Management's Discussion and Analysis

Six months ended June 30, 2011

August 10, 2011

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 six month period ended June 30, 2011 is the second interim period for which the Corporation has prepared its financial statements under International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board.

Financial and Operations Overview

For the six months ended June 30, 2011 and 2010

(thousands of dollars except per share amounts and shares outstanding)

	2011 **$**	2010 $
Funds from operations *	**(1,089)**	(472)
Per share – basic	**(0.01)**	(0.01)
Net Income (loss)	**(7,058)**	(2,211)
Per share – basic	**(0.05)**	(0.03)
Average production (boe/d)	**837 boe/d**	291 boe/d
Capital expenditures		
Land and seismic	**7,902**	2,877
Drill and complete	**7,333**	685
Property acquisitions	**---**	---
Equipment, facilities and other	**3,296**	36
	18,531	3,598
Common shares o/s at period-end (000's)	**139,009**	69,996

** before changes in non-cash capital*

HIGHLIGHTS

- Strategic was forced to shut-in approximately 600 bopd of its 800 bopd of crude oil production from Steen River in late April, 2011 as a result of a leak and subsequent shut down of the Rainbow pipeline in northern Alberta.

- A net loss of $7,058,000 was recorded in the period.

- Spent $18.5 million on the capital expenditure program in the six months ended June 30, 2011, primarily at Steen River and Maxhamish.

- Steen River winter program was continued and included:

    - Completed and tied in two successful Keg River oil wells at Marlowe North (8-22 and 10-22)
    - Completed an all year access road to core areas of Marlowe North
    - Completed a $3.4 million 3-D and 2-D seismic program at Marlowe North

- Committed to a drilling rig from Akita Drilling Ltd. from August 15, 2011 to April, 2012 for use primarily at the Steen River area.

- Acquired an additional 43 sections (11,008 hectares) of 100% working interest land in the North and West Marlowe areas of Steen River. These lands were acquired for an average of $250 per hectare and are contiguous to Strategic's current Steen River landholdings.

- Acquired 58 sections of land in in a new area of interest in northwest Alberta with multi-zone oil potential.

- Completed an all season road and well pads with its partner at Maxhamish. The all season infrastructure will facilitate drilling, completion and production operations through most of the year.

- Commenced drilling program at Maxhamish in July, 2011.

- Line of credit increased from $5.0 million to $21.0 million, reflecting the increased reserve base from the Steen River acquisition and the subsequent workover and drilling program.

- Finalized a drilling plan for Steen River for the next six months, with drilling anticipated to commence in late August, 2011.

ADVISORIES

The following Management Discussion and Analysis ("MD&A") of financial results is dated August 10, 2011 and is to be read in conjunction with the accompanying unaudited interim consolidated financial statements and related notes for the period ended June 30, 2011 and the audited consolidated financial statements and related notes and MD&A for the year ended December 31, 2010. The interim consolidated financial statements have been prepared in accordance with International Accounting Standard 34 "Interim Financial Reporting Standards" ("IFRS"). Previously the Corporation prepared its interim and annual consolidated financial statement in accordance with Canadian generally accepted accounting principles ("previous GAAP").

The calculation of barrels ("bbl') of oil equivalent ("boe") is based on a relative energy content conversion of six thousand cubic feet ("mcf") of natural gas to one equivalent barrel of oil (6 mcf=1bbl) when measured at burner tip and does not represent a value equivalency at the wellhead. Production volumes reported are the Corporation's interest before royalties, unless otherwise stated, and all amounts are expressed in Canadian dollars, unless otherwise stated.

Certain financial measures referred to in this discussion, such as funds from operations are not prescribed by IFRS or the previous Canadian GAAP in Canada, so are considered non-GAAP measures. Funds from operations represents cash generated from operating activities before changes in non-cash working capital and asset retirement expenditures. The Corporation considers funds from operations a key measure that demonstrates the ability to generate cash to fund expenditures.

