

FORTRESS ENERGY INC.

ANNUAL INFORMATION FORM

Year ended December 31, 2008

Dated March 31, 2009

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CONVENTIONS

Unless otherwise indicated, references herein to “\$” or “dollars” are to Canadian dollars. All financial information with respect to the Corporation has been presented in Canadian dollars in accordance with generally accepted accounting principles in Canada.

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
Bbl	Barrel	Mcf	thousand cubic feet
Bbls	Barrels	MMcf	million cubic feet
MBbls	thousand barrels	Mcf/d	thousand cubic feet per day
MMBbls	million barrels	MMcf/d	million cubic feet per day
Mstb	1,000 stock tank barrels	MMbtu	Million British thermal units
Bbls/d	barrels per day	Bcf	billion cubic feet
NGLs	natural gas liquids	GJ	Gigajoule

Other

AECO	Alberta Energy Company’s natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil
ARTC	Alberta Royalty Tax Credit
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 (unless otherwise stated) Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices). BOE’S maybe misleading, particularly if used in isolation. A BOE conversion of 6 Mcf to 1Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
BOE/D	barrel of oil equivalent per day
m ³	cubic metres
MBOE	1,000 barrels of oil equivalent
WTI	West Texas Intermediate, the reference price paid is U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

CONVERSION

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls oil	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometers	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471
MMbtu	Gigajoules	1.0526

DEFINITIONS

“**ABCA**” means the *Business Corporations Act* (Alberta), as amended;

“**AIF**” means this Annual Information Form;

“**Board**” means the Board of Directors of the Corporation as constituted from time to time;

“**Business Day**” means any day other than a Sunday, Saturday or a day on which banking institutions in Calgary, Alberta are authorized or obligated by law to close;

“**COGE Handbook**” means the “Canadian Oil and Gas Evaluation Handbook”;

“**Common Shares**” means the common shares of the Corporation, as presently constituted;

“**Fortress**” means Fortress Energy Inc., a corporation incorporated under the ABCA;

“**Marauder**” means Marauder Resources West Coast Inc.;

“**NI 51-101**” means National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities*;

“**Person**” or “**Persons**” includes an individual, body corporate, partnership, syndicate or other form of unincorporated entity;

“**Petroleum Properties**” means a right, however derived, to explore for, develop, produce or market petroleum substances and includes the lands associated with such right and includes as well any lease, permit, license, farm-in agreement, participation agreement, or other arrangement of whatsoever kind and any right to acquire same;

“**Principal Holder**” means a person who, directly or indirectly, beneficially owns or controls 10% or more of any class of voting securities of the Corporation;

“**Prospect**” means drillable prospects or lands for farm-out in a geographical area in western Canada;

“**Signal**” means SignalEnergy Inc., a corporation incorporated under the laws of the Province of Quebec and a predecessor of the Corporation;

“**Sproule**” means Sproule Associates Limited, independent petroleum reservoir engineers, Calgary, Alberta; and

“**Sproule Report**” means the independent reserve analysis and report of the Corporation’s reserves effective December 31, 2008 prepared by Sproule and dated March 3, 2009.

Unless the content otherwise requires, the “**Corporation**” when used in this Annual Information Form with respect to events occurring or matters as at a date prior to February 20, 2007 shall refer to Signal (the predecessor in interest of all of the assets of Fortress) and when used with respect to events occurring or matters as at a date from and after February 20, 2007 shall refer to Fortress.

Special Note Regarding Forward-looking Statements

Certain statements contained in this Annual Information Form and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements. In

particular, the Corporation has made assumptions with respect to, prices for oil and natural gas, oil and gas reserve quantities, the discounted present value of future net cash flows from these reserves and the ultimate recoverability of reserves, timing and amount of future production, forecasts of capital expenditures and the sources of financing thereof, the amount, nature, timing and effects of capital expenditures, plans for drilling wells and the timing and location thereof, operating and other costs, and business strategies and plans of management. These statements relate to future events or the Corporation's future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Corporation believes that the expectations reflected in those forward looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be. The Corporation does not intend, and does not assume any obligation, to update these forward-looking statements, except as required by securities laws.

In particular, this AIF contains forward-looking statements pertaining to the following:

- oil and natural gas production levels;
- capital expenditure programs;
- the quantity of oil and natural gas reserves;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions, exploration and development;
- treatment under governmental regulatory regimes;
- future drilling of development locations;
- down spacing drilling plans;
- the Corporations plans for future development of undeveloped reserves;
- expected 2009 volumes of production; and
- estimated time when taxes payable.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this AIF:

- volatility in market prices for oil and natural gas;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;

- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems; and
- fluctuations in foreign exchange or interest rates and stock market volatility; and
- change in government regulations.

These factors should not be considered exhaustive. The Corporation undertakes no obligation to publicly update or revise any forward-looking statements, except as required by securities laws.

CORPORATE STRUCTURE

Name, Address and Incorporation

Fortress is incorporated under the ABCA and is the entity resulting from the reorganization of Signal on February 20, 2007.

A Reorganization (the “**Reorganization**”) of Signal, including an arrangement (the “**Arrangement**”) under the *Companies Act* (Quebec), was approved by the shareholders of Signal at a Special General Meeting of Shareholders held on February 15, 2007 and was effective February 20, 2007. Under the Arrangement, shareholders of Signal could elect to receive cash, common shares of Fortress, or a combination of both, subject to the cash amount being prorated in the event that shareholders elected to receive greater than \$30 million. Shareholders representing 63,400,000 common shares of Signal elected to receive cash resulting in a cash distribution to shareholders of \$30 million and the redemption of 23,076,923 common shares of Signal at a price of \$1.30 per share. The remaining 66,539,059 common shares of Signal were exchanged for common shares of Fortress on the basis of one common share of Fortress for every five common shares of Signal, resulting in the issuance of 13,307,815 common shares of Fortress. Signal was then dissolved pursuant to the *Companies Act* (Québec) and Fortress became the holder of all of the assets formerly held by Signal.

Effective August 31, 2005, five subsidiaries of Signal, namely Blairmore Energy Ltd., Goose River Resources Ltd., Tyke Energy Ltd., Nanodesign Inc. and Predator Exploration Ltd. amalgamated by way of a horizontal short form amalgamation under the name Predator Exploration Ltd. Effective January 1, 2008 Fortress amalgamated, by way of a vertical short form amalgamation with its two subsidiaries Predator Exploration Ltd. and Marauder. As a result Fortress has no material subsidiaries.

The registered office of the Corporation is located at Suite 1500, 407 – 2nd Street S.W., Calgary, Alberta, T2P 2Y3, Canada. The Corporation has its head office in Calgary, Alberta located at 300, 505 – 3rd Street S.W., T2P 3E6.

GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History

Effective February 27, 2006 and March 9, 2006, the Corporation entered into an agreement with a private corporation to sell certain oil and gas properties, tangible equipment, and undeveloped land for net cash proceeds of approximately \$91.2 million. The transaction involved the sale of the Corporation’s interests in its Ferrier, Carrot Creek, Kaybob, Redwater and other minor properties, with the Corporation retaining its Chigwell/Bashaw and Buick Creek properties. The transaction closed in two stages on February 27, 2006 and March 10, 2006. In 2005, these properties accounted for gross petroleum and natural gas revenues of \$17,365,000 and average daily production of approximately 850 BOE/D.

On November 15, 2006, the Corporation completed the acquisition of Marauder, a private oil and gas corporation. The Corporation acquired all of the issued and outstanding shares of Marauder in exchange for 16,349,534 Common Shares and cash costs of \$16,660,210. Marauder's main assets were natural gas properties in the Ladyfern area of NE British Columbia and the Mearon area of NW Alberta.

On February 20, 2007 Signal completed the Reorganization. Signal was then dissolved pursuant to the *Companies Act* (Québec) and Fortress became the holder of all of the assets and liabilities formerly held by Signal.

On December 21, 2007, the Corporation closed a public offering of 2,703,000 flow-through Common Shares at \$1.85 per share for total gross proceeds of \$5,000,550 (\$4,395,000 net of share issuance costs). The full expenditure commitment was renounced to subscribers effective December 31, 2007 with all expenditures to be incurred by December 31, 2008. The tax effect of the renunciation was recorded in the first quarter of 2008 when the renouncement documents were filed. As of December 31, 2008, the Corporation had incurred the full expenditure commitment.

On April 16, 2008 the Corporation entered into an agreement with an affiliate of AltaGas Income Trust (“AltaGas”) to construct a 38 km pipeline from a central point at its Square Creek, Alberta development area to the AltaGas processing facility at Clear Prairie. AltaGas paid for 100% of the costs associated with the construction of the pipeline and in exchange the Corporation dedicated a portion of its reserves in the Square Creek area and committed to a take-or pay arrangement in respect of a smaller portion of such reserves until the pipeline costs have been recovered. The take-or-pay obligation provides that the Corporation will transport a minimum volume of natural gas through the pipeline and into the processing facility over a certain number of years. A volume commitment is also a component of this arrangement whereby the Corporation cannot terminate the processing portion of the arrangement until a certain reserve threshold has been met. See “*Other Oil and Gas Information – Costs Incurred*”.

The Corporation closed a public offering of 11,033,400 units (“Units”) on June 20, 2008, June 27, 2008 and July 4, 2008, for gross proceeds of \$16,550,100 (\$14,737,000 net of issuance costs). Each Unit consists of one Common Share of the Corporation and one-half of one Common Share purchase warrant. The warrants are exercisable on or before June 20, 2011 subject to the right of Corporation to accelerate the expiry time on not less than 30 days notice to the warrant holders, if the aggregate sales price of the common shares during a period of 20 consecutive days divided by the aggregate number of Common Shares sold is at least \$3.00. Each whole warrant entitles the holder thereof to purchase one Common Share at an exercise price of \$2.00.

