Management's Discussion and Analysis

Twelve months ended December 31, 2011

March 29, 2012

Strategic Oil & Gas Ltd. ("Strategic" or the "Corporation) was incorporated under the laws of the Province of British Columbia on December 30, 1987 and continued as an Alberta corporation on September 9, 2010. On March 29, 2006, Strategic incorporated a United States of America (USA) subsidiary, Strategic Oil & Gas, Inc. ("US Subsidiary") through which all oil and gas activities in the USA are conducted. ZinMac Inc. ("ZinMac"), a private oil and gas consulting company was acquired on March 10, 2009, and Steen River Oil & Gas Ltd. ("Steen River"), a private oil and gas exploration and production company, was acquired on December 22, 2010 by Strategic. The following is Management's Discussion and Analysis (MD&A) of the consolidated operating and financial results of Strategic Oil & Gas Ltd. ("Strategic" or "the Corporation") for the year ended December 31, 2011. These results are being compared with the year ended December 31, 2010. The MD&A should be read in conjunction with the Corporation's audited consolidated financial statements for the year ended December 31, 2011, together with the accompanying notes.

Financial and Operational Highlights

	Three Months Ended December 31			Year Ended December 31		
	2011	**2010**	**% change**	**2011**	**2010**	**% change**
Financial ($000's, except per share amounts)						
Petroleum and natural gas sales	**8,606**	1,640	425	**23,853**	6,124	289
Funds from (used in) operations	**824**	1,164	(29)	**745**	(1,868)	(140)
Per share basic	**0.01**	(0.01)	(200)	**0.01**	(0.02)	(150)
Per share diluted	**0.01**	(0.01)	(200)	**0.01**	(0.02)	(150)
Net income (loss)	**(16,194)**	3,092	(624)	**(24,646)**	(339)	7,170
Per share basic	**(0.11)**	0.03	(467)	**(0.18)**	-	-
Per share diluted	**(0.11)**	0.03	(467)	**(0.18)**	-	-
Capital expenditures (excluding acquisitions)	**12,648**	7,676	65	**46,030**	13,645	237
Working capital surplus	**29,793**	24,999	8	**19,600**	25,286	(22)
Operating						
Production						
Crude oil Bbl per day)	**943**	239	295	**659**	221	198
Natural gas (Mcf per day)	**1,725**	471	266	**1,780**	493	261
Barrels of oil equivalent (Boe per day)	**1,230**	317	288	**956**	303	216
Average realized price						
Crude oil ($ per Bbl)	**93.05**	66.92	39	**88.82**	66.42	34
Natural gas ($ per Mcf)	**3.36**	3.89	(14)	**3.83**	4.26	(10)
Barrels of oil equivalent ($ per Boe)	**76.03**	56.21	35	**68.37**	55.34	24
Netback per Boe ($)						
Petroleum and natural gas sales	**76.03**	56.21	35	**68.37**	55.34	24
Royalties	**17.27**	1.68	928	**15.125**	4.62	227
Operating expenses	**30.91**	29.33	5	**32.54**	28.29	15
Transportation expenses	**2.37**	2.89	(18)	**2.17**	2.12	2
Operating Netback ($ per Boe)	**25.48**	22.31	14	**18.54**	20.31	(9)
Common Shares (000's)						
Common shares outstanding, end of period	**186,562**	138,555	35	**186,562**	138,555	35
Weighted average common shares (basic)	**144,139**	96,219	50	**140,161**	80,240	75

HIGHLIGHTS

- The Corporation increased its proved and probable oil and ngl reserves by 38%. The Corporation improved its present value before tax (10% Disc) on total proved reserves by 99% and on proved and probable by 71%. The Corporation had a loss of 39% in total proved and probable gas reserves.

- The Corporation increased its proved and probable reserves by 11.3% to 5.27 million barrels of oil equivalent. These reserves and reserves estimates were determined by the Corporation's independent reserve evaluators GLJ Petroleum Consultants Ltd. ("GLJ") at December 31, 2011.

- Oil and gas revenues during 2011 were $23.9 million and cash flow from operations were $0.7 million.

- Raised $44.6 million representing $34.6 million in common shares and $10.0 million in flow through shares in the fourth quarter of 2011.

- Production averaged 956 boe/d, an increase in underlying production of 216% over the previous year.

- Production for fourth quarter of 2011 averaged 1,230 boe/d, an increase of 288% over the same period in 2010.

- Capital of $46.0 million spent in the twelve months ended December 31, 2011, primarily at Steen River and Maxhamish.

- At December 31, 2011, the Corporation had working capital of $19.5 million and no debt.

- Production of approximately 600 boe/d was shut-in from Steen River during Q2 and Q3 due to a breach in the Rainbow pipeline which resumed operations in early September 2011.

ADVISORIES

The following Management Discussion and Analysis ("MD&A") of financial results is dated March 29, 2012 and is to be read in conjunction with the accompanying audited consolidated financial statements and related notes for the period ended December 31, 2011 and the audited consolidated financial statements and related notes and MD&A for the year ended December 31, 2010.

Basis of Presentation

The Corporation is required to apply International Financial Reporting Standards ("IFRS") for financial periods beginning on January 1, 2011, including comparative amounts for the respective periods in 2010 and an opening balance sheet as at January 1, 2010. As a result, this MD&A references Financial Statements prepared in accordance with IFRS including comparative prior period amounts. Readers are encouraged to refer to note 23 of the Financial Statements for more information.

Exclusive of the IFRS adjustments, certain December 31, 2010 prior period adjustments have been revised to conform to current period presentation categories with no impact to net income e(loss) for the period.

The discussion and analysis of our oil and natural gas production and related performance measures is presented on a working-interest, before royalties basis. For the purpose of calculating unit information, natural gas is converted to a barrel of oil equivalent ("boe") using six thousand cubic feet of natural gas equal to one barrel of oil. Readers are cautioned that boe's may be misleading, particularly if used in isolation. A conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, as the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

We make estimates and assumptions that affect the reported amounts of our assets and liabilities and the disclosure of contingent assets and liabilities at the date of the Financial Statements and our revenues and expenses during the reporting period. Management reviews these estimates, including those related to accruals, environmental and decommissioning liabilities, income taxes, and the determination of proved and

probable reserves on an ongoing basis. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates.

Non-GAAP Measurements

The Corporation utilizes the following terms for measurement within the MD&A that do not have a standardized meaning or definition as prescribed by IFRS and therefore may not be comparable with the calculation of similar measures by other entities.

"Funds from operation" is a term used to evaluate operating performance and assess leverage. The Corporation considers funds flows an important measure of its ability to generate funds necessary to finance operating activities, capital expenditures and debt repayments if any. Funds flow is calculated based on cash flow from operating activities before changes in non-cash working capital and decommissioning expenditures. Funds flow as presented is not intended to represent cash flow from operating activities, net earnings, or other measures of financial performance calculated in accordance with IFRS.

The following table reconciles funds from operations to cash flow generated by operating activities for the twelve months ended December 31:

	2011	2010
	$	$
Net cash generated by operating activities	**(4,553,274)**	(2,306,283)
Abandonment Expenses	**2,300,383**	4,542
Changes in non-cash working capital	**2,998,086**	433,383
Funds from operations	**745,195**	(1,868,358)

"Netback" is used to evaluate operating performance of our crude oil and natural gas assets. The term netback is calculated as oil and gas sales revenue, less royalties, transportation and operating costs.