Management believes that in addition to net earnings, funds from operations is a useful supplemental measure to assess the financial performance and the ability of Strategic to finance future growth through capital investment. In addition, management uses netback to analyze operating performance and leverage. Netback equals total revenue less royalties, operating costs and transportation costs calculated on a per boe basis.

The adoption of IFRS has not had a material impact on the corporation's operations, strategic decisions and cash flow. Further information on the IFRS impacts is provided in the International Financial Reporting Standards Section of the MD&A including reconciliations between previous GAAP and IFRS net loss and other financial metrics.

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 an 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 six months ended June 30, 2011 showed an increase in volumes over the comparable period in 2010. Average daily sales volume increased by 188% to 837 boe/d in 2011 versus 291 boe/d in 2010. Revenues also increased by 240% to $10,168,744 for 2011 versus $2,987,813 in 2010. The increase was the result of the acquisition of Steen River assets on December 22, 2010, successful winter 2010 drilling program, and a significant recovery in crude oil prices over the first half of 2011. The Corporation realized an average of $66.28 per boe versus $56.65 per boe in 2010 which is an increase of 17%.

For the three months ended June 30, 2011, average daily production was 884 boe/d versus 790 boe/d for the first quarter of 2011, an increase of 12%. Revenues for the second quarter of 2011 were $5,500,351 versus $4,613,816 in the first quarter of 2011. The increase in production and revenues is a result of production increase arising from the winter drilling program.

For the six months ended June 30, 2011, the Corporation had a net loss of $7,057,632 or $0.05 per share as compared to a net loss of $2,211,494 or $0.03 per share for the six months ended 2010. The increase in the net loss in 2011 was mainly attributed to the shut-in production from the Rainbow pipeline, higher operating costs from Steen River properties as well as stock based compensation expense of $2,657,400 as a result of the issuance of stock options in the first half of 2011. Negative funds from operations for the six months ended June 30, 2011 was $1,089,512 as compared to $472,218 for the six months ended June 30, 2010. The Corporation's increased production upon recommencement of the Rainbow pipeline will provide for positive funds from operations.

The winter drilling and workover program allowed Strategic to record April production of over 1,200 boe/d. However, a pipeline leak in late April, 2011 shut down the Rainbow pipeline, which transports the Corporation's Steen River crude oil to market. Strategic has been forced to shut-in approximately 600 bopd of its 800 bopd production at Steen River as a result. This has impacted significantly the Corporation's sales volumes in the second quarter and will continue to impact sales until recommencement of the pipeline. The start-up date of the pipeline is not know at this time. Strategic is reviewing alternatives to transport its Steen River liquids to market.

Strategic drilled, completed and tied-in two 100% working interest Keg River oil wells in mid-April. The 103/10-22-122-21 W5M vertical well was drilled to a depth of 1131 metres and encountered 17 metres of gross pay in the Keg River. The first 30 days of production averaged 311 bopd of 34° API oil.

The 100/08-22-122-21W5M vertical well was drilled to a depth of 1108 metres and encountered 7 metres of gross pay in the Keg River. The first 30 days of production averaged 50 bopd of 34° API oil. The Keg River in 08-22 was found to be a separate accumulation with a 3 metre lower water oil contact.

During June, 2011, Strategic was successful in acquiring Crown lands in the Steen River area of northwest Alberta. Strategic acquired 43 sections of 100% owned land (11,008 hectares) contiguous to the current Marlowe North and Marlowe West oil production in the Steen River area. Lands include all rights to key zonal targets including hydrocarbon bearing zones in the Slave Point, Sulphur Point, Muskeg Dolomite and Keg River. Strategic paid approximately $250 per hectare for these lands.

At Maxhamish, the 2011 development program is proceeding. Strategic with its operating partner Legacy Oil + Gas Inc., completed an all-weather road including well pads in early July, 2011. The all season infrastructure will facilitate drilling, completion and production operations through most of the year. Drilling operations commenced in July with up to 4 multi-frac horizontal wells to be drilled by the fourth quarter

During the second quarter, the Corporation's primary lender, Alberta Treasury Branches ("ATB) approved an increase to its available revolving operating line of credit from $5,000,000 to $21,000,000 effective May 31, 2011. The terms are similar to previous terms. The increased revolving operating line of credit will be available for future capital expenditures in Canada or for general corporate purposes.