On October 9, 2008, the Corporation initiated a normal course issuer bid process whereby a maximum of 1,351,014 Common Shares could be repurchased beginning October 14, 2008 and terminating October 13, 2009. As at December 31, 2008 the Corporation purchased 98,500 Common Shares at an average price of \$0.40 per share or \$40,000.

NARRATIVE DESCRIPTION OF THE BUSINESS

General

Fortress is a Calgary based junior oil and gas exploration and development Corporation operating in Western Canada.

PRINCIPAL PROPERTIES

The following property descriptions provide brief overviews of the Corporation's principal properties including an overview of operations conducted in 2008.

Mearon, Alberta

The Mearon North area is located approximately 175 km northeast of Fort St. John, B.C. Mearon North sits immediately east of the Ladyfern North property across the border in NW Alberta. At Mearon North, the Corporation holds an interest in 20,269 gross acres (15,949 net). The Corporation maintains a 100% working interest and operates the producing portion of the property. The Corporation has an interest in 11 wells in this area.

The Mearon North area produces from the Notikewin formation (equivalent to Upper Manville) and features stable reserves with moderate declines of 15-20% per year.

There were no capital enhancement operations conducted by the Corporation in 2008. Mearon North contributed an average 278 BOE/D for 2008 and is presently producing at 215 BOE/D.

A "Holding" was approved by the Alberta Energy and Utilities Board (the predecessor of the Energy Resource Conservation Board) on December 6, 2006 permitting the drilling of a second Notikewin well per section. An application to implement a Holding within a field or defined area is a routine practice amongst operators in the Province of Alberta. The approval of any such application permits the operator to suspend target regulations, alter standard well density and the inter-well distance between producing wells within the application area.

Square Creek, Alberta

The Square Creek area lies 150 kilometres northeast of Fort St. John and 50 kilometres east of the Alberta – British Columbia border. Fortress is the operator of the property and currently holds working interests ranging from 50% to 100% in approximately 32,000 gross acres (21,440 net) of land. The Corporation obtained its interest through a joint venture farm-in with a senior oil and natural gas producer that was entered into by a predecessor of the Corporation.

Square Creek contains a mixture of exploratory, appraisal and development drilling opportunities. Principal targets are the Cretaceous Bluesky and shallower Notikewin formations. Drilling depths in the area vary from 700 metres to 1,200 metres depending on the target formation.

2008 was a very active year in the Square Creek area. The Corporation participated in the drilling, completion and equipping and tie-in of 5 new wells (including a 100% exploratory earning well), the equipping and tie-in of 3 wells drilled in previous years, the installation of a production facility (which included a water disposal well) capable of processing 10 mmcf/d of natural gas and the construction of a 41 km trunk line from a central location at the Square Creek property to a connection point at a facility

owned and operated by a midstreamer. The Corporation also acquired 4,480 gross and net acres at Crown land sales in 2008 and in the general Square Creek area.

Although the exploratory earning well was not successful, it did allow the Corporation to fully earn its interest under the terms and conditions of its joint venture agreement with a senior oil and gas producer. Two of the wells for 2008 targeted both the shallow Notikewin and deeper Bluesky formations and were successfully completed in either or both of these zones, one of the other 2008 wells were drilled to evaluate the Bluesky formation and the remaining 2008 driller targeted and was successfully completed in the Notikewin formation.

Production start up from the property was April 1, 2008 and throughout the course of the year, gross volumes were consistently within the range of 5.4 mmcf/d to as high as 8.0 mmcf/d (as available capacity permitted) with production volumes averaging approximately 5.8 mmcf/d from the start up. Average production (net) for all of 2008 was 340 BOE/D and is presently producing at 482 BOE/D.

In the first quarter of 2009, the Corporation participated in the drilling of 3 wells, one being a 100% well to evaluate at new Bluesky prospect southwest of the main Square Creek field. The Corporation was successful in completing and tying in one of the development locations for Bluesky production, the other location, although unsuccessful in the Bluesky, showed potential in the Notikewin formation. This well will be evaluated during the next operating season. The Corporation is still assessing testing and pressure data related to the exploratory well and depending on those conclusions, may re-enter the well next operating season to undertake completion operations.

Buick Creek, British Columbia

The Buick Creek area is located approximately 75 kilometers northwest of Fort St. John, British Columbia and represents the Corporation's first property in northeastern B.C. In Buick Creek, the Corporation holds an interest in 6,737 gross acres (6,038 net). The Corporation has an interest in 4 wells in this area.

The Buick Creek area produces from the Dunlevy formation (equivalent to the Lower Mannville formation) and features long-life stable reserves with declines of 10-12% per year.

There were no capital enhancement operations conducted at Buick Creek by the Corporation in 2008. Buick Creek contributed an average of 138 BOE/D of production in 2008 and is presently producing at 119 BOE/D.

Chigwell, Alberta

The Chigwell area is located approximately 75 km southeast of Edmonton, Alberta. The Chigwell property features multi-zone targets in the Edmonton, Belly River, Viking, Glauconite and Ellerslie formations at depths of 250 m for shallow Edmonton tests to 1800 m for Lower Mannville tests. The Corporation holds an interest in 4,375 gross acres (3,207 net) in Chigwell.

Chigwell contributed an average of 12 BOE/D of production in 2008.

Bashaw, Alberta

The Bashaw area is located approximately 70 km south east of Edmonton, Alberta. The area is in close geographic proximity to the Chigwell property described above and from a technical perspective is very similar to Chigwell featuring the same multi-zone targets with primary targets being the Edmonton

sands and coal bed methane, Belly River and Ostracod formations. The Corporation holds an interest in 4,629 gross acres (2,198 net) in Bashaw. The Corporation has an interest in 20 wells in the Bashaw area.

The Bashaw assets are non-operated with Enerplus Resources Fund operating all of the Corporation's wells. During 2008, Bashaw contributed average production of 79 BOE/D and is presently producing at 73 BOE/D.

Ladyfern North, British Columbia

The Ladyfern North area is located approximately 150 km northeast of Fort St. John, B.C. At Ladyfern North, the Corporation holds an interest in 6,320 gross acres (5,910 net). The Corporation maintains a 100% working interest (and operatorship) in the producing portion of the property. The Corporation has an interest in 12 wells in this area.

The Ladyfern North area produces from the Notikewin formation (equivalent to the Upper Manville formation) and features stable reserves with moderate declines of 15-20% per year.

Exploration and development targets in the Ladyfern area have typically focused on the Devonian Slave Point, Triassic Charlie Lake/Halfway and Cretaceous Bluesky/Gething formations. This previous deeper drilling has provided the necessary infrastructure with excess compression and pipeline capacity and also uncovered the uphole potential of the Cretaceous Notikewin sand.

There were no capital enhancement operations conducted at Ladyfern North by the Corporation in 2008. Ladyfern North contributed an average 205 BOE/D for 2008 and is presently producing at 134 BOE/D.

The Corporation's application for the implementation of "Good Engineering Practice" was approved on May 16, 2005. An application for Good Engineering Practice within a field or defined area is a routine practice amongst industry operators in the Province of British Columbia. Approval of any such application allows an operator to suspend target regulations, standard well spacing and density and individual production allowables (per well) within the application area. Presently the property is drilled to 2 wells per Drilling Spacing Unit ("DSU") on 6 DSUs, 3 wells per DSU on 1 DSU and 1 DSU has only 1 well on it.

Fortress has identified at least 4 future development and appraisal drilling locations on the Ladyfern North lands. These will be drilled to accelerate production as commodity prices permit.

Ladyfern South, British Columbia

The Ladyfern South area is located approximately 125 km northeast of Fort St. John, B.C. At Ladyfern South, the Corporation holds an interest in 21,047 gross acres (12,602 net). The Corporation operates the property with a senior oil and gas producer as a joint venture partner. The Corporation has an interest in 13 wells in this area.

The Ladyfern South area produces predominantly from the Notikewin formation and features stable, long life reserves with moderate declines of 15-20% per year. .

There were no capital enhancement operations conducted at Ladyfern South by the Corporation in 2008. Ladyfern South contributed an average 173 BOE/D for 2008 and is presently producing at 150 BOE/D.

Presently the property is developed at less than normal spacing (1 well per DSU) for this play type and in relation to the drilling density on competitors held acreage in the area. The Corporation also has plans to increase drilling density in order to accommodate a second, and in some cases, third well on the Corporation's lands with 30 Notikewin future locations planned for as commodity prices permit.

Velma, British Columbia

The Velma area is located approximately 400 km northeast of Fort St. John, B.C. At Velma, the Corporation holds an interest in 8,384 gross acres (6,567 net). The Corporation maintains a 100% working interest (and operates) the producing portion of the property. The Corporation has a 100% working interest in two wells in this area.

The Velma area produces from the Bluesky formation and features stable reserves with moderate declines of 15-20% per year.

There were no capital enhancement operations conducted at Velma by the Corporation in 2008. Velma contributed an average 278 BOE/D for 2008 and is presently producing at 140 BOE/D.

In addition to the producing Bluesky wells, Fortress has identified 12 future development locations in the shallower Notikewin Formation. As is the case with Ladyfern South, these development locations will be drilled when supported by commodity prices with the primary purpose of mitigating expected production declines in the area.

Pine Creek, Alberta

The Pine Creek area is located approximately 200 km west of Edmonton, Alberta, and is a high impact, medium risk exploration property. The Corporation holds an interest in 640 gross and net acres of land in the area and acquired its leasehold interest on this prospect in July 2008.

The area offers multi-zone potential (in both the deep and shallow horizons) and year round access. The Corporation's primary target was located in the Lower Cretaceous group of formations.

Operations in 2008 included the drilling of an exploration outpost well to a depth of approximately 2,670 meters which was rig released in December 2008. The Corporation's is currently evaluating the results of this well in order to better assess next steps in the development of this property.

Land Holdings

The following table sets out the developed and undeveloped land holdings of the Corporation as at December 31, 2008.