Forward-looking information

Certain information set forth in this document, including management's assessment of future plans and operations contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, many of which are beyond management's control. Those risks include, without limitation, the effect of general economic conditions, risks associated with oil and gas exploration, development, production, marketing and transportation, loss of markets, the fact the Strategic does not operate all of its properties, industry conditions and competition, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the ability to access qualified personnel and oilfield services, decisions by regulators and the ability to access sufficient capital from internal and external sources. Readers are cautioned not to place undue reliance on the forward-looking statements as the assumptions used in the preparation of such information although considered reasonable at the time of preparation, may prove to be imprecise and actual results, performance or achievements could materially differ from those expressed or implied in such forward-looking statements and accordingly, no assurance can be given that any of the events anticipated by forward looking statements will transpire or occur, or if any of them do so what benefit Strategic will derive therefrom.

OVERVIEW OF PERFORMANCE AND DISCUSSION OF OUTLOOK

The Corporation made significant progress increasing its production during 2011, due to the successful drilling program at the Steen River assets. The program was consistent with the Corporation's strategy to explore, exploit and acquire large hydrocarbons in place reservoirs. The transaction provided exposure to a significant light oil development in the Steen area.

The Corporation's 2011 production was enhanced by the Steen acquisition along with added production from the successful winter drilling program. The production averaged 956 boe per day (69% liquids) which is a 216% increase over 2010 production results.

The Corporation's 2011 financial results have benefited from increased production from the drilling program and the acquisition of Steen River combined with the strong oil price environment. The Corporation's revenue increased 289% over the 2010 financial results to $23,852,810 and cash flow from operations

increased to $745,195 from negative funds of $1,868,358 in 2010. The Corporation realized an average of $68.37 per boe, up 24% compared to $55.34 in 2010.

A pipeline breach in late April, 2011 shut down the Rainbow pipeline, which delivers the Corporation's Steen River crude oil to market. Strategic was forced to shut-in approximately 600 bop/d production at Steen River as a result. This had a significant impact on the Corporation's sales volumes in the second and third quarters. The resumption of normalized pipeline operations on the Rainbow pipeline allowed the Corporation to return to full production.

2011 Drilling Results

Strategic successfully drilled, completed and placed on production the 100/08-22-122-21 W5M well in Q1 and the 103/10-22-122-21 W5M well in Q2 of 2011. Both wells are currently producing from the Keg River formation.

In Q3, Strategic purchased a horizontal oil treater. The treater was installed at the 9-17-122-20 Steen River Gas plant as an enhancement to the already existing oil handling facilities. The installation of the treater allowed for more efficient processing of existing crude production while increasing capacity in anticipation of a successful drilling program.

Strategic commenced its Q3 and Q4 drilling program on August 28th 2011. Strategic drilled and cased a horizontal well in the Sulphur Point at 102/11-22-122-21 W5M. Completion operations continued into the fourth quarter with the well tied in and on production in November, 2011.

A second well was spudded on September 21, 2011. The 100/15-22-122-21 W5M well was successfully directionally drilled to its target depth within the Keg River formation. The wellbore encountered a significant thickness of porous, oil filled dolomite and significantly extended the northern limits of the Keg River H pool and structure. Strategic successfully completed the well in November, 2011, with the well going on production in December of 2011.

A third well, the 102/03-22-122-21W5M well was drilled as an exploratory well targeting a new play concept. The well encountered hydrocarbons from a previously untested and unexpected shallow zone. The well was cased and completed. The well is currently awaiting additional stimulation work over the summer months prior to commencement of tie in activities.

A fourth well, the 103/15-18-122-22 well was drilled at Marlowe west. The well was successfully completed as a Keg River oil well.

A fifth well, the 102/15-22-122-21 W5M was drilled as an offsetting step out well to the successful 100/15-22 well. The 102/15-22 well was placed on production in late December 2011.

A sixth well, the 102/14-22-122-21 W5M well was spudded on December 10, 2011. Drilling operations were not complete prior to the New Year. The well was ultimately successful with drilling, completion and tie in operations occurring in Q1 2012 with first production commencing in early March 2012.

At Maxhamish, Strategic, with its operating partner Legacy Oil & Gas Inc., completed an all-weather road including well pads in early July, 2011. Two wells were drilled and fracture stimulated. Liner difficulties in the first well resulted in only half the wellbore being effectively stimulated. Initial production rates have been encouraging. The second well came on production in January 2012 and continues to recover load fluid and formation oil, but is rate constrained due to surface production equipment limitations. Strategic continues to be encouraged with the play, as the two horizontal wells drilled in 2010 have been producing at a stabilized rate of approximately 55 Boe per day per well after almost two years of production.

Reserves

In accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("N 51-101"), GLJ evaluated, as at December 31, 2011, materially all of Strategic's oil, natural gas liquids and natural gas reserves.

The following table is a summary, as at December 31, 2011, of Strategic's petroleum and natural gas reserves as evaluated by GLJ. It is important to note that the recovery and reserves estimates provided herein are estimates only. Actual reserves may be greater or less than the estimates provided herein.

Gross Company Reserves Summary *(1)*

Using GLJ December 31, 2011 Forecast Prices and Costs
As at December 31, 2011

	Light and Medium Oil (MBbl)	Natural Gas (MMcf)	NGL's (MBbl)	Total Oil Equivalent (MBoe)
Proved Producing	1,661	2,437	62	2,129
Proved Developed Non-Producing	39	575	-	135
Proved Undeveloped	913	240	(1)	952
Total Proved	2,613	3,252	61	3,215
Total Proved plus Probable	4,173	5,919	112	5,271

Note 1: Gross Company Reserves means the Corporation's working interest reserves before calculations of royalties and before consideration of the Corporation's royalty interest.

OUTLOOK FOR 2012

During 2011, Strategic made great strides in establishing itself as an efficient light oil operator in Northern Alberta. Significantly increased production of light oil resulting from Q4 2011 and Q1 2012 activities at Steen River will generate substantial cash flow allowing the Corporation to continue development of its operated property at Steen River as well as continued participation at its non-operated Maxhamish property. The technical team at Strategic continues to evaluate and assemble an inventory of exploration and acquisition prospects that will be accretive to the Corporation's oil focussed asset base.

For 2012 the Corporation has an approved capital budget of $60 million that is expected to provide growth in daily crude oil production by the end of the year. The capital program includes an anticipated $35 million focused on the crude oil program at Steen River, and the remainder of the capital program will target production optimization as well as investment in land and seismic. The Corporation's drilling plan includes an estimated 20 (17 net) wells and is expected to provide 2012 average production in the range of 2,400 boe/d to 3,000 boe/d and generate funds flow of approximately $34-38 million.

Steen River, Northwest Alberta

Strategic has drilled nine wells in Q1 2012. Success in the Q4 2011 and Q1 2012 drilling programs has resulted in a large inventory of follow up drilling locations. Strategic intends to resume drilling activities in Q3 2012 and expects to drill up to five additional wells before the end of 2012. Additional work at Steen will include the acquisition of follow up 2D and 3D seismic data, the extension of an all-weather road infrastructure and the expansion of oil processing facilities at the 9-17-120-20W5 facility.