OUTLOOK FOR 2011

Maxhamish
At Maxhamish, Phase II of the development program is proceeding. This includes drilling up to four horizontal multi-frac wells in 2011.

The A-D18-J well spud on July 18. This horizontal well has been drilled to a measured depth of 3,165 metres and a vertical depth of 1,680 metres into the Chinkeh zone. The well will then be fracture stimulated and production tested. This is expected to occur before the end of the third quarter. The plan then allows for an additional two or three wells to be drilled and fracced in 2011.

Steen River, northwest Alberta
Strategic is positioned to drill and test up to three separate hydrocarbon accumulations beginning in the third quarter of 2011. Strategic's technical team has analyzed a significant amount of data to identify the productive potential of the lands in the area, including:

- A detailed regional geological study of the area, including Keg River, Muskeg Dolomite, Slave Point and the Sulphur Point;
- Tests on current productive shut-in and producing wells for Sulphur Point, Muskeg Dolomite and Keg River potential;
- Engineering review of logs for all wells in a 50 km radius; and
- Geophysical interpretation of the recently shot and processed 2-D and 3-D seismic, as well as other proprietary seismic.

Strategic has signed an agreement with Akita Drilling Ltd. to secure a drilling rig from August 15, 2011 to April 2012. Strategic plans to drill up to four wells in the remainder of 2011 with the first well expected to spud in late August. The first wells will include a combination of horizontal Sulphur Point oil tests and vertical Keg River wells. Additional drilling will follow in early 2012.

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

i) it is financed with a working capital balance of $3.5 million at the end of the second quarter and a $21 million line of credit;
ii) ongoing drilling program at Maxhamish, with over 100 sections of land;
iii) over 100 sections of undeveloped land at Steen River, an area with proven light oil potential; and
iv) politically and fiscally stable environment.

IMPACT OF CURRENT ECONOMIC VOLATILITY AND UNCERTAINTY

Crude oil prices have increased through the early months of 2011, and the Corporation was able to raise over $46 million equity in the previous year. The Corporation is therefore in a strong position to undertake its planned capital expenditures program. In addition, the Corporation has recently announced an increase in its line of credit with a Canadian financial institution from $5.0 million to $21.0 million. 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 2011.

RISK FACTORS

The reader is referred to the Management, Discussion and Analysis for the year ended December 31, 2010 as filed on SEDAR. Additional risk factors may also be found on page 12 of this Management Discussion and Analysis under "Financial Instruments".

RESULTS OF OPERATIONS

Production

Periods ended June 30	Three months		Six months	
	2011	2010	**2011**	2010
Oil, condensate, & ngls – bbls/d	**531**	226	**548**	206
Natural gas – mcf/d	**2,116**	535	**1,739**	509
Boe/d	**884**	315	**837**	291

Production for 2011 for the six months ended June 30, 2011 averaged 837 boe per day consisting of 1,739 mcf per day of natural gas, 548 bbls per day of crude oil and ngl's. Production during the period was 188% higher than the same period in 2010 of 291 boe per day. The increase can be attributed to the acquisition of Steen River assets on December 22, 2010, and a successful winter drilling program in the Steen River area.

The winter drilling and workover program allowed Strategic to record April production of over 1,200 boe/d. However, a pipeline leak in late April, 2011 shutdown the Rainbow pipeline, which transports the Corporation's Steen River crude oil to market. Strategic has shut-in approximately 600 bopd of its 800 bopd production at Steen River. The start-up date is not known, but this has impacted significantly the Corporation's sales volumes in the second quarter and will continue to impact sales until recommencement of the pipeline. The Corporation is reviewing alternatives to transport its Steen River liquids to market

The Corporation's production portfolio for the quarter was weighted 35% to natural gas and 65% to crude oil and natural gas liquids.