	Developed		Undeveloped		Total		Net Area to Expire 2009
	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	
Alberta	14,761	9,673	92,871	73,424	107,632	83,097	16,592
B.C.	27,065	20,835	25,767	19,481	52,832	40,316	1,774
Total	41,826	30,508	118,638	92,905	160,464	123,413	18,366

Notes:

- (1) "Gross" refers to the total acres in which the Corporation has an interest.
- (2) "Net" refers to the total acres in which the Corporation has an interest, multiplied by the percentage working interest therein owned by the Corporation.

The Corporation's leasehold interest in Alberta and British Columbia is predominantly in the form of petroleum and natural gas leases which do not require the drilling of wells for the continuation of same past their primary term. The Corporation does have an undivided working interest in 4 petroleum and natural gas licences in Alberta which require the drilling of wells in order to have such tenure continue into an intermediate term. The Corporation will require the drilling of 1 well during the 2009-2010 drilling season (at Halverson) at an estimated cost of \$800,000. The Corporation will also require 3 additional wells to be drilled in the 2010-2011 operating season (at Square Creek) at a net estimated cost of \$2.8 million.

Land Evaluation

An independent land evaluation dated as at December 31, 2008 was completed by Independent Land Evaluations Inc. resulting in an undeveloped land total net value of \$15,244,893.

RESERVE ESTIMATES

Sproule Report

The following tables set forth certain information relating to the oil and natural gas reserves of the Corporation's properties and the present value of the estimated future net cash flow associated with such reserves as at December 31, 2008 and have been made assuming that development of each property in respect of which the estimate is made will occur, without regard to the likely availability of funding required for that development. Abandonment costs vary per well from \$20,000 to \$30,000 and were included in the Sproule Report. The information set forth below is derived from the Sproule Report which has been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101 and the COGE Handbook. The net present value of future net revenue attributable to the Corporation's reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment and disconnect costs for all of the Corporation's wells assigned reserves. No allowances for reclamation, salvage values or production facilities were made. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Corporation's reserves estimated by Sproule represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of the Corporation's crude oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

The Sproule Report is based on certain factual data supplied by the Corporation and Sproule's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Corporation's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Corporation to Sproule and accepted without any further investigation. Sproule accepted this data as presented and neither title searches nor field inspections were conducted.

The Corporation's Board of Directors reviews the qualifications and appointment of the independent qualified reserves evaluators. The Board also reviews the procedures for providing information to the evaluators. All booked reserves are based upon annual evaluation and review by the independent qualified reserves evaluators.

Reserves presented are 100% of the reserves attributable to the Corporation and its consolidated subsidiaries. All of the properties, reserves and production of the Corporation are located in Canada in the provinces of Alberta and British Columbia.

In accordance with the requirements of NI 51-101, the Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached as Schedules A and B hereto, respectively.

Summary of Oil and Gas Reserves – Forecast Prices and Costs

Summary of Oil and Gas Reserves As of December 31, 2008 Forecast Prices and Costs

	Reserves					
	Light/Medium Oil (MBbl)		Natural Gas (MMcf)		NGL (MBbl)	
	Gross	Net	Gross	Net	Gross	Net
Proved						
Developed Producing	0.0	0.0	12,560	10,149	42.2	33.5
Developed Non-Producing	0.0	0.0	1,038	939	0.3	0.2
Undeveloped	0.0	0.0	8,345	7,307	7.1	5.5
Total Proved	0.0	0.0	21,942	18,396	49.5	39.1
Probable	0.0	0.0	14,366	12,410	22.7	17.9
Total Proved plus Probable	0.0	0.0	36,308	30,806	72.2	57.0

Summary of Net Present Values of Future Net Revenue As of December 31, 2008 Forecast Prices and Costs

	Before Income Tax Discounted At					After Income Tax Discounted At					Unit Value \$/BOE Net Reserves Discounted at 10% before Income Tax (\$/BOE)
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%	
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	
Proved											
Developed Producing	53,545	44,136	37,667	32,963	29,394	53,545	44,136	37,667	32,963	29,394	21.84
Developed Non-Producing	3,181	2,610	2,198	1,890	1,651	3,181	2,610	2,198	1,890	1,651	14.02
Undeveloped	24,322	18,388	14,143	11,002	8,611	24,322	18,388	14,143	11,002	8,611	11.56
Total Proved	81,048	65,134	54,009	45,854	39,656	81,048	65,134	54,009	45,854	39,656	17.39
Probable	59,053	43,560	33,468	26,462	21,373	52,790	39,553	30,807	24,639	20,092	16.04
Total Proved plus Probable	140,101	108,694	87,477	72,316	61,029	133,838	104,687	84,816	70,493	59,748	16.85

Notes:

- (1) The Sproule Report estimates Fortress' share of future capital expenditures necessary to achieve the estimated present worth of future net cash flows based on escalating costs from Proved Reserves to be \$13,235,000 and Proved and Probable Reserves to be \$24,188,000.

Future Net Revenue - Forecast Prices and Costs

The following table sets forth the following elements of future net revenue attributed to Proved Reserves and Proved plus Probable Reserves of the Corporation as of December 31, 2008 estimated based on forecast prices and costs and calculated without discount:

Total Future Net Revenue (Undiscounted) As of December 31, 2008 Forecast Prices and Costs

Reserves Category	Revenue (M\$)	Royalties (M\$)	Operating Costs (M\$)	Capital Development Costs (M\$)	Well Abandonment Costs (M\$)	Future Net Revenue Before Income Taxes (M\$)	Future Income Taxes (M\$)	Future Net Revenue After Income Taxes (M\$)
Proved	188,953	26,057	66,371	13,235	2,242	81,048	0	81,048
Proved plus Probable	318,890	41,760	109,783	24,188	3,057	140,101	6,263	133,838

The following table set forth the future net revenue (before deducting future income tax expenses) of the Corporation as of December 31, 2008 estimated based on forecast prices and costs and calculated using a discount rate of 10 percent:

Net Present Value of Future Net Revenue by Production Group As of December 31, 2008 Forecast Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%) (M\$)	Unit Value Before Income Taxes (discounted at 10%) (\$/BOE)
Proved	Light/Medium Oil	0	0
	Heavy Oil (including solution gas and associated by-products)	0	0
	Natural Gas (including associated by-products)	54,009	17.39
	TOTAL	54,009	17.39
Proved plus Probable	Light/Medium Oil	0	0
	Heavy Oil (including solution gas and associated by-products)	0	0
	Natural Gas (including associated by-products)	87,477	16.85
	TOTAL	87,477	16.85

Note:

(1) Columns may not add due to rounding.

Pricing Assumptions

The escalating cost and price assumptions assume the continuance of current laws and regulations and increases in wellhead selling prices, and take into account inflation with respect to future operating capital costs. In the Sproule Report operating costs are assumed to escalate at 2% per annum. Crude oil and natural gas base case prices as forecasted by Sproule Report effective January 1, 2009 are as follows:

Year	WTI Cushing Oklahoma (\$US/Bbl)	Edmonton Par Price 40° API (\$Cdn/Bbl)	Cromer Medium 29.3° API (\$Cdn/Bbl)	Natural Gas ¹ AECO Gas Prices (\$Cdn/MMBtu)	Pentanes Plus FOB Field Gate (\$Cdn/Bbl)	Butanes FOB Field Gate (\$Cdn/Bbl)	Inflation Rate ² (%/Yr)	Exchange Rate ³ (\$US/\$Cdn)
Historical								
2008	99.59	102.85	93.05	8.15	104.70	75.10	1.0	0.943
Forecast								
2009	53.73	65.35	58.16	6.82	66.93	51.15	2.0	0.800
2010	63.41	72.78	66.23	7.56	74.54	54.25	2.0	0.850
2011	69.53	79.95	72.76	7.84	81.88	59.59	2.0	0.850
2012	79.59	86.57	79.65	8.38	88.66	64.53	2.0	0.900
2013	92.01	94.97	87.38	9.20	97.27	70.79	2.0	0.950
Thereafter	Various Escalation Rates							

Notes:

- (1) This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.
- (2) Inflation rates for forecasting prices and costs.
- (3) Exchange rates used to generate the benchmark reference prices in this table.
- (4) Product sale prices will reflect those reference prices with further adjustments for quality and transportation to point of sale.

The weighted average prices received by the Corporation for 2008 were: Natural Gas - \$8.55/Mcf; Oil and Natural Gas Liquids - \$82.16/Bbl.

Definitions Applicable to Reserves Tables

“**Gross**” means the Corporation's total working interest share before deducting royalties and without including any royalty interest of Signal.

“**Net**” means the Corporation’s total working interest and/or royalty interest share after deducting the amounts attributable to royalties owned by others.

“**Royalties**” refers to royalties paid to others. The royalties deducted from the reserves are based on the percentage royalty calculated by applying the applicable royalty rate or formula. In the case of Crown sliding scale royalties which are dependent on selling prices, the price forecasts for the individual properties in question have been employed.

“**Reserves**” are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: analysis of drilling, geological, geophysical and engineering data, the use of established technology, and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates.