Maxhamish

At Maxhamish, plans for further drilling are proceeding. During 2011 an all-weather road and drilling pad were constructed to allow for all weather access and additional drilling. By January 2012 the third and fourth wells were successfully drilled and stimulated and are now producing oil. The pace of development at Maxhamish is dependent upon Strategic's operating partner Legacy Oil & Gas Inc. Strategic continues to work closely with Legacy to advance the project. Strategic expects to participate in the drilling of up to four wells at Maxhamish beginning July 2012 following spring breakup.

Amber

In 2011 Strategic acquired a large land position in an emerging oil play in Northern Alberta. Strategic has identified multiple prospective oil zones underlying its lands. Extensive road and pipeline infrastructure exists in the Amber area. Strategic plans to drill two exploratory horizontal wells commencing in Q3, 2012.

Summary

Strategic is in a unique position for a junior/emerging oil and gas company:

i) ongoing drilling program at Steen River with over 100 sections of undeveloped land;
ii) the ability to significantly increase production at Steen River utilizing existing infrastructure;
iii) ongoing drilling program at Maxhamish, with over 100 sections of land;

iv) drill ready targets in an emerging oil play at Amber;
v) access to three drilling rigs for the remainder of 2012 with options for continued utilization into 2013.

IMPACT OF CURRENT ECONOMIC VOLATILITY AND UNCERTAINTY

Crude oil prices have remained strong through 2011. The Corporation was able to raise over $44 million of equity in December 2011. In addition, the Corporation has its $21.0 million line of credit with a Canadian financial institution. Strategic is therefore in a strong financial position to undertake its planned 2012 capital budget program. The Corporation will continue to monitor its funds from operations, cash position and available credit facilities, to ensure its ability to meet its planned capital program for 2012.

RESULTS OF OPERATIONS

Production

	Three months ended		Twelve months ended	
	December 31, 2011	December 31, 2010	**December 31, 2011**	December 31, 2010
	2011	2010	**2011**	2010
Oil, condensate, & ngls – bbls/d	**943**	239	**659**	221
Natural gas – mcf/d	**1,725**	471	**1,780**	493
Boe/d	**1,230**	317	**956**	303

The Corporation's fourth quarter 2011 production increased 288% compared with the same period in 2010. The increase in production is attributed to drilling 4.0 (net 2.8) successful wells in the last quarter of 2011 as well as resumption of Rainbow pipeline previously shut down due to pipeline failure.

The Corporation's 2011 production was enhanced by the acquisition of Steen River assets on December 22, 2010, along with added production from the successful drilling program which was partially offset by the impact of the Plains Rainbow pipeline outage from April through August 2011.

The Corporation's production averaged 956 boe/d which is a 216% increase over 2010. The Corporation's production portfolio in 2011 was weighted 69% to crude oil and ngls and 31% to natural gas.

Revenue

The Corporation's fourth quarter oil & natural gas revenues increased 425% as compared to the same period in 2010 as a result of the 288% increase in production and a higher weighting to higher valued oil and liquids production. The Corporation's average conventional oil price realized increased 39% to $93.05 as compared to $66.92 in 2010. During the fourth quarter, the Corporation's average natural gas price realized decreased 14% over the same period in 2010.

The Corporation's oil and natural gas revenues for the year ending Dec 31, 2011 increased 289% to $23.9 million from $6.1 million in 2010. The increase in revenue is attributed to a 216% increase in production (on a boe basis) and 24% increase in average realized prices.

	Three months ended		Twelve months ended	
	December 31, 2011	December 31,2010	**December 31, 2011**	December 31, 2010
	$	$	**$**	$
Sales				
Oil, condensate, and ngls	**8,072,294**	1,471,347	**21,364,589**	5,357,392
Natural gas	**533,986**	168,574	**2,488,221**	766,742
	8,606,280	1,639,921	**23,852,810**	6,124,134
Other revenue	**1,108**	62,346	**198,138**	73,541
Total sales	**8,607,388**	1,702,267	**24,050,948**	6,197,675
Average prices				
Oil and ngls ($/bbl)	**93.05**	66.92	**88.82**	66.42
Natural gas ($/mcf)	**3.36**	3.89	**3.83**	4.26
Oil equivalent ($/boe)	**76.03**	56.21	**68.37**	55.34

The average price realized for oil and ngls in 2011 increased by 34% to $88.82 compared to $66.42 per bbl. However, the Corporation's average natural gas price realized decreased by 10% to $3.83 per mcf as compared to $4.26 per mcf in 2010.

Overall, the combined average prices realized increased by 24% to $68.37 per bbl compared to 2010 of $55.34 per bbl.

Royalties

Royalty expense consists of royalties paid to provincial governments (including the effect of the crown royalty initiative program), freehold land owners and overriding royalty owners. Royalty expense also includes the impact of Gas Cost Allowance ("GCA"), which is the reduction of natural gas royalties payable to the Government of Alberta to recognize capital and operating expenditures incurred in the gathering and processing of its royalty share of production.

	Three months ended		**Twelve months ended**	
	December 31 2011	December 31 2010	**December 31 2011**	December 31 2010
	$	$	**$**	$
Crown royalties	**1,676,309**	27,638	**4,599,273**	373,164
Freehold royalties	**46,066**	11,408	**109,597**	76,340
Overriding royalties	**232,026**	10,020	**564,680**	61,402
Total royalties	**1,954,401**	49,066	**5,273,550**	510,906
Per boe	**17.27**	1.68	**15.12**	4.62
Percentage of crude oil & natural gas revenues	**22.7%**	3.0%	**22.1%**	8.3%

Royalties for the three months and year ended December 31, 2011 were higher on an absolute, percentage of revenue and per boe basis in comparison to the same periods in 2010 due to the addition of Steen River assets which on average attracts higher royalty rates than the Corporations pre-acquisition production. On a percentage basis, royalty rates were 22.1 percent and 22.7 percent of crude oil and natural gas revenue for the year and three months ended December 31, 2011, respectively, compared to 8.3 percent and 3.0 percent for the same periods in 2010.

Generally royalty rates in western Canada vary based on volume produced by individual wells, prices received and the area the production is derived from. Provincial government has established royalty incentive programs to encourage producers to initiate secondary recovery schemes on existing fields. The Alberta Government has extended the royalty incentive program to 2018 on new well production. The Corporation's successful drilling program will benefit from the reduced royalty rates of five percent on the first year of production on new natural gas and conventional oil wells up to a maximum 500,000 mcf of natural gas or 50,000 bbls of crude oil. This will result in a lower royalty rate on its corporate production.

Operating and transportation costs

	Three months ended		**Twelve months ended**	
	December 31 2011	December 31 2010	**December 31 2011**	December 31 2010
	$	$	**$**	$
Operating costs	**3,499,024**	855,697	**11,353,187**	3,130,202
Transportation costs	**268,467**	84,323	**757,736**	235,028
Total operating and transportations costs	**3,767,491**	940,020	**12,110,923**	3,365,230
Per boe				
Operating costs	**30.91**	29.33	**32.54**	28.29
Transportation costs	**2.37**	2.89	**2.17**	2.12
	33.28	32.22	**34.71**	30.41

For the three months ended December 23, 2011, combined production and transportation expenses averaged $33.28 per boe compared to $32.22 per boe in the same quarter of the previous year. Operating expenses increased 263% to $11.3 million in 2011 compared to $3.1 million in 2010. On a boe basis, operating expenses increased 15% to $32.54 from $28.29 in 2010. Higher operational costs resulted largely from decreased volumes due to the shut-in of the Rainbow pipeline.

The Corporation will continue to focus on controlling unit operating expenses and transportation costs in its core areas in 2012.

