gross	Net
2008	10,156	9,726
2009	3,753	1,610

2010	14,444	11,329
2011	2,254	1,371
2012	2,641	2,641
Thereafter	114,114	112,790
Held-by-production	23,389	9,921
Total	170,751	149,388

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Title to Properties

Substantially all of our oil and gas interests are held pursuant to leases from third parties. We usually obtain a title opinion prior to the commencement of drilling operations and for the distribution of revenues resulting from successful operations on the properties. We have title opinions or have conducted thorough title review on substantially all of our producing properties and believe we have satisfactory title in accordance with standards generally accepted in the oil and gas industry. The majority of our properties are subject to: customary royalty interests; liens for current taxes; mortgages required pursuant to the Credit Agreement (the "Credit Agreement") dated as of December 27, 2007, by and among Storm Cat Energy (USA) Corporation ("Storm Cat (USA)"), one of our wholly owned subsidiaries, Wells Fargo Foothill LLC ("Wells Fargo"), as Agent, and the lenders party thereto, which provides for certain credit facilities (the "Credit Facility"); and other burdens that we believe do not materially interfere with the use of or affect the value of such properties.

Facilities

We lease 9,264 square feet of administrative office space in the United States and 5,495 square feet of administrative office space in Canada under operating lease arrangements through November 30, 2009 and March 31, 2010, respectively. A summary of future minimum lease payments under the non-cancelable operating leases as of December 31, 2007 is as follows:

In Thousands	2008	2009	2010	Total
U.S. office leases	$ 156,419	$ 145,233	$ —	$ 301,652
Canadian office leases	110,736	110,736	27,684	249,156
Total	$ 267,155	$ 255,969	$ 27,684	$ 550,808

Principal Products or Services and Markets

Our principal product is natural gas. The principal markets are natural gas marketing companies, utilities and industrial or commercial end-users. Historically, nearly all of our sales have been to a limited number of customers, however, we are not obligated to, nor dependent upon, any one purchaser or limited number of purchasers. Accordingly, the loss of a single purchaser would not materially affect our business because there are numerous other purchasers to purchase our product. For the years ended December 31, 2007, 2006 and 2005, purchases by the following entities exceeded 10% of our total natural gas revenues during at least one of the years presented:

	Year Ended December 31,		
	2007	2006	2005
Enserco	42.9%	75.5%	79.9%
OGE	4.9%	13.1%	0.0%
Oneok	24.1%	11.4%	0.0%
Tenaska	28.1%	0.0%	0.0%
Total	100.0%	100.0%	79.9%

Capital Expenditures

We invested approximately $52.2, $76.1 and $26.5 million in 2007, 2006 and 2005, respectively, on development and acquisition activities as follows:

	Year Ended December 31, 2007		
In Thousands	United States	Canada	Total

		and Other International	
Acquisitions:			
Producing properties	$ 1,938	$ —	$ 1,938
Undeveloped acreage	—	—	—
Total acquisitions	1,938	—	1,938
Exploration and development:			
Land and seismic	2,020	1,090	3,110
Drilling, facilities and equipment	35,634	10,915	46,549
Capitalized interest	466	399	865
Total exploration and development	38,120	12,404	50,524
Asset retirement obligations	(333)	(76)	(409)
Other property and equipment	56	68	124
Total capital expenditures	39,781	12,396	52,177
Dispositions	—	—	—
Net capital expenditures	$ 39,781	$ 12,396	$ 52,177

In Thousands	Year Ended December 31, 2006 United States	Canada and Other International	Total
Acquisitions:			
Producing properties	$ 11,403	$ —	$ 11,403
Undeveloped acreage	22,538	—	22,538
Total acquisitions	33,941	—	33,941
Exploration and development:			
Land and seismic	4,926	923	5,849
Drilling, facilities and equipment	17,450	16,797	34,247
Capitalized overhead	1,104	926	2,030
Total exploration and development	23,480	18,646	42,126
Asset retirement obligations	548	317	865
Other property and equipment	72	73	145
Total capital expenditures	58,041	19,036	77,077
Dispositions	(950)	—	(950)
Net capital expenditures	$ 57,091	$ 19,036	$ 76,127

In Thousands	Year Ended December 31, 2005 United States	Canada and Other International	Total
Acquisitions:			
Producing properties	$ 6,918	$ —	$ 6,918
Undeveloped acreage	1,814	—	1,814
Total acquisitions	8,732	—	8,732
Exploration and development:			
Land and seismic	471	1,933	2,404
Drilling, facilities and equipment	9,283	3,946	13,229
Capitalized overhead	312	254	566
Total exploration and development	10,066	6,133	16,199
Asset retirement obligations	714	—	714
Other property and equipment	628	189	817
Total capital expenditures	20,140	6,322	26,462
Dispositions	—	—	—
Net capital expenditures	$ 20,140	$ 6,322	$ 26,462

2008 Capital Budget

Subject to quarterly review and reauthorization by our Board of Directors, we expect to invest $38.2 million in 2008 on our capital projects. The 2008 capital expenditure budget allocates $20.0 million in the PRB to drill approximately 126 gross wells (103 net), $16.0 million to the Fayetteville Shale to drill approximately 12 gross (eight net) wells, $1.0 million in Elk Valley to continue ongoing production operations and the remaining $1.2 million on non-project capital expenditures. Included in the capital expenditure figures are estimates for other miscellaneous capital.

Financial Information

Item 8. Financial Statements and Supplementary Information of this Annual Report on Form 10-K details the last three fiscal years of revenues, all of which were derived from U.S. operations and reported in one business segment.

Employees

At December 31, 2007, we employed 25 people; 20 in our Denver, Colorado corporate office, two in our Canadian office, and three in our field operations offices.

Executive Officers

Our executive officers are elected by and serve until their successors are elected by the Board of Directors.

- Joseph M. Brooker, 48, Chief Executive Officer. Joe is a petroleum engineer and lawyer with over 25 years of experience in the oil and gas business. Prior to joining Storm Cat, Joe was Vice President and General Counsel of Medicine Bow Energy Corporation, a Denver-based private-equity-backed exploration and production company with operations in the Rockies, Mid-Continent and East Texas. Prior to that, Joe was Vice President of Land and General Counsel of Shenandoah Energy Inc, a Denver-based private-equity-backed exploration and production company with operations in the Uinta and Raton Basins. Joe earned a BS in Petroleum Engineering from Marietta College in 1982 and a JD from the University of Cincinnati College of Law in 1989.

- Keith J. Knapstad, 46, President and Chief Operating Officer. Keith is a petroleum engineer with a strong managerial and operational background. Prior to joining Storm Cat, Keith was Manager of PRB Assets for J. M. Huber Corporation; a privately held corporation with extensive unconventional resource holdings. Prior to Huber, Keith worked for Marathon Oil Company/Pennaco Energy in the Rocky Mountain region managing a multi-disciplined team responsible for engineering and development of various Rocky Mountain producing areas. Keith earned a BS in Petroleum Engineering from Montana Tech in 1984.

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- Paul Wiesner, 43, Chief Financial Officer. Paul has over 20 years experience, 13 of which have been in the oil and gas industry for upstream and mid stream companies with financial responsibilities ranging from Analyst to Vice President of Finance. Prior to joining Storm Cat, Paul was CFO for NRT Colorado Inc., a $125 million (annual revenue) corporation with over 150 employees and 20 locations. Paul holds an MBA from the MIT Sloan School of Management and a BA from Claremont McKenna College.

Seasonality

Typically, the demand and price levels for natural gas increase during the colder winter months and decrease during the warmer summer months. To mitigate the impact of seasonal price fluctuations, we enter into swap agreements with qualified counterparties that set the swap price on an annualized, as compared to monthly or quarterly, basis.

Competition

We compete with other oil and gas companies in all aspects of our business, including acquisition of producing properties and oil and gas leases, marketing of oil and gas, and in obtaining goods, services and labor. Many of our competitors have substantially larger financial and other resources. Factors that affect our ability to acquire producing properties include available funds, available information about the property and our standards established for minimum projected return on investment. Gathering systems are the only practical method for the intermediate transportation of natural gas and in some areas there may be gas-on-gas competition for space in such gathering systems. Competition is also presented by alternative fuel sources, including heating oil, imported liquefied natural gas and other fossil fuels. Because of the concentration of our natural gas reserves and management’s experience and expertise in exploiting these reserves, we believe that we effectively compete in the markets in which we are active.

Regulation

Oil and gas drilling and production operations are regulated by various Federal, state and local agencies. These agencies issue binding rules and regulations that carry penalties, often substantial, for failure to comply. We anticipate our aggregate burden of Federal, state and local regulation will continue to increase, particularly in the area of rapidly changing environmental laws and regulations. We also believe that our present operations substantially comply with applicable regulations. To date, such regulations have not had a material effect on our operations or the costs thereof. There are no known environmental or other regulatory matters related to our operations that are reasonably expected to result in material liability.

Environmental Regulation

Our operations are subject to government laws and regulations concerning pollution, protection of the environment and the handling and transport of hazardous materials in both the United States and Canada. These laws and regulations generally require that we to remove or remedy the effect of our activities on the environment at present and former operating sites, including dismantling production facilities and remediating damage caused by our use. We believe that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. While we believe that we are in substantial compliance with applicable environmental laws and regulations in effect at the present time and that continued compliance with existing requirements will not have a material adverse impact on us, we cannot give any assurance that we will not be adversely affected in the future.

United States

Certain of our operations are conducted on Federal land pursuant to oil and gas leases administered by the Bureau of Land Management ("BLM"). These leases contain relatively standardized terms and require compliance with detailed BLM regulations and orders (which are subject to change by the BLM). In addition to permits required from other agencies, lessees must obtain a permit from the BLM prior to the commencement of drilling, and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells, the valuation of production, and the removal of facilities. Under certain circumstances, the BLM or the Mineral Management Service ("MMS"), as applicable, may require our operations on Federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition and operations.

The Comprehensive Environmental Response, Compensation and Liability Act, as amended, also known as "CERCLA" or "Superfund," and comparable state laws impose 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. Under CERCLA, these "responsible 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, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances into the environment. We might also incur liability under the Resource Conservation and Recovery Act, also known as "RCRA", which imposes requirements relating to the management and disposal of solid and hazardous wastes. While there exists an exclusion from the definition of hazardous wastes for "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy," in the course of our operations, we may generate ordinary industrial wastes, including paint wastes, waste solvents and waste compressor oils that may be regulated as hazardous waste.

We currently own or lease, and have owned or leased in the past, properties that for a number of years may have been used for the exploration and production of oil and gas. Although we utilize operating and disposal practices that are standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us or on or under other locations where such wastes have been taken for disposal. In addition, some of these properties may have been operated by third parties whose disposal or release of hydrocarbons or other wastes was not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes or property contamination or to perform remedial operations to prevent future contamination.

The Federal Water Pollution Control Act of 1972, as amended, also known as the "Clean Water Act" and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and gas wastes, into state or Federal waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or the state. The Clean Water Act provides civil and criminal penalties for any discharge of oil in harmful quantities and imposes liabilities for the costs of removing an oil spill.

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The Clean Air Act, as amended (“CAA”), restricts the emission of air pollutants from many sources, including oil and gas operations. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to incur capital costs in order to remain in compliance. In addition, the EPA has promulgated more stringent regulations governing emissions of toxic air pollutants from sources in the oil and gas industry, and these regulations may increase the costs of compliance for some facilities.

Under the National Environmental Policy Act (“NEPA”), a Federal agency, in conjunction with a permit holder, may be required to prepare an environmental assessment or a detailed environmental impact statement, also known as an “EIS,” before issuing a permit that may significantly affect the quality of the environment.

We expect to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed in the United States and Canada. We accrue for our asset retirement obligation (“ARO”) liability according to Statement of Financial Accounting Standards (“SFAS”) 143 “Accounting for Asset Retirement Obligations.” As of December 31, 2007 our total accrued ARO was $1.7 million.

Additional proposals and proceedings that might affect the oil and gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission ("FERC"), and the courts. We cannot predict when or whether any such proposals may become effective. No material portion of our business is subject to renegotiation of profits or termination of contracts or subcontracts at the election of the Federal government.

Canada

The oil and gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government. Federal authorities do not regulate the price of oil and gas in export trade. Legislation exists, however, that regulates the quantities of oil and natural gas which may be removed from the provinces and exported from Canada in certain circumstances. Regulatory requirements also exist related to licensing for drilling of wells, the method and ability to produce wells, surface usage, transportation of production from wells, and conservation matters.

The provinces in which we operate have legislation and regulation which govern land tenure, royalties, production rates and taxes, and environmental protection and other matters under their respective jurisdictions. The royalty regime in the provinces in which we operate is a significant factor in the profitability of our production. Crown royalties are determined by government regulation and are typically calculated as a percentage of the value of production. The value of the production and the rate of royalties payable depends on prescribed reference prices, well productivity, geographical location, and the type or quality of the product produced, and any royalties payable on production from lands other than Crown lands are determined by negotiations between us and the other parties.

Glossary

The following is a description of the meanings of some of the natural gas and oil industry terms used in this Annual Report on Form 10-K.
Basis Differential. The difference between the spot or cash price of a commodity and the price of the nearest futures contract for the same or a related commodity.

Bcf. Billion cubic feet of natural gas.

Btu or British Thermal Unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

BWPD. Barrels of water per day (equivalent to 42 gallons).

"CIG" Colorado Interstate Gas. CIG is a major transporter of natural gas in the Rocky Mountain region. The Colorado Interstate Gas system is connected to nearly every major supply basin in the Rocky Mountains as well as production areas in the Texas Panhandle, western Oklahoma, western Kansas, and Wyoming. Our PRB gas is typically priced at the CIG index price.

Completion. The installation of permanent equipment for the production of natural gas or oil.

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production. Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dth. Decatherms.

Dth/D. Decatherms per day.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Exploratory well. A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir. Generally, an exploratory well is any well that is not a development well, a service well, or a stratigraphic test well.

Farm-in or farm-out. An agreement under which the owner of a working interest in a natural gas and oil lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a "farm-in" while the interest transferred by the assignor is a "farm-out."

Field. An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Flow-through shares. Shares in an exploration company that allow the tax deduction or credits for mineral exploration to be passed from the company to the shareholder. Tax deductions and credits, normally available only to a corporation, are given to the owners of the corporation's flow-through shares. Canadian exploration and mining companies are able to issue such shares at a premium because investors are considered to be funding exploration and development costs and are therefore entitled to deduct these expenses from all other income.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

MBtu. Thousand British Thermal Units.

Mcf. Thousand cubic feet of natural gas.

Mcfe. Thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

MMcf/d. One MMcf per day.

MMcfe. Million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or wells, as the case may be.

Net feet of pay. The true vertical thickness of reservoir rock estimated to both contain hydrocarbons and be capable of contributing to producing rates.

Overriding royalty interest. A revenue interest in oil and gas created out of a working interest. Like the lessor's royalty, it entitles the owner to a share of the proceeds from gross production, free of any operating or production costs.

PRB. Powder River Basin. The region covers Southeast Montana and Northern Wyoming and is approximately 120 miles East to West and 200 miles North to South. Major cities in this area include Gillette and Sheridan, Wyoming. Storm Cat operates only in Wyoming.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved area. The part of a property to which proved reserves have been specifically attributed.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

Royalty. A payment to a landowner or mineral rights owner by a leaseholder on each unit of resources produced, free of any operating or production costs.

Service well. A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

Spud. The initial phase of drilling a well.

Unconventional resources. Resources derived from fractured shales, coal seams and tight sand formations.

Unconventional reserves. Reserves from fractured shales, coal seams and tight sand formations.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains proved reserves.

Unproved properties. Properties with no proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.

ITEM 1A. RISK FACTORS

In evaluating Storm Cat, careful consideration should be given to the risk factors discussed in this Item 1A. These risks are not the only risks we face. Additional risks and uncertainties not currently known us or that we currently deem to be immaterial may become material in the future and affect our business, financial condition and/or operating results, as well as adversely affect the value of our common shares.