“**Proved**” reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

“**Developed Producing**” reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

“**Developed Non-Producing**” reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

“**Undeveloped**” reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

“**Probable**” reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

RECONCILIATIONS OF CHANGES IN RESERVES

The following table sets out the reconciliation of changes in Gross Reserves (before Royalties) by principal product type for the period from December 31, 2007 to December 31, 2008 using forecast prices and costs:

Factors	Light and Medium Oil			Heavy Oil			Coalbed Methane			Associated and Non-Associated Gas ⁽¹⁾			Natural Gas Liquids		
	Gross Proved (MBbl)	Gross Probable (MBbl)	Gross Proved Plus Probable (MBbl)	Gross Proved (MBbl)	Gross Probable (MBbl)	Gross Proved Plus Probable (MBbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (MBbl)	Gross Probable (MBbl)	Gross Proved Plus Probable (MBbl)
December 31, 2007	-	-	-	-	-	-	1,137	560	1,698	23,069	13,359	36,427	73.8	28.1	101.9
Extensions	-	-	-	-	-	-	114	176	290	997	786	1,783	0.6	0.5	1.1
Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	68	0	68	(342)	(1,521)	(1,863)	(19.3)	(6.2)	(25.5)
Discoveries	-	-	-	-	-	-	-	-	-	-	1,120	1,120	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	1	1	2	(13)	(114)	(127)	1.4	0.3	1.7
Production	-	-	-	-	-	-	(85)	0	(85)	(3,004)	(2)	(3,006)	(7.0)	0	(7.0)
December 31, 2008	-	-	-	-	-	-	1,235	738	1,972	20,707	13,628	34,336	49.5	22.7	72.2

Notes:

- (1) Includes solution gas.
- (2) Except for coal bed methane, Fortress has no unconventional reserves (Bitumen, Synthetic Crude Oil, Hydrates, Shale Oil or Shale Gas)
- (3) Gross Reserves means the Corporation’s working interest reserves before calculation of royalties, and before consideration of the Corporation’s royalty interests.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

The following table sets forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, attributed to the Corporation:

Year	Undeveloped Reserves	Light and Medium Oil (MBbls)	Heavy Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	MBOE
2005	Proved	43.2	-	1,974	13.4	386
2006	Proved	-	-	7,101	-	1,184
2007	Proved	-	-	11,354	5.2	1,898
2008	Proved	-	-	8,345	7.1	1,398
2005	Probable	109.4	-	6,155	144.9	1,280
2006	Probable	1.8	-	5,692	14.5	963
2007	Probable	-	-	9,701	13.0	1,630
2008	Probable	-	-	10,511	13.2	1,765

In general, undeveloped reserves of the Principal Properties of the Corporation are scheduled to be developed within the next two years. See “*Principal Properties*” for general development plans of the Corporation.

Significant Factors or Uncertainties Affecting Reserves Data

There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond the control of the Corporation. The reserve data included or incorporated by reference herein represents estimates only.

In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary considerably from actual results. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. The actual production, revenues, taxes and development and operating expenditures of the Corporation with respect to these reserves will vary from such estimates, and such variances could be material.

Estimates with respect to proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be substantial, in the estimated reserves.

Consistent with the securities disclosure legislation and policies of Canada, as interpreted by the securities regulatory authorities in Canada, the Corporation has used forecast prices and costs in calculating reserve quantities included herein. Actual future net cash flows also will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Future Development Costs

The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserve categories noted below.

Year	Forecast Prices and Costs (undiscounted)	
	Proved (M\$)	Proven plus Probable (M\$)
2009	7,808	12,483
2010	5,428	11,706
2011	-	-
2012	-	-
2013	-	-
Total	13,235	24,188

The source of funding for future development costs of the reserves of the Corporation will be derived from a combination of funds from operations, debt and new equity. Management does not anticipate that the costs of funding, referred to above, will materially affect the disclosed reserves and future net revenues of the Corporation or will make the development of any of the properties uneconomic.

OTHER OIL AND GAS INFORMATION

Oil and Gas Wells

The following table summarizes the Corporation's interest as at December 31, 2008 in wells, which are producing, or which the Corporation considers to be capable of production:

Alberta	Gross ⁽¹⁾		Net ⁽²⁾	
	Producing	Shut-in ⁽³⁾	Producing	Shut-in ⁽³⁾
Oil	-	-	-	-
Gas	36	8	20.1	5.6
Total	36	8	20.1	5.6
British Columbia				
Oil	-	-	-	-
Gas	27	5	21.8	4.1
Total	27	5	21.8	4.1

Notes:

- (1) "Gross" refers to all wells in which the Corporation has an interest.
- (2) "Net" wells refer to the total number of wells in which the Corporation has an interest multiplied by the Corporation's percentage working interest therein.
- (3) "Shut-in" wells are defined as wells which have encountered crude oil or natural gas and are capable of producing crude oil or natural gas but which are not producing due to the lack of transportation facilities, available markets or other reasons.

The majority of the Corporation's shut-in wells and booked reserves are in the Ladyfern North & South, and Mearon North areas.

In the first quarter of 2009, the Corporation drilled two (1.0 net) development wells and one (1.0 net) exploration well in the Square Creek area. See "Principal Properties – Square Creek Alberta". Additional activities include optimization workovers in the Mearon and Ladyfern North areas. This

optimization work entails performing cleanouts on existing wells and upsizing the tubing strings to achieve better lifting capacity for any fluids in the wellbores.

Commodity Contracts

The Corporation uses commodity contracts to manage its exposure to fluctuations in the price of natural gas. For 2008, the Corporation realized a loss on commodity contracts of \$1,564,000, or \$0.52/mcf, and an unrealized gain of \$2,107,000, or \$0.70/mcf. In 2008 approximately 56% of the Corporation's production was under contract.

The Corporation recorded an unrealized gain on commodity contracts in the fourth quarter of 2008 of \$1,062,000 compared to an unrealized gain on commodity contracts for the fourth quarter of 2007 of \$19,000. For 2008, the Corporation recorded an unrealized gain on commodity contracts of \$2,395,000 compared to \$92,000 for 2007. At December 31, 2008 the Corporation had the following commodity contracts in place:

Type	Period	Volume (GJ/d)	Fixed Price (\$/GJ)
Swap	November 1, 2008 to March 31, 2009	1,250	9.58
Swap	November 1, 2008 to March 31, 2009	3,750	8.25
Swap	April 1, 2009 to December 31, 2009	5,100	7.20
Swap	January 1, 2010 to March 31, 2010	2,600	8.38

Additional information concerning Abandonment and Reclamation Costs

The Corporation is liable for its share of the ultimate reclamation of the working interest properties upon abandonment. The Corporation typically estimates well abandonment costs by area. Such costs are included in the Sproule Report as deductions in arriving at future net revenue.

The total expected abandonment disconnect costs included in the Sproule Report for 98 net wells under the Proved reserves category is \$2,242,000 undiscounted (\$1,128,000 discounted at 10%), of which a total of \$203,000 is estimated to be incurred in 2009, 2010 and 2011.

The Corporation has created a liability for existing asset retirement obligations. The undiscounted estimated cash flows required to settle the obligation is \$6.0 million. The discounted amount recognized during 2008 was \$3.4 million. Due to use of management estimates in determining the asset retirement obligation liability, actual results could differ from those reported. The asset retirement obligation recorded in the Corporation's consolidated balance sheet at December 31, 2008 exceeds that used in the Sproule Report because the Sproule Report makes no allowances for surface lease reclamation, salvage values, or abandonment costs of suspended wells, gathering systems, batteries, plants or processing facilities.

Tax Horizon

Based on production from existing reserves, the Corporation estimates that it will not be required to pay income taxes for the next several years.

The estimated tax pools of the Corporation at December 31, 2008 are as follows:

	(M\$)
Canadian Oil and Gas Property Expenses	13,404
Canadian Development Expenses	27,457
Canadian Exploration Expenses	12,508
Undepreciated Capital Cost	26,313
	79,682

For further details regarding income taxes, refer to the Corporations Management Discussion and Analysis and Annual Financial Statements as at and for the year ended December 31, 2008 filed on SEDAR at www.sedar.com.

Costs Incurred

The following table summarizes capital expenditures net of certain proceeds and including capitalized general and administrative expenses related to the Corporation's activities for the years ended December 31, 2008 and 2007:

	Year ended December 31,
	2008 (M\$)
Exploration	
Land and seismic	1,679
Development	
Drilling and completions	9,689
Equipment and facilities	14,937
Acquisitions	
Proved Property	-
Unproved Property	1,106
Dispositions	(8,150)
Capitalized overhead costs	1,006
	20,267

Total capital expenditures for 2008 were \$20,267,000. The 2008 winter capital program was focused on the follow-up to the discovery of the Bluesky and Notikewin gas pools from the 2007 winter drilling program. Fortress drilled two additional wells in the Bluesky formation and three wells in the Notikewin to better delineate the two structures. The Corporation also constructed a 10 mmcf/d gathering and production facility to service wells it has in the area.

The Corporation completed the construction of a 41 km pipeline to deliver the gas to the Clear Prairie gas plant to service the Square Creek area, the corridor along which it owns 41,800 net acres of land opening up a significant exploration area for the Corporation. The pipeline was completed and commissioned in March for a total cost of \$8,578,000 and was sold to a mid-stream service provider in April for proceeds of \$8,150,000.

At the Clear Prairie facility, Fortress has arrangements for 5.0 mmcf/d (2.5 mmcf/d net) of firm processing capacity and has processing service available on a best efforts basis for larger volumes. Fortress' ability to produce natural gas at optimum rate from the from the Square Creek area is restricted

by processing capacity at the Clear Prairie facility owned by a third party. Fortress is working with the third party to increase production capacity.

Commitments

Office space and equipment

The Corporation is committed to minimum annual lease payments under operating leases for office premises and equipment to March, 2013, as follows:

	Equipment Rental (M\$)	Office Lease (M\$)	Total (M\$)
2009	170	458	628
2010	25	470	495
2011	9	475	484
2012	-	474	474
2013	-	119	119
	204	1,996	2,200

Transportation and Processing

The Corporation has an agreement for the transportation and processing of natural gas from the Corporation's Square Creek, Alberta area. The Corporation is committed to pay the greater of a fee calculated as monthly volumes at an established rate per mcf, or an established minimum monthly processing fee based on estimated gas throughput of 2 mmcf per day until the earlier of April 1, 2015 or the delivery of a total of 15 bcf.

Committed payments are as follows:

	(M\$)
2009	1,259
2010	1,088
2011	767
2012	767
2013	767
Thereafter	895
	5,543

The Corporation's joint interest partner in the Square Creek area has agreed to be responsible for all terms and conditions of the agreement related to their 50% working interest in this area. Committed payments represent only the Corporation's 50% working interest.

Letter of Credit

On February 1, 2008, the Corporation issued a letter of credit of \$1,000,000 with an expiry of February 1, 2009, related to a gas transportation and processing agreement. Upon the expiry of the existing letter of credit, a replacement letter of credit of \$900,000 was issued with an expiry of February 1, 2010.

