

FORTRESS ENERGY INC.

ANNUAL INFORMATION FORM

Year ended December 31, 2009

Dated March 29, 2010

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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	<p>AECO Alberta Energy Company’s natural gas storage facility located at Suffield, Alberta</p> <p>API American Petroleum Institute</p> <p>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.</p> <p>ARTC Alberta Royalty Tax Credit</p> <p>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.</p> <p>BOE/D barrel of oil equivalent per day</p> <p>m³ cubic metres</p> <p>MBOE 1,000 barrels of oil equivalent</p> <p>WTI West Texas Intermediate, the reference price paid is U.S. dollars at Cushing, Oklahoma for crude oil of standard grade</p>		

CONVERSION

<u>To Convert From</u>	<u>To</u>	<u>Multiply By</u>
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	3.28 1
Miles	Kilometres	1.609
Kilometers	Miles	0.62 1
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;

“**Boyer Assets**” means those petroleum and natural gas interests more particularly described under “*General Development of the Business – Recent Developments.*”

“**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, 2009 prepared by Sproule and dated February 11, 2010.

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: the ability of the Corporation to obtain financing for the completion of the acquisition of the Boyer Assets and the willingness and ability of both parties to satisfy all conditions upon which the acquisition depends, 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:

- the completion of the acquisition of the Boyer Assets;
- oil and natural gas production levels;

- forward selling of the Corporation's production;
- capital expenditure programs;
- future costs described under "*Other Oil and Gas Information - Commitment*";
- the quantity of oil and natural gas reserves;
- projections of market prices and costs;
- future abandonment 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 Corporation's plans for future development of undeveloped reserves;
- expected 2010 volumes of production; and
- estimated time when taxes are payable and potential tax refunds.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve an implied assessment based on certain estimates of assumptions that the reserves described exist in the quantities predicted or estimated and can be profitably produced in the future.

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:

- the inability of the Corporation to obtain financing for the acquisition of the Boyer Assets on favourable terms or to obtain regulatory approval of the acquisition;
- the failure of the Corporation and the vendor of the Boyer Assets to reach agreement on the terms of a formal agreement
- 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. 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

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 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*”.

In July 2009, the Corporation completed a strategic asset acquisition in the Ladyfern, Mearon and Velma areas for \$12.5 million, adding proven reserves of 1,040 mboe and proven plus probable reserves of 1,546 mboe. The acquisition included 54,232 net acres of undeveloped land, consolidating the Corporation’s land position in its core Ladyfern, Mearon and Velma areas.

On October 23, 2009, the Corporation closed the previously announced acquisition of its partner’s 50% working interest in the Square Creek area of Alberta for cash consideration of \$7,000,000, subject to final adjustments.

In 2009, the Corporation took several key steps to materially reduce operating costs including the purchase of a rented compressor, camp, rig mats and other rented equipment at Square Creek. In addition, the Corporation replaced the field operations contractor at Square Creek, effective August 1st, 2009 and replaced the field operations contractor at the third party facility at Clear Prairie that processes the Corporation’s Square Creek production effective November 15th, 2009.

Recent Developments

On March 4, 2010, the Corporation announced that it had entered into a letter of intent to acquire, for a purchase price of \$170 million, a 100% working interest in a significant producing natural gas property (the "Boyer Assets") located in the Boyer area of Alberta. The Boyer Assets have the following attributes:

- 27Mmcf/d per day of natural gas production (4,500 boe/d), mainly from the Bluesky formation
- Proven and Probable Reserves of 136 Bcf
- Reserve life Index of 13.8 years and 8% annual decline rates
- Over 200 development drilling locations identified and production enhancement projects
- Over 787,000 acres of contiguous land
- 100% working interest, including the gathering and processing facilities

The acquisition of the Boyer Assets is subject to the execution of a formal purchase and sale agreement, financing and regulatory approval.

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 2009.

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 has a 100% working interest in approximately 33,280 gross and net acres of land.

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.

In 2009, the Corporation took several material steps to significantly reduce operating costs from the Square Creek area including the purchase of a rented compressor, camp, rig mats and other rented equipment. In addition, the Corporation replaced the field operations contractor at Square Creek effective August 1, 2009 and replaced the field operations contractor at the third party facility at Clear Prairie that processes the Corporation's Square Creek production effective November 15, 2009.