Exploration and Evaluation Expense

	Three months ended		**Twelve months ended**	
	December 31	December 31	**December 31**	December 31
	2011	2010	**2011**	2010
	$	$	**$**	$
Exploration and Evaluation	**906,566**	819,470	**1,284,981**	883,276
Per boe	**8.01**	28.10	**3.68**	7.99

The Corporation's exploration and evaluation expense represents all pre-license costs, undeveloped land and geophysical and geological costs that are initially capitalized costs on exploration and evaluation assets that have been subsequently expensed due to a lack of technical feasibility and commercial viability. These costs represent exploration and evaluation costs associated with an exploration area and costs incurred prior to obtaining the legal right to explore. Surface rentals associated with exploratory assets are capitalized and amortized over the lease term of five years.

For the year ended December 31, 2011, the Corporation recorded $1.3 million of exploration and evaluation expenses compared to $0.9 million for the same period in the prior year. This increase is due to an increase in pre-licencing costs incurred during the year, more land leases that expired during the year as well as unsuccessful exploration and evaluation costs, previously capitalized to exploration and evaluation assets, derecognized in the year compared to the prior year.

Operating netbacks

	Three months ended		**Twelve months ended**	
	December 31	December 31	**December 31**	December 31
	2011	2010	**2011**	2010
	$	$	**$**	$
Per boe				
Revenues	**76.03**	56.21	**68.37**	55.34
Royalties	**(17.27)**	(1.68)	**(15.12)**	(4.62)
Operating costs	**(30.91)**	(29.33)	**(32.54)**	(28.29)
Transportation costs	**(2.37)**	(2.89)	**(2.17)**	(2.12)
Netback per boe	**25.48**	22.31	**18.54**	20.31

The Corporation's fourth quarter operating netback increased by 14% to $25.48 per boe as compared to the same period in 2010 as a result of higher production. The period ending December 31, 2011, the operating netback decreased by 9% to $18.54 per boe as compared to $20.31 per boe at the end of 2010. The decrease is primarily attributed to depressed production through Rainbow pipeline failure during the period. The Corporation anticipates higher operating netbacks in 2012 due to its successful drilling program.

General and administrative expenses

	Three months ended		Twelve months ended	
	December 31, 2011	December 31, 2010	**December 31, 2011**	December 31, 2010
	$	$	**$**	$
Wages and employee benefits	**1,281,704**	759,845	**3,015,558**	1,702,824
Professional fees	**240,257**	191,443	**453,311**	334,971
Consulting fees	**220,263**	147,402	**887,830**	610,534
Public reporting	**83,924**	67,877	**314,442**	194,820
Occupancy costs	**127,034**	89,933	**493,793**	334,950
Travel	**55,220**	75,949	**225,497**	164,401
Miscellaneous general and administrative	**28,226**	524,734	**315,260**	711,348
Total	**2,036,632**	1,857,183	**5,705,691**	4,053,848
Per boe	**17.99**	63.66	**16.35**	36.63

During the fourth quarter of 2011, general and administrative expenses ("G&A") increased 10% to $2.0 million compared to $1.9 million in the same period in 2010. On a boe basis G&A decreased by 72% to $17.99 per boe as compared to $63.66 per boe. The decrease is directly attributed to an increase in production.

For the year ended December 31, 2011, G&A expenses increased by 41% to $5.7 million compared to $4.1 million in 2010. The overall costs increased due to general corporate growth and adding additional staff from the acquisition of Steen River. The costs per boe for 2011 decreased by 55% to $16.35 per boe as compared to $36.63 per boe in 2010. The costs per boe are anticipated to decrease in 2012, reflecting higher production volume anticipated from the winter drilling program.

Finance Expense

	Three months ended		Twelve months ended	
	December 31 2011	December 31 2010	**December 31 2011**	December 31 2010
	$	$	**$**	$
Interest expense – bank loan	**29,750**	11,910	**81,795**	110,707
Interest expense – debenture	**28,622**	-	**156,716**	-
Accretion expense	**44,128**	28,074	**200,880**	125,300
Total	**102,500**	39,984	**439,391**	236,007
Per boe	**0.91**	1.37	**1.26**	2.13

Overall finance expense in 2011 increased 86% to $439,391 compared to $236,007 in 2010. Interest expense decreased by 26% to $81,795 compared to $110,707 due to lower debt levels. Interest on the debenture was due to the assumption of debt as part of the acquisition of Steen River. On November 30, 2011, the Corporation redeemed all of the outstanding secured debentures in the amount of $3,425,225.

Accretion expense is a measure of the increase in the present value of the decommissioning obligation due to the passage of time. In 2011, the Corporation recorded an upward revision in the estimated cost of future site restoration resulting in an increase in the decommissioning obligation. Correspondingly, accretion expense for the twelve month period ended December 31, 2011 increased to $200,880 from $125,300 in 2010.

Stock based compensation

Stock based payments are non-cash charges which reflect the estimated value of stock options granted. The Corporation uses the fair value method of accounting for stock options granted to directors, officers, employees and consultants. The fair value of all stock options granted is recorded as a charge to operations over the period from the grant date to the vesting date of the option. The fair value of common share options granted is estimated on the date of grant using the Black-Scholes options pricing model.

During the year ended December 31, 2011 the Corporation recorded $2,602,294 related to the options granted as compared to $741,164 recorded in the previous year. The increase in share based payments is primarily

due to new stock options being issued to directors, officers and employees during the year ended December 31, 2011.

Depletion, depreciation and amortization

	Three months ended		Twelve months ended	
	December 31 2011	December 31 2010	**December 31 2011**	December 31 2010
	$	$	**$**	$
Depreciation, depletion, and amortization	**3,174,315**	1,084,139	**9,382,695**	2,577,046
Per boe	**28.04**	37.16	**26.89**	23.29

Depletion and depreciation is computed on a unit of production basis. Such expense, on a boe basis, fluctuates period to period primarily as a result of changes in the underlying proved and probable reserve base and in the amount of costs subject to depletion and depreciation. Such costs are segregated and depleted on an area by area basis relative to the respective underlying proved and probable reserves base. The depletion and depreciation expense for the twelve months ended December 31, 2011 increased by 264% to $9.3 million compared to the same period in 2010 at $2.6 million. The increase in depletion is a result of increased production in 2011. On a boe basis, the costs increased by 15% to $26.89 per boe compared to $23.29 for the twelve months ending December 31, 2010. The increase is the result of higher capital and future development costs subject to depletion, offset by the higher additions to the proved and probable reserves base.

Impairment Loss

Impairment testing is performed at the cash generating unit ("CGU") level and is a point in time process for testing and measuring a potential impairment of assets whereby each CGU's carrying value net of the related decommissioning liability is compared to the fair value of the assets less costs to sell the asset. Impairment testing is required when there are indicators of impairment such as a significant drop in commodity prices or a downward revision of proved and probable oil and gas reserves. During the year ended December 31, 2011, the Corporation recognized an impairment of $12.3 million due to a downward revision of proved and probable reserves at the GCU level. The impairment was based on the difference between the period-end net book value of the assets and the recoverable amount determined using fair value based on the discounted cash flows of proved and probable reserves using forecast commodity prices and costs.