Risks Related to the Business

Price volatility may affect financial condition: The prices of oil and natural gas are volatile and our operating results and future rate of growth depend heavily on prevailing market prices for these resources. A substantial or extended decline in prices for these resources would have a material adverse effect on us. These prices are affected by numerous factors beyond our control, including international economic and political trends, the effects of inflation, currency exchange fluctuations, interest rates and global or regional consumption patterns, worldwide and domestic supplies of oil and gas, the ability of members of the Organization of Petroleum Exporting Countries (“OPEC”) to agree to and maintain oil price and production controls, actions of governmental authorities, the availability of transportation facilities, increased production due to new discoveries or improved recovery techniques and weather conditions.

Storm Cat operates in a highly competitive industry: We compete with other energy development companies for properties, equipment, materials and labor. The industry is highly competitive in all aspects. Many of our competitors have larger operations and greater financial resources. Competition in our business may adversely affect our ability to acquire properties, equipment and materials, attract and retain qualified labor and attract the necessary capital to sustain resource exploration and production in the future.

Oil and gas exploration is a speculative undertaking: Oil and gas exploration is a speculative business. Our future success depends on our ability to economically locate oil and gas production and reserves in commercial quantities. Our anticipated exploration and development activities are subject to reservoir and operational risks. Even when oil and gas is found in what are believed to be commercial quantities, reservoir risks, which may be heightened in new discoveries, may lead to higher costs and/or lower production than originally anticipated. These risks include the inability to sustain deliverability at commercially productive levels as a result of decreased reservoir pressures, large amounts of water, or other factors that might be encountered. The effects of these factors may result in us not receiving an adequate return on investment capital.

Reserve quantities and values are subject to many variables and estimates and actual results may vary: This Annual Report on Form 10-K contains estimates of our proved reserves and the estimated future net cash flow from those reserves. Any significant negative variance in these estimates could have a material adverse effect on our future performance. We also have no oil reserves at present.

Reserve estimates are based on various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data.

Reserve estimates are dependent on many variables, and therefore, as more information becomes available, it is reasonable to expect that there will be changes to the estimates. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves disclosed by us. In addition, estimates of proved reserves will be adjusted in the future to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

As of December 31, 2007, approximately 38.2% of our estimated proved reserves are classified as proved undeveloped. Recovery of proved undeveloped reserves generally requires significant capital expenditures and successful drilling operations. Revenues from proved developed non-producing and proved undeveloped reserves will not be realized until some time in the future. The reserve estimate includes an estimate of the capital expenditures required to develop these reserves as well as the timing of such expenditures. Although we have prepared estimates of our proved undeveloped reserves and the associated development costs in accordance with industry standards and the opinion of our independent consultants, they are based on estimates, and actual results may vary.

The present value of future net cash flow from proved reserves, or PV-10, should not be interpreted as the current market value of reserves attributable to our properties. The 10% discount factor, which is required for reporting purposes, may not necessarily be the most appropriate discount factor given actual interest rates and risks to which our business or the oil and natural gas industry in general are subject. We have based the PV-10 on prices and costs as of the date of the reserve estimate, in accordance with applicable SEC regulations. Actual future prices and costs may be materially higher or lower. In addition to the price volatility factors discussed above, factors that will affect actual future net cash flows, include:

- the amount and timing of actual production;
- curtailments or increases in consumption by oil and natural gas purchasers or pipelines; and
- changes in governmental regulations or taxation.

Our actual future net cash flows, therefore, could be materially different from the estimates included in this Annual Report on Form 10-K.

Storm Cat faces operating risks in its exploration and production activities: Our business involves operating risks, including well blowouts, craterings, explosions, uncontrollable flows of oil, natural gas or well fluids, leaks, fires, formations with abnormal pressures, pipeline ruptures or spills, pollution, releases of toxic gas and other environmental hazards and risks, any one of which can cause personal injury, damage to property, equipment and the environment, as well as interruption of operations. We maintain insurance against some, but not all, of these risks. If any of these events occurred, we could face substantial losses that could reduce or even eliminate funds available for operations.

The industry is highly regulated: Our industry is heavily regulated by Federal, state, and local authorities. These regulations control many aspects of our business including, among other things, land use, prospecting, the drilling and spacing of wells, protection of ground water, conservation of soil, safety standards, site reclamation, restoration, exports, labor standards, occupational health, waste disposal, toxic substances and other matters. The regulations and laws governing the industry are under constant review and may be amended or expanded. Regulation increases the cost of doing business and decreases profitability. If we fail to comply with these laws and regulations, we may be subject to substantial penalties or suspension or termination of operations.

Storm Cat's operations are subject to complex environmental regulations: Our current and anticipated future operations require permits from various Federal, state and local governmental authorities and such operations are and will be regulated by laws and regulations governing various elements of the oil and gas industries.

We cannot predict what environmental legislation, regulation or policy will be enacted or adopted in the future or how in the future laws and regulations will be administered or interpreted. The recent trend in environmental legislation and regulation generally is toward stricter standards and this trend is likely to continue in the future. This recent trend includes, without limitation, laws and regulations relating to air and water quality, waste handling and disposal, the protection of certain species and the preservation of certain lands. These regulations may require permits or other authorizations for certain activities. These laws and regulations may also limit or prohibit activities on certain lands lying within wetland areas, areas providing for habitat for certain species or other protected areas. Compliance with more stringent laws and regulations, as well as potentially more vigorous enforcement policies or stricter interpretation of existing laws, may necessitate significant capital expenditures, may materially affect the results of operations and business, or may cause material changes or delays in our intended activities.

There can be no assurance that we will be able to obtain all permits required for future exploration on reasonable terms or that such laws and regulations, or new legislation or modifications to existing legislation, will not have an adverse effect on any project that might undertaken. Our failure to comply with applicable laws, regulations and permitting requirements may result in enforcement actions, including orders issued by regulatory or judicial authorities causing our operations to cease or be curtailed, and may include corrective measures requiring capital expenditures, installation of additional equipment or remedial actions.

Increases in taxes on energy sources may adversely affect Storm Cat's operations: Federal, state and local governments that have jurisdiction in areas where we operate impose taxes on the oil and natural gas products sold. Historically, there has been on-going consideration by Federal, state and local officials concerning a variety of energy tax proposals. Such matters are beyond our ability to accurately predict or control.

Storm Cat does not have adequate cash flow to fund capital projects and additional debt or equity financing will be required: We make, and will continue to make, significant capital expenditures to find, acquire, develop and produce oil and gas reserves. If natural gas prices decrease, or if operating difficulties are encountered that result in cash flow from operations being less than expected, we may have to reduce capital expenditures unless additional funds are raised through debt or equity financing. Debt or equity financing or cash generated by operations may not be available in sufficient amounts or on acceptable terms to meet these requirements.

Future cash flows and the availability of financing will be subject to a number of variables, such as:

- our success in locating and producing new reserves;
- the level of production from existing wells; and
- prices of natural gas;

Issuing additional equity securities to satisfy our financing requirements could cause substantial dilution to existing shareholders. Additional debt financing could make us more vulnerable to competitive pressures and adverse impact from economic downturns.

Competition for materials and services is intense and could adversely affect Storm Cat: Major oil companies, independent producers, and institutional and individual investors are actively seeking oil and gas properties throughout the world, along with the equipment, labor and materials required to develop and operate properties. Shortages for equipment, labor or materials may result in increased costs or the inability to obtain such resources as needed. Many of our competitors have financial and technological resources which exceed those available to us.

Storm Cat's hedging arrangements involve credit risk and may limit future revenues from price increases: To manage our exposure to price volatility associated with the sale of natural gas, we periodically enter into hedging transactions for a portion of our estimated natural gas production. These transactions may limit our potential gains if natural gas prices rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- the contractual counterparties fail to perform under the contracts; or
- a sudden, unexpected event, materially impacts natural gas prices.

The terms of our hedging agreements may also require that we furnish cash collateral, letters of credit or other forms of performance assurance in the event that mark-to-market calculations result in settlement obligations to the counterparties, which would encumber our liquidity and capital resources.

In addition, hedging transactions using derivative instruments involve basis risk. Basis risk in a hedging contract occurs when the index upon which the contract is based is more or less variable than the index upon which the hedged asset is based, thereby making the hedge less effective.

We have minimized ineffectiveness by entering into gas derivative contracts indexed to CIG – Rocky Mountain index price. As our derivative contracts contain the same index as our sales contracts, this results in hedges that are highly correlated with the underlying hedged item.

The marketability of Storm Cat's natural gas production is dependent upon infrastructure, such as gathering systems, pipelines and processing facilities, that we do not own or control: The marketability of our natural gas production depends in part upon the availability, proximity and capacity of natural gas gathering systems, pipelines and processing facilities necessary to move our natural gas production to market. We do not own this infrastructure and are dependent on other entities to provide it.

Storm Cat has a history of net losses and a current working capital deficit: Since our incorporation in May of 2000, we have experienced annual net losses. For the year ended December 31, 2007 we had a net loss of $41.0 million and our cumulative net loss from date of incorporation to December 31, 2007 is $57.6 million. There is no guarantee as to when, if ever, we will realize net profits. At December 31, 2007 we had a working capital deficit of $2.0 million.

Fluctuations in foreign currency exchange rates could adversely affect the business: We maintain accounts in U.S. and Canadian dollars. A material decrease in the value of the Canadian dollar relative to the U.S. dollar could negatively impact our results of operations and share price.

Storm Cat depends on certain key personnel: We depend heavily on the business and technical expertise of our management and key personnel. There is little possibility that this dependence will decrease in the near term. We carry no “key man” life insurance on any of our executives. As operations expand, we will require additional key personnel and related resources.

Some of Storm Cat’s directors serve as officers and directors of other companies: Some of our directors are also officers and directors of other companies, including those that are similarly engaged in the business of acquiring, developing and exploiting oil and gas producing properties. Such associations may give rise to conflicts of interest from time to time. Our directors are required by law to act honestly, in good faith and in our the best interest and to disclose any interest that they may have in any competing project or opportunity. Further, we have an internal conflict policy (“Code of Business Conduct and Ethics”) which addresses directors’ conflicts of interest. Under the policy, if a conflict of interest arises at a meeting of the Board, any director with a conflict must disclose his interest and abstain from voting on such matters.

Storm Cat focuses heavily on unconventional plays, which rely on technological advances that in the future may not be effective: Unconventional resources are reserves from fractured shales, coal seams and tight sand formations and they are a central element of our business model. The development of unconventional plays may involve greater finding and development costs than conventional plays. Often, the commercial viability is less known in an unconventional play. Therefore, the process of developing an unconventional play involves significant expenditures before commercial viability can be ascertained and presents a risk of cost overruns and inadequate gas recovery.

Further, technological innovation is a key component to realizing the economic value of unconventional plays. We continue to explore and rely on advances in technologies such as drilling, well completion and geophysical technologies that have helped the viability of the unconventional play.

Storm Cat may incur compression difficulties and expense: As production increases, more compression is generally required to maximize pipeline capacity. In addition to increased capital expenditures associated with the compression infrastructure, production costs also increase from a higher fuel usage associated with additional compression requirements. Further, the compression process is a mechanical process, and should a breakdown occur, we may be unable to deliver gas until repairs to the machinery are completed.

Storm Cat does not obtain title insurance or other warranties of title with its leases and working interests: We do not obtain title insurance or other guaranty or warranty of good title for our interests. Title insurance is not available for oil and gas leases. Accordingly, third parties may assert claims against our legal entitlement to our interest. In order to alleviate this risk, we require a title search and title opinion on all leases prior to drilling. There is no assurance, however, that all title defects will be cured prior to drilling.

Risks Related to Storm Cat’s Common Shares

U.S. Investors may have difficulty effecting service of process against some of Storm Cat’s Canadian directors: We are incorporated under the laws of the Province of British Columbia, Canada. Consequently, it may be difficult for United States investors to effect service of process in the United States upon our directors or officers who are not residents of the United States, or to realize in the United States upon judgments of United States courts predicated upon civil liabilities under the Exchange Act. A judgment of a U.S. court predicated solely upon such civil liabilities would probably be enforceable in Canada by a Canadian court if the U.S. court in which the judgment was obtained had jurisdiction, as determined by the Canadian court, in the matter. There is substantial doubt whether an original action could be brought successfully in Canada against any of such persons, or against us, predicated solely upon such civil liabilities.

Storm Cat is subject to the Continued Listing Criteria of the AMEX and the TSX: Our common shares are listed on AMEX and the TSX.

In order to maintain our listing on AMEX, we must maintain certain minimum share prices, financial and distribution targets, including maintaining a minimum amount of shareholders' equity and a minimum number of public shareholders. In addition to objective standards, AMEX may delist the securities of any issuer if in its opinion, the issuer's financial condition and/or operating results appear unsatisfactory; if it appears that the extent of public distribution or the aggregate market value of the security has become so reduced as to make further dealings on AMEX inadvisable; if the issuer sells or disposes of principal operating assets or ceases to be an operating company; if an issuer fails to comply with AMEX's listing requirements; if an issuer's common shares sell at what AMEX considers a "low selling price" and the issuer fails to correct this via a reverse split of shares after notification by AMEX; or if any other event shall occur or any condition shall exist which makes further dealings with AMEX, in its opinion, unadvisable.

Similarly, if we fail to meet any of the continued listing criteria of the TSX or are not in compliance with all TSX requirements applicable to listed companies, including TSX rules, policies, rulings and procedural requirements and any additions or amendments which may be made thereto from time to time, the TSX may delist our securities. Without limiting the generality of the foregoing, the TSX requires that we: (i) not issue any securities without the prior consent of the TSX; (ii) not undergo a material change in our business or affairs without the prior consent of the TSX; (iii) file copies of all written correspondence sent to holders of our listed securities with the TSX; (iv) not change the provisions attaching to any warrants, rights or other outstanding securities without the prior consent of the TSX; (v) pay all applicable TSX fees; and (vi) file, at any time upon demand, such other information or documentation concerning our business and affairs as the TSX may reasonably require.

The TSX has the right, at any time, to halt or suspend trading in any of listed securities with or without notice and with or without giving any reason for such action, or to delist such securities, provided that the TSX will not delist the securities without providing us with an opportunity to be heard.

If AMEX or the TSX delists our common shares, investors may face material adverse consequences, including, but not limited to, a lack of trading market for our securities, decreased analyst coverage of its securities, and an inability to obtain additional financing to fund operations.

Storm Cat's common shares are traded on more than one market and this may result in price variations: Our common shares are traded on AMEX and on the TSX. Trading in our common shares on these markets is effected in different currencies (U.S. dollars on AMEX and Canadian dollars on the TSX) and at different times, as the result of different time zones, different trading days and different public holidays in the United States and Canada. Consequently, the trading prices of our common shares on these two markets often differ, resulting from the factors described herein as well as differences in exchange rates and from political events and economic conditions in the United States and Canada. Any decrease in the trading price of our common shares on one of these markets could cause a decrease in the trading price of our common shares on the other market.

Storm Cat's share price has fluctuated and could continue to fluctuate significantly: The market price for our common shares, as well as the price of shares of other energy companies, has been volatile. Numerous factors, many of which are beyond our control, may cause the market price of our common shares to fluctuate significantly, such as:

- Fluctuations in our quarterly revenues and results of operations and those of our publicly held competitors;
- Shortfalls in operating results from levels forecast by securities analysts;
- Announcements concerning us or our competitors;
- Changes in pricing policies by us or our competitors;
- General market conditions and changes in market conditions in the industry; and
- The general state of the securities market.

In addition, trading in shares of companies listed on AMEX and the TSX, generally, and trading in shares of energy companies, specifically, has experienced price and volume fluctuations that have often been unrelated or disproportionate to operating performance. These broad market and industry factors may depress our share price, regardless of actual operating results. In addition, if we issue additional shares in financings or acquisitions, our shareholders may experience additional dilution and the existence of more shares could decrease the amount that purchasers are willing to pay for our common shares.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

From time to time, we may be involved in litigation relating to claims arising out of our operations in the normal course of business. As of the date of this Annual Report on Form 10-K, we are not a party to any material pending legal proceedings. No such proceedings have been threatened and none are contemplated by us.

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

None.

PART II

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

The following tables set forth, for each of the quarterly periods indicated, the range of high and low sales prices for our common stock on the AMEX under the symbol "SCU" and the TSX under the symbol "SME".

