

## FINANCIAL AND OPERATING SUMMARY

	Three months ended December 31,				Year ended December 31,			
	2009		2008		2009		2008	
	(\$000s)	\$/boe	(\$000s)	\$/boe	(\$000s)	\$/boe	(\$000s)	\$/boe
Petroleum and natural gas sales	4,798	37.17	5,962	47.41	18,589	39.87	24,834	48.68
Royalties	71	0.55	(943)	(7.50)	(714)	(1.53)	(4,364)	(8.55)
Operating expenses	(1,995)	(15.45)	(1,823)	(14.50)	(7,422)	(15.92)	(7,388)	(14.48)
Transportation expenses	(223)	(1.73)	(279)	(2.22)	(915)	(1.96)	(1,187)	(2.32)
Operating netback <sup>(1)</sup>	2,651	20.54	2,917	23.19	9,538	20.46	11,895	23.33
Environmental remediation	(134)	(1.03)	-	-	(134)	(0.29)	-	-
General and administrative expenses	(821)	(6.36)	(715)	(5.69)	(2,908)	(6.24)	(2,479)	(4.86)
Professional fees	(73)	(0.57)	(311)	(2.47)	(675)	(1.44)	(712)	(1.40)
Bad debts	(132)	(1.02)	(84)	(0.67)	(294)	(0.63)	(2)	-
Interest expense	(277)	(2.15)	(534)	(4.24)	(917)	(1.97)	(1,585)	(3.11)
Current income tax expense	(42)	(0.33)	(160)	(1.27)	(96)	(0.21)	(160)	(0.31)
Funds from operations <sup>(1)</sup>	1,172	9.08	1,113	8.85	4,514	9.68	6,957	13.65
Unrealized gain (loss) on commodity contracts	(808)	(6.26)	1,062	8.44	(1,166)	(2.50)	2,395	4.70
Depletion, depreciation and accretion expense	(2,720)	(21.07)	(3,727)	(29.64)	(13,170)	(28.24)	(14,354)	(28.14)
Ceiling test impairment	(4,820)	(37.34)	-	-	(19,096)	(40.95)	-	-
Stock-based compensation	(153)	(1.19)	(18)	(0.14)	(388)	(0.83)	(167)	(0.33)
Loss on sale of pipeline asset	(304)	(2.35)	-	-	(304)	(0.65)	(428)	(0.84)
Loss before future income taxes	(7,633)	(59.13)	(1,570)	(12.49)	(29,610)	(63.49)	(5,597)	(10.96)
Future income tax reduction	276	2.14	946	7.53	3,868	8.29	1,844	3.62
Net loss	(7,357)	(56.99)	(624)	(4.96)	(25,742)	(55.20)	(3,753)	(7.34)
Sales volume (boe/d)	1,403		1,367		1,278		1,393	

<sup>(1)</sup> Non-GAAP measure. See discussion in the following MD&A.

## MANAGEMENT'S DISCUSSION AND ANALYSIS

March 25, 2010

Management's discussion and analysis (MD&A) should be read in conjunction with the consolidated financial statements of Fortress Energy Inc. ("Fortress" or the "Company") for the years ended December 31, 2009 and 2008. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (GAAP). All tabular amounts in the following discussion are in thousands of Canadian dollars unless otherwise noted. Additional information is available on the Company's web site at [www.fortressenergy.ca](http://www.fortressenergy.ca) or under the Company's profile at [www.sedar.com](http://www.sedar.com).

### Non-GAAP Measurements

The terms "funds from operations" and "operating netback" used in the MD&A are not recognized measures under GAAP. Management believes that in addition to net income, funds from operations and operating netback are useful supplemental measures as they provide an indication of the results generated by the Company's principal business activities before the consideration of how those activities are financed. Investors are cautioned, however, that these measures should not be construed as alternatives to net income determined in accordance with GAAP.

The Company's method of calculating funds from operations may differ from that of other companies, and, accordingly, it may not be comparable to measures used by other companies. The Company calculates funds from operations by taking cash flow from operating activities as determined under GAAP before changes in non-cash operating working capital and abandonment expenditures. The consolidated statements of cash flows included in the consolidated financial statements present the reconciliation between net income (loss) and funds from operations. A summary of this reconciliation is as follows:

(\$000s)	Three months ended		Year ended	
	December 31,		December 31,	
	2009	2008	2009	2008
Cash provided by (used in) operating activities	641	(432)	2,720	9,461
Change in non-cash operating working capital	530	1,515	1,621	(2,615)
Abandonment expenditures	1	30	173	111
<b>Funds from operations</b>	<b>1,172</b>	<b>1,113</b>	<b>4,514</b>	<b>6,957</b>

Operating netback is calculated on a per boe basis taking the sale price and deducting royalties, operating costs and transportation costs, as follows:

	Three months ended December 31,				Year ended December 31,			
	2009		2008		2009		2008	
	(\$000s)	(\$/boe)	(\$000s)	(\$/boe)	(\$000s)	(\$/boe)	(\$000s)	(\$/boe)
Petroleum and natural gas sales	4,798	37.17	5,962	47.41	18,589	39.87	24,834	48.68
Royalties	71	0.55	(943)	(7.50)	(714)	(1.53)	(4,364)	(8.55)
Operating expenses	(1,995)	(15.45)	(1,823)	(14.50)	(7,422)	(15.92)	(7,388)	(14.48)
Transportation expenses	(223)	(1.73)	(279)	(2.22)	(915)	(1.96)	(1,187)	(2.32)
<b>Operating netback</b>	<b>2,651</b>	<b>20.54</b>	<b>2,917</b>	<b>23.19</b>	<b>9,538</b>	<b>20.46</b>	<b>11,895</b>	<b>23.33</b>

### BOE Presentation

Natural gas reserves and volumes recorded in thousand cubic feet are converted to barrels of oil equivalent ("boe") on the basis of six thousand cubic feet ("mcf") of gas to one barrel ("bbl") of oil. The term "barrels of oil equivalent" may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf to 1 bbl is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead.

## Forward-Looking Statements

Certain statements in this MD&A may contain forward-looking information including expectations of future production, components of cash flow and earnings, expected future events and/or financial results that are forward-looking in nature and subject to substantial risks and uncertainties. Without limiting the generality of the foregoing, the Company has made materially forward-looking statements:

- (i) Under “Operating Expenses ” regarding the expected reduction in operating costs;
- (ii) Under “Liquidity and Capital Resources” regarding working capital requirements, repayment of the non-revolving loan facility, completion of the Boyer acquisition and the proposed equity and debt financing;
- (iii) Under “Income Tax Refund” regarding potential refunds; and
- (iv) Under “Subsequent Events” regarding the proposed Boyer acquisition.

The forward-looking statements are based on certain assumptions including completion of the Boyer acquisition, obtaining a new credit facility and a new equity financing, continued operating efficiencies and the continued performance of the Corporation’s properties including those acquired in the Boyer acquisition. The reader is cautioned that assumptions used in the preparation of such information may prove to be incorrect. The Company cautions the reader that actual performance will be affected by a number of factors, including changes in economic and political circumstances throughout the world. Events or circumstances may cause actual results to differ materially from those predicted, a result of numerous known and unknown risks, uncertainties, and other factors, many of which are beyond the control of the Company. These risks include, but are not limited to: risks associated with completing the Boyer acquisition or not realizing the benefits of the acquisition (applicable to the forward-looking statements (i), (ii) and (iv) above) the risks associated with the oil and natural gas industry, commodity prices and exchange rate changes; industry related risks could include, but are not limited to, operational risks in exploration, development and production (applicable to the forward-looking statements (i), (ii) and (iv) above), and delays or changes in plans (applicable to the forward-looking statements identified in (i) through (iv) above); risks associated with the uncertainty of reserve estimates, health and safety risks and the uncertainty of estimates and projections of production, costs and expenses. These external factors beyond the Company’s control may affect the marketability of oil and natural gas produced and include industry conditions and changes in laws and regulations, changes in income tax regulations, increased competition, fluctuations in commodity prices, interest rates, and variations in the Canadian/United States dollar exchange rate. The reader is cautioned not to place undue reliance on this forward-looking information.