Funds from operations and net income (loss)

	Three months ended		Twelve months ended	
	December 31, 2011	December 31, 2010	**December 31, 2011**	December 31, 2010
	$	$	**$**	$
Funds (used in) from operations	**823,889**	1,163,531	**745,195**	(1,868,358)
Per share				
basic	**0.01**	(0.01)	**0.01**	(0.02)
diluted	**0.01**	(0.01)	**0.01**	(0.02)
Net income (loss)*(1)*	**(16,193,634)**	3,091,917	**(24,646,463)**	(338,912)
Per share				
basic	**(0.11)**	0.03	**(0.18)**	0.00
diluted	**(0.11)**	0.03	**(0.18)**	0.00

For the quarter ended December 31, 2011, net loss realized was $16.2 million compared to a net income of $3.1 million during the same period in 2010. The net loss for the fourth quarter of 2011 includes $12.3 million of impairment due to a downward revision of proved and probable reserves at the GCU level. The net income for the fourth quarter of 2010 includes a $9.3 million gain on the Steen River acquisition. Basic and diluted net loss per share for the fourth quarter of 2011 was $0.11, compared to basic and diluted earnings per share of $0.03 during the same period in the prior year. Funds generated by operations increased to $0.8

million for the three months ended December 31, 2011, compared to negative $1.2 million during the same period in 2010, due primarily to higher operating netback on a boe basis from higher production volumes. Basic and diluted funds generated by operations per share for the fourth quarter of 2011 were $0.01 compared to negative $0.01 during the same period in the prior year.

For the year ended December 31, 2011, the Corporation recorded net loss of $24.6 million compared to $0.3 million in the prior year. The net loss for the year ended December 31, 2011 includes $12.3 million of PPE impairment as well as $0.6 million impairment of goodwill. The net loss for the prior year includes $9.3 million gain on the Steen River acquisition. Basic and diluted net loss per share for the year ended December 31, 2011 was $0.18 compared to basic and diluted net loss per share of $0.00 in the prior year. Funds generated by operations increased to $0.7 million for the year ended December 31, 2011 compared to negative $1.9 million during the prior year, due primarily to additional production from the properties acquired with higher netback. Basic and diluted funds generated by operations per share for the year ended December 31, 2011 was $0.01 compared to negative $0.02 per basic and diluted share in the prior year.

Capital Expenditures

	Three months ended		**Twelve months ended**	
	December 31	December 31	**December 31**	December 31
	2011	2010	**2011**	2010
	$	$	**$**	$
Drilling and completions	**6,000,955**	3,277,948	**30,293,777**	5,289,126
Equipping and facilities	**6,183,001**	79,620	**7,875,986**	103,952
Other	**38,002**	3,423	**145,439**	17,985
	12,221,958	3,360,991	**38,315,202**	5,411,063
Drilling incentive credits	**-**	-	**-777,291**	-
Total Property, plant and equipment	**12,221,958**	3,360,991	**37,537,911**	5,411,063
Land and seismic	**426,133**	4,315,250	**8,492,425**	8,233,918
Total exploration and evaluations	**426,133**	4,315,250	**8,492,425**	8,233,918
Total net capital expenditures	**12,648,091**	7,676,241	**46,030,336**	13,644,981

During the fourth quarter of 2011, the Corporation invested $12.2 million on drilling activities compared to $3.4 million in 2010. Capital expenditures for the fourth quarter were mainly focused on developing Steen River and Maxhamish.

The Corporation's 2011 capital program is focused primarily on oil opportunities. During 2011, capital spending was $37.5 million as compared to $5.4 million in 2010. For the 2011 capital program the following were undertaken:

- Drilled, cased and tied in a Keg River well at 100/8-22-122-21 W5M.
- Drilled, cased and tied in a Keg River well at 103/10-22-122-21 W5M.
- Drilled, cased and tied in a Keg River well at 03/15-18-122-21 W5M.
- Drilled, cased a Sulphur Point dolomite horizontal well at 102/11-22-122-21 W5M.
- Drilled, cased and tied in a Keg River well at 100/15-22-122-21 W5M.
- Drilled, cased and tied in a Keg River well at 102/15-22-122-21 W5M.
- Upgrading and maintenance of the all-weather access road at Steen.
- Upgrading roads at Steen.
- Expanded oil handling capabilities at Steen 9-17-122-20 W5M facility.
- Drilling and completion operations by partner at AD18J-94-O-11 in Maxhamish.
- Drilling and casing operations by partner at B19J-94-O-11 in Maxhamish.

Exploration and evaluation costs are area expenditures where technical feasibility and commercial viability has not yet been determined. Costs incurred prior to acquisition are expensed as incurred. Exploration and evaluation costs increased due to shooting and processing of seismic in order to evaluate potential drilling locations.

During the fourth quarter of 2011, the Corporation spent $0.4 million on additional undeveloped land in the Steen area compared to $4.3 million spent at Conrad and Maxhamish in 2010.

SUMMARY OF QUARTERLY FINANCIAL DATA

The following table summarizes quarterly financial results:

Quarter ended	**Dec-11**	Sep-11	Jun-11	Mar-11	Dec-10	Sep-10	Jun-10	Mar-10
	$	$	$	$	$	$	$	$
Petroleum and natural gas sales	**8,606,280**	5,200,398	5,432,235	4,618,296	1,639,921	1,504,357	1,293,250	1,686,606
Income (loss)	**(16,193,634)**	(1,395,197)	(2,166,533)	(4,891,099)	3,091,917	(1,219,335)	(985,893)	(1,225,601)
Income (loss) per share								
Basic	**(0.11)**	(0.01)	(0.01)	(0.04)	0.03	(0.02)	(0.01)	(0.02)
Diluted	**(0.11)**	(0.01)	(0.01)	(0.04)	0.03	(0.02)	(0.01)	(0.02)
Production boe/d	**1,230**	914	884	790	317	314	266	315
Average price/boe	**76.03**	61.83	67.54	64.92	56.21	52.08	53.38	59.44

LIQUIDITY AND CAPITAL RESERVES

The Corporation considers its capital structure to include shareholders' equity, and working capital, including bank debt. The objectives of the Corporation are to maintain a strong balance sheet affording the Corporation financial flexibility to achieve goals of continued growth and access to capital.

In order to maintain or adjust the capital structure, the Corporation may issue new common shares, issue new debt, or adjust exploration and development capital expenditures.

The Corporation monitors its capital program based on available funds, which is the combination of working capital and remaining unused line of credit, as calculated below:

	December 31 2011	December 31 2010
	$	$
Current assets	**37,443,051**	34,838,496
Accounts payable and accrued liabilities	**(17,908,179)**	(6,127,032)
Debentures	**-**	(3,425,225)
Net working capital surplus	**19,534,872**	25,286,239
Total line of credit	**21,000,000**	5,000,000
Authorized Letters of Guarantee	**(800,000)**	-
Unutilized line of credit	**20,200,000**	5,000,000
Net available funds	**39,734,872**	30,286,239

The Corporation is currently projecting its remaining 2012 capital program to be approximately $60 million, and expects the current available funds, line of credit, plus anticipated cash flow will be able to fund it. The amount of the credit facility is based on petroleum and natural gas reserves with certain financial covenants. The credit facility also contains a financial covenant that requires the Corporation to maintain a certain minimum working capital ratio. The Corporation is compliant with all covenants.