SME Quarterly High and Low Market Price for the Two Most Recent Fiscal Years on the TSX (CDN$)

Quarter Ended		High		Low
December 31, 2007	$	0.74	$	0.53
September 30, 2007	$	1.20	$	0.64
June 30, 2007	$	1.30	$	0.93
March 31, 2007	$	1.39	$	0.83
December 31, 2006	$	2.04	$	1.35
September 30, 2006	$	2.60	$	1.50
June 30, 2006	$	3.41	$	2.11
March 31, 2006	$	3.86	$	2.85

SCU Quarterly High and Low Market Price for the Two Most Recent Fiscal Years on the AMEX ($ U.S.)

QuaQuarter Ended		High		Low
December 31, 2007	$	0.75	$	0.54
September 30, 2007	$	1.14	$	0.72
June 30, 2007	$	1.18	$	0.80
March 31, 2007	$	1.40	$	0.73
December 31, 2006	$	1.82	$	1.16
September 30, 2006	$	2.50	$	1.34
June 30, 2006	$	3.00	$	1.85
March 31, 2006	$	3.37	$	2.38

On March 13, 2008, the last sale price of our common shares as reported on the AMEX was $0.84 per share and the last sale price of our common shares as reported on the TSX was CDN$0.83 per share.

Holders

As of March 13, 2008, the number of record holders of our common shares was 58.

Outstanding Share Data

As of December 31, 2007, we had 81,087,320 shares issued and outstanding. There were also 2,126,582 share purchase, finders fee and agent warrants outstanding, all of which will expire on March 19, 2008 if unexercised. Additionally, at December 31, 2007 we had 4,645,000 common share options and RSUs outstanding under our Amended and Restated Share Option Plan and Restricted Share Unit Plans combined. The total amount of common shares authorized for issuance under the plans is 10,000,000 common shares.

Also in 2007, we issued $50.2 million in Series A Subordinated Convertible Notes due March 31, 2012 (the "Series A Notes") and Series B Subordinated Convertible Notes due March 31, 2012 (the "Series B Notes" and collectively, with the Series A Notes, the "Convertible Notes"). The Convertible Notes are convertible into our common shares at a price of $1.17 per share, as may be adjusted in accordance with the terms of Convertible Notes (as applicable). If the Notes are fully converted, we will issue an additional 42,901,709 common shares.

During the year ended December 31, 2007, 500,000 options were exercised for gross proceeds of $169,145. In addition, 157,500 RSUs vested for a total value of $155,015 at the date of vesting.

Issuer Purchases of Equity Securities

We have not repurchased any of our common shares since inception and have no plans to do so in the near future.

Unregistered Sales of Equity Securities and Use of Proceeds

There were no equity securities transactions during the year ended December 31, 2007 that were not registered under the Securities Act, and not previously included in a Quarterly Report on Form 10-Q or in a Current Report on Form 8-K.

Securities Authorized for Issuance Under Equity Compensation Plans

Please see Note 7. Shareholders' Equity in the Notes to Consolidated Financial Statements for details concerning our equity compensation plan including the total shares authorized, shares issued, exercised and forfeited.

Dividends

We have not paid any dividends to common stock holders since inception and have no plans to do so in the near future.

Stock Price Performance

The following stock price performance graph is intended to allow review of shareholder returns, expressed in terms of the appreciation of our common shares relative to two broad-based stock performance indices. The information is included for historical comparative purposes only and should not be considered indicative of future stock performance. The graph compares the yearly percentage change in the cumulative total shareholder return on our common shares with the cumulative total return of the Standard & Poor's Composite 500 Stock Index and of the Dow Jones U.S. Exploration and Production Index (formerly Dow Jones Secondary Oils Stock Index) from December 31, 2002 through December 31, 2007.

Figure 8: Comparison of Five Year Cumulative Total Return
For the Year Ended December 31, 2007

	2002	2003	2004	2005	2006	2007
Storm Cat Energy Corporation ("SME")	100.0	316.0	2160.0	1352.0	556.0	280.0
S & P's Composite 500 Stock	100.0	126.4	137.7	141.9	161.2	166.9
DJ U.S. Exploration & Production Index*	100.0	129.4	181.8	298.3	312.1	445.2

* formerly DJ Secondary Oil Stock Index

The information in this Annual Report on Form 10-K appearing under the heading "Stock Price Performance" is being "furnished" pursuant to Item 201(e) of Regulation S-K under the Securities Act, as amended, and shall not be deemed to be "soliciting material" or "filed" with the SEC or subject to Regulation 14A or 14C, other than as provided in Item 201(e) of Regulation S-K, or to liabilities of Section 18 of the Exchange Act.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth certain financial information and is qualified in its entirety by reference to the historical financial statements and notes thereto included in Item 8. Financial Statements and Supplementary Data. The statement of operations and balance sheet data included in this table for each of the five years in the period ended December 31, 2007 were derived from the audited financial statements and the accompanying notes to those financial statements.

In Thousands, except per share amounts	Year Ended December 31,				
Financial Information	2007	2006	2005	2004	2003
Statement of Operations Data:					
REVENUE:					
Natural gas sales	$ 16,757	$ 9,444	$ 4,214	$ 104	$ —
EXPENSES:					
Gathering and transportation costs	2,313	1,921	906	39	—
Lease operating expenses	6,132	3,443	2,354	4	—
General and administrative	7,121	3,912	3,662	951	173
Stock-based compensation	1,145	2,783	1,914	—	—
Depreciation, depletion, amortization and accretion	7,976	3,916	1,648	19	—
Impairment of oil and gas properties	27,861	2,027	2,125	—	—
Interest and other misc. expense (income)	6,514	(173)	(27)	—	—
Income tax expense (income)	(1,350)	(1,524)	—	—	—
Total expenses	57,712	16,305	12,582	1,013	173
Net loss	$ (40,955)	$ (6,861)	$ (8,368)	$ (909)	$ (173)
Net loss per share (1) :					
Basic and diluted net loss per share	$ (0.51)	$ (0.10)	$ (0.18)	$ (0.04)	$ (0.02)
Basic and diluted weighted average shares outstanding	80,912,950	70,429,219	47,321,481	21,455,630	11,236,892
Working capital	$ (2,061)	$ (15,594)	$ 18,445	$ 2,257	$ 566
Total assets	132,566	111,964	56,957	5,743	488
Short-term liabilities	12,040	29,061	12,709	601	30
Long-term liabilities	95,147	21,221	793	79	—
Shareholders’ equity	25,379	61,682	43,455	5,063	458
Cash dividends declared per common share	$ —	$ —	$ —	$ —	$ —
Operating Data					
Production Volumes:					
Gas (Mcf)	3,154.3	1,606.2	693.5	17.3	—
Average sales price before hedging:					
Per Mcf	$ 3.54	$ 5.19	$ 6.08	$ 6.01	$ —
Average sales price after hedging:					

Per Mcf	$ 5.31	$ 5.88	$ 6.08	$ 6.01	$ —
Total Proved Reserves:					
Gas (Mcf)	44,488.0	25,015.3	10,009.9	458.2	—
Estimated future net cash flow	$ 132,794.5	$ 41,945.0	$ 37,461.0	$ 1,011.0	$ —
Estimated future net cash flow, discounted at 10%	$ 98,425.1	$ 32,036.4	$ 29,017.2	$ 807.0	$ —

(1) The effect of the two for one stock split on March 31, 2005 is retroactively applied to all historical share and per share data.

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

Unless the context otherwise requires, the terms "Storm Cat," we", "us," "our" and the "Company", when used herein refer to Storm Cat Energy Corporation, together with its operating subsidiaries. When the context requires, we refer to these entities separately. The following Management's Discussion and Analysis of Financial Condition and Results of Operations of the Company should be read in conjunction with the Consolidated Financial Statements and notes related thereto included in this Annual Report on Form 10-K.

Overview

Our business is to develop, produce and sell natural gas from our predominantly unconventional natural gas resource properties in the PRB, the Arkoma Basin, Elk Valley - British Columbia, the WCSB and Cook Inlet - Alaska, almost all of which we operate.

In 2007, we achieved several record financial and operating results:

- Average daily production was 8.641 MMcf/d, a 96% increase over 2006 average daily production.
- Year end proved reserves were 44.5 Bcf, a 78% increase over 2006 year end proved reserves.
- Our estimated discounted future net cash flow of proved reserves discounted at 10% was $98.4 million, an increase of 208% over 2006.
- Our reserve replacement ratio was 718% in 2007.
- Our total net revenue from gas sales was $16.8 million, a 77% increase over 2006.

We are even more pleased that the foregoing results were achieved notwithstanding a very difficult commodity price environment covering almost all of our operations. 2007 presented several challenges to the Rocky Mountain producing region and, specifically, our PRB operations.

First, insufficient pipeline takeaway capacity created difficult "gas-on-gas" competition throughout much of the year, resulting in significant natural gas price deterioration in the Rockies. The Rocky Mountain basis differential to NYMEX (i.e., Henry Hub, Louisiana) averaged $3.03/MMBtu for 2007 as compared to $1.38/MMBtu for 2006. This difficult price environment forced us to reprioritize our capital budget with the goal of bringing most of our production growth on line at the end of 2007 rather than sequentially throughout the year.

Second, force majeure related to a September 16, 2007 fire on the Cheyenne Plains interstate gas pipeline reduced Rockies take-away capacity even further, deteriorating already reduced Rockies gas prices. For example, the First of the Month pricing for Colorado Interstate Gas – Rocky Mountains for October 2007 was $1.11/MMBtu compared to the NYMEX price of $6.43 per MMBtu for the corresponding period. As a consequence, we were forced to curtail our production in the third and fourth quarters of 2007. Fortunately, our hedging allowed us to partially mitigate the impacts of this price collapse and deliverability curtailment.

Finally, certain pipeline interruptions and operational delays occurred in the fourth quarter within our operating areas in the PRB that impacted our ability to maximize production from our properties. Impacts of interruptions and delays are still being experienced in the first quarter of 2008, but we believe that we will ultimately recover fully from these impacts.

The negative impacts of "gas-on-gas" competition within the Rockies have been mitigated recently with the start up of a portion of the Rockies Express Pipeline ("REX"), a pipeline that, when fully operational in late 2009, will extend from Cheyenne, Wyoming to eastern Ohio and add 25% more take-away capacity to the Rocky Mountain natural gas market. Additional proposed pipeline projects in the Rockies, if constructed, would mitigate possible future "gas-on-gas" competition. The REX pipeline will make the U.S. gas markets more integrated and efficient, significantly reducing the basis differentials experienced in the Rockies in 2007 over the next few years.

Our Ability to Continue to Grow

Our primary responsibility is to create shareholder value. We create shareholder value by investing our capital resources in projects with attractive rates of return that allow us to continue to grow. Our ability to continue to grow is dependent upon three main variables: (1) our assets; (2) access to capital; and (3) commodity prices.

Our Assets

In Items 1 and 2. Business and Properties of this Annual Report on Form 10-K, we discuss the five areas where we hold assets. Of those five areas, three represent our core areas – the PRB, the Fayetteville Shale and Elk Valley. Subject to qualifications regarding geology and engineering, the PRB, Fayetteville Shale and Elk Valley assets provide critical pathways to continue to grow our Company.

Powder River Basin

Our PRB asset base has been our growth vehicle to date. As shown in Figure 9, our PRB production grew initially through acquisitions and since our acquisition in the fall of 2006 our growth has been through the drill bit. In 2007, we invested $23.6 million in capital on our drilling and completion activities in the PRB and grew proved reserves there by 18.3 Bcf after consideration of production of 3.154 Bcf in 2007. Our resulting organic finding and development cost ("F&D") of $1.29/Mcf is significantly better than the market trend of $2.79/Mcf.

Figure 9: Aggregate Gross Wellhead Production from Powder River Basin Assets

While our current inventory of drilling locations in the PRB will be depleted in late 2009, we will continue to look for "bolt-on" acquisition opportunities within the PRB that compliment our current acreage position and allow continued deployment of our technical expertise.

Our $23.6 million investment in our PRB operations is divided into drilling and completion, acquisitions, and maintenance activities as follows:

- Drilling and Completion. $21.7 million to add 107 wells, of which $1.2 million was incurred for permitting, staking and water management plans for the 2007 and 2008 drilling programs and $2.6 million was related to our 2006 activities.

- Maintenance. Approximately $1.9 million on roads, water management infrastructure upgrades and well repair and maintenance.

Fayetteville Shale

Our Fayetteville Shale position provides significant opportunity for growth in 2008 and beyond. We were encouraged not only by our geologic successes in 2007 with the drilling of our first three wells but also by our engineering and operational achievements and efficiencies we experienced in the drilling of those wells. Moreover, we were able to book proved reserves for the project at December 31, 2007. We have assigned the highest priority to the Fayetteville Shale in our 2008 capital budget.

Our task will be to expand the producing fairway to the North and West from the fairway established by Southwestern Energy (see Figure 4). In comparison to the producing fairway, our acreage is shallower. With less depth will be lower pressures, but, conceivably better permeability. Moreover, the reservoir is thicker in our area than in the deeper parts of the producing fairway. Our initial wells suggest productivity characteristics consistent with our expectation.

We invested $12.2 million in 2007 in our Fayetteville Shale operations on drilling and completion, acquisitions and well site preparation as follows:

- Drilling and Completion. $11.1 million to drill and complete three operated wells and costs associated with 16 non-operated wells; and

- Acquisitions. $1.1 million to acquire 4,283 gross and 4,283 net acres, over 100% of which is undeveloped, and legal and title work associated with integration.

Assuming success in our project and access to capital, we anticipate drilling 12 gross / eight net wells in our Fayetteville acreage in 2008. In 2009, we anticipate drilling 24 gross / 16 net wells. Fayetteville provides a very attractive growth opportunity for us for several years if we are able to achieve repeatable success across the prospect.

Our Fayetteville position also provides diversity to our asset base and partially mitigates the commodity price exposure we had in 2007 by being a Rockies producer only. Commodity pricing will be tied to the Centerpoint East market index, which has traded at a basis differential to NYMEX in the $0.70 to $0.80/MMBtu range in past year as compared to the $3.03/MMBbtu basis differential for Rockies gas in 2007. Moreover, the construction of additional pipeline infrastructure in the Fayetteville area should afford us sufficient takeaway capacity in the foreseeable future.

Recent transactions in the Fayetteville have resulted in significantly higher per acre pricing. Notwithstanding, we continue to look for opportunities to expand our position. The process of integrating drilling units provides the immediate opportunity to add additional interests in our developing areas. Discussions continue with other interest owners concerning acquisitions or trades in the area. Notwithstanding the significant run-up in pricing, we will continue to look for opportunities to add to our position; our low entry point cost into the play continues to afford us significant value appreciation in our holdings.

Elk Valley

As stated in Items 1 and 2. Business and Properties above, our challenge in Elk Valley is that tectonic activities associated with our geologic setting have significantly altered the permeability in the coal seams. Commercial productivity is conditioned upon inducing or connecting permeable pathways into our wellbores to allow the extraction of water and resulting desorption of natural gas from the coal seams.

In response to this permeability challenge, in 2006 we designed the drilling and completion of the five producing wells we drilled to aggressively stimulate the coal seams, in contrast to the efforts of the prior operator. Our hydraulic fracturing treatments combined significantly higher fluid volumes and sand volumes with significantly higher pump rates, methods that have met with significant success in the shale resource plays in the United States such as the Barnett Shale and Fayetteville Shale. Results from our drilling and stimulation approach are shown graphically in Figure 10, a graph showing water and gas production history from the commencement of the prior operator's activities to date. As shown, the prior operator's five producing wells produced, in the aggregate, 300 to 750 BWPD and gas production ranged from 250 to 500 Mcf/d during the prior operations. Our actions show that we have produced 2,000 to 2,500 BWPD and upwards of 1,300 Mcf/d from the nine producing wells during our operating period. We are encouraged that this step-change in water and gas producing rates suggests that we have induced more permeability and connectivity into the coal seams, suggesting we may have contacted a greater reservoir area. It is axiomatic in coal bed natural gas development that water begets gas. The more water we can remove, it follows that more gas should be desorbed and produced.