Statements throughout this MD&A that are not historical facts may be considered “forward-looking statements.” These forward-looking statements sometimes include words to the effect that management believes or expects a stated condition or result. All estimates and statements that describe the Company’s objectives, goals or plans are forward-looking statements. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to any number of risks including, but not limited to:

- (i) Risks associated with the oil and natural gas industry and regulatory bodies (e.g. operational risks in exploration, development and production, or changes in royalty rates);
- (ii) Delays or changes in plans with respect to exploration or development projects or capital expenditures;
- (iii) Uncertainty of estimates and projections relating to recoverable reserves, costs and expenses;
- (iv) Health, safety and environmental risks;
- (v) Commodity price and exchange rate fluctuations; and
- (vi) Liquidity risk and working capital requirements (refer to “Liquidity and Capital Resources”).

Forward-looking statements contained herein are made as of the date hereof subject to the requirements of applicable securities legislation and except as otherwise required by law, the Company assumes no

obligation to update any forward-looking statements, whether as a result of new information, future events and results, or otherwise. There can be no assurance that forward-looking statements will prove to be accurate, as actual results and future events could differ materially from those anticipated in such statements. Accordingly, the reader is cautioned not to place undue reliance on forward-looking statements.

## **DESCRIPTION OF THE BUSINESS**

Fortress' primary focus is the exploration and development of natural gas reserves in Western Canada. The Company has approximately 93,000 net acres of undeveloped land in the Ladyfern, Velma and Buick Creek areas in northeast British Columbia and the Chigwell, Bashaw, Square Creek, Halverson, Mearon and Dahl areas of Alberta.

The Company's strategy is to 'acquire and exploit' properties that are early in their development cycle and that offer exploration, appraisal and development drilling opportunities, while maintaining low finding and development costs. Fortress is the operator of most of its production enabling it to have control over cost management of its operating and capital programs.

## **CORPORATE HIGHLIGHTS**

During the year ended December 31, 2009, Fortress accomplished the following activity considered important by management:

- Acquired a partner's 50 percent working interest in its Square Creek property. The completion of the acquisition provides Fortress an additional 2.7 Mmcf/d of production and the potential to increase production from the area. Since Fortress is the operator of the property, no additional staff or overhead were required to manage these additional assets.
- Performed pressure work at the Company's Square Creek property that proved up a significantly larger gas resource in the main Bluesky formation.
- Closed a public offering of 21,779,000 units and 6,594,000 flow-through common shares (total common shares issued of 28,373,000) for gross proceeds of \$11,385,185 (\$10,320,000 net of issuance costs). Each unit consists of one common share of the Company and one common share purchase warrant. The warrants are exercisable on or before September 30, 2011. Each warrant entitles the holder thereof to purchase one common share at an exercise price of \$0.55.
- AECO natural gas prices averaged \$3.97 per mcf, and Fortress was able to enjoy the benefits of its forward sale to receive an average price of \$6.62 per mcf for the year.
- Used the period of low gas prices to perform maintenance at Buick Creek and re-route gas production at Velma, saving processing and contract operating costs at this property.
- Took several key steps in 2009 to materially reduce operating costs going forward in its main areas of operation. At Square Creek the Company purchased the rental compressor, camp, rig mats and other rented equipment. The Company also replaced the field operations contractor at Square Creek, effective August 1, and replaced the field operations contractor at the third party facility at Clear Prairie through which the Company's Square Creek production is produced, effective November 15. At Ladyfern North, Ladyfern South and Mearon North the Company negotiated a significant reduction in contract operating fees for its field operations; and
- Announced the appointment of Ronald McIntosh to the Board of Directors, effective November 10, 2009. Mr. McIntosh has extensive oil and natural gas and board experience. His work experience has included corporate leadership roles in Canada, the United States and internationally.

## DETAILED FINANCIAL ANALYSIS

### Production

	Three months ended December 31,		Year ended December 31,	
	2009	2008	2009	2008
Sales volume:				
Natural gas (mcf/d)	8,288	8,118	7,574	8,234
Oil and NGL (bbls/d)	19	14	15	21
Total (boe/d)	1,403	1,367	1,278	1,393

Sales volumes for the three months ended December 31, 2009 were 1,403 boe/d compared to 1,367 boe/d for the three months ended December 31, 2008. This increase is due to additional sales volumes from the Square Creek area. The Company's share of sales volumes from the Square Creek area increased to 824 boe/d for the three months ended December 31, 2009, from 468 boe/d for the three months ended December 31, 2008, reflecting the Company's acquisition of its partner's 50 percent working interest effective October 23, 2009. This increase in sales volumes was offset or reduced by several wells that were shut-in and other operational issues during the three months ended December 31, 2009 resulting in lost production of approximately 304 boe/d, as follows:

- 115 boe/d at Ladyfern North due to a pipeline failure resulting in the entire field being shut-in for 35 days;
- 110 boe/d at Square Creek due to a wellhead failure at the 5-28 well and mechanical issues at the third-party Clear Prairie facility that kept the entire field offline and producing at reduced rates for 10 days;
- 35 boe/d at Buick Creek as result of the plant upgrade and maintenance; and
- 44 boe/d at Ladyfern South, Mearon North and Bashaw due to wells freezing off.

Sales volumes for the year ended December 31, 2009 were 1,278 boe/d compared to 1,393 boe/d for the prior year, a decrease of 8 percent. This decrease is due to production that was shut-in at various times during the second half of 2009, as previously noted.

The Company's Square Creek field has shown no decline in production capability since it came on production in March 2008. In the second quarter of 2009, the Company elected to reduce Square Creek production by 1.8 mmcf/d (300 boe/d) due to low natural gas prices. This production was then restored later in 2009 as gas prices began to rebound. Peak production from Square Creek in 2009 hit 8.5 Mmcf/d (1,400 boe/d) although still limited by the third party facility at Clear Prairie. Due to the low natural gas prices the Company has not pursued a plant expansion at the Clear Prairie facility.

### Revenue

	Three months ended December 31,		Year ended December 31,	
	2009	2008	2009	2008
Petroleum and natural gas sales (\$000s)	4,798	5,962	18,589	24,834
Average realized prices:				
Natural gas (\$/mcf)	4.19	6.99	4.19	8.55
Realized gain (loss) on commodity contracts (\$/mcf)	1.96	0.89	2.43	(0.52)
Realized natural gas price (\$/mcf)	6.15	7.88	6.62	8.03
Oil and NGL (\$/bbl)	51.10	60.42	53.71	82.16
Total (\$/boe)	37.17	47.41	39.87	48.68
Benchmark prices:				
AECO average natural gas price (\$/mcf)	4.55	6.69	3.97	8.15
Edmonton par (\$/bbl)	76.99	64.18	89.18	103.27

For the three months ended December 31, 2009, petroleum and natural gas sales were \$4,798,000 (including realized gains on commodity contracts of \$1,498,000) compared to \$5,962,000 (including realized gains on commodity contracts of \$668,000) for the three months ended December 31, 2008 - a year-over-year decrease of 20 percent. This decrease is attributable to a 22 percent decrease in the realized natural gas price in the three months ended December 31, 2009.

Petroleum and natural gas sales were \$18,589,000 (including realized gains on commodity contracts of \$6,722,000) for the year ended December 31, 2009 compared to \$24,834,000 (including realized losses on commodity contracts of \$1,564,000) for the year ended December 31, 2008 - a decrease of 25 percent. This decrease is attributable to an 18 percent decrease in the realized natural gas price and an 8 percent decrease in sales volumes in 2009, as previously noted.