Drilling Commitments

As at December 31, 2008, the Corporation had committed to drill a well in Alberta pursuant to a farm-in agreement, at an estimated cost of \$700,000. The drilling of the well was to be completed by February 15, 2009. Based on further geological assessment the Corporation elected to incur a \$200,000 penalty in 2009 and forego the drilling of the well.

Income Tax Refund

In September 2008, the Corporation re-filed its income tax returns for the 1997 to 1999 tax years to claim additional scientific research and experimental development (“**SR&ED**”) credits related to the bio-technology business of its predecessor Corporation. These additional claims could result in a refund of approximately \$3.4 million to the Corporation. The Corporation has not recorded this refund at December 31, 2008.

Technology Royalties

The Corporation will pay to various university research centers royalties amounting to between 2% and 5% on sales of licensed products related to a research contract and acquired technology rights and 15% of sublicense revenues from products related to the acquired technology rights. At December 31, 2008 and 2007, there were no royalties payable under these agreements.

Income Tax Refund

In September 2008, the Corporation re-filed its income tax returns for the 1997 to 1999 tax years to claim additional scientific research and experimental development (“**SR&ED**”) credits related to the bio-technology business of its predecessor company. These additional claims could result in a refund of approximately \$3.4 million to the Corporation.

Income Tax Reassessment

Based on the results of an audit concluded in March 2009 by Canada Revenue Agency (“**CRA**”) of the 2004 flow-through expenditures of a business acquired by the Corporation in 2006, the Corporation has been notified that it will be reassessed by CRA for interest of \$277,000 on expenditures not qualifying for renunciation under the flow-through share program in the amount of \$1,916,000. The additional interest has been recorded in the statement of operations at December 31, 2008. The Corporation may file a Notice of Objection after consultation with its tax advisors and legal counsel. The Corporation has indemnified the subscribers of this flow-through share offering from income taxes related to the offering.

Exploration and Development Activities

Drilling Activity

During the twelve month period ending December 31, 2008, the Corporation drilled 5 gross (3.0 net) wells resulting in 4 gross (2.0 net) producing wells:

Year Ended December 31, 2008	Crude Oil		Natural Gas		Suspended		Service		Dry		Total
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Net
Exploratory	-	-	-	-	-	-	-	-	1	1	1
Development	-	-	4	2.0	-	-	-	-	-	-	2.0

For a description of the Corporation's intended exploration and development activities see the description under "*Principal Properties*".

Estimated 2009 Production Volumes

The following table provides the volume of production of the Corporation estimated for 2009 for its reserves:

	Forecast Prices and Costs (undiscounted)	
	Proved Reserves	Proved plus Probable Reserves
Corporate		
2009 Production (Gross)		
Oil (MBbl)	-	-
Natural Gas (MMcf)	32,851	53,937
Natural Gas Liquids (MBbl)	87.1	117.5
Oil equivalent (MBOE)	5,562.3	9,107.1
2009 Production (Net)		
Oil (MBbl)	-	-
Natural Gas (MMcf)	21,942	36,308
Natural Gas Liquids (MBbl)	49.5	72.2
Oil equivalent (MBOE)	3,706.6	6,123.6

The Corporation's Square Creek field represents more than 20% of the Corporation's 2009 estimated production as follows:

	Forecast Prices and Costs (undiscounted)	
	Proved Reserves	Proved plus Probable Reserves
Square Creek		
2009 Production (Gross)		
Oil (MBbl)	-	-
Natural Gas (MMcf)	10,315	15,048
Natural Gas Liquids (MBbl)	7.3	10.6
Oil equivalent (MBOE)	1,726.5	2,518.6
2009 Production (Net)		
Oil (MBbl)	-	-
Natural Gas (MMcf)	5,158	7,524
Natural Gas Liquids (MBbl)	3.6	5.3
Oil equivalent (MBOE)	863.3	1,259.3

Production History for 2008

Daily Sales Volumes and Netback

The following table sets forth the sales volumes and netbacks attributable to the Corporation's oil and gas assets on a quarterly basis for the periods indicated:

	Production Volume (Bbls or Mcf)	Average per Unit of Volume			
		Price (\$/Bbl or Mcf)	Royalties (\$/Bbls or Mcf)	Costs (\$/Bbls or Mcf)	Netback ⁽¹⁾ (\$/Bbls or Mcf)
Light & Medium Oil (Bbls)					
First Quarter	-	-	-	-	-
Second Quarter	-	-	-	-	-
Third Quarter	-	-	-	-	-
Fourth Quarter	-	-	-	-	-
Natural Gas (Mcf)					
First Quarter	672,581	7.71	1.40	1.99	4.32
Second Quarter	790,790	8.68	1.61	2.57	4.50
Third Quarter	803,436	6.71	1.42	2.62	2.67
Fourth Quarter	746,856	7.88	1.25	2.79	3.84
Natural Gas Liquids (Bbls)					
First Quarter	3,003	79.61	8.42	11.94	59.25
Second Quarter	1,365	108.04	9.71	15.40	82.93
Third Quarter	2,116	82.29	8.51	15.72	58.06
Fourth Quarter	1,288	60.42	7.50	16.72	36.20
Light & Medium Oil & Natural Gas Liquids Combined (Bbls)					
First Quarter	115,115	47.12	8.42	11.94	26.76
Second Quarter	133,133	52.53	9.71	15.40	27.42
Third Quarter	135,976	40.74	8.51	15.72	16.51
Fourth Quarter	125,743	47.41	7.50	16.72	23.19

Notes:

- (1) Netback is calculated as price realized by the Corporation (including realized gains and losses on commodity contracts), less royalties, and less operating costs.
- (2) The Corporation had substantially no light and medium oil production in 2008.

FURTHER DESCRIPTION OF THE BUSINESS

Employees

As of December 31, 2008, the Corporation had 11 employees and 5 consultants.

Competitive Conditions

The Corporation actively competes for reserve acquisitions, exploration leases, licenses and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial resources than the Corporation. The Corporation's competitors include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators.

The oil and gas industry is highly competitive. The Corporation's competitors for the acquisition, exploration, production and development of oil and natural gas properties, and for capital to finance such activities, include companies that have greater financial and personnel resources available to them than the Corporation.

Certain of the Corporation's customers and potential customers are themselves exploring for oil and natural gas, and the results of such exploration efforts could affect the Corporation's ability to sell or supply oil or gas to these customers in the future. The Corporation's ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment

Business Cycle and Seasonality

The Corporation's business is generally not cyclical; however its revenue from the sale of natural gas is highly seasonal, with demand for natural gas rising during cold winter months and hot summer months. Access to the Corporation's properties for exploration and development activities is restricted to the winter months. Any unreasonable winter temperatures could adversely affect the Corporation's drilling activities.

Renegotiation or Termination of Contracts

It is not expected that the Corporation's business will be affected in the current financial year by the renegotiation or termination of contracts or sub-contracts.

Environmental Protection Requirements

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and federal, provincial and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to foreign governments and third parties and may require the Corporation to incur costs to remedy such discharge. No assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Corporation's financial condition, results of operations or prospects.

RISK FACTORS RELATING TO THE OIL AND GAS BUSINESS

Substantial Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As the Corporation's revenues may decline as a result of decreased commodity pricing, Fortress may be required to reduce capital expenditures. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Corporation to additional access to capital risk. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that

it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on Fortress' business, financial condition, results of operations and prospects.

Volatility of Oil and Natural Gas Prices

The results of operations and financial condition are dependent on the prices received for the Corporation's oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are subject to fluctuations in response to relatively minor changes in supply, demand, market uncertainty and other factors that are beyond the Corporation's control. These factors include, but are not limited to, worldwide political instability, foreign supply of oil and natural gas, the level of consumer product demand, government regulations and taxes, the price and availability of alternative fuels and the overall economic environment. Any decline in oil or natural gas prices could have a material adverse effect on the Corporation's operations, financial condition, proved reserves and the level of expenditures for the development of its oil and natural gas reserves. No assurance can be given that oil and natural gas prices will be at levels which will generate profits for the Corporation.

Capital Markets

As a result of the weakened global economic situation, the Corporation along with all participants in the oil and gas industry, will have restricted access to capital and increase borrowing costs. The lending capacity of all financial institutions has diminished and risk premiums have increased independent of the Corporation's business and asset base. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors, the overall state of capital markets and investor demand for investments in the energy industry and the Corporation's securities in particular.

The extent that external sources of capital become limited or unavailable or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and are continuing in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward. These factors may impact the ability of the Corporation to obtain equity or debt financing in the future and, if obtained, on terms favourable to the Corporation. If these increased levels of volatility and market turmoil continue, the Corporation's operations could be adversely impacted and the trading price of the Common Shares could continue to be adversely affected.

Oil and natural gas prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing global credit and liquidity concerns.

New Alberta Royalty Regime

On October 25, 2007, the Alberta government released a report entitled “The New Royalty Framework” (“**NRF**”) containing the government's proposals for Alberta’s new royalty regime that will be effective on January 1, 2009. The new regime would introduce new royalties for conventional oil, natural gas and bitumen, effective January 1, 2009, that are linked to price and production levels and would apply to both new and existing conventional oil and gas activities and oil sands projects.

Royalties payable pursuant to petroleum and natural gas leases with the Government of Alberta are ad *valorem* royalties, calculated using the oil or natural gas price and the level of production. Royalties payable to the Government of Alberta currently are 30 and 35 percent in the case of old and new conventional oil, respectively, 5 to 35 percent in the case of natural gas and 15 to 50 percent in the case of NGLs.

Under the NRF, the royalty formula for conventional oil will operate on a sliding rate formula containing separate elements that account for oil price and well production and specialty royalty programs will be eliminated along with “old” and “new” tiers. Royalty rates for conventional oil will range up to 50 percent, with rate caps once the price of conventional oil reaches Cdn. \$120 per barrel.