Presently, we continue to progress in our dewatering efforts. To avoid migrating coal fines and sloughing of hydraulic fracture sand, we intentionally have not withdrawn water at maximum rate. A column of water remains in the wellbores that exerts hydrostatic pressure against the coal seams, particularly the lower coal seams. While we believe we are making progress on dewatering, we will not be in a position to fully evaluate this project's potential until we have fully lowered the column of water in each wellbore and are able to observe the rate and volume of natural gas that can be desorbed and produced from all coal seams.

Figure 10: Elk Valley Aggregate Production

In addition, we are permitted to surface discharge the fresh water produced from our dewatering activities from our existing wells. We continually explore alternatives to our water management and coordinate closely with British Columbia regulatory authorities overseeing our operations. Efficient and environmentally responsible methods for water management are essential for the viability of this project.

We invested approximately $9.1 million in Elk Valley to finish completion and production initiation of five wells drilled in 2006, and for dewatering operating expenses, miscellaneous repairs and maintenance, and line projects.

In summary, significant progress was made on the project during 2007. However, we believe that in order to fully assess the gas production potential of the project, fluid levels in the producing wellbores must be lowered from the upper coal seams to below the bottom coal seams. This will then allow evaluation of the unrestricted productive potential (water and gas) of all completed coal seams.

Western Canadian Sedimentary Basin

We invested approximately $1.3 million in Alberta on the drilling and completion of two wells and the associated geologic and geophysical costs.

Access to Capital

Our ability to grow is dependent upon our ability to access capital. We will continue to focus on methods to improve our balance sheet and improve liquidity to drive growth. Our capital resources are limited and we lack sufficient liquidity to make meaningful additions via acquisition. We, therefore, might find it necessary to seek additional capital from sources other than the Credit Facility.

In early 2007, we completed a $50.2 million capital raise upon the closing of the Convertible Notes as described in further detail below. The Convertible Notes convert at a common share price of $1.17. We may force conversion at a sustained stock price of $2.05 per share beginning 18 months after issuance. Our goal is to move our stock price to the forced conversion price through the execution of our business plan and recognition in the market of the successes created by execution of that plan.

On December 27, 2007, we announced the refinancing of our existing credit facility from JPMorgan Chase Bank, N.A. with a new $80.0 million Credit Facility from Regiment Capital Advisors LLC and Wells Fargo Foothill (described in further detail below). This Credit Facility combined with our estimated free cash flow may provide us liquidity to execute a $38.2 million capital expenditure budget for 2008. With an additional $25.0 million capacity through borrowing base growth, and assuming that such growth occurs, we anticipate that capital could be available under the Credit Facility to execute a 2009 capital budget.

Commodity Prices

Given our debt levels and the need to access capital and cash flow to fund our capital budget, we hedge a significant portion of our production when we observe the opportunity to implement opportunistic hedges. While there is risk we may not be able to realize the full benefit of rising prices, we will continue our hedging strategy because of the benefits provided by predictable, stable cash flow, including:

- the ability to more efficiently plan and execute our capital program, which facilitates predictable production growth;
- the ability to forecast and plan our cash flow;
- the ability to access capital; and
- the ability to achieve more consistent rates of return on investments.

To this end, we have entered into swap agreements covering 80% of our mid-year 2007 forecasted 2008 and 2009 production from proved developed properties. The following chart summarizes the hedges:

Figure 11: Percent Hedged

Figure 12: Hedge Price

We will continue to look for opportunities to enhance our commodity prices and limit our downside risks.

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RESULTS OF OPERATIONS

Comparison of Financial Results and Trends Between 2007 and 2006

Selected Operating Data:	Year Ended December 31,			
	2007	2006	$ Change	% Change
Net natural gas sales volume (MMcf)	3,154.3	1,606.2	1,548.1	96.4%
Natural gas sales (In Thousands)	$ 16,757	$ 9,444	$ 7,313	77.4%
Average sales price (per Mcf)	$ 5.31	$ 5.88	$ (0.57)	(9.6)%
Additional data (per Mcf):				
Gathering and transportation	$ 0.73	$ 1.20	$ (0.47)	(39.2)%
Operating expenses:				
Lease operating expenses	$ 1.54	$ 1.43	$ 0.11	7.7%
Ad valorem and property taxes	$ 0.40	$ 0.71	$ (0.31)	(43.7)%
Depreciation, depletion, amortization and accretion expense	$ 2.49	$ 2.44	$ 0.05	2.1%
Asset impairment	$ 8.83	$ 1.26	$ 7.57	600.8%
General and administrative expense, excluding stock-based compensation and gain on sale of property	$ 2.26	$ 2.55	$ (0.29)	(11.4)%
Stock-based compensation	$ 0.36	$ 1.73	$ (1.37)	(79.2)%

Natural Gas Sales. Increased natural gas sales are a direct result of increased production from our successful drilling activities over the past year and from an acquisition made in the third quarter of 2006. Volume increases offset the decline in Rocky Mountain natural gas prices and declining production from existing wells.

Gathering and Transportation. Gathering and transportation expenses increased approximately $0.4 million from $1.9 million in 2006 to $2.3 million in 2007. The increase in total expense was a direct result of increased production volumes. Gathering expense per Mcf decreased as the per Mcf fuel use charge, which is based directly on natural gas prices, decreased along with the price of natural gas.

Lease Operating Expenses. Lease operating expenses (excluding taxes) increased to $4.8 million in 2007 from $2.4 million in 2006. The increase is primarily a result of additional wells added from our successful drilling program and from an acquisition made in the third quarter 2006. Lease operating expenses increased $0.11 per Mcf from 2006 to 2007. Most of this increase was due to initial operating expenses incurred after new wells were placed on production.

Ad Valorem and Property Taxes. Ad valorem and property taxes increased approximately $0.2 million to $1.3 million in 2007 compared to $1.1 million in 2006. The increase resulted from gas volume increases over the past year. Ad valorem and property taxes as a percentage of natural gas sales decreased from 11.1% in 2006 to 7.9% in 2007. Additionally, the decrease in ad valorem and property tax on a per Mcf basis between 2006 and 2007 was due to lower gas prices in the PRB in 2007. Volatility in gas sales prices has been normalized by our hedge contracts, but the valuation for taxes is based on market price.

Depreciation, Depletion, Amortization and Accretion. Depreciation, depletion and amortization increased by $4.1 million to $8.0 million in 2007 compared to $3.9 million in 2006. This increase resulted from increased production resulting from our successful drilling activities over the past year and from an acquisition made in the third quarter of 2006. The per Mcf rate increased marginally primarily due to additions to the reserve estimate.

Asset Impairment. We calculated the ceiling value of our proved reserves based upon the September 30, 2007 market price for natural gas of $1.9855 per MMBtu at the Colorado Interstate Gas ("CIG") – Mainline index and the impact of our natural gas hedges. At that date, our full cost pool exceeded this calculated ceiling value by $27.8 million. Therefore, we recognized an impairment of $25.0 million against the book value of our proved properties. Also in the third quarter of 2007, we evaluated our Alberta, Canada unproved properties. Using the lower of cost basis or market value test, we recognized an impairment of $2.8 million against the book value of our unproved Alberta properties.

General and Administrative Expense. Net general and administrative expense increased $1.6 million to $8.3 million in 2007 compared to $6.7 million in 2006. One of the largest components of the increase is attributed to salaries and related benefits and taxes which totaled $3.4 million in 2007 compared to $2.5 million in 2006; an increase of $0.9 million. The increase in salaries was attributable to additional salaries and bonuses paid in 2007, and a $0.36 million severance payment made to our former President and CEO. Stock-based compensation decreased $1.6 million to $2.8 million in 2006 from $1.2 million in 2007 primarily due to a decline in our stock price from period-to-period, and the change in accounting method to expense Canadian dollar options granted to U.S. employees using the liability method. Finally, capitalized overhead and other general and administrative costs decreased $2.1 million from 2006 to 2007.

	Year Ended December 31,			
	2007	2006	$ Change	% Change
General and administrative expense	$ 7,121	$ 6,168	$ 953	15.5%
Stock-based compensation	1,145	2,783	(1,638)	(58.9)%
Capitalized overhead	—	(2,071)	2,071	—
Gain on sale of property	—	(185)	185	—
General and administrative expense, net	$ 8,266	$ 6,695	$ 1,571	23.5%

Income Tax. The income tax benefit realized in 2007 was $1.35 million. This is a tax benefit that is passed on to our flow-through shareholders. The flow-through shareholders pay a premium above market for their shares in order to have this tax benefit. This premium is reduced in equity and recorded as a liability. As the capital obligation is spent, the liability is reduced and an income tax benefit is recorded to the income statement.

Interest Expense. Interest expense during 2007 relates primarily to amounts borrowed pursuant to the Credit Agreement, dated as of July 28, 2006, by and between Storm Cat, Storm Cat (USA) and JPMorgan Chase Bank, N.A., as Global Administrative Agent (the "JPMorgan Facility") and our Convertible Notes. The Convertible Notes were not in place in 2006, and the JPMorgan Facility was not established until late July 2006.

Expected Future Trends. We expect continued increases in revenue, lease operating expenses and interest expense resulting from planned capital expenditures and wells coming on production. We also expect ongoing significant capital expenditures in order to explore and develop our current acreage.

Unproved Properties

The cost of our unproved properties, net of impairments, by state and by cost center, are as follows:

	Year Ended December 31,	
In Thousands	2007	2006
Wyoming	$ 9,971	$ 22,519
Alaska	—	4,883
Arkansas	5,168	4,528
Total U.S. unproved properties	15,139	31,930
Total Canada unproved properties	36,299	22,943
Total unproved properties	$ 51,438	$ 54,873

Comparison of Financial Results and Trends Between 2006 and 2005

Selected Operating Data:	Year Ended December 31,			
	2006	2005	$ Change	% Change
Net natural gas sales volume (MMcf)	1,602.2	693.5	912.7	131.6%
Natural gas sales (In Thousands)	$ 9,444	$ 4,214	$ 5,230	124.1%
Average sales price (per Mcf)	$ 5.88	$ 6.08	$ (0.20)	(3.3)%
Additional data (per Mcf):				
Gathering and transportation	$ 1.20	$ 1.31	$ (0.11)	(8.4)%
Operating expenses:				
Lease operating expenses	$ 1.43	$ 2.62	$ (1.19)	(45.4)%
Ad valorem and property taxes	$ 0.71	$ 0.78	$ (0.07)	(9.0)%
Depreciation, depletion, amortization and accretion expense	$ 2.44	$ 2.38	$ 0.06	2.5%
Asset impairment	$ 1.26	$ 3.06	$ (1.80)	(58.8)%
General and administrative expense, excluding stock-based compensation and gain on sale of property	$ 2.55	$ 5.28	$ (2.73)	(51.7)%
Stock-based compensation	$ 1.73	$ 2.76	$ (1.03)	(37.3)%

Natural Gas Sales. The volume increase resulted primarily from acquisitions and successful drilling over the past year that produced new sales volumes that offset the natural decline in production.

Gathering and Transportation. Gathering and transportation expenses increased approximately $1.0 million from $0.9 million in 2005 to $1.9 million in 2006. The increase in total expense was a direct result of increase production volumes. The decrease on a per Mcf basis is attributed to economies realized in transporting greater volumes.

Lease Operating Expenses. Lease operating expenses (excluding taxes) increased approximately $0.6 million to $2.4 million in 2006 compared to $1.9 million in 2005. The increase resulted primarily from costs associated with new property acquisitions and drilling in the current year. Lease operating expenses as a percentage of natural gas sales decreased from 44.0% during 2005 to 25.4% in 2006 as lease operating cost increases did not keep pace with volume increases.

Ad Valorem and Property Taxes. Ad valorem and property taxes increased approximately $0.5 million to $1.1 million in 2006 compared to $0.5 million in 2005. The increase resulted from gas volume increases over the past year. Ad valorem and property taxes as a percentage of natural gas sales decreased from 12.8% during in 2005 to 11.1% in 2006. Ad valorem and property tax per Mcf decreased due to production volume increases.

Depreciation, Depletion, Amortization and Accretion. Depreciation, depletion, and amortization increased by $2.1 million to $3.7 million during in 2006 compared to $1.6 million in 2005. This increase resulted from increased production from recent acquisitions, increased capital costs and an increase in the DD&A rate. The per Mcf rate increased marginally by $0.03 from $2.28 in 2005 to $2.31 in 2006 primarily due to additions to the reserve estimate. Accretion expense increased by $0.1 million to $0.2 million in 2006 from $0.1 million in 2005. This increase was the result of additional drilling in the PRB and Elk Valley as well as the acquisition of properties in the PRB.

General and Administrative Expense. Net general and administrative expense increased $1.3 million to $6.9 million in 2006 compared to $5.5 million in 2005. One of the largest components of the increase is attributed to salaries and related benefits and taxes which totaled $2.4 million in 2006 compared to $1.3 million in 2005. The increase in salaries was attributable to an increase in the employee base, from 15 employees in 2005 to 27 employees in 2006, resulting from our continued growth. Additionally, Sarbanes-Oxley and audit fees increased by $0.3 million, director and officer insurance increased by $0.2 million, legal fees increased by $0.2 million and bank fees increased by $0.3 million (primarily related to the amortized portion of up-front fees associated with the JPMorgan Facility, all of which were the result of growth and fund-raising activities in 2006). Stock-based compensation increased $0.9 million to $2.8 million in 2006 from $1.9 million in 2005 primarily due to an increase in the number of employees between periods. Capitalized overhead increased by $1.5 million to $2.1 million in 2006 from $0.6 million in 2005. This increase in capitalized overhead was due to a combination of increases in the number of operated properties, new acquisitions, stepped-up drilling activity and the associated increased employee costs in 2006.

	Year Ended December 31,			
	2006	2005	$ Change	% Change
General and administrative expense	$ 6,168	$ 4,254	$ 1,914	45.0%
Stock-based compensation	2,783	1,914	869	45.4%
Capitalized overhead	(2,071)	(592)	(1,479)	249.9%
Gain on sale of property	(185)	—	(185)	100.0%
General and administrative expense, net	$ 6,695	$ 5,576	$ 1,119	20.1%

Income Tax. The income tax benefit realized in 2006 was $1.3 million. This benefit is from spending capital that qualifies for immediate tax deduction and, in turn, this tax benefit is passed on to our flow-through shareholders. In order to have this tax benefit, the flow-through shareholders pay a premium above market for their shares. This premium is reduced in equity and recorded as a liability. As the capital obligation is spent, the liability is reduced and an income tax benefit is recorded to the income statement. Our flow-through share liability was fully spent by December 31, 2007.

Interest Expense. Interest expense during 2006 consists primarily of interest expense related to the JPMorgan Facility. The JPMorgan Facility was not in place in 2005.

Additional Comparative Data

Information regarding natural gas production revenues:

	Change Between Years	
Revenues in Thousands	2007 and 2006	2006 and 2005
Increase in natural gas production revenues (including hedges)	$ 7,313	$ 5,230
Components of natural gas revenue increases (decreases):		
Realized price change per Mcf (including hedges)	$ (0.57)	$ (0.20)
Realized price percentage change	(9.6)%	(3.2)%
Production change (MMcf)	1,548.1	912.7
Production percentage change	96.4%	131.6%

Information regarding the effects of natural gas hedging activity:

	Year Ended December 31,		
Revenues in Thousands	2007	2006	2005
Percentage of gas production hedged	72.8%	22.8%	—%
Natural gas volumes hedged (MMBtu)	2,295.5	366.5	—
Increase (decrease) in gas revenue from hedges	$ 5,589	$ 1,102	$ —

Average realized gas price per Mcf before hedging	$	3.54	$	5.19	$	6.08
Average realized gas price per Mcf after hedging	$	5.31	$	5.88	$	6.08

Commodity Price Sensitivity Analysis

As the following table indicates, our operations are highly sensitive to changes in commodity prices.