In October 2009, the Corporation closed the acquisition of its partner's 50% working interest in the Square Creek property and related facilities at well below industry metrics, providing it with a 100% working interest position going forward. Since that time, the Corporation has increased flow rates from 5.4 Mmcf/d to as much as 8.5 Mmcf/d, restricted only by constraints at the third party operated Clear Prairie facility through which the gas is produced.

Pressure work on the main Bluesky formation in 2009 confirmed a significant increase in the discovered natural gas resource, resulting in a 44% increase to the initial gross recoverable reserves for the area at year end 2009.

In the first quarter of 2009, the Corporation drilled two development wells at Square Creek and drilled one working interest exploratory well. 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. The Corporation also acquired 4,985 gross and net acres at Crown land sales in 2009 in the general Square Creek area.

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 an optimum rate from the Square Creek area is restricted by processing capacity at the Clear Prairie facility owned by a third party. Due to the low natural gas prices the Corporation has not pursued the plant expansion at the Clear Prairie Facility. Average production (net) for all of 2009 was 576 BOE/D (reflecting a 50% working interest to October 23, 2009) and is presently producing at 1,167 BOE/D.

Mearon, Alberta

The Mearon area is located approximately 175 km northeast of Fort St. John, B.C. Mearon sits immediately east of the Ladyfern North property across the border in NW Alberta. At Mearon, the Corporation holds an interest in 21,550 gross acres (17,230 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 regionally extensive Notikewin formation (equivalent to Upper Mannville) and features stable reserves with declines of 15-20% per year.

There were no capital enhancement operations conducted by the Corporation in 2009, however the Corporation was successful in reducing its contract operating fees for the area by 40% effective December 1, 2009.

Mearon North contributed an average 184 BOE/D for 2009 and is presently producing at 176 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.

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 4,255 gross acres (3,636 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.

The Corporation completed a major upgrade to the Buick Creek gas processing facility in the third quarter of 2009. Buick Creek contributed an average of 73 BOE/D of production in 2009 and is presently producing at 64 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 Mannville formation) and features stable reserves with declines of 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 2009, however the Corporation was successful in reducing its contract operating fees for the area by 40% effective December 1, 2009.

Ladyfern North contributed an average 143 BOE/D for 2009 and is presently producing at 112 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 20,348 gross acres (12,182 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 20% per year.

There were no capital enhancement operations conducted at Ladyfern South by the Corporation in 2009, however the Corporation was successful in reducing its contract operating fees for the area by 40% effective December 1, 2009.

Ladyfern South contributed an average 125 BOE/D for 2009 and is presently producing at 119 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 40 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.

In August 2009, the Corporation re-routed its Velma production to another third party processing plant which is expected to improve productivity and reduce gas processing costs at Velma. Velma contributed an average 109 BOE/D for 2009 and is presently producing at 101 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.

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, 2009 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. 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, 2009
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	19,718	12,630	28.4	22.6
Developed Non-Producing	0.0	0.0	1,615	1,433	3.7	2.9
Undeveloped	0.0	0.0	4,273	3,866	5.6	4.4
Total Proved	0.0	0.0	25,606	17,929	37.7	29.9
Probable	0.0	0.0	16,210	13,507	20.1	16.0
Total Proved plus Probable	0.0	0.0	41,816	31,436	57.8	46.0

*Summary of Net Present Values of Future Net Revenue
As of December 31, 2009
Forecast Prices and Costs*

	Before Income Tax					After Income Tax					Unit Value \$/BOE Net Reserves Discounted at 10% before Income Tax (\$/BOE)
	Discounted At					Discounted At					
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%	
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	
Proved											
Developed	47,975	39,767	34,068	29,890	26,699	47,975	39,767	34,068	29,890	26,699	16.01
Producing											
Developed	3,683	2,882	2,320	1,912	1,605	3,683	2,882	2,320	1,912	1,605	9.60
Non-Producing											
Undeveloped	11,292	8,271	6,126	4,571	3,422	11,292	8,271	6,126	4,571	3,422	9.44
Total Proved	62,950	50,920	42,514	36,372	31,725	62,950	50,920	42,514	36,372	31,725	14.09
Probable	39,454	28,109	20,771	15,739	12,146	32,259	22,979	17,000	12,901	9,966	9.16
Total Proved plus Probable	102,405	79,029	63,285	52,112	43,871	95,209	73,899	59,514	49,273	41,692	11.97

Note:

- (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 \$7,456,000 and Proved and Probable Reserves to be \$22,267,000.