The average realized natural gas price for the three months ended December 31, 2009 was \$4.19/mcf compared to the average AECO natural gas price of \$4.55/mcf. The average realized natural gas price in the three months ended December 31, 2008 was \$6.99/mcf and the average AECO natural gas price was \$6.69/mcf. The average realized natural gas price for the year ended December 31, 2009 was \$4.19/mcf compared to the average AECO natural gas price for the period of \$3.97/mcf. This compares to the average realized natural gas price in the year ended December 31, 2008 of \$8.55/mcf and an average AECO price of \$8.15/mcf. The Company receives a slight premium to the AECO natural gas price of approximately 4 percent to 5 percent due to the higher heating value of its natural gas.

The Company uses commodity contracts to manage its exposure to fluctuations in the price of natural gas. For the three months ended December 31, 2009, the Company realized a gain on commodity contracts of \$1,498,000, or \$1.96/mcf, compared to a realized gain on commodity contracts of \$668,000, or \$0.89/mcf for the three months ended December 31, 2008. Realized gains and losses on commodity contracts are included in petroleum and natural gas sales. The Company also recorded an unrealized loss on commodity contracts in the three months ended December 31, 2009 of \$808,000 compared to an unrealized gain on commodity contracts of \$1,062,000 for the three months ended December 31, 2008.

For the year ended December 31, 2009, the Company 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 Company has sold forward approximately 65 percent of its natural gas production through to end of 2010 giving the Company a degree of certainty over its cash flow. The estimated mark-to-market value of the Company'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

In February 2010, the Company 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.

### Royalties

	Three months ended December 31,		Year ended December 31,	
	2009	2008	2009	2008
Royalties (\$000s)	(71)	943	714	4,364
\$/boe	(0.55)	7.50	1.53	8.55
Percentage of petroleum and natural gas sales (1)	(2.1)%	17.8%	6.0%	16.5%

(1) Before realized gains and losses on commodity contracts.

For the three months ended December 31, 2009, the Company recorded a recovery of royalties of \$71,000 compared to an expense for the three months ended December 31, 2008 of \$943,000. The reduction over this period is due to a 40 percent reduction in the average realized price of natural gas upon which Alberta Crown royalties are based and the recognition of 2008 Alberta Gas Cost Allowance and Custom Processing credits of approximately \$637,000. These credits are attributable to the Company's Square Creek property which commenced production in March 2008.

For the year ended December 31, 2009, royalties were \$714,000 compared to \$4,364,000 for the year ended December 31, 2008. This decrease is attributed to a 51 percent decrease in the average realized natural gas price and royalty credits of \$944,000 processed in 2009. Royalties are not calculated or payable on realized gains and losses on commodity contracts. The effective royalty rate for the year ended December 31, 2009 was 6 percent compared to 16.5 percent for the prior year.

### Operating Expenses

	Three months ended December 31,		Year ended December 31,	
	2009	2008	2009	2008
Operating expenses (\$000s)	1,995	1,823	7,422	7,388
\$/boe	15.45	14.50	15.92	14.48

For the three months ended December 31, 2009, operating expenses were \$1,995,000, or \$15.45/boe, compared to \$1,823,000, or \$14.50/boe, for the three months ended December 31, 2008. Operating expenses increased in the three months ended December 31, 2009 due to the acquisition of the Company's partner's 50 percent working interest in Square Creek in October 2009. On a per boe basis, operating expenses increased in the three months ended December 31, 2009 to \$15.45/boe from \$14.50/boe for the three months ended December 31, 2008 as a significant component of operating expenses are fixed as opposed to varying with production.

For the year ended December 31, 2009, operating expenses were \$7,422,000 compared to \$7,388,000 for the year ended December 31, 2008. Operating expenses on a per boe basis are higher for the year ended December 31, 2009 due to lower production and a higher proportion of fixed costs.

The Company took several key steps in 2009 to materially reduce operating costs going forward in its main areas of operation. At Square Creek the Company purchased the rental compressor, camp, rig mats and other rented equipment. The Company also replaced the field operations contractor at Square Creek, effective August 1, and replaced the field operations contractor at the third party facility at Clear Prairie through which the Company's Square Creek production is produced effective November 15. At Ladyfern North, Ladyfern South and Mearon North the Company negotiated a significant reduction in contract operating fees for its field operations. At Velma the Company replaced the contract operator and re-routed its production to another third party processing plant thereby reducing contract operating, gathering and processing fees. These changes are expected to save the Company approximately \$1,700,000 annually.

### Transportation Expenses

	Three months ended December 31,		Year ended December 31,	
	2009	2008	2009	2008
Transportation expenses (\$000s)	223	279	915	1,187
\$/boe	1.73	2.22	1.96	2.32

Transportation expenses include transportation and fuel costs associated with the usage of natural gas pipelines. For the three months ended December 31, 2009, transportation expenses were \$223,000 compared to \$279,000 for the three months ended December 31, 2008. Transportation expenses for the year ended December 31, 2009 were \$915,000 compared to \$1,187,000 for the year ended December 31, 2008. This decrease is due to reduced throughput due to shut-in production volumes in 2009.

### General and Administrative Expenses

	Three months ended December 31,				Year ended December 31,			
	2009		2008		2009		2008	
	(\$000s)	(\$/boe)	(\$000s)	(\$/boe)	(\$000s)	(\$/boe)	(\$000s)	(\$/boe)
General and administrative expenses, net of recoveries	821	6.36	715	5.69	2,908	6.24	2,479	4.86
Professional fees	73	0.57	311	2.47	675	1.44	712	1.40
Bad debts	132	1.02	84	0.67	294	0.63	2	-
Total	1,026	7.95	1,110	8.83	3,877	8.31	3,193	6.26

General and administrative expenses, net of recoveries, increased to \$821,000 in the three months ended December 31, 2009 from \$715,000 in the three months ended December 31, 2008. This increase is due to lower overhead recoveries from partners due to reduced capital spending in the three months ended December 31, 2009 compared to the three months ended December 31, 2008. For the year ended December 31, 2009, general and administrative expenses, net of recoveries, were \$2,908,000 compared to \$2,479,000 for the year ended December 31, 2008. This increase is also due to lower overhead recoveries from partners due to reduced capital spending in 2009. The Company also incurred additional costs in 2009 to update its safety program and site specific emergency response plans.

Professional fees include fees for lawyers, auditors, income tax professionals, and independent reserves evaluators. Professional fees decreased in the three months ended December 31, 2009 to \$73,000 from \$311,000 for the three months ended December 31, 2008. This decrease is due to a reduction in legal fees. In the three months ended December 31, 2008, the Company incurred additional legal fees related to the final resolution of various matters. Also, the Company incurred additional advisory fees in the three months ended December 31, 2008 related to property divestitures that were not consummated. Professional fees for the year ended December 31, 2009 were \$675,000 compared to \$712,000 for the year ended December 31, 2008. This decrease is due to a reduction in legal and advisory fees in 2009 from the prior year. The Company incurred additional costs in 2009 related to income tax compliance.

Bad debts for the three months ended December 31, 2009 were \$132,000 compared to \$84,000 for the three months ended December 31, 2008. Bad debts expense for the year ended December 31, 2009 was \$294,000 compared to \$2,000 for the year ended December 31, 2008. Bad debts reflect the accounts of former joint venture partners that are considered uncollectible; many of these accounts are related to companies that were acquired by the Company.