Revenue

Periods ended June 30	Three months		Six months	
	2011 $	2010 $	**2011 $**	2010 $
Sales				
Oil, condensate, and ngls	**4,644,537**	1,099,150	**8,777,284**	2,539,180
Natural gas	**787,698**	194,099	**1,268,847**	440,676
	5,432,235	1,293,249	**10,046,131**	2,979,856
Other revenue	**68,116**	4,923	**122,613**	7,957
Total sales	**5,500,351**	1,298,172	**10,168,744**	2,987,813
Average prices				
Oil and ngls ($/bbl)	**96.08**	64.80	**88.56**	68.05
Natural gas ($/mcf)	**4.09**	4.41	**4.03**	4.78
Oil equivalent ($/boe)	**67.54**	53.18	**66.28**	56.65

The average price realized for oil, condensate and ngls for the three months and six months of 2011 was $96.08 and $88.56 per bbl as compared to $64.80 and $68.05 per bbl for the same time frame in 2010 reflecting a 48% and 30% price increase respectively. For the three and six months ended June 30, 2011, the gas price was $4.09 and $4.03 per mcf as compared to $4.41 and $4.78 per mcf in the three and six months period ended June 30, 2010.

Overall, the combined price in the three and six months ended June 30, 2011 of $67.54 and $66.28 per boe is 27% and 17% higher than the combined prices of $53.18 and $56.65 per boe in the three and six months ended 2010. The increase in revenues is the result of an increase of 188% in production and 30% increase in realized prices for the six months ended June 30, 2011.

Royalties

Periods ended June 30	Three months		Six months	
	2011 **$**	2010 $	**2011** **$**	2010 $
Crown royalties	**1,150,036**	93,269	**2,301,384**	255,734
Freehold royalties	**8,145**	13,191	**28,126**	33,653
Overriding royalties	**146,715**	16,620	**251,940**	45,764
Net royalties	**1,304,896**	123,080	**2,581,450**	335,151
Per boe	**16.22**	5.08	**17.03**	6.37
Percentage of revenues	**24.0%**	9.6%	**25.7%**	11.2%

The Corporation recorded $1,304,896 of royalties during the second quarter of 2011 as compared to $123,080 for the same period in 2010. On a boe basis, the average royalty increased by 150% from 9.6% to 24% as the Steen River crude oil production attracts an average royalty rate of nearly 40% as it reaches the maximum rate under the new Alberta royalty framework. In comparison to the previous quarter of 2011, average royalty rate decreased from 27.7% to 24% as a result of the new royalty regime and new wells attracting a 5% royalty rate.

On March 3, 2009 the Alberta government announced incentives for the energy sector in response to the global economic slowdown. The incentives include a drilling royalty credit for new conventional oil and natural gas wells of up to $200 per meter drilled for wells spud on or after April 1, 2009 to June 30, 2011, and a maximum five percent royalty rate for the first year of production from new oil or gas wells brought on production after April 1, 1009, up to a maximum of 500,000 mcf of natural gas or 50,000 bbls of crude oil production.

On March 11, 2010, the Alberta government announced further changes to its royalty regime as a result of its "Competitiveness Review" which will take effect beginning January 1, 2011. The key changes are:

- the current incentive program of five percent for the first year of production on new natural gas and conventional oil wells will become permanent with the time and volume limits as currently stated;
- the maximum royalty rate for conventional oil will be reduced at higher price levels from 50 percent to 40 percent;
- the maximum royalty rate for conventional and unconventional natural gas will be reduced at higher price levels from 50 percent to 36 percent; and
- the transitional royalty framework will continue until its original announced expiration on December 31, 2013. However, effective January 1, 2011, no new wells will be allowed to select the transitional royalty rates.

Operating and transportation costs

Periods ended June 30	Three months		Six months	
	2011 **$**	2010 $	**2011** **$**	2010 $
Operating costs	**2,575,484**	757,577	**5,880,615**	1,406,283
Transportation costs	**153,626**	50,182	**299,995**	109,945
	2,729,110	807,759	**6,180,610**	1,516,228
Per boe				
Operating costs	**32.02**	31.27	**38.80**	26.73
Transportation costs	**1.91**	2.07	**1.98**	2.09
	33.93	33.34	**40.78**	28.82

The operating and transportation costs for the three and six months ending June 30, 2011 averaged $33.93 and $40.78 per boe compared to $33.34 and $28.82 per boe for similar time frames in 2010.