SHARE CAPITAL

	Three Months Ended December 31		**Year Ended December 31**	
	2011	2010	**2011**	2010
Outstanding Common shares				
Weighted average Common shares outstanding				
- Basic	144,139,198	96,218,518	140,161,040	80,239,777

	December 31, 2011
Outstanding Securities	
- Common Shares	186,562,068
- Common Share Options	6,780,333

Subsequent to the year end, the Corporation granted 2,260,000 stock options to directors, officers and employees, of which 1,975,000 went to officers and directors. Each option entitles the holder to acquire one

common share of the Corporation for a period of five years at a price of $.90 per share. These options were issued in accordance with the Corporation's incentive stock option plan.

TRANSACTIONS WITH RELATED PARTIES

Legal fees in the amount of $296,648 (December 31, 2010 - $477,142) were incurred to a legal firm of which a director is a partner, and included as general and administrative expenses or share issue costs. Consulting fees in the amount of $33,325 (December 31, 2010 - $30,755) were incurred to a director for geophysical consulting services. Software charges of $93,000 (December 31, 2010 - $123,000) were charged to a company controlled by an officer. Accounts payable and accrued liabilities at December 31, 2011 include $150,707 (December 31, 2010 - $307,198, January 1, 2010 - $20,843) due to related parties. The above transactions were conducted in the normal course of operations and were recorded at exchange amounts which were agreed upon between the Corporation and the related parties.

COMMITMENTS

a) The Corporation has lease agreements for office space resulting in the following commitments:

Year ended	$
2012	292,596
2013	263,213
	555,809

b) Pursuant to the issue of flow-through shares in December 2011, the Corporation is committed to incur a total of $10,010,000 on qualify expenditures prior to December 31, 2012.

OUTSTANDING SHARE DATA

Common Shares

The Corporation is authorized to issue an unlimited number of common shares. As at March 29, 2012 the Corporation had 187,062,068 common shares outstanding and 8,040,335 stock options outstanding under its stock-based compensation program.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Corporation is exposed to a number of different financial risks from normal course business exposures, as well as the Corporation's use of financial instruments. These risk factors include market risk, liquidity risk, and credit risk.

a) Market Risk

Market risk is the risk or uncertainty arising from possible market price movements and their impact on the future performance of the business. The market price movements that could adversely affect the value of the Corporation's financial assets, liabilities and expected future cash flows include commodity price risk, interest rate risk and foreign exchange risk. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimising the return.

i) Commodity Price Risk

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by not only the relationship between the Canadian and United States dollar but also world economic events that dictate the levels of supply and demand. The Corporation's financial performance is closely linked to natural gas and crude oil prices. While the Corporation may employ the use of various financial instruments in the future to manage these price exposures, the Corporation is not currently using any such instruments. The Corporation may, in certain circumstances, enter into oil or natural gas

hedging contracts to provide stability of future cash flows by fixing the price of future deliveries of saleable product.

As at December 31, 2011 and December 31, 2010, the Corporation had no hedging contracts. The following table analyzes the Corporation's cash flow sensitivity to commodity price changes:

	December 31, 2011 **$**	December 31, 2010 $
10% change in oil price	**1,569,409**	**487,157**
10% change in gas price	**239,993**	**73,989**

**Note: change in revenue is in the same direction as change in price*

ii) Interest Rate Risk

The Corporation is exposed to interest rate risk as changes in interest rates may affect future cash flows. The Corporation's primary debt facility has a floating interest rate that will fluctuate based on prevailing market conditions. Cash flows are sensitive to changes in interest rates on this instrument. As at December 31, 2011, if interest rates had increased by 1% with all other variables held constant, net income would have decreased by $nil (2010 – $nil) as no amounts were outstanding.

iii) Foreign exchange risk

Prices for oil are determined in global markets and generally denominated in United States dollars. Natural gas and oil prices obtained by the Corporation are influenced by both US and Canadian demand and the corresponding North American supply, and recently, by imports of liquefied natural gas. The exchange rate effect cannot be quantified but generally an increase in the value of the $CDN as compared to the $US will reduce the prices received by the Corporation for its petroleum and natural gas sales. As at December 31, 2011 and 2010, the Corporation had no contracts in place to reduce the foreign exchange risk.

b) Liquidity Risk

Liquidity risk is the risk that an entity will encounter difficulty in meeting obligations associated with financial liabilities.

The Corporation's approach to managing liquidity is to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Corporation's reputation.

Typically the Corporation ensures that it has sufficient cash on demand to meet expected operational expenses for a period of 30 days, including the servicing of financial obligations; this excludes the potential impact of extreme circumstances that cannot reasonably be predicted, such as natural disasters. To achieve this objective, the Corporation prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Corporation utilizes authorizations for expenditures on both operated and non-operated projects to further manage capital expenditure. The Corporation also attempts to match its payment cycle with collection of oil and natural gas revenue on the 25th of each month. In addition, the Corporation maintains a $21 million credit facility to provide capital when needed of which $20.2 million net of letters of credit line was available at the end of the 2011.

All of the Corporation's liabilities matured in 2011 as the Corporation's accounts payable were due on demand. There was no loan balance at December 31, 2011. (December 31, 2010 - $nil, January 1, 2010 - $1.5 million), so minimal additional liquidity risk.

c) Credit Risk

Credit risk is the risk that a customer or counterparty will fail to perform an obligation or fail to pay amounts due causing a financial loss. The Corporation's trade and other receivables are with customers and joint venture partners in the oil and gas industry and are subject to normal credit risks. The Corporation's production is predominately sold directly after taking its product in kind. Currently, over 75% of the oil and natural gas is being sold through marketing companies and revenues are collected on the 25th day of the month following the month of production. The majority of the remaining accounts receivables are from joint venture partners which are collected between two and

four months after the production month. In order to mitigate collection risk, the Corporation assesses the credit worthiness of customers by assessing the financial strength of the customers and by routinely monitoring credit risk exposures.

Collection of the remaining balances can be dependent upon industry factors such as commodity prices, risk of unsuccessful drilling and partner disputes. Otherwise, the Corporation does not typically obtain collateral from joint venture partners, and relies upon industry standard legal remedies for collection.

The Corporation's most significant customer, a Canadian oil and natural gas marketer, accounts for 54% of the trade receivables at December 31, 2011 (December 31, 2010: 23%, January 1, 2010: 58%).

As at December 31, 2011 and 2010, the Corporation's trade and other receivables are aged as follows:

	2011	2010
	$	**$**
Current (less than 90 days)	3,598,234	2,034,407
Past due (more than 90 days)	1,552,170	1,122,539
Total	5,150,404	3,156,946

At December 31, 2011, the allowance for doubtful accounts was $25,545 (2010 - $nil).

INTERNATIONAL FINANCIAL REPORTING STANDARDS

The Corporation prepares its financial statements in accordance with Canadian generally accepted accounting principles as set out in the Handbook of the Canadian Institute of Chartered Accountants. In 2010, the CICA Handbook was revised to incorporate International Financial Reporting Standards and interpretations (collectively referred to as "IFRS") as issued by the International Accounting Standards Board, and require publicly accountable enterprises to apply such standards effective for years beginning on or after January 1, 2011 (CICA Handbook Part I – IFRS). In these consolidated financial statements, the term "Canadian GAAP" refers to Canadian GAAP before the adoption of IFRS (CICA Handbook Part V – Pre-changeover accounting standards).