#### Stock-based Compensation Expense

	Three months ended December 31,		Year ended December 31,	
	2009	2008	2009	2008
Stock-based compensation expense (\$000s):				
Stock options	154	20	303	145
Restricted stock units	(1)	(2)	85	22
Total	153	18	388	167
\$/boe	1.19	0.14	0.83	0.33

Stock-based compensation expense for the three months ended December 31, 2009 was \$153,000 compared to \$18,000 for the three months ended December 31, 2008. In November 2009, the Company granted 3,680,000 stock options and issued 400,000 restricted stock units resulting in an increase in stock-based compensation expense for the period. Stock-based compensation expense for the year ended December 31, 2009 was \$388,000 compared to \$167,000 for the year ended December 31, 2008. This increase is due to stock options and restricted stock units that were issued in July 2008 and November 2009. In July 2008, the Company granted 1,684,633 stock options.

#### Interest Expense

	Three months ended December 31,		Year ended December 31,	
	2009	2008	2009	2008
Interest expense (\$000s):	277	534	917	1,585
\$/boe	2.15	4.24	1.97	3.11

The Company recorded interest expense of \$277,000 for the three months ended December 31, 2009 compared to \$534,000 for the three months ended December 31, 2008. Interest expense for the three months ended December 31, 2009 reflects interest on the Company's bank indebtedness. Interest expense for the three months ended December 31, 2008 reflects interest on bank indebtedness and accrued interest on flow-through commitments. Interest expense for the year ended December 31, 2009 was \$917,000 compared to \$1,585,000 for the year ended December 31, 2008. This decrease is due to a decrease in the prime lending rate. Also, interest expense for the year ended December 31, 2008 included interest on flow-through commitments of \$419,000.

## Depletion, Depreciation and Accretion Expense

	Three months ended December 31,		Year ended December 31,	
	2009	2008	2009	2008
Depletion and depreciation expense (\$000s)	2,659	3,725	12,937	14,233
Accretion of asset retirement obligations (\$000s)	61	2	233	121
Depletion, depreciation and accretion expense (\$000s)	2,720	3,727	13,170	14,354
Ceiling test impairment (\$000s)	4,820	-	19,096	-
Depletion and depreciation expense (\$/boe)	20.60	29.62	27.74	27.90
Accretion of asset retirement obligations (\$/boe)	0.47	0.02	0.50	0.24
Depletion, depreciation and accretion expense (\$/boe)	21.07	29.64	28.24	28.14
Ceiling test impairment (\$/boe)	37.34	-	40.95	-

Depletion and depreciation expense is calculated based on capital expenditures, production rates, and proved reserves. Depletion and depreciation expense was \$2,659,000 for the three months ended December 31, 2009 compared to \$3,725,000 for the three months ended December 31, 2008. This decrease is due to a ceiling test impairment charge of \$19,096,000 that was recorded in 2009, decreasing the asset base that is subject to depletion. On a per boe basis, depletion and depreciation expense for the three months ended December 31, 2009 was \$20.60/boe compared to \$29.62/boe for the three months ended December 31, 2008.

Depletion and depreciation expense for the year ended December 31, 2009 was \$12,937,000 compared to \$14,233,000 for the year ended December 31, 2008. On a per boe basis, depletion and depreciation expense decreased to \$27.74/boe for the year ended December 31, 2009 from \$27.90/boe for the year ended December 31, 2008. The Company recorded a ceiling test impairment charge of \$19,096,000 in 2009, as previously noted.

Estimated future development costs for proved undeveloped properties included in the calculation of depletion expense at December 31, 2009 decreased to \$7,456,000 from \$13,235,000 at December 31, 2008 due to the Company's development activities at Square Creek in the first quarter of 2009. In addition, pressure testing conducted in March 2009 on wells at Square Creek indicated that the Company does not need to drill any additional wells to drain the Bluesky pool, resulting in an additional reduction of future development costs and an increase in recoverable reserves. Undeveloped land costs at December 31, 2009 decreased to \$7,518,000 from \$8,622,000 at December 31, 2008 and were excluded from assets subject to depletion. Undeveloped land costs decreased in 2009 due to expiries in the Halverson area.

Accretion expense for the three months ended December 31, 2009 was \$61,000 compared to \$2,000 for the three months ended December 31, 2008. The accretion expense for the three months ended December 31, 2009 reflects changes to the assumptions used to calculate the Company's asset retirement obligations and an adjustment in the fourth quarter for accretion expense of prior periods. For the year ended December 31, 2009, accretion costs amounted to \$233,000 compared to \$121,000 for the year ended December 31, 2008. This increase is due to changes to the assumptions used to calculate asset retirement obligations.

The Company recorded a ceiling test impairment in 2009 of \$19,096,000 due to a significant decrease in natural gas prices. The impact of the ceiling test impairment charge was \$37.34/boe and \$40.95/boe for the three months and year ended December 31, 2009, respectively.

## Income Tax

	Three months ended December 31,		Year ended December 31,	
	2009	2008	2009	2008
Income tax expense (\$000s)	42	160	96	160
Future income tax reduction (\$000s):	(276)	(946)	(3,868)	(1,844)
Total, net (\$000s)	(234)	(786)	(3,772)	(1,684)
\$/boe	(1.82)	(6.26)	(8.08)	(3.31)

The Company recorded an income tax reduction for the three months ended December 31, 2009 of \$234,000 compared to \$786,000 for the three months ended December 31, 2008. For the year ended December 31, 2009, the Company recorded an income tax reduction of \$3,868,000 compared to \$1,684,000

for the year ended December 31, 2008. In the year ended December 31, 2009, the Company recorded a ceiling test impairment charge of \$19,096,000 which resulted in the reversal of the previously recorded future income tax liability. A full valuation allowance has been taken against the resulting future income tax asset.

For the three months ended December 31, 2009, the Company recorded current income tax expense of \$42,000. For the year ended December 31, 2009, current income tax expense of \$96,000 was recorded, consisting of arrears interest and penalties. All of the Company's income tax returns have been filed but not all have yet been assessed by CRA.

The estimated tax pools of the Company at December 31, 2009 are as follows:

	(\$000's)
Canadian Oil and Gas Property Expenses	20,300
Canadian Development Expenses	28,146
Canadian Exploration Expenses	12,960
Undepreciated Capital Cost	29,141
	90,547

#### Net Loss

	Three months ended		Year ended	
	December 31, 2009	December 31, 2008	December 31, 2009	December 31, 2008
Net loss (\$000s)	(7,357)	(624)	(25,742)	(3,753)
Net loss per share - basic and diluted (\$)	(0.13)	(0.02)	(0.76)	(0.17)
Net loss per boe (\$)	(56.99)	(4.96)	(55.20)	(7.34)

The Company recorded a net loss of \$7,357,000 for the three months ended December 31, 2009 compared to a net loss of \$624,000 for the three months ended December 31, 2008. This translates into a net loss per basic and diluted share of \$0.13 for the three months ended December 31, 2009 compared to a loss per basic and diluted share of \$0.02 for the three months ended December 31, 2008. The net loss for the three months ended December 31, 2009 is mainly due to lower commodity prices and a ceiling test impairment charge and unrealized loss on commodity contracts. The net loss for the year ended December 31, 2009 was \$25,742,000 compared to \$3,753,000 for the year ended December 31, 2008. The net loss for the year ended December 31, 2009 is mainly attributable to the ceiling test impairment charge \$19,096,000 and lower realized sales prices.

#### Funds from Operations

	Three months ended		Year ended	
	December 31, 2009	December 31, 2008	December 31, 2009	December 31, 2008
Funds from operations (\$000s)	1,172	1,113	4,514	6,957
Funds from operations (\$/boe)	9.08	8.85	9.68	13.65
Funds from operations per share – basic and diluted (\$)	0.02	0.04	0.13	0.32

Funds from operations for the three months ended December 31, 2009 were \$1,172,000 compared to \$1,113,000 for the three months December 31, 2008. This increase is attributable to lower interest and general and administrative expenses recorded in the three months ended December 31, 2009. Funds from operations for the year ended December 31, 2009 were \$4,514,000 compared to \$6,957,000 for the year ended December 31, 2008. This decrease is due to lower production levels, lower realized natural gas prices and higher general and administrative expenses experienced in the first three quarters of 2009.