	Year Ended December 31, 2007					
In Thousands	Change in PV-10 Revenue		Change in PV-10 Expenses		Change in PV-10 Net Cash Flow	
10 % increase in price ($6.06 to $6.666 or $5.454 per Mcf)	$	15,675	$	3,919	$	11,756

The discounted PV-10 revenue increase or decrease resulting from a 10% change in the December 31, 2007 year-end average price for the sale of our natural gas ($6.06) would be $15.7 million. The associated expenses discounted at 10% would change by $3.9 million. Therefore, net discounted PV-10 cash flow would change by $11.8 million.

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LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity are cash provided by operating activities, borrowings under our Credit Facility, our Convertible Notes offering completed in 2007 and sales of equity. Exploration and development expenditures have generally been funded from debt and equity offerings. Our current $80.0 million Credit Facility provides liquidity to fund our 2008 capital budget. This assumes the borrowing base determined by the bank is not adversely affected by lower commodity prices, a reduced level of proved reserves or a reduction in cash flows. We also must remain in compliance with all loan covenants to continue to have access to capital under the Credit Facility.

The following table summarizes our cash flows from operating, investing and financing activities for each of the three years ended December 31, 2007, 2006 and 2005.

	Year Ended December 31,		
In Thousands	2007	2006	2005
Net cash used in operations	$ (7,232)	$ (2,687)	$ (2,272)
Net cash used in investing activities	(63,212)	(70,738)	(15,733)
Net cash provided by financing activities	64,191	48,947	44,920
Effect of exchange rate changes on cash	2,087	275	(78)
Net cash flow	$ (4,166)	$ (24,203)	$ 26,837

Operating activities. Net cash used in operating activities increased by $4.5 million during the year ended December 31, 2007 as compared to the corresponding period in 2006. The change is primarily due to interest expense incurred in 2007. Total year-to-date interest expense in 2007 was $4.7 million, as compared to $0.4 million in 2006. We also had additional general and administrative expense of $0.9 million. This was offset by an increase of $3.9 million in operating income.

Investing activities. Net cash used in investing activities was $63.2 million, a decrease of $7.5 million from the year ended December 31, 2006 to the corresponding period in 2007. Capital spending was higher in 2006 due to a $30.6 million acquisition in Wyoming during the third quarter of 2006. $46.2 million was invested in our capital projects, $8.4 million related to differences in accruals from 2006 to 2007, $4.5 million related to foreign currency exchange rate fluctuations, and $4.1 million related to lease rentals, capitalized interest and non-project capital.

Financing activities. Net cash provided by financing activities increased $15.2 million from the year-ended December 31, 2006 to the corresponding period in 2007. The increase is primarily the result of proceeds received from the issuance of the Convertible Notes issued in 2007 in the amount of $50.2 million and additional funds drawn on the Credit Facility. In 2006, $27.5 million was drawn under the JPMorgan Facility to fund the Wyoming acquisition and a private placement of 13,767,776 common shares was completed in September 2006 for proceeds of $19.3 million.

Working Capital Deficit

At December 31, 2007 our current liabilities of approximately $12.0 million exceeded current assets of $10.0 million resulting in a working capital deficit of $2.0 million. This compares to a working capital deficit of $15.6 million as of December 31, 2006. Current liabilities as of December 31, 2007 consisted of trade payables of $5.8 million, revenues due third parties $1.7 million, accrued capital and other liabilities of $4.1 million, interest payable of $0.1 million and a stock-based compensation liability of $0.4 million.

Credit Facility

On December 27, 2007, Storm Cat (USA) entered into the Credit Agreement (the "Credit Agreement") to provide for the new Credit Facility. Additionally, Storm Cat agreed to guarantee the obligations of Storm Cat (USA) under the Credit Facility. The Credit Facility consists of a term loan facility in an aggregate principal amount of $30.0 million and a revolving facility in an aggregate principal amount of $50.0 million. Our current borrowing base is $55.0 million under the Credit Facility. The Credit Agreement provides for a semi-annual evaluation of such amount, determined based on our oil and natural gas reserves.

Each loan under the Credit Facility bears interest at a base rate or Eurodollar rate, as we request, plus an applicable percentage based on our usage of the facility. The applicable margin above the base rate and the Eurodollar rate for the term loan is 5.75% and 7.00%, respectively. The applicable margin above the base rate and the Eurodollar rate for the revolving Credit Facility ranges from 0.75% to 1.25% and 2.00% and 2.50%, respectively, in each case depending on our usage under the borrowing base. Interest on funds drawn will be paid monthly, except that interest on loans based on the Eurodollar rate will be payable at the end of each Eurodollar interest period.

A detailed discussion of our Credit Facility is provided in Note 5. Bank Credit Facility of the Notes to the Consolidated Financial Statements.

In connection with the refinancing in December, we expensed the remaining $1.0 deferred financing fees related to the JPMorgan Facility that was replaced by the $80.0 Credit Facility.

Due to pipeline interruptions and delays which affected our fourth quarter 2007 and first quarter 2008 production, it is probable that we will not meet our minimum daily average production covenant of 16.8 MMcf/d for the first quarter 2008 as required by the Credit Agreement. We are currently in discussion with our lenders to amend or waive this covenant.

Convertible Notes

On January 19, 2007, we entered into a Series A Note Purchase Agreement for the private placement of Series A Notes in a total aggregate principal amount of $18.5 million and a Series B Note Purchase Agreement for the private placement the Series B Notes in a total aggregate principal amount of $31.7 million. The Convertible Notes were bifurcated because a shareholder vote was required for issuance above the amount issued under the Series A Notes. The Series A Notes and the Series B Notes are convertible into our common shares at a price of $1.17 per share, as may be adjusted in accordance with the terms of the Series A Notes or the Series B Notes (as applicable), and we may force the conversion of the Series A Notes or the Series B Notes (as applicable) at any time 18 months after the closing date of the applicable issuance that our common shares trade above $2.05, as may be adjusted, for 20 days within a period of 30 consecutive trading days. On the day of the agreement, the $1.17 conversion price was at premium to our closing stock price of $1.00. The Series A Notes and the Series B Notes bear interest at a rate of 9.25% per annum. Interest is payable quarterly in arrears on March 31, June 30, September 30 and December 31 of each year, beginning on June 30, 2007.

Further detail of the agreement between us and the holders of the Series A Notes and the Series B Notes is disclosed in the Note 6. Convertible Notes of the Notes to the Consolidated Financial Statements. We also filed three Form 8-Ks on January 25, February 5, and April 5, 2007 which provided further information about this transaction.

Additional Financing

We are constantly investigating participation opportunities in additional exploration and development projects. If new project interests are identified, we will require additional funds for acquisition and exploitation and development of these new projects.

Off Balance Sheet Arrangements

We do not have any investments in unconsolidated entities or persons that could materially affect the liquidity or the availability of capital resources. Any amounts due to off balance sheet arrangements that we have entered into are included in the table of contractual obligations and commitments in the section that follows.

Contractual Obligations

The table that follows summarizes our obligations and commitments to make future contractual payments as of December 31, 2007. We have not guaranteed the debt or obligations of any third party, nor do we have any other arrangements or relationships with other entities that could potentially result in unconsolidated debt or losses.

In Thousands	Total	< 1 Yr.	1-3 Yrs.	3-5 Yrs.	> 5 Yrs.
Convertible Notes payable (1):					
Principal	$ 50,195	$ —	$ —	$ 50,195	$ —
Interest	20,171	4,746	14,238	1,187	—
Credit Facility (2):					
Principal	43,000	—	—	43,000	—
Interest	16,874	—	—	16,874	—
Derivative contract liabilities (3)	183	—	183	—	—
Gas transportation commitments (4)	19,970	950	16,720	2,300	—
Operating leases (5)	583	292	291	—	—
Total contractual obligations	$ 150,976	$ 5,988	$ 33,432	$ 113,556	$ —

(1) Reflects the principal and interest due on our Convertible Notes. The Convertible Notes will mature on March 31, 2012, unless earlier converted, redeemed or repurchased.

(2) Reflects the principal balance payable to Wells Fargo Foothill at December 31, 2007. Interest calculated on the Credit Facility is through September 27, 2011 (the maturity date of the Credit Facility, which may be extended to December 27, 2012 in the event the Convertible Notes are entirely converted into equity, with no remaining cash payment obligations or are refinanced with a maturity date not earlier than June 27, 2013).

(3) We have entered into swaps to hedge our exposure to natural gas price fluctuations. As of December 31, 2007, fixed prices specified by these swaps generally exceeded the market price, resulting in a current unrealized gain of $1.76 million and long-term unrealized loss of $0.18 million. If market prices are higher than the contract prices when the cash settlement amount is calculated, we are required to pay the contract counterparties. While such payments generally will be funded by higher prices received from the sale of our production, timing differences between our receipt of sales from production and payment due to counterparties can result in draws on our revolving Credit Facility.

(4) We have entered firm transportation contracts with various pipelines for various terms through 2013. Under these contracts, we are obligated to transport minimum daily gas volumes, as calculated on a monthly basis, or pay for any deficiencies at a specified rate. We also have field gathering, compression and transportation agreements that contain financial obligations requiring a minimum level of fees through a fixed period.

(5) Reflects operating leases for office rent and office equipment (primarily copier leases) for our U.S. and Canadian offices.

The above table does not include asset retirement obligations as discussed in Note 1. Summary of Significant Accounting Policies of the accompanying Consolidated Financial Statements, as we cannot determine with accuracy the timing of such payments. We have no forward sales contracts as of December 31, 2007.

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Other Developments in 2007

Senior Management Transition

On April 9, 2007, our former President and CEO resigned. On July 2, 2007, Joseph M. Brooker was appointed CEO and Director and Keith Knapstad, who had been acting as interim President and CEO during the transition, was named President and COO.

On July 31, 2007, our Vice President of Canadian and International Development out of our Calgary office, resigned. We chose not to hire a replacement for this position.

Significant Developments Since 2007

On January 10, 2008, we entered into another commodity swap cash settlement transaction. The outstanding quantity committed to the swap is 4,020 MMBtu's per day beginning January 1, 2009 through December 31, 2009. The total quantity is 1,464,000 MMBtu's. The fixed price in the agreement is $7.00 per MMBtu (CIG pricing).

On January 24, 2008, we granted an additional 1,802,000 stock options to employees and directors. The options have an exercise price of $0.70 (U.S.) and vest over a period of 24 months for employees and 18 months for directors.

On February 6, 2008, the S-1 registration statement we filed on October 30, 2007 relating to the common shares that would be issued upon the conversion of the certain of the Series A and the Series B Notes became effective.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

In December 2005, we adopted the U.S. dollar as our functional and reporting currency because the majority of our activity is conducted in U.S. dollars. We believe this will facilitate a more direct comparison to other North American exploration and development companies. Prior to December 2005, we presented our financial statements using generally accepted accounting principles in Canada, and utilized the Canadian dollar as our functional and reporting currency.

Critical accounting estimates used in the preparation of the financial statements include our estimate of the value of stock-based compensation. These estimates involve considerable judgment and are, or could be, affected by significant factors that are out of our control. See Note 1. Summary of Significant Accounting Policies of the Notes to Consolidated Financial Statements for further discussion.

Accounting for Oil and Gas Reserves

We follow the full cost method of accounting whereby all costs related to the acquisition and development of oil and gas properties are capitalized into a cost center, on a country-by-country basis, referred to as a "full cost pool." We currently have two full cost pools; one in the United States and one in Canada. Depreciation, depletion and amortization of oil and gas properties is computed using the units-of-production method based upon estimated proved oil and gas reserves. Under the full cost method of accounting, costs to be amortized shall include (A) all capitalized costs, less accumulated depletion, depreciation, amortization and impairment, other than the cost of properties; (B) the estimated future expenditures (based on current costs) to be incurred in developing proved reserves; and (C) estimated dismantlement and abandonment costs, net of estimated salvage values. Capitalized oil and gas property costs may not exceed an amount equal to the sum of the present value, discounted at 10%, of estimated future net revenues from proved oil and gas reserves, the lower of the estimated fair value of evaluated properties, the cost of unevaluated properties, and the tax effects of the difference between book and tax basis of the evaluated and unevaluated properties. Should capitalized costs, within a cost center, less related deferred income taxes, exceed this ceiling, the excess shall be charged to expense with the offset directly to the full cost pool.

Costs of acquiring and evaluating unproved properties are initially excluded from depreciation, depletion and amortization calculations. These unproved properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned, the cost of the property is added to costs subject to depreciation, depletion and amortization. When an unproved property is considered to be impaired, the costs are subject to depreciation, depletion and amortization expense. Proceeds from sales, if any, of oil and gas properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would significantly alter the relationship between capitalized costs and the estimated proved oil and gas reserves attributable to a cost center.

Estimated reserve quantities and future net cash flows have the most significant impact on us because these estimates are used in providing a measure of our overall value. These estimates are also used in the quarterly calculations of depreciation, depletion and impairment of our proved oil and gas properties.

The most accurate method of determining proved reserve estimates is based upon historical production, which consists of extrapolating future reservoir pressure and production from historical pressure decline and production data. The accuracy of the decline analysis method generally increases with the length of the production history. Since most of our wells have been producing less than five years, their production history is relatively short, so other (generally less accurate) methods such as volumetric analysis and analogy to the production history of wells of other operators in the same reservoir were used in conjunction with the decline analysis method to determine our estimates of proved developed producing, developed non-producing and undeveloped reserves. As our wells are produced over time and more data is available, the estimated proved reserves will be re-determined on a periodic basis and may be adjusted based on that data.

We calculated the ceiling value of our proved reserves based upon the December 31, 2007 market price for natural gas of $6.04 per MMBtu at the Colorado Interstate Gas (“CIG”) – Mainline index and $6.215 per MMBtu at Centerpoint East as of December 31, 2007, resulting in a weighted average price of $6.06. At that date, our ceiling value exceeded our full cost and no impairment was required.

At September 30, 2007, we recognized an impairment of $25.0 million against the book value of our proved properties. We also evaluated and moved all $4.9 million of our unproved Alaskan costs into the U.S. full cost pool, which also then became subject to the ceiling test. Additionally, we evaluated a portion of our Alberta, Canada unproved properties. Using the lower of cost basis or market value test, we recognized an impairment of $2.8 million against the book value of our unproved Alberta properties.

Note Regarding Reserves Data and Other Oil and Gas Information

National Instrument 51-101 ("NI 51-101") of the Canadian Securities Administrators imposes oil and gas disclosure standards for Canadian public companies engaged in oil and gas activities. We have provided the reserves data and other oil and gas information included in this Annual Report on Form 10-K in accordance with U.S. disclosure requirements and practices, and have filed in Canada separate disclosure forms in compliance with NI 51-101. The information disclosed in this Annual Report, as well as the information that we disclose in the future in SEC filings, may differ from the corresponding information prepared in accordance with NI 51-101 standards.

The primary differences between the U.S. requirements and the NI 51-101 requirements are that (1) the U.S. standards require disclosure only of proved reserves, whereas NI 51-101 requires disclosure of proved and probable reserves, but not possible reserves, and (2) the U.S. standards require that the reserves and related future net revenue be estimated under existing economic and operating conditions (i.e., prices and costs as of the date of the estimate) whereas NI 51-101 requires disclosure of proved reserves and the related future net revenue estimated using constant prices and costs as of the effective date of the estimate, and of proved and probable reserves and related future net revenue using forecast prices and costs. The definitions of proved reserves also differ, but according to the Canadian Oil and Gas Evaluation Handbook (the reference source for the definition of proved reserves under NI 51-101), differences in the estimated proved reserve quantities based on constant prices should not be material. We concur with this assessment.

We have disclosed proved reserve quantities using the standards contained in SEC Regulation S-X, and the standardized measure of discounted future net cash flows relating to proved oil and gas reserves determined in accordance with United States Statement of Financial Accounting Standards No. 69 "Disclosures About Oil and Gas Producing Activities" ("SFAS 69").

Under U.S. disclosure standards, reserves and production information is disclosed on a net basis (after royalties). The reserves and production information contained in this annual information form is shown on that basis.

Revenue Recognition

Our revenue is derived from the sale of natural gas from our producing wells. This revenue is recognized when natural gas is produced and sold. We typically receive payment for production sold one to three months subsequent to the month of the sale. For this reason, we must estimate the revenue that has been earned but not yet received as of the reporting date. We use actual production reports to estimate the quantities sold and the relevant market price, less marketing and transportation, compression and quality adjustments to estimate the sales price of the production. Variances between estimates and the actual amounts received are recorded in the month the payment is received.