For the six months ending June 30, 2011, the net operating costs increased to $6,180,610 versus $1,516,228 for the equivalent period in 2010 due to the increased costs associated with the acquisition of Steen River assets as well as workover costs on oil and natural gas wells.

Operating costs on a boe basis averaged $40.78 per boe for the first six months of 2011 compared to $28.82 for the corresponding period in 2010. Strategic had anticipated these higher operating costs in the first half of 2011 arising from the integration of the Steen River assets. Costs were higher for several reasons:

i) reduced volumes of Steen River from the pipeline break and related high fixed cost components of the facility.
ii) winter operations inherently have higher costs due to annual maintenance and repair programs.
iii) a workover and optimization program was initiated much of which is non-recurring operating expense.

The Corporation has budgeted operating costs of less than $30.00 per boe for the remainder of 2011.

Exploration and Evaluation Expense

Periods ended June 30	Three months		Six months	
	2011 $	2010 $	**2011 $**	2010 $
Exploration and Evaluation *(1)*	**187,659**	49,100	**369,054**	49,100
Per boe	**2.3**3	2.03	**2.43**	0.93

Note (1): Exploration and Evaluation for the six months ended June 30, 2011 has been presented as a result of adopting IFRS with a transition date of January 01, 2010.

All exploratory costs incurred subsequent to acquiring the right to explore for oil and natural gas are capitalized as exploration and evaluation assets pending determination of technical feasibility and commercial liability. The costs included in exploration and evaluation expense generally include pre-license costs, undeveloped land and geophysical and geological costs. If the assets are subsequently determined to be technically feasible and commercially viable, the exploration costs are tested for impairment and then reclassified from exploration and evaluation assets to development and production assets. If exploratory costs are determined not to be technically feasible and commercial viable, the costs are expensed as exploration and evaluation expense.

For the six months ended June 30, 2011, the Corporation expensed exploration and evaluation costs of $369,054 compared to $49,100 for the similar timeframe in 2010..

Operating netbacks

Periods ended June 30	Three months		Six months	
	2011 $	2010 $	**2011 $**	2010 $
Per boe				
Revenues	**67.54**	53.38	**66.28**	56.65
Royalties	**(16.22)**	(5.08)	**(17.03)**	(6.37)
Operating costs	**(32.02)**	(33.30)	**(38.80)**	(27.67)
Transportation costs	**(1.91)**	(2.07)	**(1.98)**	(2.09)
Netback per boe	**17.39**	12.93	**8.47**	20.52

The operating netback of $17.39 per boe was higher than the first quarter of 2011 ($(1.61) per boe) and 35% higher compared to the second quarter of 2010. The increase in operating netback for the quarter ending June 30, 2011 from the quarter ending March 31, 2011 is mainly due to a decrease in operating costs and royalties primarily related to the Steen River properties. Significant components of the operating costs at Steen River are fixed and the higher revenue and production from the light crude oil will allow for significantly improved netbacks as the production increases at Steen River once the Rainbow pipeline is restarted.

General and administrative expenses

Periods ended June 30	Three months		Six months	
	2011 **$**	2010 $	**2011** **$**	2010 $
Wages and employee benefits	**527,739**	310,584	**1,073,993**	625,307
Professional fees	**85,767**	81,200	**149,581**	90,431
Consulting fees	**233,865**	171,719	**465,577**	304,283
Public reporting	**84,885**	39,982	**183,807**	75,558
Occupancy costs	**127,205**	74,333	**240,545**	159,955
Travel	**68,207**	33,041	**123,080**	61,766
Miscellaneous general and administrative	**66,347**	79,758	**130,758**	163,923
Total	**1,194,015**	790,617	**2,367,341**	1,481,223
Per boe	**14.84**	32.63	**15.62**	28.16

General and administrative expenses decreased by 55% for the three month period and 45% for the six month period on a boe basis for the periods ending June 30, 2011. Total general and administrative costs increase to $1,194,015 and $2,367,341 for the three and six months ending June 20, 2011 from $790,617 and $1,481,223 for the same period. The overall costs increased due to staffing increases and consulting costs associated with higher activity levels arising from the Steen River acquisition. The cost per boe is anticipated to drop in the remainder of 2011, reflecting higher production volumes.