## Capital Expenditures

(\$000s)	Three months ended December 31,		Year ended December 31,	
	2009	2008	2009	2008
Land and seismic	119	624	530	2,785
Drilling and completions	447	4,600	4,678	9,689
Equipment and facilities	769	(864)	3,592	14,937
Acquisitions	6,986	-	6,986	-
Dispositions	-	-	-	(8,150)
Capitalized overhead costs	321	253	1,022	1,006
Other	16	(65)	43	-
	8,658	4,548	16,851	20,267

In the three months ended December 31, 2009, the Company acquired its partner's 50 percent working interest in Square Creek for \$6,986,000 giving the Company 100 percent working interest in the property. The Company 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 Company'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 Company 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 Company's core producing property. The Company also participated in the drilling of two development wells at Square Creek and drilled one 100 percent 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 Company also constructed a 10 mmcf/d gathering and production facility to service eight wells it has in the Square Creek area. The Company completed the construction of a 41 kilometer 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 Company. 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, which is owned by a third party. Due to low natural gas prices the Company has not pursued the plant expansion at the Clear Prairie Facility.

## Outstanding Securities

Outstanding securities	
Common shares	55,294,788
Warrants (exercise price \$2.00)	5,516,700
Warrants – A (exercise price \$0.55)	21,779,000
Stock options	4,774,579
Total outstanding securities at December 31, 2009 and March 25, 2010	87,365,067

On September 30, 2009, the Company closed a public offering of 21,779,000 units and 6,594,000 flow-through common shares for gross proceeds of \$11,385,185 (\$10,320,000 net of issuance costs). Each unit consists of one common share of the Company and one common share purchase warrant. The warrants are exercisable on or before December 31, 2011. Each warrant entitles the holder thereof to purchase one common share at an exercise price of \$0.55. The expenditure commitment resulting from the issuance of 6,594,000 flow-through common shares is \$3,000,270 and was renounced to subscribers effective December 31, 2009 with all expenditures to be incurred by December 31, 2010.

Options to purchase 4,774,579 (December 31, 2008 – 1,805,875) common shares and warrants to purchase 27,295,700 (December 31, 2008 – 5,516,700) common shares at December 31, 2009 were not included in the calculation of diluted common shares outstanding because they were anti-dilutive.

### Liquidity and Capital Resources

The Company's consolidated financial statements have been prepared on a going concern basis, which assumes the realization of assets and discharge of liabilities in the normal course of business for the foreseeable future. The Company has experienced consecutive losses, has an accumulated deficit of \$98,739,000 and a working capital deficiency of \$23,497,000 as at December 31, 2009.

As of December 31, 2009 the Company had a \$24,000,000 demand operating loan facility with its bank, bearing interest at the bank's prime lending rate plus 1.0 percent (effective interest rate for 2009 of 3.44 percent and for 2008 of 5.05 percent). At December 31, 2009, \$23,044,000 (December 31, 2008 - \$20,533,000) was drawn on this facility. The Company 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 subsequently acquired property of the Company.

Effective January 18, 2010, the authorized borrowing amount of the Company's demand operating loan facility was reduced to \$17,000,000 as a result of a reduction in the Company's borrowing base due to low natural gas prices. The demand operating loan bears interest at the bank's prime lending rate plus 2 percent. 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 percent. The demand non-revolving loan is to be repaid by March 31, 2010. In recent discussions, the Company's bank has indicated that it will delay or forgo the repayment pending the completion of a property acquisition announced on March 4, 2010. In connection with the transaction, the Company anticipates obtaining up to \$100,000,000 in new credit facilities to replace the existing credit facilities from a syndicate of banks. The Company anticipates that the new credit facilities will have industry standard terms and financial covenants. If the Company is unable to close this transaction, the Company anticipates that the bank will continue to work with the Company 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, the lender's interest in particular business sectors, such as energy and the relative strength of the borrower. The next review is scheduled for April 1, 2010.

There is significant uncertainty regarding the Company's ability to continue as a going concern, which is dependent upon achieving on-going cash flow from operating activities and receiving additional support from its lenders and investors. In the event that natural gas prices decline, the future operations of the Company are dependent on its ability to successfully raise capital and receive the continued financial support of its lender. The outcome of these matters cannot be predicted at this time.

The Company 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 Company is in compliance with this covenant as at December 31, 2009. The Company's ability to maintain compliance with these financial covenants is dependent on certain factors, certain of which are outside the Company's control. Such factors include future industry and capital market conditions and commodity pricing. Based on current market conditions and commodity prices, the Company 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 Company's capital resources available at December 31, 2009 are as follows:

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

As at December 31, 2009, the Company had a working capital deficiency of \$23,497,000. Available capital resources as at December 31, 2009 were \$503,000. Future capital requirements will be funded through cash flows from operations. There is no assurance that Fortress will be able to sustain its current borrowing base and it may be required to reduce its outstanding operating loan facility. Fortress has options available to deal with a borrowing base reduction including the sale of non-core properties, dedication of cash flows, and liquidation of its commodity contracts.

Cash provided by operating activities for the three months ended December 31, 2009 was \$641,000 compared to cash used in operating activities for the three months ended December 31, 2008 of \$432,000. This increase is due to a decrease in non-cash working capital balances in the three months ended December 31, 2008. Cash provided by operating activities for the year ended December 31, 2009 was \$2,720,000 compared to \$9,461,000 for the year ended December 31, 2008. This decrease is due to lower realized natural gas prices and a decrease in non-cash working capital balances.

Cash provided by financing activities for the three months ended December 31, 2009 was \$2,135,000 compared to \$669,000 for the three months ended December 31, 2008. Cash provided by financing activities for the three months ended December 31, 2009 reflects an increase in amounts drawn on the operating loan from the prior quarter. Cash provided by financing activities for the year ended December 31, 2009 was \$12,831,000 compared to \$12,637,000 for the year ended December 31, 2008. Cash provided by financing activities for the year ended December 31, 2009 reflects the net proceeds from an equity financing in the third quarter of \$10,320,000. Cash provided by financing activities for the year ended December 31, 2008 reflects the net proceeds of an equity financing of \$14,737,000 and a reduction in the amount drawn on the operating loan facility.

Cash used in investing activities for the three months ended December 31, 2009 was \$9,775,000 compared to \$93,000 for the three months ended December 31, 2008. The Company's capital expenditures in the three months ended December 31, 2009 were \$1,672,000 plus an additional \$6,986,000 for the Square Creek acquisition compared to \$4,467,000 in the three months ended December 31, 2008. In addition, in the three months ended December 31, 2009 the Company acquired its partner's working interest at Square Creek for \$6,986,000. In the three months ended December 31, 2008, the Company drilled an exploratory well on its lands at Pine Creek. Cash used in investing activities for the year ended December 31, 2009 was \$15,667,000 compared to \$21,962,000 for the year ended December 31, 2008. For the year ended December 31, 2009, the Company incurred capital expenditures of \$9,865,000 and acquired its partner's interest at Square Creek for \$6,986,000. This compares to net capital expenditures of \$20,267,000 for the year ended December 31, 2008.

#### **Related-Party Transactions**

In 2009 the Company was charged \$321,000 (2008 - \$544,000) by a law firm of which a director of the Company is a partner.

In 2009, the Company was charged \$125,000 (2008 - \$63,000) by a director for consulting services of which \$9,000 is included in accounts payable and accrued liabilities at December 31, 2009.