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, 2009 estimated based on forecast prices and costs and calculated without discount:

**Total Future Net Revenue
(Undiscounted)
As of December 31, 2009
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	190,464	44,144	74,217	7,456	1,696	62,950	0	62,950
Proved plus Probable	323,056	62,449	133,211	22,267	2,725	102,405	7,195	95,209

The following table set forth the future net revenue (before deducting future income tax expenses) of the Corporation as of December 31, 2009 estimated based on forecast prices and costs and calculated using a discount rate of 10%:

**Net Present Value of Future Net Revenue by Production Group
As of December 31, 2009
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)	42,514	14.09
	TOTAL	42,514	14.09
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)	63,285	11.97
	TOTAL	63,285	11.97

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 effective January 1, 2010 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)
<i>Historical</i>								
2009	61.63	66.20	62.77	4.19	68.13	47.07	2.0	0.880
<i>Forecast</i>								
2010	79.17	84.25	80.04	5.36	86.28	59.65	2.0	0.920
2011	84.46	89.99	84.59	6.21	92.16	63.72	2.0	0.920
2012	86.89	92.61	85.20	6.44	94.84	65.57	2.0	0.920
2013	90.20	96.19	87.53	7.23	98.51	68.11	2.0	0.920
2014	92.01	98.13	88.32	7.98	100.50	69.48	2.0	0.920
Thereafter	Escalation Rates of 2%							

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 2009 were: Natural Gas - \$4.19/Mcf; Oil and Natural Gas Liquids - \$53.71/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, 2008 to December 31, 2009 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, 2008	-	-	-	-	-	-	1,235	738	1,972	20,707	13,628	34,336	49.5	22.7	72.2
Extensions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	(175)	(316)	(490)	2,189	(260)	1,928	(9.0)	(4.0)	(13.0)
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	4,772	2,366	7,138	3.2	1.5	4.7
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	(3)	(2)	(5)	(345)	56	(289)	(0.5)	(0.1)	(0.6)
Production	-	-	-	-	-	-	(94)	-	(94)	(2,680)	-	(2,680)	(3.5)	-	(5.5)
December 31, 2009	-	-	-	-	-	-	963	420	1,383	24,643	15,790	40,433	37.7	20.1	57.8

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:

	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
	First Attributed Gross (Mbbl)	Booked Gross (Mbbl)	First Attributed Gross (Mbbl)	Booked Gross (Mbbl)	First Attributed Gross (MMcf)	Booked Gross (MMcf)	First Attributed Gross (Mbbl)	Booked Gross (Mbbl)
Proved Undeveloped								
December 31, 2007	-	-	-	-	11,354	11,354	5.2	5.2
December 31, 2008	-	-	-	-	569	8,345	0.5	7.1
December 31, 2009	-	-	-	-	4,273	-	-	5.6
Probable Undeveloped								
December 31, 2007	-	-	-	-	6,531	6,531	8.8	8.8
December 31, 2008	-	-	-	-	355	6,662	0.5	8.4
December 31, 2009	-	-	-	-	-	10,561	-	10.5

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\$)
2010	100	550
2011	4,644	11,176
2012	2,713	10,373
2013	-	167
2014	-	-
Total	7,456	22,267

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, 2009 in wells, which are producing, or which the Corporation considers to be capable of production:

	<u>Gross⁽¹⁾</u>		<u>Net⁽²⁾</u>	
	<u>Producing</u>	<u>Shut-in(3)</u>	<u>Producing</u>	<u>Shut-in(3)</u>
<i>Alberta</i>				
Oil	-	-	-	-
Gas	33	12	21.7	9.1
Total	33	12	21.7	9.1
 <i>British Columbia</i>				
Oil	-	-	-	-
Gas	26	5	20.8	4.5
Total	26	5	20.8	4.5

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 Corporation's shut-in wells are spread throughout its various properties.

Commodity Contracts

The Corporation uses commodity contracts to manage its exposure to fluctuations in the price of natural gas. Realized gains and losses on commodity contracts are included in petroleum and natural gas sales. For the year ended December 31, 2009, the Corporation realized a gain on commodity contracts of \$6,722,000, or \$2.43/mcf, compared to a realized loss on commodity contracts of \$1,564,000 or \$0.52/mcf for the year ended December 31, 2008. In addition, the unrealized loss on commodity contracts in the year ended December 31, 2009 was \$1,166,000 compared to an unrealized gain on commodity contracts of \$2,395,000 for the year ended December 31, 2008. The Corporation has sold forward approximately 65% of its natural gas production through to March 31, 2011 giving the Corporation a degree of certainty over its cash flow. The estimated mark-to-market value of the Corporation's commodity contracts at December 31, 2009 was \$1,321,000.