Under the new royalty regime, natural gas royalties will be set by a sliding rate formula sensitive to price and well production rate. Vintages will be eliminated along with certain specialty royalty programs, though a form of deep gas royalty holiday will be retained and lower royalty rates will be applied over a wider price range for wells with less productivity. Royalty rates for natural gas will range from 5 to 50 percent with rate caps once the price of natural gas reaches \$16.59/GJ (gigajoule). A shallow rights reversion program will also be implemented that will result in the reversion to the Government of Alberta of mineral rights to undeveloped geological formations above developed zones. Royalties for NGLs will be set at 40 percent for pentanes and 30 percent for butanes and propane.

In addition to this, and in response to the drop in oil prices experienced during the second half of 2008, the Government of Alberta announced on November 19, 2008, the introduction of a five year program of transitional royalty rates with the intent of promoting new drilling. Companies drilling new natural gas or conventional oil deep wells on or before November 19, 2008 (between 1000 and 3,500 meters) will be given a one-time option per well to adopt the new transitional royalty rates or those outlined in the NRF.

On December 2, 2008 Bill 47 *Mines and Minerals (New Royalty Framework) Amendment Act* received royal assent and will come into force on various dates, with the rate adjustments contemplated by it coming into effect on January 1, 2009.

On March 3, 2009, the Government of Alberta announced a three-point incentive program to encourage additional activity in the province’s conventional oil and gas industry. The program includes a drilling royalty tax credit, a new well incentive program and additional investment by the province in reclamation and abandonment of oil and gas well sites.

The implementation of the recently enacted changes to the royalty regime in Alberta is subject to certain risks and uncertainties. The changes require legislation amendments, changes to existing legislation and regulations and development of proprietary software to support the calculation and

collection of royalties. Additionally, there may be further modifications introduced to the royalty structure.

Debt Service

The Corporation has a \$24,000,000 demand operating loan facility with its bank, bearing interest at the Bank's prime lending rate plus 1.0% (effective interest rate for 2008 of 5.05% and for 2007 of 6.5%). At December 31, 2008, the Corporation had drawn \$20,533,000 against this facility. The Corporation also has a \$1,000,000 letter of guarantee facility. These facilities are collateralized by a security interest over all present and after acquired property of the Corporation. The authorized limits are subject to annual review and re-determination of the Corporation's borrowing base by the Bank. The next annual review date has been set for June 30, 2009.

The credit facility has a covenant that requires the Corporation to maintain its working capital ratio at 1:1 or greater. The working capital ratio is defined as current assets plus the unutilized portion of the credit facility divided by current liabilities less the balance drawn against the credit facility. The Corporation is in compliance with this covenant at December 31, 2008.

	As at December 31, 2008 (M\$)
Operating loan available	24,000
Working capital deficiency	(20,993)
Capital resources available	3,007

The Corporation's capital budget for 2009 is approximately \$4 million and will focus on the Square Creek development area. The 2009 capital program will be funded through a combination of cash flows from operations and the available credit facility. There is no assurance that the Corporation will be able to sustain its current borrowing base and may be required to reduce its outstanding operating loan facility. The Corporation has options available to deal with a borrowing base reduction including the sale of non-core properties, dedication of cash flows, and liquidation of its commodity contracts.

The Corporation has utilized its currently available operating credit facilities to finance its 2008 capital program. The Corporation has experienced positive cash flows from operations for 2008. The ability of the Corporation to meet its debt service obligations will depend on the future operating performance and financial results of the Corporation, which will be primarily subject to factors beyond its control. If it is unable to obtain sufficient cash to service its debt, it may be required to refinance all or a portion of its debt, obtain additional financing or sell certain of its assets. There can be no assurance that any such refinancing would be possible or that any additional financing could be obtained on acceptable terms, nor can there be any assurance as to the timing of any such asset sales or the proceeds which could be realized therefrom.

Need to Replace Reserves

The Corporation's future oil and natural gas reserves and production, and therefore its cash flows, are highly dependent upon the Corporation's success in exploring its current reserve base and acquiring or discovering additional reserves. Without reserve additions through exploration, acquisition or development activities, the Corporation's reserves and production will decline over time as reserves are exploited. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient and external sources of capital become limited or unavailable, the Corporation's ability to make the necessary capital investments to maintain and expand

its oil and natural gas reserves will be impaired. In addition, there can be no assurance that the Corporation will be able to find and develop or acquire additional reserves to replace production at acceptable costs.

Operating Hazards and Other Uncertainties

Acquiring, developing and exploring for oil and natural gas involves many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. These risks include, but are not limited to, encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, equipment failures and other accidents, cratering, sour gas releases, uncontrollable flows of oil, natural gas or well fluids, adverse weather conditions, pollution, other environmental risks, fires and spills. Although the Corporation maintains insurance in accordance with customary industry practice, the Corporation is not fully insured against all of these risks. Losses resulting from the occurrence of these risks could have a material adverse impact on us. Like other oil and natural gas companies, the Corporation attempts to conduct its business and financial affairs so as to protect against political and economic risks applicable to operations in the jurisdictions where the Corporation operates but there can be no assurance that the Corporation will be successful in so protecting itself.

The Corporation is also subject to deliverability uncertainties related to the proximity of its reserves to pipeline and processing facilities and the possible inability to secure space on pipelines, which deliver oil and natural gas to commercial markets.

Business Cycle and Seasonality

See “*Further Description of the Business – Business Cycle and Seasonality*”.

Sale of Additional Common Shares

The Corporation may issue an unlimited number of additional Common Shares in the future to finance its activities without the approval of shareholders. The Board has the discretion to set the price and terms of the issuance of any such additional Common Shares and any issuance of additional Common Shares may have a dilutive effect on the holders of Common Shares.

Significant Factors or Uncertainties Affecting Reserves Data

See “*Other Oil and Gas Information – Significant Factors or Uncertainties Affecting Reserves Data*”.

Competitive Conditions

See “*Further Description of the Business – Competitive Conditions*”.

Environmental Protection Requirements

See “*Further Description of the Business – Environmental Protection Requirements*”.

Acquisition Risks

The Corporation intends to continue acquiring oil and natural gas properties. Although the Corporation performs a review of the acquired properties that the Corporation believes is consistent with industry practices, it generally is not feasible to review in depth every individual property involved in

each acquisition. Ordinarily, the Corporation will focus its review efforts on the higher-value properties and will sample the remainder. However, even a detailed review of records and properties may not necessarily reveal every existing or potential problem, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the Corporation often assume certain environmental and other risks and liabilities in connection with acquired properties. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and actual future production rates and associated costs with respect to acquired properties, and actual results may vary substantially from those assumed in the estimates.

Kyoto Protocol

The Kyoto Protocol came into effect on February 16, 2005. As yet, however, no specific details regarding its implementation in Canada have been made by the Federal Government. The Kyoto Protocol was established to set legally binding targets to reduce emissions of carbon dioxide, methane, nitrous oxide and other so-called “greenhouse gases”. The Corporation’s exploration and production facilities and other operations and activities emit a small amount of greenhouse gases which may subject us to legislation regulating emissions of greenhouse gases. Numerous uncertainties regarding details of the Kyoto Protocol’s implementation remain that make it difficult to ascertain the cost estimate, including when third party costs related to the Kyoto Protocol factor their way into the Corporation’s supply chain of goods and services. There is no assurance that the cost impact to the Corporation of the Kyoto Protocol or subsequent legislation related to the Kyoto Protocol will not be significant, which could result in a material adverse effect on the Corporation’s financial condition or results of operations. Future federal legislation, together with provincial emission reduction requirements, may require the reduction of emissions or emissions intensity produced by the Corporation's operations and facilities. The direct or indirect costs of these regulations may adversely affect the business of the Corporation.

Governmental Regulation

The oil and natural gas business is subject to regulation and intervention by governments in such matters as the awarding of exploration and production interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields (including restrictions on production) and possibly expropriation or cancellation of contract rights. As well, governments may regulate or intervene with respect to prices, taxes, royalties and the exportation of oil and natural gas. Such regulation may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for oil and natural gas, increase the Corporation’s costs and have a material adverse impact on us.

Third Party Credit Risk

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on Fortress’ business, financial condition, results of operations and prospects.

DIVIDENDS

No cash dividends have been declared by the Corporation in respect of any class of the Corporation's shares for any of the three most recently completed financial years. The Corporation does not currently have a policy of paying dividends.

DESCRIPTION OF CAPITAL STRUCTURE

Common Shares

The Corporation is authorized to issue an unlimited number of Common Shares without nominal or par value, of which 26,921,788 were issued and outstanding as at the date hereof as fully paid and non-assessable.

The holders of the Common Shares are entitled to dividends as and when declared by the Board of Directors, to one vote per share at meetings of shareholders of the Corporation and, upon liquidation, to receive such assets of the Corporation as are distributable to the holders of the Common Shares.

Preferred Shares

The Corporation is authorized to issue an unlimited number of preferred shares without nominal or par value (the "Preferred Shares") issuable in series. No series of Preferred Shares have been created and there are no Preferred Shares outstanding.

The Preferred Shares shall be entitled to preference over the Common Shares of the Corporation and over any other shares ranking junior to the Preferred Shares with respect to distribution of assets in the event of liquidation, dissolution or winding-up of the Corporation.

MARKET FOR SECURITIES

The Common Shares of Fortress are listed and posted for trading on The Toronto Stock Exchange under the symbol FEI. In 2008 there were 10,649,232 Common Shares traded at prices ranging from a low of \$0.21 to a high of \$2.45.