All related-party transactions are in the normal course of business and have been measured at the agreed-to exchange amounts, which are the amounts of consideration established and agreed to by the related parties and which are similar to those negotiated with third parties.

## Commitments and Contingencies

### Office space and equipment

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

(\$000s)	Equipment Rental	Office Lease	Total
2010	12	470	482
2011	9	475	484
2012	-	474	474
2013	-	119	119
	21	1,538	1,559

### Transportation and Processing

The Company has an agreement for the transportation and processing of natural gas from the Company's Square Creek, Alberta area. The Company 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:

	\$000s
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 Company 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 this letter of credit, a replacement letter of credit of \$810,000 was issued with an expiry of February 1, 2011.

### Income Tax Refund

In September 2008, the Company 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 Company.

## Income Tax Reassessment

Based on the results of an audit concluded in March 2009 by the Canada Revenue Agency (CRA) on the 2004 flow-through expenditures of a business acquired by the Company in 2006, the Company was reassessed by 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 Company filed a Notice of Objection with CRA on July 31, 2009 after consultation with its tax advisors and legal counsel and is appealing this reassessment. The Company 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 Company's position is that the more likely than not criteria for recognition have not been met.

## Income Tax Audit

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

## Subsequent Events

On February 12, 2010, the Company entered into a commodity price 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.

On March 4, 2010 the Company entered into a Letter of Intent to acquire 100 percent working interest in a producing natural gas property in the Boyer area of Alberta for cash consideration of \$170,000,000, subject to adjustments. The acquisition is subject to the execution of a formal purchase and sale agreement and financing. It is expected the acquisition will be financed by a combination of debt and equity. In connection with the acquisition, the Company anticipates obtaining up to \$100,000,000 in new credit facilities to replace existing facilities from a syndicate of banks. Upon the closing of the equity financing, the Company expects to execute a formal purchase and sale agreement and to close the acquisition in May 2010. There can be no assurance that the Company will be able to complete the financing or close the acquisition.

## SELECTED QUARTERLY INFORMATION

	2009				2008			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production:								
Natural gas (mcf/d)	8,288	6,741	7,603	7,665	8,118	8,733	8,690	7,391
Oil and NGL's (bbl/d)	19	13	12	14	14	23	15	33
Total (boe/d)	1,403	1,137	1,279	1,292	1,367	1,478	1,463	1,265
Average realized price:								
Natural gas (\$/mcf)	6.15	6.65	6.22	7.47	7.88	7.02	8.98	8.03
Oil and NGL (\$/bbl)	51.10	82.45	45.11	37.72	60.42	82.29	108.04	79.61
Combined average (\$/boe)	37.17	40.53	37.35	44.79	47.41	42.64	54.31	48.96
Benchmark prices:								
AECO average natural gas price (\$/mcf)	4.55	3.00	3.45	4.92	6.69	7.76	9.82	7.90
Edmonton Par crude oil price (\$/bbl)	76.99	71.65	66.70	51.13	64.18	123.08	126.37	98.45
Financial (\$'000's unless otherwise noted):								
Petroleum and natural gas sales <sup>(1)</sup>	4,798	4,240	4,346	5,206	5,962	5,802	7,231	5,637
Net income (loss)	(7,357)	(3,787)	(14,605)	7	(624)	1,070	(744)	(3,455)
Net income (loss) per share – basic (\$)	(0.13)	(0.14)	(0.54)	0.00	(0.02)	0.04	(0.04)	(0.22)
Net income (loss) per share – diluted (\$)	(0.13)	(0.14)	(0.54)	0.00	(0.02)	0.04	(0.04)	(0.22)
Funds from operations	1,172	1,393	557	1,393	1,113	1,193	2,627	2,025
Operating costs (\$/boe)	15.45	16.81	15.95	15.62	14.50	15.72	15.40	11.94
Weighted average shares outstanding – basic (000)	55,295	27,230	26,922	26,922	26,965	26,965	16,809	15,980
Weighted average shares outstanding – diluted (000)	55,295	27,230	26,922	26,922	26,965	27,004	16,809	15,980

(1) Restated to include realized gains and losses on commodity contracts and for the effects of transportation costs which previously were netted from petroleum and natural gas sales.

## **Disclosure Controls and Procedures**

The Company has established disclosure controls and procedures to ensure timely and accurate preparation of financial and other reports. Disclosure controls and procedures are designed to provide reasonable assurance that material information required to be disclosed is recorded, processed, summarized and reported within the periods specified by securities regulations and that information required to be disclosed is accumulated and communicated to the appropriate members of management and properly reflected in the Company's filings. The Chief Executive Officer and the Chief Financial Officer oversee this evaluation process and have concluded that the design and operation of these disclosure controls and procedures are adequate and effective in ensuring that the information required to be disclosed by the Company in reports filed with the Canadian Securities Administrators is accurate and complete and filed within the periods required. The Chief Executive Officer and Chief Financial Officer have individually signed certifications to this effect.

## **Internal Controls over Financial Reporting**

Management has designed internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. The Company's management, under the direction and supervision of the Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the design and effectiveness of the internal controls over financial reporting as at December 31, 2009. Based on their assessment management determined that the internal controls over financial reporting were effective as at December 31, 2009.

There was no change in the Company's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting. Management, including the Chief Executive Officer and the Chief Financial Officer, do not expect that the Company's disclosure controls or the Company's internal controls over financial reporting will prevent or detect all error or fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the control system's objectives will be met. The design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs.

Given the Company's limited staff level, certain duties within the accounting and finance department cannot be properly segregated. However, none of the segregation of duty deficiencies resulted in a misstatement to the financial statements as the Company relies on certain compensating controls, including substantive periodic review of the financial statements and other information by the Chief Executive Officer and Audit Committee. This weakness is considered to be a common area of deficiency for many smaller listed companies in Canada.

## **Changes in Accounting Policies and Practices**

The Canadian Institute of Chartered Accountants (CICA) Handbook Section 3064, *Goodwill and Intangible Assets*, replaced Section 3062, *Goodwill and Other Intangible Assets*, and resulted in the withdrawal of Section 3450, *Research and Development Costs*, and amendments to Accounting Guideline (AcG) 11, *Enterprises in the Development Stage* and Section 1000, *Financial Statement Concepts*. The standard reduces the differences with International Financial Reporting Standards (IFRS) in the accounting for intangible assets and results in closer alignment with U.S. GAAP. The objectives of Section 3064 are to reinforce the principle-based approach to the recognition of assets only in accordance with the definition of an asset and the criteria for asset recognition; and clarify the application of the concept of matching revenues and expenses such that the current practice of recognizing as assets items that do not meet the definition and recognition criteria is eliminated. The standard also provides guidance for the recognition of internally developed intangible assets (including research and development activities), ensuring consistent treatment of all intangible assets, whether separately acquired or internally developed. The adoption of this standard by Fortress on January 1, 2009 did not have an impact on the Company's financial statements.

On January 20, 2009 the CICA Emerging Issues Committee (EIC) issued EIC-173 *Credit Risk and the Fair Value of Financial Assets and Financial Liabilities*. Under EIC-173, an entity's own credit risk and the credit risk of the counterparty with which it conducts transactions should be taken into account in determining the fair value of financial assets and liabilities, including derivative instruments. Fortress adopted the requirements of EIC-173 effective January 1, 2009. The adoption of this standard did not have an impact on the Company's financial statements.

In June 2009, the AcSB amended Handbook Section 3862, *Financial Instruments – Disclosures*, to converge with *Improving Disclosures about Financial Instruments* (Amendments to IFRS 7). The amendments expand the disclosures required in respect of recognized fair value measurements and clarify existing principles for disclosures about the liquidity risk associated with financial instruments. This standard was effective for the annual period ending December 31, 2009.