Contracts in place as of December 31, 2009 are as follows:

Type	Period	Volume (GJ/d)	Fixed Price (\$/GJ)
Swap	January 1, 2010 to March 31, 2010	2,600	8.38
Swap	January 1, 2010 to March 31, 2010	2,500	6.80
Swap	April 1, 2010 to December 31, 2010	5,000	5.69

Subsequent to December 31, 2009, the Corporation entered into an additional contract to sell 2,000 GJ/d of natural gas at \$5.50/GJ for the period of April 1, 2010 to March 31, 2011.

Land Holdings

The following table sets out the developed and undeveloped land holdings of the Corporation as at December 31, 2009.

	Developed		Undeveloped		Total		Net Area to Expire 2010
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)	
Alberta	16,533	13,432	87,278	76,465	103,811	89,897	7,680
B.C.	26,355	20,125	21,894	16,231	48,249	36,356	560
Total	42,888	33,557	109,172	92,696	152,060	126,253	8,240

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 will 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, 2009 was completed by Independent Land Evaluations Inc. resulting in an undeveloped land total net value of \$12,616,908.

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 46 net wells under the Proved reserves category is \$1,696,000 undiscounted (\$829,000 discounted at 10%), of which a total of \$228,000 is estimated to be incurred in aggregate in 2010, 2011 and 2012.

The Corporation has created a liability for existing asset retirement obligations. The undiscounted estimated cash flows required to settle the obligation is \$6.7 million. The discounted amount recognized during 2009 was \$4.2 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, 2009 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. At December 31, 2009, the Corporation has approximately \$90 million of available resource pools and undepreciated capital cost pools.

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, 2009 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, 2009 and 2008:

	Year ended December 31, 2009 (M\$)	Year ended December 31, 2008 (M\$)
Exploration		
Land and seismic	530	1,679
Development		
Drilling and completions	4,678	9,689
Equipment and facilities	3,592	14,937
Acquisitions		
Proved Property	6,986	-
Unproved Property	-	1,106
Dispositions	-	(8,150)
Capitalized overhead costs	1,022	1,006
Other	43	
	16,851	20,267

In the three months ended December 31, 2009, the Corporation acquired its partner's 50% working interest in Square Creek for \$6,986,000 giving the Corporation a 100% working interest in the property. The Corporation also completed a major upgrade to the Buick Creek gas processing facility and the re-

routing of Velma production to another third party processing facility. The total cost of the Buick Creek upgrade was approximately \$1,062,000. Capital expenditures for the three months ended December 31, 2008 included the drilling of an exploratory well on the Corporation's lands at Pine Creek.

Capital expenditures for the year ended December 31, 2009 were \$16,851,000 compared to \$20,267,000 for the year ended December 31, 2008. During the first quarter of 2009, the Corporation finished operations relating to the completion of an exploratory well in the Pine Creek area and undertook the drilling of three wells in the Square Creek area, the Corporation's core producing property. The Corporation also participated in the drilling of two development wells at Square Creek and drilled one 100% working interest exploratory well. One of the development wells was successfully equipped and tied-in during the first quarter of 2009. The capital program for the first quarter of 2008 was focused on the follow-up to the discovery of the Bluesky and Notikewin gas pools from the 2007 winter drilling program and compression and optimization at Ladyfern. The Corporation also constructed a 10 mmcf/d gathering and production facility to service eight wells it has in the Square Creek area. The Corporation completed the construction of a 41 km pipeline to deliver 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 2008 for a total cost of \$8,882,000 and was sold to a mid-stream service provider in April for proceeds of \$8,150,000 resulting in a loss on the sale of the pipeline asset of \$732,000 (of which \$428,000 was recorded in 2008 and a further \$304,000 in 2009).

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 an optimum rate from the Square Creek area is restricted by processing capacity at the Clear Prairie facility owned by a third party. Due to the low natural gas prices the Corporation has not pursued the plant expansion at the Clear Prairie Facility.

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\$)
2010	12	470	482
2011	9	475	484
2012	-	474	474
2013	-	119	119
	21	1,538	1,559

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\$)
2010	1,935
2011	1,533
2012	1,533
2013	1,533
2014	1,533
2015	545
	8,612

Letter of Credit

On February 1, 2009, the Corporation issued a letter of credit of \$900,000 with an expiry of February 1, 2010, related to a gas transportation and processing agreement. Upon the expiry of the existing letter of credit, a replacement letter of credit of \$810,000 was issued with an expiry of February 1, 2011.