Finance Expense

Periods ended June 30	Three months		Six months	
	2011 **$**	2010 $	**2011** **$**	2010 $
Interest expense – bank loan	**20,316**	24,862	**33,724**	64,330
Interest expense – debenture	**42,640**	-	**84,927**	-
Accretion expense *(1)*	**54,744**	31,670	**106,061**	64,718
Total	**117,700**	56,532	**224,712**	129,048
Per boe	**1.46**	2.33	**1.48**	2.45

Note (1): Accretion for the six months ended June 30, 2010 was restated and reclassified for the effect of adopting IFRS.

Finance expenses increased to $117,700 for the three months period and $224,712 for the six months period ended June 30, 2011. Interest expense decreased in the second quarter of 2011 compared to the same period in 2010 due to lower debt levels. Interest on the debenture was due to the assumption of debt as part of the acquisition of Steen River.

Accretion represents the change in time value of the decommissioning liability. Accretion expense increased for the six months ended June 30, 2011 compared to the same period of 2010 due to new obligations from wells drilled, and the acquisition of crude oil and natural gas assets. The underlying liability may increase over a period based on new obligations incurred from drilling wells, constructing facilities, acquiring operations or adjusting future estimates of timing or amounts. Similarly this obligation can be reduced as a result of abandonment work undertaken and reducing future obligations.

Stock based compensation

Stock based payments are non-cash charges which reflect the estimated value of stock options issued to directors and employees of Strategic. The value of the award is recognized as an expense over the period from the grant date to the date of vesting of the award.

For the period ended June 30, 2011, the Corporation recorded $2,657,400 of expense from the issuance of 3,125,000 common share options which were issued in January, 2011 and vested immediately.

Depletion, depreciation and accretion

Periods ended June 30	Three months		Six months	
	2011 **$**	2010 $	**2011** **$**	2010 $
Depreciation, depletion, and amortization *(1)*	**2,132,968**	449,302	**3,891,546**	954,056
Per boe	**24.72**	18.54	**25.67**	18.14

Note (1): Depletion and depreciation for the six months ended June 30, 2010 was restated for the effect of adopting IFRS.

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 six months ended June 30, 2011 increased by 308% to $3,891,546 compared to the same period in 2010 at $954,056. On a boe basis, the costs increased by 42% to $25.67 compared to $18.14 for the six months ending June 30, 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.

Funds from operations and net income (loss)

Periods ended June 30	Three months		Six months	
	2011 **$**	2010 $	**2011** **$**	2010 $
Funds (used in) from operations*(1)*	**205,288**	(510,079)	**(1,089,512)**	(472,218)
Per share				
basic	**0.00**	0.00	**(0.01)**	(0.01)
diluted	**0.00**	0.00	**(0.01)**	(0.01)
Net income (loss)*(1)*	**(2,166,533)**	(985,893)	**(7,057,632)**	(2,211,494)
Per share				
basic	**(0.02)**	(0.01)	**(0.05)**	(0.03)
diluted	**(0.02)**	(0.01)	**(0.05)**	(0.03)

Note (1): Funds from operations and net income for the six months ended June 30, 2010 were stated and reclassified for the effect of adopting IFRS.

The increase in funds from operations for the second quarter of 2011 is attributable to the higher production and revenues offset by higher operating and general and administrative expenses. The Corporation generated a net loss for the second quarter of 2011 of $2,166,533 compared to $995,893 during the three months ended June 30, 2010. The increase in net loss is the result of increase in operating expenses, general and administrative costs and depreciation and amortization expense in 2011.