### **New Canadian Accounting Pronouncements**

In December 2008, the CICA issued Handbook Section 1582, *Business Combinations*, which will replace Section 1581 of the same name. Under this guidance, the purchase price used in a business combination is based on the fair value of shares exchanged at their market price at the date of the exchange. Currently, the purchase price used is based on the market price of the shares for a reasonable period before and after the date of the acquisition is agreed upon and announced. This new standard generally requires all acquisition costs to be expensed, which currently are capitalized as part of the purchase price. Contingent liabilities are to be recognized at fair value at the acquisition date and re-measured at fair value through earnings each period until settled. Currently, only contingent liabilities that are resolved and payable are included in the cost to acquire the business. In addition, negative goodwill is required to be recognized immediately in earnings, unlike the current requirement to eliminate it by deducting it from non-current assets in the purchase price allocation. Section 1582 is effective January 1, 2011.

### **International Financial Reporting Standards**

The Canadian Accounting Standards Board (AcSB) has confirmed that the use of IFRS will be required in 2011 for publicly accountable profit-oriented enterprises. The official changeover date is for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the Company for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010.

The Company has started the process to transition from current Canadian GAAP to IFRS. The Company's Chief Financial Officer has been appointed to lead the conversion project. Resource requirements have been identified and all IFRS requirements will be met with internal employees supplemented with consultants as needed. Regular progress reporting to the Board of Directors on the status of the IFRS conversion has been implemented. The Company has begun the process of training key personnel within the accounting function. Training occurred through external IFRS oil and gas workshops that were attended by key members of the accounting team in 2008 through to the first quarter of 2010. A training session will be scheduled for the Board of Directors in the third quarter of 2010.

The Company's IFRS conversion project is made up of three phases:

- Scoping and diagnostic phase – this phase involves performing a high-level impact analysis to identify areas that may be affected by the transition to IFRS. The results of this analysis are priority ranked according to complexity and the amount of time required to assess the impact of changes in transitioning to IFRS.
- Impact analysis and evaluation phase – during this phase, items identified in the scoping and diagnostic phase are addressed according to the priority levels assigned to them. This phase involves analysis of policy choices allowed under IFRS and their impact on the financial statements. In addition, certain potential differences are further investigated to assess whether there may be a broader impact to the Company's debt agreements, compensation arrangements or management reporting systems. The conclusion of the impact analysis and evaluation phase will require the Board of Directors to review and approve all accounting policy choices as proposed by management.
- Implementation phase – involves implementation of all changes approved in the impact analysis and evaluation phase and will include changes to information systems, business processes, modification of agreements and training of all staff who are impacted by the conversion.

The Company has completed the scoping and diagnostic phase of the project and has commenced the analysis of various accounting policy choices available under IFRS. The Company has not yet completed its accounting policies and is unable to quantify the impact of adopting IFRS on the financial statements. Due to the impact of low natural gas prices experienced in 2009 and the resulting reallocation of staff resources,

the Company is behind on its schedule. The Company is in discussions with consultants and other external resources to assist with the project.

#### First-Time Adoption of IFRS

IFRS 1, "*First-Time Adoption of International Financial Reporting Standards*", provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions in certain areas to the general requirement for full retrospective application of IFRS. The Company is analyzing the various accounting policy choices available and will implement those determined to be the most appropriate for the Company as summarized below:

- Business Combinations – IFRS 1 would allow the Company to use the IFRS rules for business combinations on a prospective basis rather than re-stating all business combinations. The IFRS business combination rules converge with the new CICA Handbook Section 1582 that is also effective for the Company on January 1, 2011; however, early adoption is permitted.
- Property, Plant and Equipment ("PP&E") – IFRS 1 provides the option to value the PP&E assets at their deemed cost being the Canadian GAAP net book value assigned to these assets as at the date of transition, January 1, 2010. This amendment is permissible for entities, such as Fortress, that currently follow the full cost accounting guideline under Canadian GAAP that accumulates all oil and gas assets into one cost centre. Under IFRS, the Company's PP&E assets must be divided into smaller cost centres. The net book value of the assets on the date of transition will be allocated to the new cost centres on the basis of reserve volumes or values at January 1, 2010.
- Share-Based Payments – IFRS 1 allows Fortress an exemption on IFRS 2, "*Share-Based Payments*" to equity instruments granted on or before November 2, 2002 or which are vested before the Company's transition date to IFRS.

The transition from Canadian GAAP to IFRS is a significant undertaking that may materially affect the Company's reported financial position and results of operations. At this time, the Company has identified key differences that will impact the financial statements as follows:

- Re-classification of Exploration and Evaluation (E&E) expenditures from PP&E – Upon transition to IFRS, Fortress will re-classify all E&E expenditures that are currently included in the PP&E balance on the Consolidated Balance Sheet. E&E assets will consist mainly of the book value for the Company's undeveloped land that relates to exploration properties. E&E assets will not be depleted and must be assessed for impairment when indicators suggest the possibility of impairment. In addition, IFRS requires that E&E expenditures incurred before the Company has acquired the legal right to explore an area be expensed. Under current Canadian GAAP these expenditures would be capitalized to PP&E. Once E&E assets have reached technical feasibility and commercial viability they are reclassified to production assets.
- Calculation of depletion expense for PP&E assets – Upon transition to IFRS, the Company has the option to calculate depletion using a reserve base of proved reserves or both proved and probable reserves, as compared to the Canadian GAAP method of calculating depletion using only proved reserves. The Company has not yet concluded which method for calculating depletion will be used.
- Impairment of PP&E assets – Under IFRS, impairment of PP&E must be calculated at a more granular level than what is currently required under Canadian GAAP. Impairment calculations will be performed at the cash-generating unit level using either total proved or proved plus probable reserves. IFRS requires an impairment test on the adoption of IFRS on January 1, 2010. The test for impairment under IFRS requires the use of a discounted cash flow model to determine fair value, whereas Canadian GAAP uses an undiscounted cash flow model and then discounted cash flow model to assess impairment. Market factors such as discount rates and the price of natural gas will affect the Company's assessment of impairment. Depending upon these factors, the Company may have an impairment loss on adoption of IFRS. Also, impairment charges may be more frequent under IFRS as individual E&E projects that do not reach technical feasibility or commercial viability will be written down to their recoverable amount, whereas under Canadian GAAP these projects may continue to remain part of the full cost pool subject only to a ceiling test.
- Decommissioning Liabilities (Asset Retirement Obligations) – Under Canadian GAAP the Company recognizes a liability for the estimated fair value of future retirement obligations related to PP&E.

This liability is based on the estimated costs to abandon and reclaim the Company's net working interest in wells and facilities, including an estimate of when these costs will be incurred. These cash outflows are discounted using a credit-adjusted risk-free interest rate. Changes in net present value of the future retirement obligation are expensed through accretion expense. Under IFRS the liability is calculated at each reporting date using estimates of risk-adjusted cash outflows discounted using the risk-free rate. Changes in the net present value are expensed through accretion expense. As a result of the change in discount rate from a credit-adjusted risk-free rate to a risk-free rate, the Company expects that there may be an increase in the value of the decommissioning liability under IFRS compared to Canadian GAAP; however, the difference is not known at this time.

- Income Tax - In transitioning to IFRS, the carrying amount of the Company's tax balances will be directly impacted by the tax effects resulting from changes required by the above IFRS accounting policy differences. Therefore, at this time the income tax impacts of the differences are not reasonably determinable.