Drilling Commitments

As at December 31, 2009, the Corporation has a commitment related to a flow-through share offering of approximately \$3,000,000 to be incurred by December 31, 2010.

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, 2009 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 the Canada Revenue Agency (the “**CRA**”) on the 2004 flow-through expenditures of a business acquired by the Corporation in 2006, the Corporation was reassessed by the CRA for interest and penalties of \$300,000 on expenditures not qualifying for renunciation under the flow-through share program in the amount of \$1,916,000. The Corporation filed a Notice of Objection with the CRA on July 31, 2009 after consultation with its tax advisors and legal counsel and is appealing this reassessment. The Corporation has indemnified the subscribers of this flow-through share offering from income taxes related to the offering. The amount of the potential indemnification is approximately \$765,000. The amounts of the interest and penalties and potential indemnification have not been recorded as the Corporation’s position is that the more likely than not criteria for recognition have not been met.

Income Tax Audit

In January 2010, the Corporation received an audit letter from the CRA pertaining to the conversion of SignalEnergy Inc., predecessor to the Corporation and formerly known as SignalGene Inc., into an oil and gas enterprise. The CRA proposes to deny the use of tax pools existing at the time of the conversion. The Corporation is responding to the audit letter and believes that this matter will be resolved in the Corporation's favor. If the CRA is successful in its challenge to the Corporation's interpretation of the tax legislation, it will result in additional taxes, interest and penalties of a material amount.

Exploration and Development Activities

Drilling Activity

During the twelve month period ending December 31, 2009, the Corporation drilled 3 gross (3.0 net) wells resulting in 1 gross (1.0 net) producing wells:

Year Ended December 31, 2009	Crude Oil		Natural Gas		Suspended		Service		Dry		Total
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Net
Exploratory	-	-	-	-	-	-	-	-	1.0	1.0	1.0
Development	-	-	1.0	1.0	-	-	-	-	1.0	1.0	2.0

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

Estimated 2010 Production Volumes

The following table provides the volume of production of the Corporation estimated for 2010 for its reserves:

Corporate	Forecast Prices and Costs (undiscounted)	
	Proved Reserves	Proved plus Probable Reserves
2010 Production (Gross)		
Oil (MBbl)	-	-
Natural Gas (MMcf)	4,152	4,198
Natural Gas Liquids (MBbl)	5.1	5.2
Oil equivalent (MBOE)	697.1	704.9
2010 Production (Net)		
Oil (MBbl)	-	-
Natural Gas (MMcf)	2,838	2,872
Natural Gas Liquids (MBbl)	4.0	4.1
Oil equivalent (MBOE)	477.0	482.8

The Corporation's Square Creek field represents more than 20% of the Corporation's 2010 estimated production as follows:

	Forecast Prices and Costs (undiscounted)	
	Proved Reserves	Proved plus Probable Reserves
Square Creek		
2010 Production (Gross)		
Oil (MBbl)	-	-
Natural Gas (MMcf)	2,935	2,950
Natural Gas Liquids (MBbl)	-	-
Oil equivalent (MBOE)	489.2	491.7
2010 Production (Net)		
Oil (MBbl)	-	-
Natural Gas (MMcf)	1,771	1,780
Natural Gas Liquids (MBbl)	-	-
Oil equivalent (MBOE)	295.2	296.7

Production History for 2009

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)	Operating Costs (\$/Bbls or Mcf)	Transportation 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	689,850	7.47	0.69	2.60	0.35	3.83
Second Quarter	691,873	6.22	0.63	2.66	0.36	2.57
Third Quarter	620,172	6.65	(0.22)	2.80	0.31	3.76
Fourth Quarter	762,496	6.15	(0.09)	2.58	0.29	3.37
Natural Gas Liquids (Bbls)						
First Quarter	1,260	37.72	4.11	15.62	2.12	15.87
Second Quarter	1,092	45.11	3.80	15.95	2.14	23.22
Third Quarter	1,196	82.45	(1.29)	16.81	1.88	65.05
Fourth Quarter	1,748	51.10	(0.55)	15.45	1.73	34.47
Light & Medium Oil & Natural Gas Liquids Combined (Bbls)						
First Quarter	1,260	37.72	4.11	15.62	2.12	15.87
Second Quarter	1,092	45.11	3.80	15.95	2.14	23.22
Third Quarter	1,196	82.45	(1.29)	16.81	1.88	65.05
Fourth Quarter	1,748	51.10	(0.55)	15.45	1.73	34.47

Notes:

- (1) Netback is calculated as price realized by the Corporation (including realized gains and losses on commodity contracts), less royalties, less operating costs and less transportation costs.
- (2) The Corporation had substantially no light and medium oil production in 2009.