The audited consolidated financial statements as at December 31, 2011 represent the first annual consolidated financial statements of the Corporation prepared in accordance with IFRS as issued by the IASB. The Corporation adopted IFRS in accordance with IFRS 1, *First-time Adoption of International Financial Reporting Standards*. These consolidated financial statements present the Corporation's financial results of operations and financial position as at and for the year ended December 31, 2011, including 2010 comparative periods. Previously, the Corporation prepared its consolidated financial statements in accordance with Canadian GAAP.

Note 23 discloses the impact of the transition to IFRS on the Corporation's reported equity and financial position as at January 1, 2010 and the Corporation's reported financial results of operations and financial position as at and for the year ended December 31, 2010, including a summary of the significant changes to Corporations accounting policies on adoption of IFRS.

The Corporation concluded that the adoption of IFRS did not have a significant impact on any of its internal control processes.

A summary of the significant accounting policies used by the Corporation can be found in Note 3 of the December 31, 2011 audited consolidated financial statements and Note 23 summarizes the impact of adopting these policies. In addition, Note 23 of the Corporation's audited consolidated financial statements for the year ended December 31, 2011 provides the following reconciliations from Canadian GAAP to IFRS:

- Consolidated Statement of Financial Position at the date of transition to IFRS – January 1, 2010;
- Consolidated Statement of Comprehensive Income (Loss) for the year ended December 31, 2010;
- Consolidated Statement of Changes in Equity as at December 31, 2010; and

- Consolidated Statement of Cash Flows for the year ended December 31, 2010

The following discussion explains the significant differences between IFRS and the Canadian GAAP followed by the Corporation.

a) Property, plant and equipment

Under Canadian GAAP, the Corporation, like many Canadian oil and Gas reporting issuers, applied the "full cost" concept in accounting for its oil and gas assets. Under full cost accounting, capital expenditures were maintained in a single cost centre and the cost centre was subject to a single depletion and depreciation calculation and impairment test. Under IFRS, the Corporation makes a much more detailed assessment of its oil and gas assets that impact depreciation and impairment calculations. Included in this assessment is an ongoing appraisal of exploration and evaluation expenditures ("E&E"). Under Canadian GAAP, it was only necessary to track costs associated with unproved properties that would be excluded from depletion and depreciation calculations. Under IFRS, a company may choose to account for E&E under its previous GAAP and capitalize such costs without recording depreciation expense until the expenditures are determined to represent technically feasible and commercially viable projects at which time the costs are moved to development properties or expenses accordingly. The Corporation capitalizes E&E costs except for costs incurred before the acquisition of rights to explore, and to begin depreciating when technically feasible and commercially viable. As at transition on January 1, 2010, $Nil was reclassified from property, plant and equipment to exploration and evaluation assets.

As well, under Canadian GAAP the Corporation did not recognize gains or losses on the disposal of oil and gas properties unless such dispositions would change the depletion rate by 20% or more while IFRS requires such recognition. This results in an increase to the carrying value and a gain on sale of property, plant equipment.

b) Exploration and Evaluation

Costs associated with acquiring an exploration license, including costs to acquire acreage and exploration rights, legal and other professional fees and land brokerage fees are capitalized as exploration and evaluation assets. Geological and geophysical costs (including seismic) associated with assessing exploration licenses are also capitalized to E&E. Land acquisition costs and expenditures directly associated with exploratory wells are capitalized and remain capitalized until the Corporation has chosen to discontinue all exploration activities in the associated area. Costs directly associated with an exploration well are capitalized as exploration and evaluation assets until the drilling of the well is complete and the results have been evaluated.

Land acquisition costs, related seismic and costs directly associated with exploratory wells with proved reserves are tested for impairment and reclassification to PP&E. If no reserves are found, the capitalized exploration costs are charged to expense as exploration expense, including dry hole costs.

The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved reserves are determined to exist. A review of each exploration area is carried out, at least annually, to ascertain whether proved reserves have been discovered. Upon determination of proved reserves, exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from E&E assets to property, plant, and equipment.

E&E assets are assessed for impairment if (i) sufficient data exists to determine the lack of technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, exploration and evaluation asset are allocated to cash-generating units.

As at December 31, 2010, the Corporation transferred $5,724,148 from PP&E to E&E as the commercial viability was established.

c) Depreciation

For Canadian GAAP purposes, the full cost method of accounting for oil and gas properties requires a single calculation of depletion and depreciation of the carrying value of PP&E based on proved reserves. However, IFRS requires an allocation of the amount recognized as PP&E to each significant identified component and each component depreciated separately, utilizing an appropriate

method of depreciation. This component depreciation of PP&E results in an increased number of calculations of depreciation expense and impacts the amount of depreciation calculation. The Corporation has utilized proved and probable reserves to calculate depreciation expense as the Corporation believes it represents a better approximation of useful life and depletion of reserves.

d) Impairment of Assets

Under Canadian GAAP, impairment calculations are prepared according to a two-step test generally conducted at a country level. Step one involves a comparison of the PP&E carrying value to the undiscounted net cash flows of proved reserves. If a company should fail step one, step two is completed to measure the amount of impairment whereby the PP&E carrying value is compared to a calculated fair value with any excess carrying value above the fair value recognized as an impairment loss. Impairment losses recognized under Canadian GAAP are not subsequently reversed. Under IFRS, impairment testing is completed at an individual asset group or "Cash Generating Unit" level ("CGU") when indicators suggest there may be impairment. A CGU is defined as the smallest measuring asset that produces independent cash flows. Impairment of assets at a CGU level use a one-step approach for testing and measuring asset impairment, with asset carrying values compared to the higher of "Value in Use" and "Fair Value less Costs to Sell". The IFRS methodology may result in the possibility of more frequent impairments in the carrying value of PP&E. However, under IFRS previous impairment losses must be reversed where circumstances change such that the previously recognized impairment has been reduced.

e) Decommissioning Liabilities

Both Canadian GAAP and IFRS require a company to provide for a liability related to decommissioning PP&E. Both methodologies are similar and the Corporation has determined there to be no significant difference for the Corporation, other than a difference related to discount rates. Canadian GAAP previously required that the decommissioning liability be discounted at a credit-adjusted risk-free rate while IFRS requires that the decommissioning liability be discounted at an appropriate rate with either the cash flows or rate adjusted for risks. The Corporation has selected to use the risk–free rate for discounting purposes and at transition date the decommission liability was increased by $1,084,844 and charged to deficit.

f) Deferred Income Taxes

Deferred income tax calculated according to IFRS is substantially similar to Canadian GAAP and arises from differences between the accounting and tax bases of our assets and liabilities. To the extent that assets and liabilities have changed from transition to IFRS, the amount of deferred income tax liability has been impacted. Additionally, under Canadian GAAP deferred income tax liabilities were required to be disclosed as either current or long-term. Under IFRS, all deferred income tax liabilities are considered to be non-current liabilities.

Future accounting pronouncements

The following standards and interpretations have not been in effect as they will only be applied for the first time in future periods. They may result in consequential changes to the accounting policies and other note disclosures.

- **IFRS 10**
  Consolidated Financial Statements builds on existing principles and standards and identifies the concept of control as the determining factor in whether an entity should be included within the consolidated financial statements of the parent company.

- **IFRS 11**
  Joint Arrangements establishes the principles for financial reporting by entities when they have an interest in arrangements that are jointly controlled.

- **IFRS 12**
  Disclosure of Interest in Other Entities provides the disclosure requirements for interests held in other entities including joint arrangements, associates, special purpose entities and other off balance sheet entities.