	Volume	High (\$)	Low (\$)	Close (\$)
January 2008	99,178	1.40	1.14	1.29
February 2008	88,566	1.70	1.29	1.61
March 2008	410,341	2.00	1.50	1.76
April 2008	125,686	1.90	1.62	1.76
May 2008	863,541	2.45	1.65	1.85
June 2008	1,277,318	1.77	1.26	1.39
July 2008	1,666,578	1.55	1.25	1.50
August 2008	281,142	1.54	1.25	1.35
September 2008	1,234,563	1.38	0.85	1.07
October 2008	1,839,439	1.09	0.35	0.42
November 2008	1,289,548	0.55	0.30	0.31
December 2008	1,473,332	0.36	0.21	0.25
January 2009	168,840	0.40	0.25	0.26
February 2009	371,020	0.34	0.16	0.24

ESCROWED SECURITIES

There were no escrowed securities as at December 31, 2008.

DIRECTORS AND OFFICERS

The name, occupation and security holdings of each of the directors and senior officers of the Corporation are as follows:

Name and Municipality of Residence	Position Held with Fortress	Year First Appointed	Present Occupation During the Last Five Years	Fortress Shares Beneficially Owned
J. Cameron Bailey Calgary, Alberta	President and Chief Executive Officer and Director	2003	President and Chief Executive Officer, of Fortress. Prior thereto, Managing Director of Network Capital Inc., a private investment firm from December 1999	895,480
Richard Grafton ⁽¹⁾⁽²⁾ Calgary, Alberta	Director	2008	President and Chief Executive Officer, Grafton Capital Corporation (a private investment company) Prior thereto, Vice-Chairman of Canaccord Capital Prior thereto, Managing Director and a founding shareholder of First Energy Capital Corp.	342,000
George Watson ⁽¹⁾ Calgary, Alberta	Director	2003	Chief Executive Officer of Critical Control Solutions Inc., a public technology company, since January, 2000. Prior thereto, President and Chief Executive Officer of TransCanada Pipelines Ltd.	30,938
Joel Dryer Chicago, Illinois, USA	Director	2008	President and CEO, Lab To Company LLC a private technology company	30,000
Brent Defosse ⁽¹⁾⁽²⁾ Calgary, Alberta	Director	2008	President and CEO, Brennex Resources Ltd, since February 2005 a private company. Prior thereto, Chief Operating Officer of Acclaim Energy Trust	-
Donald Leitch ⁽²⁾ Calgary, Alberta	Director	2007	Partner, Carscallen Leitch LLP, a law firm	50,000
Darren Jackson Calgary, Alberta	Vice-President, Operations and Chief Operating Officer	2007	Vice-President Operations, Chief Operating Officer of Fortress Prior thereto, VP Operations, Connacher Oil and Gas Ltd. from Nov 2006 to May 2007. Prior thereto Director of Production, Acclaim Energy Trust from May 2002 to Nov 2006.	63,829
Jamie Jeffs Calgary, Alberta	Vice President, Finance and Chief Financial Officer	2005	Vice President, Finance and Chief Financial Officer of Fortress Prior thereto, Vice President, Finance, of CriticalControl Solutions Corp. from June 2002 to July 2005 Prior thereto, Director, Finance of VeriticalBuilder.com Inc. from July 2000 to June 2002	43,445

Name and Municipality of Residence	Position Held with Fortress	Year First Appointed	Present Occupation During the Last Five Years	Fortress Shares Beneficially Owned
Robert D' Adamo	Vice President, Land	2007	Vice President Land of Fortress Senior Land Negotiator for EnCana Corporation since 2006 Prior thereto, Vice President, Business Development, Land and Marketing at NAV Energy Trust. Prior thereto, 1997 to 2003, Manager, Land Negotiations at Petro-Canada Oil and Gas	50,316

Notes:

- (1) Member of the Audit Committee.
- (2) Member of the Compensation Committee.

As at December 31, 2008, the directors, officers and senior management of the Corporation, as a group, beneficially owned, directly or indirectly, 1,506,008 Common Shares of the Corporation or approximately 5.6% of the issued and outstanding Common Shares.

The term of the office of each director will expire at the next annual general meeting of the shareholders.

Conflicts of Interest

Circumstances may arise where members of the board of directors of the Corporation are directors or officers of corporations which are in competition to the interests of the Corporation. No assurances can be given that opportunities identified by such board members will be provided to the Corporation. Pursuant to the ABCA, directors who have an interest in a proposed transaction upon which the board of directors is voting are required to disclose their interests and refrain from voting on the transaction.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

No director or executive officer of the Corporation is as at the date hereof, or has been, within 10 years of the date hereof, a director or chief executive officer or chief financial officer of any company, including Fortress:

- (a) while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer was the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days; or
- (b) was subject to a cease trade order or similar order, or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days, after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

No current director or executive officer or securityholder holding a sufficient number of securities of Fortress to affect materially the control of Fortress:

- (a) is at the date hereof or has been within the last 10 years prior to the date hereof a director or executive officer of any company (including Fortress) that, while such person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement for compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or
- (b) has within the last 10 years prior to the date hereof become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or securityholder.

No current director or executive officer or securityholder holding a sufficient number of securities of Fortress to affect materially the control of Fortress has been subject to:

- (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or
- (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

AUDIT COMMITTEE INFORMATION

The full text of the audit committee mandate is included in Schedule "C" of this AIF.

Composition of the Audit Committee as at March 31, 2009

George Watson

Mr. Watson holds a Bachelor of Science (Engineering) degree and MBA from Queen's University, as well as an AMP from Harvard University. Mr. Watson served as Chief Financial Officer of TransCanada Pipelines Ltd. for several years. Mr. Watson is independent and financially literate.

Brent Defosse

Mr. Defosse is a Professional Engineer with over 28 years experience in the oil and gas industry. Currently, he is President & CEO of Brennex Resources Limited, a private oil and gas engineering consulting company. Mr. Defosse is a former Chief Operating Officer of an oil and gas energy trust company and has also directed and managed all operational aspects of an organization which grew from 5,000 boe/d to 42,000 boe/d within a three year period. Mr. Defosse is independent and financially literate.

Rick Grafton

Mr. Grafton is President and CEO of Grafton Capital Corporation, a private capital Corporation concentrating on long term value creation. Prior thereto, Mr. Grafton acted as Executive Vice President & Managing Director, Global Head of Energy of Canaccord Adams. He was responsible for all aspects of the firm's oil and gas operations. Mr. Grafton was a former Managing Director and a Founding

Shareholder of FirstEnergy Capital Corp. (“**FirstEnergy**”). Mr. Grafton graduated from the University of British Columbia with a Bachelor of Commerce majoring in Finance in 1977. Mr. Grafton is independent and financially literate.

Pre-Approval Policies and Procedures

Under the mandate of the audit committee, the audit committee must pre-approve the retention of the auditor for any significant non-audit services permitted under applicable securities laws and the fee for such service.

External Auditor Service Fees

The following table provides information about the fees billed to the Corporation for professional services rendered by Ernst & Young LLP Chartered Accountants during fiscal years 2008 and 2007:

	2008 (\$)	2007 (\$)
Audit Fees ⁽¹⁾	126,000	120,000
Audit-Related Fees ⁽²⁾	125,000	117,000
Tax Fees ⁽³⁾	37,596	102,645
All Other Fees ⁽⁴⁾	2,400	1,100
Total	290,996	340,745

Notes:

- (1) Audit fees consist of fees for the audit of the Corporation’s annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements.
- (2) Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of the Corporation’s financial statements and are not reported as Audit Fees. During fiscal years 2008 and 2007, the services provided in this category included research of accounting and audit-related issues and procedures related to the reorganization of Signal and the issuance of common shares.
- (3) Tax fees consist of fees for tax compliance services, tax advice and tax planning. During fiscal year 2008, the services provided in this category included assistance and advice in relation to the preparation of corporate income tax returns.
- (4) The services provided in this category included Annual CPAB levy (Public Accountability Board).

PROMOTERS

There are no persons or companies, within the three most recently completed financial years or during the current financial year, acting as promoters of the Corporation.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings in progress for any claims for damages that exceed 10% of the current assets of the Corporation. There have been no penalties or sanctions imposed against the Corporation by a court or regulatory body (whether relating to securities legislation or otherwise) or settlement agreements entered into with a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as described above there have been no material transactions with directors, executive officers or with a beneficial owner who owns more than ten percent of the Common Shares, or with any

of their associates or affiliates within the last three most recently completed financial years or during the current financial year.

AUDITOR, TRANSFER AGENT AND REGISTRAR

The Corporation's Auditor is Ernst & Young LLP, Chartered Accountants located at 1000, 440 - 2nd Avenue S.W., Calgary, Alberta. Ernst & Young LLP, Chartered Accountants have been the auditors of the Corporation since 1996.

The Corporation's Transfer Agent and Registrar is Olympia Trust Company at, its offices in Calgary and Toronto.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, there have been no material contracts entered into by the Corporation within the most recently completed financial year, or before the most recently completed financial year that are still in effect.

INTERESTS OF EXPERTS

Sproule Associates Limited has prepared a report pursuant to National Instrument 51-101 dated March 3, 2009, relating to the Corporation's oil and gas reserves.

The Corporation has been advised that Sproule Associates Limited and their officers, directors and employees hold less than 1% of the securities issued by the Corporation.

ADDITIONAL INFORMATION

Additional information including director's and officer's remuneration and indebtednesses, principal holders of the Corporation's securities and securities issued, and authorized for issuance under the Corporation's equity compensation plan will be contained in the Corporation's 2009 proxy materials relating to its annual shareholders meeting to be held on May 27, 2009.

Additional financial information is provided in the Corporation's financial statements and MD&A for its most recently completed financial year.

Additional information relating to the Corporation can be found in the public documents of the Corporation which can be accessed on the SEDAR website at www.sedar.com.

Form 51-101F2

Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor

Report on Reserves Data

To the Board of Directors of Fortress Energy Inc. (the "Company"):

1. We have evaluated the Company's Reserves Data as at December 31, 2008. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008, estimated using forecast prices and costs.
2. The Reserves Data are the responsibility of the Company's management. Our responsibility is to express an opinion on the Reserves Data based on our evaluation.

We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook"), prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.