FURTHER DESCRIPTION OF THE BUSINESS

Employees

As of December 31, 2009, the Corporation had 12 employees and 3 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.

In December, 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "ALUF"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. The ALUF calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. The *Alberta Land Stewardship Act* (the "ALSA") was proclaimed in force in Alberta on October 1, 2009, providing the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA are deemed to be legislative instruments equivalent to regulations and are binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits licenses approvals and authorizations in order for the purposes of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans of contained in the ALSA are conservation easements, which can be granted for the protection, conversation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment. Although no regional plans have been established under the ALSA, the planning process is underway for the Lower Athabasca Region (which contains the majority of oil sands development) and the South Saskatchewan Region. While the potential impact of the regional plans established under the ALSA cannot yet be determined, it is clear that such regional plans may have a significant impact on land use in Alberta and may affect the oil and gas industry.

RISK FACTORS RELATING TO THE OIL AND GAS BUSINESS

Substantial Capital Requirements

The Corporation intends to acquire the Boyer Assets and thereafter 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, borrowing capacity, profitability, cash flow from operating activities and the level of expenditures for the development of its oil and natural gas reserves. Such decline could therefore have an effect on the amounts to be distributed to shareholders. 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 increased 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.

To 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.

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% in the case of old and new conventional oil, respectively, 5% to 35% in the case of natural gas and 15% to 50% 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%, 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% 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% for pentanes and 30% 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.

On March 11, 2010 the Alberta Government announced further changes to the royalty structure for conventional oil and gas production in order to improve the province's competitiveness for oil and gas development. The result is that the maximum royalty rate for conventional oil will be reduced from 50% to 40%, and the maximum rate for natural gas will be reduced from 50% to 36%. Details of the changes are yet to be presented to industry, but the direction of the changes is expected to be positive to the Corporation going forward.

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

As of December 31, 2009 the Corporation had a \$24,000,000 demand operating loan facility with its bank (the "Bank"), bearing interest at the Bank's prime lending rate plus 1.0% (effective interest rate for 2009 of 3.44% and for 2008 – 5.05%). At December 31, 2009, a total of \$23,044,000 (December 31, 2008 - \$20,533,000) was drawn on this facility. The Corporation also has a \$900,000 letter of guarantee facility of which \$900,000 was drawn at December 31, 2009 (December 31, 2008 - \$1,000,000). These facilities are collateralized by an interest over all present and after acquired property of the Corporation.

Effective January 18, 2010, the authorized borrowing amount of the Corporation's demand operating loan facility was reduced to \$17,000,000 as a result of a reduction in the Corporation's borrowing base due to low natural gas prices. The demand operating loan bears interest at the Bank's prime lending rate plus 2%. In addition, a \$7,000,000 demand non-revolving loan facility was established with interest on this facility being charged at the Bank's prime lending rate plus 5%. The demand non-revolving loan is to be repaid by March 31, 2010. In recent discussions, the Bank has indicated that it will delay or forgo the repayment pending the completion of the acquisition of the Boyer Assets. In connection with this acquisition, the Corporation anticipates obtaining up to \$100,000,000 in new credit facilities to replace the existing credit facilities from a syndicate of banks. The Corporation anticipates that the new credit

facilities will have industry standard terms and financial covenants. If the Corporation is unable to close this transaction, the Corporation anticipates that the Bank will continue to work with the Corporation to establish a repayment schedule.

Scheduled reviews of the revolving operating loan focus on the borrowing base supporting lending limits and are influenced by the lender's willingness to lend in general, commodity price forecasts used to determine the lending base, lender's interest in particular business sectors, such as energy and the relative strength of the borrower. Given these constraints, there is no assurance that the Corporation will be able to sustain its current borrowing base and may be required to reduce its outstanding loan. Should there be a requirement of the Corporation to reduce its outstanding loan, there are a number of options available including, but not limited to:

- Issuance of additional equity;
- Negotiation of incremental borrowings with subordinated lenders; and
- Divestiture of assets.