Capital Expenditures

Periods ended June 30	Three months		Six months	
	2011 **$**	2010 $	**2011** **$**	2010 $
Drilling and completions	**1,751,269**	53,789	**7,913,605**	684,992
Facilities	**857,669**	19,764	**3,276,862**	21,633
Other	**7,116**	11,731	**19,687**	14,562
	2,616,054	85,284	**11,210,154**	721,187
Drilling incentive credits	**(464,960)**	-	**(581,274)**	-
Total Property, plant and equipment	**2,151,094**	85,284	**10,628,880**	721,187
Land and seismic	**4,458,259**	1,320,861	**7,902,267**	2,877,226
Total exploration and evaluations	**4,458,259**	1,320,861	**7,902,267**	
Total net capital expenditures	**6,609,353**	1,406,145	**18,531,147**	3,598,413

The Board of Directors of the Corporation has approved a 2011 capital budget of $37 million, prior to consideration of any acquisitions.

Capital spending in the second quarter of 2011 was significantly higher than the second quarter of 2010 due to the following activities:

- Participation in two new wells (2.0 net) at Steen River
- Recompletions/workovers at Steen River
- Construction of an all-weather access road to the 10-22 pad at Steen River
- Completion of a $3.4 million 3-D and 2-D seismic program at Steen River

- Construction of an all year access road and drilling pads at Maxhamish
- Land acquisitions in northwest Alberta

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.

SUMMARY OF QUARTERLY FINANCIAL DATA

The following table summarizes quarterly financial results:

Quarter ended	Jun-11 $	Mar-11 $	Dec-10 $	Sep-10 $	Jun-10 $	Mar-10
Petroleum and natural gas sales	5,432,234	4,891,099	1,639,921	1,504,357	1,293,250	1,686,606
Income (loss)	(2,166,533)	(4,684,099)	3,091,917	(1,219,336)	(985,892)	(682,392)
Income (loss) per share Basic Diluted	 (0.05) (0.05)	 (0.04) (0.04)	 .03 .03	 (0.02) (0.02)	 (0.02) (0.02)	 (0.01) (0.01)
Production boe/d	884	790	317	314	266	315
Average price/boe	67.54	64.85	56.21	52.08	53.38	59.44

LIQUIDITY AND CAPITAL RESERVES

The Corporation started 2011 with working capital of $25,286,239 including the debentures. During the first half of 2011, negative funds of $1,089,512 were generated from operations and $18,531,147 was expended on capital projects. The Corporation has a working capital surplus of $3,503,373 at June 30, 2011, which includes $8,777,269 of cash in the bank.

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:

	June 30, 2011 **$**
Current assets	**13,325,869**
Accounts payable and accrued liabilities	**(6,397,273)**
Debentures	**(3,425,225)**
Net working capital surplus	**3,503,373**
Total line of credit	**21,000,000**
Year end loan balance	**0**
Unutilized line of credit	**21,000,000**
Net available funds	**24,503,373**

The Corporation is currently projecting its remaining 2011 capital program to be in the range of $13 million, and expects the current funds available, line of credit plus cash flow will be able to fund it.

The valuation 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 working capital ratio of not less than 1:1, but for the purposes of the ratio calculation the unused portion of the facility is included in current assets, and the current portion of the debt is excluded from current liabilities. As at June 30, 2011, this ratio was 5.4:1. In June, the Corporation signed an agreement to increase its line of credit with its financial institution to $21 million under the same terms and conditions as the current loan.

SHARE DATA

At August 10, 2011 Strategic had 139,009,068 common shares, and 6,688,333 stock options with a weighted average exercise price of $0.80 per share outstanding. All warrants were exercised during the period.

Common Shares
Authorized:

Unlimited number of common shares without par value

Issued:	**Number of shares**	**$**
Balance, December 31, 2010	**138,555,366**	**83,374,222**
Warrants exercised	370,370	100,000
Options exercised	83,332	31,249
Fair value of options and warrants exercised		49,935
Share issue costs		(6,205)
Balance, June 30, 2011	**139,009,068**	**83,547,201**

During the period ending June 30, 2011, 370,370 warrants were exercised for proceeds of $100,000 and 83,332 stock options were exercised for proceeds of $31,249. The fair value adjustment of these warrants and options of $47,835 was recorded and deducted from contributed surplus.