Asset Retirement Obligation

The estimated fair value of the future costs associated with dismantlement, abandonment and restoration of natural gas properties is recorded when the assets are placed into service, generally through acquisition or completion of a well. The net estimated costs are discounted to present values using a risk-adjusted rate over the estimated economic life of the properties. Such costs are capitalized as part of the basis of the related asset and are depleted as part of the applicable full cost pool. The associated liability is recorded initially as a long-term liability. Subsequent adjustments to the initial asset and liability are recorded to reflect revisions to estimated future cash flow requirements. In addition, the liability is adjusted to reflect accretion expense as well as settlements during the period.

Stock-based Compensation

We grant stock options at exercise prices equal to the fair market value of our common shares at the date of the grant using the Black-Scholes pricing model. The Black-Scholes model is a widely accepted mathematical model for valuing stock-based compensation, but is not the only model available. The Black-Scholes model takes into account the common share price at the grant date, the exercise price, the volatility of the underlying shares and the expected dividends and the risk-free interest rate over the expected life of the option to determine fair value.

SFAS 123(R) requires companies to recognize share-based payments to employees as compensation expense using a fair value method. Under the fair value recognition provisions of SFAS 123(R), stock-based compensation cost is measured at the grant date based on the fair value of the award and is recognized as an expense over the service period on a straight-line basis. The expense recognized over the service period is required to include an estimate of the awards that will be forfeited. Previously, we only recorded the impact of forfeitures as they occurred for employee options. We assumed an approximate 10.0% forfeiture rate for the year ending December 31, 2007.

SFAS No. 123(R) paragraph B129, "Equity Instruments with Exercise Prices Denominated in a Foreign Currency," requires that all equity instruments with exercise prices denominated in a currency other than the currency of the market in which the underlying equity instrument primarily trades be accounted for as liabilities. An exception is made for awards granted to an employee that provides for a fixed exercise price denominated in the currency in which the employee's pay is denominated shall not required to be classified as a liability. Because we have granted options that are priced in Canadian dollars and our stock is primarily traded on the AMEX, the liability method is required relative to all U.S. employees.

- The liability method to account for options granted to U.S. employees in Canadian dollars. Under this method, we record a liability for vested options equal to the value of such vested options as calculated by the Black-Scholes model using the option exercise price and the fair value per share of the common stock underlying the option as of the measurement date.

- The equity method to account for options granted to Canadian employees and options granted to U.S. employees in U.S. dollars. We calculate the expense under this method based on the Black-Scholes value of the option at the date of the grant. This expense is recorded in equal amounts as the options vest; typically over two years.

The fair value of stock-based compensation is expensed, with a corresponding increase to additional paid-in capital for the equity method, or the stock-based compensation liability for the liability method. Upon exercise of stock options, the consideration paid upon exercise is recorded as additional value of common shares and the amount previously recognized in additional paid-in capital is reclassified to common stock.

Both of the aforementioned methods of calculating stock-based compensation require us to make several estimates including when stock options might be exercised, the stock price volatility, forfeiture rates, and the model used to calculate value. The timing for exercise of options is outside our control and depends upon a variety of factors including the market value our common shares and the financial objectives of the holders of the options, among other factors. We calculate volatility using historical data; however, future volatility is inherently uncertain. As of December 31, 2007, we assumed a cumulative forfeiture rate of approximately 10.0% based on historical forfeitures of stock-based compensation grants.

Accounting Pronouncements

In June 2006, the Financial Accounting Standards Board ("FASB") issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes ("FIN 48"). The interpretation clarifies the accounting for uncertainty in income taxes recognized in a company's financial statements in accordance with SFAS 109, "Accounting for Income Taxes." 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 the related de-recognition, classification, interest and penalties, accounting for interim periods, disclosure and transition of uncertain tax positions. Tax positions must meet a "more-likely-than-not" recognition threshold at the effective date to be recognized upon the adoption of FIN 48 and in subsequent periods. The adoption of FIN 48 had an immaterial impact on our consolidated financial position and did not result in unrecognized tax liabilities or benefits being recorded. We file tax returns in Canada and remain in a net operating loss position. We also file income tax returns in the U.S. Federal jurisdiction and various states. There are currently no Federal or state income tax examinations underway for these jurisdictions. Furthermore, we are no longer subject to U.S. Federal income tax examinations by the Internal Revenue Service for tax years before 2003 and for state and local tax authorities for years before 2002. We do, however, have prior year net operating losses which remain open for examination. The interpretation was effective January 1, 2007 for us.

In December 2006, the FASB issued FASB Staff Position ("FSP") EITF 00-19-2, "Accounting for Registration Payment Arrangements." This FSP specifies that the contingent obligation to make future payments or otherwise transfer consideration under a registration payment arrangement should be separately recognized and measured in accordance with FASB Statement No. 5, "Accounting for Contingencies". This FSP is effective immediately for registration payment arrangements and the financial instruments subject to those arrangements that are entered into or modified subsequent to December 21, 2006. For registration payment arrangements and financial instruments subject to those arrangements that were entered into prior to December 21, 2006, the guidance in the FSP is effective January 1, 2006 for us. We do not believe that this FSP will have a material impact on our financial position or results from operations.

On June 1, 2005, the FASB issued SFAS No. 154, "Accounting Changes and Error Corrections," which replaced Accounting Policy Board ("APB") Opinion No. 20, "Accounting Changes," and SFAS No. 3. SFAS 154 provided guidance on the accounting for and reporting of accounting changes and error corrections. It established retrospective application, or the latest practicable date, as the required method for reporting a change in accounting principle and the reporting of a correction of an error. SFAS 154 was effective for accounting changes and corrections of errors made January 1, 2006. The adoption of SFAS No. 154 had no impact on our financial statements.

In February 2006, the FASB issued SFAS No. 155, "Accounting for Certain Hybrid Financial Instruments-An Amendment of FASB Statements No. 133 and 140." SFAS No. 155 amends SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," and SFAS No. 140, "Accounting for Transfers and Servicing of

Financial Assets and Extinguishments of Liabilities," and also resolves issues addressed in SFAS No. 133 Implementation Issue No. D1, "Application of Statement 133 to Beneficial Interests in Securitized Financial Assets." SFAS No. 155 was issued to eliminate the exemption from applying SFAS No. 133 to interests in securitized financial assets so that similar instruments are accounted for in a similar fashion, regardless of the instrument's form. We do not believe that our financial position, results of operations or cash flows will be impacted by SFAS No. 155 as we do not currently hold any hybrid financial instruments.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements." This Statement defines fair value as used in numerous accounting pronouncements, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosure related to the use of fair value measures in financial statements. The Statement is to be effective for our financial statements issued in 2008; however, earlier application is encouraged. We are currently evaluating the timing of adoption and the impact that adoption might have on our financial position or results of operations.

In September 2006, the SEC issued Staff Accounting Bulletin ("SAB") No. 108 "Consideration of Prior Years' Errors in Quantifying Current Year Misstatements." Due to diversity in practice among registrants, SAB 108 expresses SEC staff views regarding the process by which misstatements in financial statements are evaluated for purposes of determining whether financial statement restatement is necessary. SAB 108 is effective for fiscal years ending after November 15, 2006, and early application is encouraged. The adoption of SAB 108 did not have a material impact on our financial position or results from operations.

On February 15, 2007, the FASB issued SFAS No. 159 "The Fair Value Option for Financial Assets and Financial Liabilities." This Statement establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective for our financial statements issued in 2008. We are currently evaluating the impact that the adoption of SFAS No. 159 might have on our financial position or results of operations.

In December 2007, the FASB issued SFAS 141(R), "Business Combinations," which requires the acquiring entity in a business combination to recognize and measure all assets and liabilities assumed in the transaction and any non-controlling interest in the acquiree at fair value as of the acquisition date. SFAS No. 141(R) also establishes guidance for the measurement of the acquirer shares issued in consideration for a business combination, the recognition of contingent consideration, the accounting treatment for pre-acquisition gain and loss contingencies, the treatment of acquisition related transaction costs, and the recognition of changes in the acquirer's income tax valuation allowance and deferred taxes. SFAS No. 141(R) is effective for fiscal years beginning after December 15, 2008, and is to be applied prospectively as of the beginning of the fiscal year in which the statement is applied. Early adoption is not permitted. SFAS No. 141(R) will be effective for us beginning with the 2009 fiscal year. We are currently evaluating the impact of SFAS No. 141(R) on our accompanying consolidated financial statements when effective, but the nature and magnitude of the specific effects will depend upon the nature, terms, and size of the acquisitions we consummate after the effective date.

In December 2007, the FASB issued SFAS No. 160, "Non-controlling Interests in Consolidated Financial Statements – an amendment of ARB 51," which establishes accounting and reporting standards that require non-controlling interests to be reported as a component of equity. SFAS No. 160 also requires that changes in a parent's ownership interest while the parent retains its controlling interest be accounted for as equity transactions and that any retained non-controlling equity investment upon the deconsolidation of a subsidiary be initially measured at fair value. SFAS No. 160 is effective for fiscal years beginning after December 15, 2008, and is to be applied prospectively as of the beginning of the fiscal year in which the statement is applied. We are required to adopt SFAS No. 160 beginning with the 2009 fiscal year. We are currently evaluating the potential impact, if any, of the adoption of SFAS No. 160 on our accompanying consolidated financial statements when effective.

FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K includes certain statements that may be deemed to be "forward-looking statements" within the meaning of Section 27A of the Securities Act, and Section 21E of the Exchange Act, as amended. All statements included in this Annual Report on Form 10-K, other than statements of historical facts, address matters that we reasonably expect, believe or anticipate will or may occur in the future. Forward-looking statements may relate to, among other things:

- our future financial position, including working capital and anticipated cash flow;
- amounts and nature of future capital expenditures;
- operating costs and other expenses;
- wells to be drilled or reworked;
- oil and natural gas prices and demand;
- existing fields, wells and prospects;
- diversification of exploration;
- estimates of proved oil and natural gas reserves;
- reserve potential;
- development and drilling potential;
- expansion and other development trends in the oil and natural gas industry;
- our business strategy;
- production of oil and natural gas;
- effects of Federal, state and local regulation;
- insurance coverage;
- employee relations;
- investment strategy and risk; and
- expansion and growth of our business and operations.

Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to be correct. Disclosure of important factors that could cause actual results to differ materially from our expectations, or cautionary statements, are included under Risk Factors and elsewhere in this Annual Report on 10-K, including, without limitation, in conjunction with the forward-looking statements. The following factors, among others that could cause actual results to differ materially from our expectations, include:

- unexpected changes in business or economic conditions;
- significant changes in natural gas and oil prices;
- timing and amount of production;
- unanticipated down-hole mechanical problems in wells or problems related to producing reservoirs or infrastructure;
- changes in overhead costs; and
- material events resulting in changes in estimates.

All forward-looking statements speak only as of the date made. All subsequent written and oral forward-looking statements attributable to us, or persons acting on our behalf, are expressly qualified in their entirety by the cautionary statements. Except as required by law, we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which it is made or to reflect the occurrence of anticipated or unanticipated events or circumstances.

ITEM 7A. QUANTATATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Rate and Price Risk

Market risk is the potential loss arising from adverse changes in market rates and prices such as foreign currency exchange and interest rates and commodity prices.

The graph below illustrates the rate of return for new wells drilled on our existing properties using natural gas price rates at the point of sale for each property. We estimate that a 10% decrease in natural gas prices would reduce field level cash flow by approximately 11.5%. Without factoring in hedge volume, the impact on field level cash flow would be approximately 20%.

Figure 13: Rate of Return at Various Price Points of Sale

We manage exposure to commodity price fluctuations by periodically hedging a portion of estimated future natural gas production. As of December 31, 2007, we had an inception-to-date unrealized gain on hedges of $1.58 million; of which $1.76 million was classified as a current asset and $0.18 million was classified as a long-term liability. All of our natural gas derivative instruments qualified as cash flow hedges for accounting purposes under SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities,” as of this date.

Our natural gas hedges are inherently effective because they have been indexed to the first of the month CIG index. The CIG index is the same index that determines the actual natural gas revenue received by is for our PRB production. Therefore, the hedges are highly correlated to changes in cash flows from natural gas sales.

Interest Rate Risk

Changes in interest rates can affect the amount of interest we earn on cash, cash equivalents and short-term investments and the amount of interest we pays on borrowings under our Senior Credit Facility. Changes in interest rates do not affect the amount of interest we pay on our fixed rate Convertible Notes, but does affect the fair value of that debt.

Foreign Currency Risk

We conduct business in both U.S. and Canadian dollars and, thus, are exposed to fluctuations in foreign currencies. We monitor this exposure but have not entered into any hedging arrangements to protect from currency fluctuations. As such, we are subject to foreign currency exchange rate risk on cash flows related to sales, expenses, financing, and investing transactions. Substantially all of our Canadian revenues and costs are denominated in Canadian dollars. While the value of the Canadian dollar does fluctuate in relation to the U.S. dollar, we believe that any currency risk associated with our Canadian operations would not have a material impact on our results of operations

Commodity Swaps

At the time of the filing of this report, we had the following commodity swaps in place:

Natural Gas	From	To	Qtrly. Vol. (MMBtu)
July 21, 2005 (1,500 MMBtu / day) CIG fixed price per MMBtu $7.16	Jan-08	Mar-08	136,500
	Apr-08	Jun-08	136,500
	Jul-08	Sep-08	138,000
	Oct-08	Dec-08	138,000
	Jan-09	Mar-09	135,000
	Apr-09	Jun-09	136,500
	Jul-09	Jul-09	46,500
			867,000
August 29, 2006 (2,000 MMBtu / day) CIG fixed price per MMBtu $7.27	Jan-08	Mar-08	182,000
	Apr-08	Jun-08	182,000
	Jul-08	Sep-08	184,000
	Oct-08	Dec-08	184,000
	Jan-09	Mar-09	180,000
	Apr-09	Jun-09	182,000
	Jul-09	Aug-09	124,000
			1,218,000

December 21, 2006 (1,200 MMBtu / day) CIG fixed price per MMBtu $6.61	Jan-08	Mar-08	109,200
	Apr-08	Jun-08	109,200
	Jul-08	Sep-08	110,400
	Oct-08	Dec-08	110,400
			439,200
April 25, 2007 (3,920 MMBtu / day) CIG fixed price per MMBtu $7.14	Jan-08	Mar-08	343,000
	Apr-08	Jun-08	389,000
	Jul-08	Sep-08	365,000
	Oct-08	Dec-08	332,000
			1,429,000
October 3, 2007 (2,220 MMBtu / day) CIG fixed price per MMBtu $6.14	Jan-08	Mar-08	137,000
	Apr-08	Jun-08	152,000
	Jul-08	Sep-08	241,000
	Oct-08	Dec-08	272,000
			802,000
April 25, 2007 (4,290 MMBtu / day) CIG fixed price per MMBtu $7.38	Jan-09	Mar-09	383,000
	Apr-09	Jun-09	305,000
	Jul-09	Sep-09	385,000

	Oct-09	Dec-09	488,000
			1,561,000
April 25, 2007 (4,680 MMBtu / day) CIG fixed price per MMBtu $7.75	Jan-10	Mar-10	427,000
	Apr-10	Apr-10	130,000
			557,000
September 21, 2007 (3,020 MMBtu / day) CIG fixed price per MMBtu $6.265	May-10	Jun-10	211,000
	Jul-10	Sep-10	282,000
	Oct-10	Dec-10	245,000
			738,000
Hedges in place at December 31, 2007			7,611,200
January 10, 2008 (4,020 MMBtu / day) CIG fixed price per MMBtu $7.00	Jan-09	Mar-09	292,000
	Apr-09	Jun-09	352,000
	Jul-09	Sep-09	395,000
	Oct-09	Dec-09	425,000
			1,464,000
Hedges in place at the time of this filing			9,075,200

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The following table reflects our commodity swaps executed and in place as of December 31, 2007, by quarter:

	Quarter Ended	Qtrly. Vol. (MMBtu)	Weighted Average CIG Fixed Price per MMBtu
	03/31/08	907,700	$ 6.95
	06/30/08	968,700	$ 6.95
	09/30/08	1,038,400	$ 6.88
	12/31/08	1,036,400	$ 6.85
Total 2008		3,951,200	$ 6.90
	03/31/09	698,000	$ 7.31
	06/30/09	623,500	$ 7.30
	09/30/09	555,500	$ 7.34
	12/31/09	488,000	$ 7.38
Total 2009		2,365,000	$ 7.33
	03/31/10	427,000	$ 7.75
	06/30/10	341,000	$ 6.83
	09/30/10	282,000	$ 6.27
	12/31/10	245,000	$ 6.27
Total 2010		1,295,000	$ 6.90
Total All		7,611,200	$ 7.01

In addition to the commodity swaps shown above, on January 10, 2008, we entered into another commodity swap cash settlement transaction. The outstanding quantity committed to the swap is 4,020 MMBtu's per day beginning January 1, 2009 through December 31, 2009. The total quantity is 1,464,000 MMBtu's. The fixed price in the agreement is $7.00 per MMBtu (CIG pricing).