The Corporation is required to maintain its working capital ratio at 1:1 or greater while the facilities are outstanding. 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 as at December 31, 2009. The Corporation's ability to maintain compliance with this financial covenant is dependent on certain factors, certain of which are outside the Corporation's control. Such factors include future industry and capital market conditions and commodity pricing. Based on current market conditions and commodity prices, the Corporation may have difficulty maintaining compliance with this financial covenant in the next 12 month period and the Bank can demand repayment of the operating loan facility.

The Corporation's capital resources available at December 31, 2009 are as follows:

	As at December 31, 2009 (M\$)
Operating loan available	24,000
Working capital deficiency	(23,497)
Capital resources available	503

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. Losses resulting from the occurrence of any of these risks could have a material effect on the Corporation's financial condition and therefore on the amounts to be distributed to shareholders.

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 *“Additional Information Relating to Reserves Data – 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 acquire the Boyer Assets and to thereafter 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 assumes 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.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

In addition to the acquisition of the Boyer Assets, the Corporation makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Corporation.

Climate Change

Canada is a signatory to the United Nations Framework Convention on Climate change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so called "greenhouse gases". There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Recently, representatives from approximately 170 countries met in Copenhagen, Denmark to attempt to negotiate a successor to Kyoto Protocol. The result of such meeting was the Copenhagen Accord, a non-binding political consensus rather than a binding international treaty such as the Kyoto Protocol. The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and require the Corporation to comply with Alberta's greenhouse gas emissions legislation contained in the *Climate Change and Emissions Management Act* and the *Specified Gas Emitters Regulation*. The Corporation will also be required to comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which are now expected to be consistent with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases regulations, whether to meet the limits required by the Kyoto Protocol, the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirement, it is not possible to predict the impact on the Corporation and its operations and financial condition.

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 55,298,788 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 2009 there were 35,764,366 Common Shares traded at prices ranging from a low of \$0.16 to a high of \$0.53.

	Volume	High (\$)	Low (\$)	Close (\$)
January 2009	168,840	0.40	0.22	0.26
February 2009	371,020	0.34	0.16	0.24
March 2009	875,680	0.27	0.20	0.23
April 2009	116,710	0.33	0.24	0.27
May 2009	1,380,456	0.31	0.25	0.28
June 2009	430,935	0.29	0.22	0.24
July 2009	617,841	0.25	0.21	0.22
August 2009	9,788,048	0.50	0.16	0.44
September 2009	6,546,417	0.53	0.30	0.30
October 2009	5,203,903	0.35	0.24	0.26
November 2009	7,336,262	0.29	0.22	0.27
December 2009	2,928,254	0.38	0.26	0.34
January 2010	2,015,359	0.34	0.29	0.30
February 2010	769,592	0.32	0.26	0.28

PRIOR SALES

In the twelve months prior to the date hereof the Corporation issued the following securities:

On September 30, 2009 Fortress issued 21,779,000 units at a price of \$0.385 per unit and 6,594,000 Common Shares on a flow-through basis at a price of \$0.455 per flow-through share by way of a short form prospectus. Each unit was composed of one Common Share and one Common Share purchase warrant ("Warrant"). The Warrants are exercisable into one Common Share at a price of \$0.55 for a period of 24 months from September 30, 2009. Stock options exercisable into 3,520,000 Common Shares at \$0.245 per share were issued effective November 19, 2009.

ESCROWED SECURITIES

There were no escrowed securities as at December 31, 2009.

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.	895,480
Ronald McIntosh ⁽¹⁾⁽²⁾ Calgary, Alberta	Director	2009	President and CEO of Navigo Energy from 2002 until 2004. Prior thereto Senior Vice President and COO of Gulf Canada Resources, Vice President, Exploration and International of Petro Canada, Executive Vice President and COO of Amerada Hess Canada, and Senior Vice President of AEC Oil and Gas.	-
George Watson ⁽¹⁾ Calgary, Alberta	Director	2003	Executive Chairman of CriticalControl Solutions Inc, since May 2007. Prior thereto Chief Executive Officer of Critical Control Solutions Inc., a public technology company, since January, 2002.	30,938
Joel Dryer ⁽¹⁾⁽²⁾ Chicago, Illinois, USA	Director	2008	President and CEO, Lab To Company LLC a private technology company	30,000
Donald Leitch, Q.C. ⁽²⁾ Calgary, Alberta	Director	2007	Partner, Carscallen Leitch LLP, a law firm	50,000
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	43,445
Robert D'Adamo Calgary, Alberta	Vice President, Land	2007	Vice President, Land of Fortress Prior thereto, Senior Land Negotiator for EnCana Corporation since 2006 Prior thereto, Vice President, Business Development, Land and Marketing at NAV Energy Trust	50,316
Jeff Shaw Calgary, Alberta	Vice President, Engineering	2009	Vice President, Engineering of Fortress. Prior thereto, VP Technical Resources / VP Engineering O&G Asset Clearinghouse & Canaccord Enermarket since 2006. Prior thereto, Manager SE Saskatchewan Business Unit at APF Energy Trust since 2003.	-