4. The following table sets forth the estimated future net revenue attributed to proved plus probable reserves, estimated using forecast prices and costs on a before tax basis and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us as of December 31, 2008, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M\$)	Evaluated (M\$)	Reviewed (M\$)	Total (M\$)
Sproule	Evaluation of the P&NG Reserves of Fortress Energy Inc., As of December 31, 2008, prepared January to March 2009	Canada				
Total			Nil	87,477	Nil	87,477

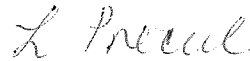
5. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are presented in accordance with the COGE Handbook.
6. We have no responsibility to update the report referred to in paragraph 4 for events and circumstances occurring after its preparation date.
7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

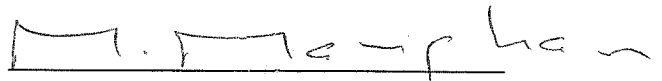
Sproule Associates Limited
Calgary, Alberta
March 03, 2009



Colleen M. Rogers, C.E.T.
Shareholder



Lucia M. Precul, P.Eng.
Associate



Michael W. Maughan, C.P.G., P.Geol.
Vice-President, Geoscience



Harry J. Helwerda, P.Eng.
Executive Vice-President

SCHEDULE "B"
FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Fortress Energy Inc. (the "**Corporation**") is responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Board of Directors of the Corporation has:

- (a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;
- (b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
- (c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Board of Directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has approved:

- (a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
- (b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and
- (c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Signed, and dated effective March 31, 2009.

"signed"
J. Cameron Bailey
President and Chief Executive Officer

"signed"
Darren Jackson
Chief Operating Officer

"signed"
Joel Dryer
Director

"signed"
Donald Leitch
Director

SCHEDULE “C”

AUDIT COMMITTEE MANDATE

The Audit Committee (the “Committee”) of the Board of Directors (the “Board”) of Fortress Energy Inc. (“Corporation”) shall have the oversight responsibility, authority and specific duties as described below.

I. Composition, Independence and Compensation

The Committee shall be comprised of three or more directors as determined by the Board. The members shall be independent as determined by applicable regulatory requirements.

All members of the Committee shall have a working familiarity with basic finance and accounting practices, and shall have the ability to read and understand the financial statements of the Corporation and the accounting issues raised therein and at least one member of the Committee shall have accounting or related financial management expertise.

Members of the Committee shall be appointed by the Board and shall serve until their successors are duly appointed. The Chair of the Committee may be designated by the members of the Committee.

II. Responsibility

The Committee’s primary purpose is to assist the Board in fulfilling its oversight responsibilities with respect to (i) the integrity of the annual and quarterly financial statements to be provided to shareholders and regulatory bodies; (ii) the Corporation’s compliance with accounting and finance based legal and regulatory requirements; (iii) the independent auditor’s qualifications and independence; (iv) the system of internal accounting and financial reporting controls that management has established; and, (v) performance of the external audit process and the independent auditor. The Committee shall also prepare such reports as are required to be prepared by it by applicable securities law. In addition, the Committee provides an avenue for communication between each of the internal audit, the independent auditors, financial and senior management and the Board. The Committee shall have a clear understanding with the independent auditors that they must maintain an open and transparent relationship with the Committee, and that the ultimate accountability of the independent auditors is to the Committee, as representatives of the shareholders. The Committee shall make regular reports to the Board concerning its activities. The Committee, in its capacity as a committee of the Board, subject to shareholder approval requirements, is directly responsible for the appointment, compensation, retention and oversight of the work of the independent auditors.

The Committee shall make regular reports to the Board concerning its activities.

III. Meetings

The Committee shall meet at least four times annually and as many additional times as the Committee deems necessary to carry out its duties effectively. The Committee shall meet in separate sessions with management, the senior internal audit executive of the Corporation and the independent auditors at each regularly scheduled meeting.

IV. Specific Duties

To carry out its oversight responsibilities, the Committee shall:

A. AUDIT SPECIFIC DUTIES

(i) Auditor Qualifications and Selection

1. Subject to applicable law requiring shareholder approval of auditors, be solely responsible for selecting, retaining, compensating, overseeing and, where necessary, terminating the independent auditors, who shall be registered with the Canadian Public Accountability Board. The independent auditor shall be required to report directly to the Committee. The Committee shall be entitled to adequate funding from the Corporation for the purpose of compensating the independent auditor for completing an audit and audit report.
2. Evaluate the independent auditor's qualifications, performance and independence. As part of that evaluation, at least annually obtain and review a report by the independent auditor describing: the firm's (auditor's) internal quality-control procedures; any material issues raised by the most recent internal quality-control review, or peer review, of the firm, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the firm, and any steps taken to deal with any such issues; and (to assess the auditor's independence) all relationships between the independent auditor and the Corporation; and ensure that the independent auditors do not provide non-audit services that would disqualify them as independent under applicable regulations.
3. Review the experience and qualifications of the senior members of the independent auditor team and the quality control procedures of the independent auditor; ensure that the lead audit partner of the independent auditor is replaced periodically, in accordance with regulatory requirements applicable to the Corporation; recommend to the Board guidelines for the Corporation's hiring of senior employees and former employees of the independent auditor who were engaged on the Corporation's account.

(ii) Audit Process

1. Pre-approve all auditing services; subject to applicable securities laws, pre-approve the retention of the independent auditor for any significant non-audit services permitted under applicable securities law and the fee for such services. All pre-approvals of such non-audit services shall be disclosed as required by applicable securities law. The Committee may delegate to one or more of its members the authority to grant pre-approvals required hereunder provided that any pre-approvals so granted are presented in writing to the Committee at the next regularly scheduled meeting.
2. Meet with the independent auditor prior to the audit to review the scope and general extent of the independent auditor's annual audit including the planning and staffing of the audit. This review should include an explanation from the independent auditors of the factors considered by the auditors in determining their audit scope, including the major risk factors.
3. Require the independent auditor to provide a timely report setting forth (i) all critical accounting policies, significant accounting judgments and practices to be used; (ii) all alternative treatments of financial information within Generally Accepted Accounting Principles ("GAAP") that have been discussed with management, ramifications of the use of such alternative disclosures and treatments and the treatment preferred by the

independent auditor; and, (iii) other material written communications between the independent auditor and management.

4. Upon completion of the annual audit, review the following with management and the independent auditors:
 - The annual financial statements including related footnotes and the MD&A to be included in the Corporation's annual report to shareholders or included in the Corporation's Annual Information Form.
 - The significant accounting judgements and reporting principles, practices and procedures applied by the Corporation in preparing its financial statements including any newly adopted accounting policies and the reasons for their adoption.
 - The results of the audit of the financial statements and the related audit report thereon. The independent auditors should confirm to the Committee that no limitations were placed on the scope or nature of their audit procedures.
 - Significant changes to the audit plan, if any, and any serious disputes or difficulties with management encountered during the audit, including any problems or disagreements with management which, if not satisfactorily resolved, would have caused the independent auditors to issue a non-standard report on the Corporation's financial statements.
 - The co-operation received by the independent auditors during their audit, including access to all requested records, data and information.
 - Any other matters not described above that are required to be communicated by the independent auditors to the Committee pursuant to Auditing Standards.
5. Generally, as part of the review of the annual financial statements, receive an oral report(s), at least annually, concerning legal and regulatory matters that may have a material impact on the financial statements. Discuss major financial risk exposures and steps management has taken to monitor and control such exposures.

B. ONGOING DUTIES

1. Review and reassess the adequacy of this Mandate periodically and recommend any proposed changes to the Board for approval.
2. Report regularly to the Board and review with the Board any issues that arise with respect to the quality or integrity of the Corporation's financial statements, the Corporation's compliance with legal or regulatory requirements, the performance and independence of the Corporation's independent auditor, or the performance of the internal audit function.
3. Discuss the types of information that it is appropriate for the Corporation to disclose in earnings press releases or other earnings guidance. Review with management and the Corporation's independent auditors all quarterly financial statements and MD&A prior to the filing of such reports with the applicable securities regulators and prior to any public announcement of financial results for the periods covered, including the results of the independent auditor's reviews of the quarterly financial statements, significant adjustments, new accounting policies, and any disagreements between the independent

auditors and management. The Chair of the Committee may represent the entire Committee for purposes of this review.

4. The Committee shall have the authority to engage independent counsel and other advisors as it determines necessary to carry out its duties.
5. 5. Perform any other activities consistent with this Mandate, the Corporation's By-Laws and applicable law, as the Committee or the Board deems necessary or appropriate.

C. INTERNAL CONTROL SUPERVISION DUTIES

1. Review with the Corporation's management and the independent auditors the Corporation's internal accounting and financial reporting controls, any significant deficiencies in them and any proposed major changes to them.
2. Review with management, the Chief Financial Officer and the independent auditors the methods used to establish and monitor the Corporation's policies with respect to unethical or illegal activities by Corporation employees that may have a material impact on the financial statements.
3. Meet with management and the independent auditors to discuss any relevant significant recommendations that the independent auditors may have, particularly those characterized as "material" or "serious".
4. Review the appointment of the senior accounting executive.
5. Review with management any correspondence with regulators or governmental agencies and any employee complaints or published reports which raise material issues regarding the Corporation's financial statements or accounting policies.
6. Review with management and the independent auditor any off-balance sheet financing mechanisms, transactions or obligations of the Corporation.
7. Review with management and the independent auditor any related party transactions.
8. Establish, implement and, as necessary, revise the procedures for (i) the receipt, retention, and treatment of complaints received by the Corporation regarding accounting, financial reporting controls, or auditing matters; and, (ii) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.
9. 9. Review with the independent auditors the quality of the Corporation's accounting personnel; review with management the responsiveness of the independent auditors to the Corporation's needs.

D. REGULATORY COMPLIANCE DUTIES

1. Prepare the necessary disclosure regarding the Committee and its duties and action as is required under applicable regulatory policy.
2. Prepare such reports as are required to be prepared by the Committee pursuant to applicable securities law.