As of December 31, 2007, a 10% change in CIG gas prices would result in a change of $4.3 million in the value of unrealized derivatives.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Consolidated Financial Statements

STORM CAT ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
(Stated in thousands of U.S. dollars, except share amounts)

	December 31, 2007	December 31, 2006
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 1,133	$ 5,299
Accounts receivable:		
Joint interest billing	1,701	1,932
Revenue receivable	2,444	2,121
Fair value of derivative instruments	1,760	2,670
Prepaid costs and other current assets	2,941	1,445
Total current assets	9,979	13,467
PROPERTY AND EQUIPMENT (full cost method), at cost:		
Oil and gas properties:		
Unproved properties	51,438	54,873
Proved properties	78,096	46,446
Less: accumulated depreciation, depletion, and amortization	(12,228)	(4,764)
Oil and gas properties, net	117,306	96,555
Other property	1,180	1,057
Accumulated depreciation	(778)	(408)
Total other property, net	402	649
Total property and equipment, net	117,708	97,204
OTHER NON-CURRENT ASSETS:		
Restricted cash	685	511
Debt issuance costs, net of accumulated amortization of $1,988 and $522, respectively	3,435	—
Accounts receivable – long-term	759	—
Fair value of derivative instruments	—	782
Total other non-current assets	4,879	1,293
Total assets	$ 132,566	$ 111,964
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 5,825	$ 7,302
Revenue payable	1,678	2,063
Accrued and other liabilities	4,131	10,011
Interest payable	12	952
Stock-based compensation liability	394	—
Flow-through shares liability	—	1,233
Notes payable	—	7,500
Total current liabilities	12,040	29,061
NON-CURRENT LIABILITIES:		
Asset retirement obligation	1,713	1,871
Fair value of derivative instruments	183	—
Notes payable	43,056	19,350
Convertible Notes payable	50,195	—

Total non-current liabilities		95,147		21,221
Total liabilities		107,187		50,282
Commitments (Note 10 and Note 13)				
SHAREHOLDERS' EQUITY:				
Common Shares, without par value, unlimited common shares authorized, issued and outstanding: 81,087,320 at December 31, 2007 and 80,429,820 at December 31, 2006		69,834		69,518
Additional paid-in capital		5,640		4,910
Accumulated other comprehensive income		7,483		3,877
Accumulated deficit		(57,578)		(16,623)
Total shareholders' equity		25,379		61,682
Total liabilities and shareholders' equity	$	132,566	$	111,964

See accompanying notes to consolidated financial statements.

STORM CAT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(Stated in thousands of U.S. dollars, except share amounts)

	Year Ended December 31, 2007	2006	2005
OPERATING REVENUES:			
Natural gas revenue	$ 16,757	$ 9,444	$ 4,214
OPERATING EXPENSES:			
Gathering and transportation	2,313	1,921	906
Lease operating expenses	6,132	3,443	2,354
General and administrative	8,266	6,695	5,576
Depreciation, depletion, amortization and accretion of asset retirement obligation	7,976	3,916	1,648
Impairment of oil and gas properties	27,861	2,027	2,125
Total operating expenses	52,548	18,002	12,609
Operating loss	(35,791)	(8,558)	(8,395)
OTHER INCOME (EXPENSE):			
Interest expense	(4,745)	—	—
Interest and other miscellaneous income	219	173	27
Amortization of debt issuance costs	(1,988)	—	—
Total other income (expense)	(6,514)	173	27
Loss before taxes	(42,305)	(8,385)	(8,368)
Recovery of future income tax asset from flow-through shares	1,350	1,524	0
NET LOSS	$ (40,955)	$ (6,861)	$ (8,368)
Basic and diluted net loss per share	$ (.51)	$ (0.10)	$ (0.18)
Weighted average number of shares outstanding	80,912,950	70,429,219	47,321,481

See accompanying notes to consolidated financial statements.

STORM CAT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY AND COMPREHENSIVE LOSS
(Stated in thousands of U.S. dollars)

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Other Comprehensive Income	Accumulated Deficit	Total Shareholders' Equity
BALANCE AT DECEMBER 31, 2004	32,560,714	$ 5,940	$ 289	$ 229	$ (1,394)	$ 5,064
Private placements	18,993,826	37,745	—	—	—	37,745
Warrants exercised	13,453,180	10,661	—	—	—	10,661
Stock options exercised	646,668	287	—	—	—	287
Stock issuance costs	—	(3,043)	—	—	—	(3,043)
Flow-through shares	—	(731)	—	—	—	(731)
Stock-based compensation	—	—	1,914	—	—	1,914
Net loss	—	—	—	—	(8,368)	(8,368)
Foreign currency translation	—	—	—	(78)	—	(78)
Other comprehensive loss	—	—	—	—	—	(8,446)
BALANCE AT DECEMBER 31, 2005	65,654,388	$ 50,859	$ 2,203	$ 151	$ (9,762)	$ 43,451
Warrants exercised	753,906	1,297	—	—	—	1,297
Stock options exercised	227,500	145	—	—	—	145
Private placement of flow-through shares	6,172,839	9,933	—	—	—	9,933
Private placement	7,594,937	10,728	—	—	—	10,728
Restricted share units vested	26,250	43	—	—	—	43
Stock issuance costs	—	(1,430)	—	—	—	(1,430)
Flow-through shares	—	(2,086)	—	—	—	(2,086)
Stock-based compensation	—	—	2,707	—	—	2,707
Other	—	29	—	—	—	29
Net loss	—	—	—	—	(6,861)	(6,861)
Foreign currency translation and fair value of derivatives	—	—	—	3,726	—	3,726
Other comprehensive loss	—	—	—	—	—	(3,135)
BALANCE AT DECEMBER 31, 2006	80,429,820	$ 69,518	$ 4,910	$ 3,877	$ (16,623)	$ 61,682
Stock options exercised	500,000	169	—	—	—	169
Restricted share units vested	157,500	155	—	—	—	155
Stock issuance costs	—	(8)	—	—	—	(8)
Stock-based compensation	—	—	730	—	—	730
Net loss	—	—	—	—	(40,955)	(40,955)
Foreign currency translation and fair value of derivatives	—	—	—	3,606	—	3,606
Other comprehensive loss	—	—	—	—	—	(37,349)
BALANCE AT DECEMBER 31, 2007	81,087,320	$ 69,834	$ 5,640	$ 7,483	$ (57,578)	$ 25,379

See accompanying notes to consolidated financial statements.

STORM CAT ENERGY CORPORATION
CONSOLIDATED STATEMENT OF CASH FLOWS
(Stated in thousands of U.S. dollars)

	Year Ended December 31, 2007	2006	2005
Cash flows from operating activities:			
Net loss	$ (40,955)	$ (6,861)	$ (8,368)
Adjustments to reconcile net loss to net cash used in operating activities:			
Recovery of future tax asset from flow-through shares	(1,350)	(1,524)	—
Stock-based compensation	1,145	2,707	1,914
Depreciation, depletion, amortization and accretion of asset retirement obligations	7,976	3,777	1,637
Asset impairment	27,861	1,975	2,125
Gain on disposition of properties	—	(185)	(56)
Amortization of debt issuance costs	1,988	—	—
Changes in operating working capital:			
Accounts receivable	(84)	(3,180)	(1,099)
Other current assets	(3,295)	(666)	(360)
Accounts payable	970	(3,331)	509)
Accrued interest and other current liabilities	(1,488)	4,601	1,426
Net cash used in operating activities	(7,232)	(2,687)	(2,272)
Cash flows from investing activities:			
Restricted cash	(917)	(335)	(150)
Capital expenditures - oil and gas properties	(62,240)	(71,258)	(14,766)
Proceeds from sale of gathering system	—	1,000	—
Other capital expenditures	(55)	(145)	(817)
Net cash used in investing activities	(63,212)	(70,738)	(15,733)
Cash flows from financing activities:			
Issuance of stock	293	18,660	44,189
Flow-through shares	—	2,755	731
Proceeds from (repayments of) bank debt	12,729	27,532	—
Proceeds from Convertible Notes payable	51,169	—	—
Net cash provided by financing activities	64,191	48,947	44,920
Effect of exchange rate changes on cash	2,087	275	(78)
Net increase (decrease) in cash and cash equivalents	(4,166)	(24,203)	26,837
Cash and cash equivalents and beginning of year	5,299	29,502	2,665
Cash and cash equivalents at end of year	$ 1,133	$ 5,299	$ 29,502
Cash paid during the year for:			
Interest	$ 7,288	$ —	$ —

See accompanying notes to consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED DECEMBER 31, 2007, 2006 AND 2005

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The accompanying consolidated financial statements include Storm Cat and its wholly-owned subsidiaries. All significant intercompany transactions have been eliminated.

Certain reclassifications have been made to prior years to conform to the classification used in the current year. The reclassifications had no effect on the net loss in prior years.

Cash and Cash Equivalents

Cash equivalents consist of highly liquid investments with original maturities of three months or less.

Short-Term Investments

Short-term investments consist solely of investment sweep accounts held with our three banks (Wells Fargo, Bank of America and Scotia Bank). Available funds are swept overnight and invested in short-term treasury.

Concentration of Credit Risk

Substantially all of our receivables are within the oil and natural gas industry, primarily from purchasers of natural gas and from joint interest owners. These receivables are due from many companies with collectability being dependent upon the financial wherewithal of each individual company as well as the general economic conditions of the industry. The receivables are not collateralized. To date we have had minimal bad debts.

Off-Balance Sheet Arrangements

From time-to-time, we enter into off-balance sheet arrangements and transactions that can give rise to off-balance sheet obligations. As of December 31, 2007, the off-balance sheet arrangements and transactions that we have entered into include undrawn letters of credit, operating lease agreements and gas transportation commitments. We do not believe that these arrangements are reasonably likely to materially affect our liquidity or availability of, or requirements for, capital resources.

Fair Value of Financial Instruments

Our financial instruments including cash and cash equivalents, accounts receivable, accounts payable and debt are carried at cost, which approximates fair value due to the short-term maturity of these instruments or interest rates that approximate current market rates.

Revenue Recognition

We derive our revenue primarily from the sale of natural gas. We report revenue gross for the amounts received before taking into account production taxes and transportation costs which are reported as separate expenses. Revenue is recorded in the month production is delivered to the purchaser at which time title changes hands. Payment is generally received between 30 and 90 days after the date of production. We estimate the amount of production delivered to purchasers and the prices we will receive. We use our knowledge of our properties; their historical performance; the anticipated effect of weather conditions during the month of production; CIG and local spot market prices; and other factors as the basis for these estimates. Variances between estimates and the actual amounts received are recorded when payment is received.

A majority of our sales are made under contractual arrangements with terms that are considered to be usual and customary in the oil and gas industry. The contracts are for periods of up to five years with prices determined based upon a percentage of a pre-determined and published monthly index price. The terms of these contracts have not had an effect on how we recognize our revenue.

Accounting Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates with regard to these financial statements include the estimate of proved oil and natural gas reserve quantities and the related present value of estimated future net cash flows there from. These estimates impact our calculation of depletion and amortization as well as our impairment calculations.

Foreign Currency Conversion

For the twelve months ended December 31, 2007, balances in the statement of operations were converted from Canadian to U.S. dollars at a weighted average exchange rate of $0.93565 CDN to $1.00 U.S., and balance sheet amounts were converted at a rate of $1.0194 CDN to $1.00 U.S. based on the exchange rate on December 31, 2007.

Accounting for Oil and Gas Properties

We follow the full cost method of accounting for oil and gas operations whereby all costs of exploring for and developing oil and gas reserves are initially capitalized on a country-by-country (cost center) basis. Such costs include land acquisition costs, geological and geophysical expenditures, carrying charges on non-producing properties, drilling costs, overhead charges directly related to acquisition, exploration and development activities. We capitalize interest costs to our natural gas properties on qualifying expenditures made in connection with exploration and development projects that are not subject to depletion. Interest is capitalized only for the period that activities are in progress to bring these projects to their intended use. During 2007, we capitalized interest of approximately $0.4 million to our Canadian properties, and approximately $0.5 million to our U.S. properties.

Capitalized costs, less estimated salvage value, are depleted using the units-of-production method whereby historical costs, including future development costs, are amortized over the total estimated proved reserves. Costs of acquiring and evaluating unproved properties and major development projects are initially excluded from the depletion and depreciation calculation until it is determined whether or not proved reserves can be assigned to such properties. Costs of unproved properties and major development projects are transferred to depletable costs as the associated production produces additional reserves. These costs are assessed periodically to ascertain whether impairment has occurred. Our total impairment charges, by cost center, are reflected in the table below:

In Thousands	Year Ended December 31, 2007	2006	2005
United States	$ 25,000	$ —	$ —
Canada	2,861	1,939	—
Mongolia	—	88	2,125
Total	$ 27,861	$ 2,027	$ 2,125

Under the full cost method of accounting, capitalized oil and gas property costs, less accumulated depletion and net of related deferred income taxes, if any, may not exceed an amount referred to as the “ceiling.” The ceiling is the sum of the present value, discounted at 10%, of estimated future net revenues from proved oil and gas reserves plus the lower of cost or fair market value of unproved properties. The present value of estimated future net revenues is computed by pricing estimated future production of proved reserves at current period end product prices, and then deducting future expenditures estimated to be incurred in developing and producing the proved reserves assuming the continuation of existing economic conditions. If the amount of capitalized costs exceeds the ceiling, a write-down of the capitalized costs is required unless commodity prices increase subsequent to the end of the year such that the deficiency is reduced or eliminated. Once a write-down has been recorded, it may not be reversed in a subsequent year.

Natural Gas Reserves

We currently have no oil reserves. The determination of depreciation and depletion expense as well as ceiling test write-downs related to the recorded value of our natural gas properties are highly dependent on the estimates of the proved natural gas reserves. Natural gas reserves include proved reserves that represent estimated quantities of 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. There are numerous uncertainties inherent in estimating natural gas reserves and their values, including many factors beyond our control. Accordingly, reserve estimates may differ from the quantities of natural gas ultimately recovered and the estimated lifting costs associated with the recovery of these reserves may differ from those actually incurred.

Price changes may affect the economic lives of natural gas properties and, therefore, price changes may cause reserve revisions.

Our proved properties at December 31, 2007 have an average expected reserve life of seven to ten years (unaudited). This measure is a weighted average, therefore, some of our properties will have a life shorter than the average and some will have a life longer than the average. The expected economic lives of our properties may vary widely depending upon, among other things, natural gas prices, possible curtailments in consumption by purchasers, and changes in governmental regulations or taxation. As a result, our actual future net cash flows from proved reserves could be materially different from our estimates.

Industry Segment and Geographic Information

We operate in one industry segment, which is the exploration, exploitation, development, acquisition, and production of natural gas. All of our operations are conducted in the continental United States and Canada. Consequently, we currently report as a single industry segment. Our Canadian operations produce no income from operations and segmentation of operating information is not applicable. However, our Canadian properties represent approximately 31.0% of our assets. As such, we have shown information by segment in Note 3. Oil and Gas Property, and also relative to acreage, capital expenditures and impairment discussions throughout this document.