Notes:

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

As at December 31, 2009, the directors, officers and senior management of the Corporation, as a group, beneficially owned, directly or indirectly, 1,100,179 Common Shares of the Corporation or approximately 2% 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

Other than as set out below, 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.

George Watson was the director of RepeatSeat Ltd., an Alberta-based company until his resignation in June, 2009. To the knowledge of George Watson, RepeatSeat Ltd. became insolvent during the 2009 calendar year but did not become legally bankrupt, make a proposal under any legislation relating to bankruptcy or insolvency and was not subject to or did not institute any proceeding, arrangement or compromise with creditors, or have a receiver, receiver manager or trustee appointed to hold its assets.

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 29, 2010

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.

Ron McIntosh

Mr. McIntosh has extensive oil and gas and board experience. His work experience has included leadership roles in Canada and the United States as well as internationally. He was President and CEO of Navigo Energy from 2002 until 2004 and oversaw its conversion into NAV Energy Trust and C1 Energy. Prior to that he held leadership roles including Senior Vice President and COO of Gulf Canada Resources, Vice President, Exploration and International of Petro Canada, Executive Vice President and COO of Amerada Hess Canada, and Senior Vice President of AEC Oil and Gas. Mr. McIntosh is independent and financially literate.

Joel Dryer

Mr. Dryer brings to Fortress over 30 years experience in the finance, technology, and manufacturing industries. Most recently he has focused on microcap equity financing. Mr. Dryer graduated from The University of Illinois with a BSBA, followed by an MBA from the University of Massachusetts in 1978. Mr. Dryer is financially literate.

Reliance on Exemption

During the most recently completed financial year, the Corporation relied on an exemption under Section 3.5 of National Instrument 52-110 from the requirement that every member of the audit committee be independent. Due to certain resignations from the board of directors, the board found itself in a position where it could not appoint three (3) members to the audit committee who were all independent. As a result, the board appointed Mr. Joel Dryer to the audit committee. Mr. Dryer is financially literate and the board determined that, notwithstanding any consulting arrangement Mr. Dryer may have with the Corporation, such arrangement would not interfere with the exercise of Mr. Dryer's independent judgment and therefore the board determined that his appointment would not materially affect the ability of the audit committee to act independently. The Corporation continues to seek qualified independent directors.

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, the Corporation's former auditors, during fiscal years 2009 and 2008, and KPMG LLP during the 2009 fiscal year:

	2009	2008
	(\$)	(\$)
Audit Fees ⁽¹⁾	75,000	222,138
Audit-Related Fees ⁽²⁾	144,393	125,000
Tax Fees ⁽³⁾	199,347	37,596
All Other Fees ⁽⁴⁾	3,920	2,400
Total	422,660	387,134

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 2009 and 2008, 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 2009 and 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 two 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 10% 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 KPMG LLP, Chartered Accountants located at 2700, 205 – 5th Avenue S.W., Calgary, Alberta. KPMG LLP is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

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 February 11, 2010, relating to the Corporation's oil and gas reserves. Independent Land Evaluations Inc. has prepared an evaluation of the Corporation's undeveloped land.

The Corporation has been advised that each of Sproule Associates Limited and Independent Land Evaluations Inc. and their respective 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 25, 2010.

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, 2009. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, 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, 2009, 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:

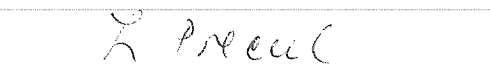
Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M\$)	Evaluated (M\$)	Reviewed (M\$)	Total (M\$)
Sproule	Evaluation of the P&NG Reserves of Fortress Energy Inc., As of December 31, 2009, prepared January to February 2010	Canada				
Total			Nil	63,285	Nil	63,285


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
February 11, 2010


for Colleen Rogers, C.E.T.
Shareholder


Lucy M. Precul, P.Eng.
Associate


John Hanko, P.Geol.
Associate


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, 2009, 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 29, 2010.

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

"signed"
Jeff Shaw
V.P., Engineering

"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.