In addition to accounting policy differences, the Company's transition to IFRS will impact the internal controls over financial reporting, the disclosure controls and procedures, the Company's business activities and information technology systems as follows:

- Internal controls over financial reporting – As the review of the Company's accounting policies is completed, an assessment will be made to determine changes required for internal controls over financial reporting. As an example, additional controls will be implemented for the IFRS 1 changes such as the allocation of PP&E as well as the process for re-classifying E&E expenditures from PP&E. This will be an ongoing process through 2010 to ensure that all changes in accounting policies include the appropriate additional controls and procedures for future IFRS reporting requirements.
- Disclosure controls and procedures – Throughout the transition process, the Company will be assessing stakeholders' information requirements and will ensure that adequate and timely information is provided so that all stakeholders are kept apprised. The Company anticipates delivering investor presentations during the fourth quarter of 2010 to explain the differences between the historical Canadian GAAP statements and the IFRS statements.
- Business activities – The Company has been cognizant of the upcoming transition to IFRS and as such will work with counterparties and lenders to ensure that agreement references to Canadian GAAP statements are modified to allow for IFRS statements. Based on the expected changes to the Company's accounting policies, there are no foreseen issues with the existing wording of debt covenants and related agreements as a result of the conversion to IFRS.
- Information technology systems – The Company has identified several accounting system upgrades required for IFRS reporting and is working with its software provider to make the necessary changes. The modifications are not significant; however, they are critical in order to allow for reporting of both Canadian GAAP and IFRS statements in 2010 as well as the modifications required to track PP&E costs and E&E costs to a more granular level of detail for IFRS reporting. Additional system modifications may be required based on final policy choices.

## **CRITICAL ACCOUNTING ESTIMATES**

The reader is advised that the critical accounting estimates, policies, and practices as described here continue to be critical in determining Fortress' financial results.

The reader is further cautioned that the preparation of financial statements in accordance with GAAP requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Estimating reserves is also critical to several accounting estimates and requires judgments and decisions based upon available geological, geophysical, engineering and economic data. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available, and as the economic environment changes. Changes in these judgments and estimates could have a material impact on the financial results and financial condition. The following discussion outlines accounting policies and practices that are critical to determining the Company's financial results.

## **Accounting for Petroleum and Natural Gas Operations**

The Company follows the full cost method of accounting whereby all costs relating to the acquisition of, exploration for and development of oil and natural gas reserves are capitalized in a single Canadian cost centre. Such costs include lease acquisition, lease rentals on undeveloped properties, geological and geophysical costs, drilling productive and non-productive wells, production equipment and overhead charges directly related to acquisition, exploration and development activities.

The application of the full cost method of accounting requires management's judgment to determine the proper designation of wells as either developmental or exploratory, which will ultimately determine the proper income tax treatment of the costs incurred.

Full cost accounting depends on the estimated proved reserves that are believed to be recoverable from the Company's oil and natural gas properties. The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and natural gas prices and costs change. The Company's reserve estimates are based on current production forecasts, prices and economic conditions. Fortress' reserves were evaluated by the independent engineering firm Sproule Associates Ltd.

Reserve estimates are critical to many of Fortress' accounting estimates, including:

- Calculating the Company's unit-of-production depletion and future site restoration rates. Proved reserve estimates are used to determine rates that are applied to each unit-of-production in calculating depletion expense; and
- Assessing when necessary, oil and natural gas assets for possible impairment. Estimated future undiscounted cash flows are determined using proved reserves. The criteria used to assess impairment, including the impact of changes in reserve estimates, are discussed below.

As circumstances change and additional data becomes available, reserve estimates also change, possibly materially impacting net income. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although Fortress makes every reasonable effort to ensure that its reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Positive or negative revisions to the Company's reserve estimates can arise from changes in oil and natural gas prices, and reservoir performance.

## **Impairment of Petroleum and Natural Gas Properties**

The Company reviews its full cost pool for impairment annually. An impairment provision is recorded whenever events or circumstances indicate that the carrying value of the Company's properties may not be recoverable. The impairment provision is based on the excess of carrying value over fair value. Fair value is defined as the present value of the estimated future net revenues from production of total proved plus probable petroleum and natural gas reserves, as estimated by the Company on the balance sheet date. Reserve estimates, as well as estimates for petroleum and natural gas prices and production costs, may change and there can be no assurance that impairment provisions will not be required in the future.

Management's assessment of, among other things, the results of exploration activities, commodity price outlooks, planned future development and sales impacts the amount and timing of impairment provisions.

## **Asset Retirement Obligations**

The provision for asset retirement obligations recorded in the consolidated financial statements is based on an estimate of total costs for future site restoration and abandonment of the Company's petroleum and natural gas properties. This estimate is based on management's analysis of production structure, reservoir characteristics and depth, market demand for equipment, currently available procedures, and discussions with construction and engineering consultants. Estimating these future costs requires management to make estimates and judgments that are subject to future revisions based on numerous factors, including changing technology, political and regulatory environments.

## **Income Taxes**

The Company records future tax assets and liabilities to account for the expected future tax consequences of events that have been recorded in its consolidated financial statements and its tax returns. These amounts are estimates; the actual tax consequences may differ from the estimates due to changing tax rates and regimes, as well as changing estimates of cash flows and capital expenditures in current and future periods. The Company periodically assesses its ability to realize its future tax assets. If Fortress concluded that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, the tax asset would be reduced by a valuation allowance.

## **Claims and Litigation**

The Company is involved in various claims and litigation arising in the normal course of business. The outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Company's favour. If the outcomes of these claims are unfavourable, there could be a materially adverse impact on the Company's financial position or results of operations.

With the above risks and uncertainties, the reader is cautioned that future events and results may vary significantly from those which Fortress currently foresees.

## **BUSINESS RISKS and UNCERTAINTIES**

### **General**

Fortress' production and exploration activities are concentrated in the Western Canada Sedimentary Basin, where activity is highly competitive and includes a variety of different-sized companies ranging from smaller junior producers to the much larger integrated petroleum companies. Fortress is subject to various types of business risks and uncertainties including:

- Finding and developing oil and natural gas reserves at economic costs;
- Production of oil and natural gas in commercial quantities; and
- Marketability of oil and natural gas produced;

In order to reduce exploration risk, the Company strives to employ highly qualified and motivated professional employees with a demonstrated ability to generate high-quality proprietary geological and geophysical prospects. To help maximize drilling success, Fortress combines exploration in areas that afford multi-zone prospect potential, targeting a range of low to moderate-risk prospects with some exposure to selected high-risk with high-reward opportunities.

The Company mitigates its risk related to producing hydrocarbons through the utilization of the most appropriate technology and information systems. In addition, the Company seeks to maintain operational control of its prospects.

Oil and natural gas exploration and production can involve environmental risks such as pollution of the environment and destruction of natural habitat, as well as safety risks such as personal injury. In order to mitigate such risks, Fortress conducts its operations at high standards and follows safety procedures intended to reduce the potential for personal injury to employees, contractors and the public at large. The Company maintains current insurance coverage for general and comprehensive liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect changing corporate requirements, as well as industry standards and government

regulations. Fortress may periodically use financial or physical delivery hedges to reduce its exposure against the potential adverse impact of commodity price volatility, as governed by formal policies approved by senior management subject to controls established by the Board of Directors.

### **Substantial Capital Requirements**

The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As the Company's revenues may decline as a result of decreased commodity pricing, it may be required to reduce capital expenditures. In addition, uncertain levels of near-term industry activity coupled with the current global credit crisis expose the Company to 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 Company. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on its business, financial condition, results of operations and prospects.

### **Third-party Credit Risk**

The Company 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 Company, such failures may have a material adverse effect on Fortress' business, financial condition, results of operations and prospects.

Additional risk factors can be found under "Risk Factors Relating to the Oil and Gas Business" in the Company's 2009 Annual Information Form which can be found on the Company's website [fortressenergy.ca](http://fortressenergy.ca) or under the Company's profile on [www.sedar.com](http://www.sedar.com). The risks should not be construed as exhaustive. There are numerous factors, both known and unknown, that could cause actual results or events to differ materially from forecast results.