Capitalized Interest

Pursuant to FASB SFAS Statement No. 34, “Capitalization of Interest,” we are required to capitalize interest costs to natural gas properties on expenditures made in connection with exploration and development projects that are not subject to current depreciation, depletion or amortization. Interest is capitalized only for the period that activities are in progress to bring these projects to their intended use. Approximately $0.9 million and $1.0 million of interest cost was capitalized in 2007 and 2006, respectively. No interest was capitalized during 2005.

Capitalized Internal Costs

Prior to 2007, we capitalized certain internal costs including salaries, bonuses and stock-based compensation on a pro-rata basis for employees directly involved in capital projects. $2.1 million of internal costs were capitalized in the year ended December 31, 2006. Beginning in 2007, we discontinued the capitalization of internal costs, except for two employees with direct responsibility for the supervision of capital projects in the PRB. The salaries of these employees were allocated to the properties based on a percentage of time spent on each capital project. No internal costs were capitalized during 2005.

Asset Retirement Obligation

The estimated fair value of the future costs associated with dismantlement, abandonment and restoration of natural gas properties is recorded when the assets are placed into service, generally through acquisition or completion of a well. The net estimated costs are discounted to present values using a risk-adjusted rate over the estimated economic life of the properties. Such costs are capitalized as part of the basis of the related asset and are depleted as part of the applicable full cost pool. The associated liability is recorded initially as a long-term liability. Subsequent adjustments to the initial asset and liability are recorded to reflect revisions to estimated future cash flow requirements. In addition, the liability is adjusted to reflect accretion expense as well as settlements during the period.

A reconciliation of the changes in the asset retirement obligation for the years ended December 31, 2005, 2006 and 2007, respectively, is as follows (in thousands):

Balance at January 1, 2005	$	79
Liabilities assumed		649
Accretion expense		65
Balance at December 31, 2005		793
Adjustment for revision of estimated life in the PRB		(206)
Additional liabilities incurred		1,071
Accretion expense		213
Balance at December 31, 2006		1,871
Adjustment for revision of estimated life in the PRB		(727)
Additional liabilities incurred		318
Change in conversion rate		70
Accretion expense		181
Balance at December 31, 2007	$	1,713

Impairment of Long-Lived Assets

We apply SFAS No. 144, “Accounting for the Impairment or Disposal of Long-Lived Assets,” to long-lived assets not included in oil and gas properties. Under SFAS No. 144, all long-lived assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying value may not be recoverable. The carrying amount of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from its use and eventual disposition. An impairment loss is recognized when the carrying value of a long-lived asset is not recoverable and exceeds its fair value.

Other Property

Other property we own is depreciated using the straight-line method over the estimated useful life (typically three to five years).

Income Taxes

We account for income taxes in accordance with SFAS No. 109, “Accounting for Income Taxes,” which requires the use of the asset and liability method of computing deferred income taxes. The objective of the asset and liability method is to establish deferred tax assets and liabilities for the temporary differences between the book basis and the tax basis of our assets and liabilities at enacted tax rates expected to be in effect when such amounts are realized or settled.

Natural Gas Price Hedging

We periodically hedge the price of a portion of its estimated natural gas production when the potential for significant downward price movement is anticipated. Such hedges, which are accounted for as cash flow hedges, do not exceed estimated production volumes, and are expected to have reasonable correlation between price movements in the futures market and the cash markets where our production is located. Hedges are expected to be settled as related production occurs but may be settled earlier if the anticipated downward price movement occurs or if we believe that the potential for such movement has abated.

We recognize all derivatives (consisting solely of cash flow hedges) on the balance sheet at fair value at the end of each period. Changes in the fair value of a cash flow hedge are recorded in Shareholders' equity as accumulated other comprehensive income (loss) on the consolidated balance sheets. As hedge contracts are settled, they are typically reclassified from the balance sheet to the consolidated statements of operations and included in natural gas revenue.

Hedging gains and losses are recognized as adjustments to gas sales as the hedged product is produced. We had an after tax realized hedging gain of $5.6 million in fiscal 2007, and $1.1 million in fiscal 2006, which was the first year in which hedges were utilized. Hedge ineffectiveness, which was not material for the year ended December 31, 2007, has been immediately recognized in natural gas sales

Basic and Diluted Loss per Share

Basic loss per share is computed by dividing the net loss available to common shareholders by the weighted average number of common shares outstanding during the period. The shares represented by vested restricted stock units ("RSUs") issued to date are included in the calculation of the weighted average basic common shares outstanding. Diluted loss per share is calculated giving effect to the potential dilution that would occur if vested stock options, RSUs and stock purchase warrants were exercised and the Convertible Notes were converted to common shares. The dilutive effect of options, RSUs, warrants and the Convertible Notes is computed by application of the treasury stock method which assumes that proceeds from the exercise of in-the-money options and warrants would be used to repurchase common shares at average market prices during the period. Diluted amounts are not presented when the effects of the computations are anti-dilutive due to net losses incurred. Accordingly, there is no difference in the amounts presented for basic and diluted loss per share for the years end ended December 31, 2007 and 2006. Listed below is a table showing the potentially dilutive shares outstanding as of December 31, 2007, 2006 and 2005, respectively, which have been excluded from the diluted earnings per share calculation.

	Year Ended December 31,		
	2007	2006	2005
Options	4,550,000	5,470,000	3,824,166
Unvested restricted share units	95,000	—	—
Series A Notes	15,841,880	—	—
Series B Notes	27,059,829	—	—
Warrants	2,126,582 (1)	8,923,368	7,450,692
Total potentially dilutive shares outstanding	49,673,291	14,393,368	11,274,858

(1) The entire 2,126,582 of warrants outstanding at year-end 2007 will expire on March 19, 2008 if not exercised.

Recent Accounting Pronouncements

In June 2006, the Financial Accounting Standards Board ("FASB") issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes ("FIN 48"). The interpretation clarifies the accounting for uncertainty in income taxes recognized in a company's financial statements in accordance with SFAS 109, "Accounting for Income Taxes." 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 the related de-recognition, classification, interest and penalties, accounting for interim periods, disclosure and transition of uncertain tax positions. Tax positions must meet a "more-likely-than-not" recognition threshold at the effective date to be recognized upon the adoption of FIN 48 and in subsequent periods. The adoption of FIN 48 had an immaterial impact on our consolidated financial position and did not result in unrecognized tax liabilities or benefits being recorded. We file tax returns in Canada and remain in a net operating loss position. We also file income tax returns in the U.S. Federal jurisdiction and various states. There are currently no Federal or state income tax examinations underway for these jurisdictions. Furthermore, we are no longer subject to U.S. Federal income tax examinations by the Internal Revenue Service for tax years before 2003 and for state and local tax authorities for years before 2002. We do, however, have prior year net operating losses which remain open for examination. The interpretation was effective January 1, 2007 for us.

In December 2006, the FASB issued FASB Staff Position ("FSP") EITF 00-19-2, "Accounting for Registration Payment Arrangements." This FSP specifies that the contingent obligation to make future payments or otherwise transfer consideration under a registration payment arrangement should be separately recognized and measured in accordance with FASB Statement No. 5, "Accounting for Contingencies". This FSP is effective immediately for registration payment arrangements and the financial instruments subject to those arrangements that are entered into or modified subsequent to December 21, 2006. For registration payment arrangements and financial instruments subject to those arrangements that were entered into prior to December 21, 2006, the guidance in the FSP is effective January 1, 2006 for us. We do not believe that this FSP will have a material impact on our financial position or results from operations.

On June 1, 2005, the FASB issued SFAS No. 154, "Accounting Changes and Error Corrections," which replaced Accounting Policy Board ("APB") Opinion No. 20, "Accounting Changes," and SFAS No. 3. SFAS 154 provided guidance on the accounting for and reporting of accounting changes and error corrections. It established retrospective application, or the latest practicable date, as the required method for reporting a change in accounting principle and the reporting of a correction of an error. SFAS 154 was effective for accounting changes and corrections of errors made January 1, 2006. The adoption of SFAS No. 154 had no impact on our financial statements.

In February 2006, the FASB issued SFAS No. 155, "Accounting for Certain Hybrid Financial Instruments-An Amendment of FASB Statements No. 133 and 140." SFAS No. 155 amends SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," and SFAS No. 140, "Accounting for Transfers and Servicing of

Financial Assets and Extinguishments of Liabilities," and also resolves issues addressed in SFAS No. 133 Implementation Issue No. D1, "Application of Statement 133 to Beneficial Interests in Securitized Financial Assets." SFAS No. 155 was issued to eliminate the exemption from applying SFAS No. 133 to interests in securitized financial assets so that similar instruments are accounted for in a similar fashion, regardless of the instrument's form. We do not believe that our financial position, results of operations or cash flows will be impacted by SFAS No. 155 as we do not currently hold any hybrid financial instruments.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements." This Statement defines fair value as used in numerous accounting pronouncements, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosure related to the use of fair value measures in financial statements. The Statement is to be effective for our financial statements issued in 2008; however, earlier application is encouraged. We are currently evaluating the timing of adoption and the impact that adoption might have on our financial position or results of operations.

In September 2006, the SEC issued Staff Accounting Bulletin ("SAB") No. 108 "Consideration of Prior Years' Errors in Quantifying Current Year Misstatements." Due to diversity in practice among registrants, SAB 108 expresses SEC staff views regarding the process by which misstatements in financial statements are evaluated for purposes of determining whether financial statement restatement is necessary. SAB 108 is effective for fiscal years ending after November 15, 2006, and early application is encouraged. The adoption of SAB 108 did not have a material impact on our financial position or results from operations.

On February 15, 2007, the FASB issued SFAS No. 159 "The Fair Value Option for Financial Assets and Financial Liabilities." This Statement establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective for our financial statements issued in 2008. We are currently evaluating the impact that the adoption of SFAS No. 159 might have on our financial position or results of operations.

In December 2007, the FASB issued SFAS 141(R), "Business Combinations," which requires the acquiring entity in a business combination to recognize and measure all assets and liabilities assumed in the transaction and any non-controlling interest in the acquiree at fair value as of the acquisition date. SFAS No. 141(R) also establishes guidance for the measurement of the acquirer shares issued in consideration for a business combination, the recognition of contingent consideration, the accounting treatment for pre-acquisition gain and loss contingencies, the treatment of acquisition related transaction costs, and the recognition of changes in the acquirer's income tax valuation allowance and deferred taxes. SFAS No. 141(R) is effective for fiscal years beginning after December 15, 2008, and is to be applied prospectively as of the beginning of the fiscal year in which the statement is applied. Early adoption is not permitted. SFAS No. 141(R) will be effective for us beginning with the 2009 fiscal year. We are currently evaluating the impact of SFAS No. 141(R) on our accompanying consolidated financial statements when effective, but the nature and magnitude of the specific effects will depend upon the nature, terms, and size of the acquisitions we consummate after the effective date.

In December 2007, the FASB issued SFAS No. 160, "Non-controlling Interests in Consolidated Financial Statements – an amendment of ARB 51," which establishes accounting and reporting standards that require non-controlling interests to be reported as a component of equity. SFAS No. 160 also requires that changes in a parent's ownership interest while the parent retains its controlling interest be accounted for as equity transactions and that any retained non-controlling equity investment upon the deconsolidation of a subsidiary be initially measured at fair value. SFAS No. 160 is effective for fiscal years beginning after December 15, 2008, and is to be applied prospectively as of the beginning of the fiscal year in which the statement is applied. We are required to adopt SFAS No. 160 beginning with the 2009 fiscal year. We are currently evaluating the potential impact, if any, of the adoption of SFAS No. 160 on our accompanying consolidated financial statements when effective.

NOTE 2. DERIVATIVE FINANCIAL INSTRUMENTS

We recognized a $5.6 million increase in natural gas revenue from our derivative contracts in 2007, and $1.1 million increase in 2006. No hedges were in place before 2006 as indicated in the table below, which summarizes derivative instrument gain activity:

	Year Ended December 31,		
In Thousands	2007	2006	2005
Derivative contract reflected in natural gas revenue	$ 5,589	$ 1,102	$ —
Change in fair value of derivatives reflected in other comprehensive income	(1,875)	3,451	—
Total derivative instrument gain	$ 3,714	$ 4,553	$ —

Natural Gas Commodity Hedges

To mitigate a portion of the potential exposure to adverse market changes, we have entered into various derivative contracts. As of December 31, 2007, we had hedge contracts in place through December 2010 for a total of approximately 7,611,200 MMBtu of anticipated production from our PRB properties (see Item 7A. Quantitative and Qualitative Disclosures About Market Risk for a detailed listing of our commodity swaps). In addition, on January 10, 2008, we entered into another commodity swap cash settlement transaction for 1,464,000 MMBtu's beginning January 1, 2009 through December 31, 2009.
We anticipate that all forecasted transactions will occur by the end of their originally specified periods. All contracts are entered into for other than trading purposes.

As of December 31, 2007, all natural gas derivative instruments qualified as cash flow hedges for accounting purposes under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities."

Realized gains or losses from the settlement of gas derivative contracts are reported as natural gas revenues in the consolidated statements of operations. Changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income in the consolidated balance sheet. Any change in fair value resulting from ineffectiveness is recognized currently in derivative loss in the consolidated statement of operations.

Our natural gas hedges are inherently effective because they have been indexed to the first of the month CIG index. The CIG index is the same index that determines the actual natural gas revenue received us for our PRB production. Therefore, the hedges are highly correlated to changes in cash flows from natural gas sales.

NOTE 3. OIL AND GAS PROPERTY

Capitalized Costs

Total All Cost Centers	Year Ended December 31,	
In Thousands	2007	2006
Unproved properties not being amortized	$ 51,438	$ 54,873
Properties being amortized	78,096	46,446
Accumulated depreciation, depletion and amortization	(12,228)	(4,764)
Total net capitalized costs	$ 117,306	$ 96,555

United States	Year Ended December 31,	
In Thousands	2007	2006
Unproved properties not being amortized	$ 15,139	$ 31,930
Properties being amortized	78,096	46,446
Accumulated depreciation, depletion and amortization	(12,228)	(4,764)
Total net capitalized costs	$ 81,007	$ 73,612

Canada and International	Year Ended December 31,	
In Thousands	2007	2006
Unproved properties not being amortized	$ 36,299	$ 22,943
Properties being amortized	—	—
Accumulated depreciation, depletion and amortization	—	—
Total net capitalized costs	$ 36,299	$ 22,943

Unproved Oil and Gas Properties

Costs directly associated with the acquisition and evaluation of unproved properties are excluded from the amortization computation until they are evaluated. The following tables shows, by category of cost and date incurred, the unevaluated oil and gas property costs (net of transfers to the full cost pool and sales proceeds) excluded from the amortization computation as of the periods indicated, in total and by cost center:

Total All Cost Centers	For the Year Ended December 31,				
In Thousands	2007	2006	2005	Prior Balance	Total
Exploration costs	$ 14,120	$ 27,159	$ 13,229	$ 1,275	$ 55,783
Development costs	—	3,804	448	—	4,252
Acquisition costs	—	22,538	1,814	—	24,352
Reclass to evaluated	(18,507)	(6,874)	—	—	(25,381)
Impairment	(2,935)	(2,508)	(2,125)	—	(7,568)
Total net unproved oil and gas properties	$ (7,322)	$ 44,119	$ 13,366	$ 1,275	$ 51,438

United States	For the Year Ended December 31,				
In Thousands	2007	2006	2005	Prior Balance	Total
Exploration costs	$ 1,716	$ 4,258	$ 5,942	$ —	$ 11,916
Development costs	—	3,804	448	—	4,252
Acquisition costs	—	22,538	1,814	—	24,352
Reclass to evaluated	(18,507)	(6,874)	—	—	(25,381)
Total net unproved oil and gas properties	$ (16,791)	$ 23,726	$ 8,204	$ —	$ 15,139

Canada and International	For the Year Ended December 31,				
In Thousands	2007	2006	2005	Prior Balance	Total
Exploration costs	$ 12,404	$ 22,901	$ 7,287	$ 1,275	$ 43,867
Impairment	(2,935)				