- **IFRS 13**
  Fair Value Measurement defines fair value, requires disclosure about fair value measurements and provides a framework for measuring fair value when it is required or permitted within the IFRS standards.

- **IAS 1**
  In June 2011, the IASB issued IAS 1 Presentation of Items of OCI: Amendments to IAS 1 Presentation of Financial Statements. The amendments stipulate the presentation of net earnings and OCI and also require the Corporation to group items within OCI based on whether the items may be subsequently reclassified to profit or loss. Amendments to IAS 1 are effective for the Corporation beginning on January 1, 2012 with retrospective application and early adoption permitted.

- **IAS 27**
  Separate Financial Statements – The IASB issued amendments to IAS 27 Separate Financial Statements to coincide with the changes made in IFRS 10, but retains the current guidance for separate financial statements.

- **IAS 28**
  Investments in Associate and Joint Ventures revised the existing standard and prescribes the accounting for investments and sets out the requirements for the application of the equity method when accounting for investments in associates and joint ventures.

- **IFRS 7**
  Financial Instruments: Disclosures – In 2011, IASB issued amendments to IFRS 7 Financial instruments: Disclosures relating to disclosure requirements for the offsetting of financial assets and liabilities when offsetting is permitted under IFRS. The disclosure amendments are required to be adopted retrospectively for periods beginning January 1, 2013.

- **IFRS 9**
  In November 2009, the IASB published IFRS 9, "Financial Instruments," which covers the classification and measurement of financial assets as part of its project to replace IAS 39, "Financial Instruments: Recognition and Measurement." In October 2010, the requirements for classifying and measuring financial liabilities were added to IFRS 9. Under this guidance, entities have the option to recognize financial liabilities at fair value through earnings. If this option is elected, entities would be required to reverse the portion of the fair value change due to a company's own credit risk out of earnings and recognize the change in other comprehensive income. IFRS 9 is effective for the Corporation on January 1, 2015. Early adoption is permitted and the standard is required to be applied retrospectively.

CRITICAL ACCOUNTING ESTIMATES

A summary of the Corporation's significant accounting policies is contained in *Note 3* to the consolidated financial statements. These accounting policies are subject to estimates and key judgments about future events, many of which are beyond the Corporation's control. The following is a discussion of the accounting policies that are critical to the financial statements.

Crude oil and natural gas assets – reserves estimates

The Corporation retained GLJ to evaluate its crude oil and natural gas reserves, prepare an evaluation report, and report to the Corporation. The process of estimating crude oil and natural gas reserves is subjective and involves a significant number of decisions and assumptions in evaluating available geological, geophysical, engineering and economic data. These estimates will change over time as additional data from ongoing development and production activities becomes available and as economic conditions affecting crude oil and natural gas prices and costs change. Reserves can be classified as prove, probable or possible with decreasing levels of likelihood that the reserve will be ultimately produced.

Reserve estimates are a key input to the Corporation's depletion calculations and impairment tests. Property, plant and equipment within each area are depleted using the unit-of-production method based on proved reserves using estimated future prices and costs. In addition, the costs subject to depletion include an estimate of future costs to be incurred in developing proved reserves. A revision in reserve estimates or future development costs could result in the recognition of higher depletion charged to net income.

Under IFRS, the carrying amount of property, plant and equipment are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, the estimated recoverable amount is calculated. For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or "CGU"). The recoverable amount of an asset of a CGU is the greater of its value in use and its fair value less costs to sell. Fair value less costs to sell represent the value for which an asset could be sold in an arm's length transaction, and is presented as a function of the future cash flows of the proved and probable reserves. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proven and probable reserves. E&E assets are allocated to the related CGU's to assess for impairment, both at the time of any triggering facts and circumstances as well as upon their eventual reclassification to producing assets (oil and natural gas interests in property, plant and equipment). An impairment loss is recognized in income if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Reserve, revenue, royalty and operating cost estimates and the timing of future cash flows are all critical components of the impairment test. Revisions of these estimates could result in a write-down of the carrying amount of crude oil and natural gas properties.

Decommissioning liabilities

Under previous GAAP, decommissioning liabilities were measured based on the estimated costs of decommissioning, discounted to their net present value upon initial recognition using a credit-adjusted risk-free rate. The discount rate was rarely changed. Under IFRS, the discount rate used by the Corporation is the risk-free rate and the decommissioning liabilities are reassessed for the current risk-free rate at each reporting date. At the transition date, the Corporation increased the decommissioning liabilities by $1,084,844. At December 31, 2010, the Corporation further increased the decommissioning liabilities by an additional $1,560,012.

Stock based compensation

Stock-based compensation under previous GAAP, and similarly under IFRS, was calculated using the Black Scholes model and recognized using the graded vesting method over the vesting period of the options. Where previous GAAP allowed forfeitures to be recognized as they occurred, the IFRS requirement is to recognize the expense over the individual vesting periods for the grading vested awards and estimate a forfeiture rate at the date of grant and update it through the vesting period. At transition date, the Corporation recognized a decrease of $2,572 in contributed surplus to account for estimated forfeitures. For the year ended December 31, 2010, an additional decrease of $2,055 was recorded accounting for estimated forfeitures.

Other Estimates

The accrual method of accounting requires management to incorporate certain estimates including estimates of revenue, royalties, lease operating and transportation costs at a specific report date, but for which actual revenues and costs have not yet been received. In addition, estimates are made on capital projects which are in process or recently completed where actual costs have not been received by the reporting date. The Corporation obtains the estimates from the individuals with the most knowledge of the activity and from all project documentation received. The estimates are reviewed for reasonableness and compared to past performance to assess the reliability of the estimates. Past estimates are compared to actual results in order to make informed decisions on future estimates.

RISK FACTORS

The Corporation is exposed to a number of risks and uncertainties inherent in exploring for, developing and producing crude oil and natural gas. These risks and uncertainties include, but are not limited to, the following:

- Risk of fluctuating oil, natural gas prices and the cost of diluent;
- Operational risk of finding and producing reserves economically;
- Uncertainties associated with estimating the quantity of reserves and resources;
- Risk associated with securing the needed capital to carry out the Corporation's operations;
- Changes in global economic conditions, particularly in Canada and the U.S.;
- Risk from aboriginal claims;
- Risk of changes in government policies, especially related to royalty legislation, income tax laws, incentive programs, operating practices and environmental protection, social instability or other political, economic or diplomatic developments in its operations;
- Environmental and safety risks related to its oil and gas properties;
- Competition for, among other things, capital, undeveloped land, skilled labour and equipment;
- Reliance on third parties for pipeline and other infrastructure;
- Risk of fluctuating foreign currency exchange rates;
- Credit or counterparty risk with respect to non-performance by counterparties to financial instruments;
- Risk of changes to interest rates;
- Marketing oil production at acceptable prices;
- Uncertainty associated with obtaining drilling licenses and other regulatory consents and approvals.

Further information regarding these risks may be found under "Risk Factors" in the Corporation's Annual Information Form.

INTERNAL CONTROLS AND PROCEDURES

Our Chief Executive Officer and Vice President Finance have evaluated the effectiveness of our disclosure procedures and internal control over financial reporting as defined in Rule 13a – 15 under the U.S. Securities Exchange Act of 1934 and as defined in Canada under National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Strategic have concluded that, as at December 31, 2011, our disclosure controls and procedures and internal control over financial reporting were effective.

Further information with respect to the Corporation can be found on its website at www.sogoil.com and on the SEDAR website: www.sedar.com.