Stock options
The following table reconciles the changes to the Corporation's stock options for the six months ended June 30, 2011:

	Number of options	**Exercise Price $**
Balance – December 31, 2010	**3,846,667**	**0.59**
Issued	3,125,000	1.10
Exercised	(83,334)	.38
Expired	(200,000)	1.60
Balance – June 30, 2011	**6,688,333**	**0.80**

In January, 2011, 3,125,000 common share options were issued with an exercise price of $1.10 per share expiring in five years from date of issue, and vested immediately. The fair value of the options were calculated using the Black-Scholes model using an expected volatility of 102.4%, interest rate of 2.6%, estimated forfeiture rate of 8.2%, expected life of 5 years and no expected dividends resulting in $2,657,400 of stock-based compensation.

The following table sets out the outstanding options as at June 30, 2011:

All stock options, issued and exercisable		
Number of Options	**Exercise price**	**Weighted Average Life (yrs)**
660,001	$0.25	2.70
1,193,332	$0.50	3.11
1,275,000	$0.65	3.54
435,000	$0.75	2.70
3,125,000	$1.10	4.52
6,688,333	**$0.80**	**3.79**

Warrants
All 370,370 warrants were exercised during the period for total proceeds of $100,000.

TRANSACTIONS WITH RELATED PARTIES

Legal fees and expenses in the amount of $82,566 ($62,596 – June 30, 2010) 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 $12,065 ($17,018 – June 30, 2010) were incurred to a director for geophysical consulting services. Software charges of $60,000 ($nil – June 30, 2010) were charged to a company controlled by an officer. Accounts payable and accrued liabilities at June 30, 2011 include $15,181 ($45,921 – June 30, 2010) 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	**$**
2011	176,298
2012	292,596
2013	263,213
	732,107

b) Pursuant to the issues of flow through shares on October and December 2010, the Corporation is committed to incur prior to December 31, 2011, a total of $11,448,250 on qualifying expenditures. As at June 30, 2011, $7,087,348 has been incurred toward this commitment.

FINANCIAL INSTRUMENTS

The Corporation's financial instruments consist of cash and cash equivalents, short term investments, trade and other receivables, accounts payable and accrued liabilities, bank loan, and debentures. The carrying value approximates fair value due to the immediate or short term maturity of these instruments.

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.

i) Commodity Price Risk

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 June 30, 2011, the Corporation had no hedging contracts. The following table analyses the Corporation's cash flow sensitivity to commodity price changes.

	June 30, 2011 **$**	June 30, 2010 $
10% change in oil price	**629,277**	224,825
10% change in gas price	**117,191**	39,174

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 June 30, 2011, if interest rates had increased by 1% with all other variables held constant, net income would have decreased by $nil (2010 – decrease $4,882) as the outstanding debt has a fixed rate of interest.

iii) Foreign exchange risk

Although the Corporation's product revenues are denominated in Canadian dollars, the underlying market prices are affected by the exchange rate between the Canadian and United States dollar. As at June 30, 2011, 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 believes that it has access to sufficient capital through internally generated cash flows, external equity sources, and undrawn committed borrowing facilities to meet current spending forecasts. All of the corporation's liabilities mature in 2011 as the Corporation's accounts payable are due in demand. There was no loan balance at June 30, 2011, 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 accounts receivable are with customers and joint venture partners in the oil and gas industry and the Government of Canada for GST refunds, and are subject to normal credit risks. The Corporation's production is predominately sold by taking its product in kind and revenues are collected on the 25th day of the month following the month of production. The majority of the remaining balances of account receivable are from joint venture partners which are collected between two and four months after the production month. As at June 30, 2011, the Corporation's receivables were as follows:

	June 30, 2011 **$**
Joint venture partners	191,898
Petroleum and natural gas marketers	1,096,658
Other	2,312,083
Prepaid expenses	947,961
Total accounts receivable	**4,548,600**

As at June 30, 2011, the aging analysis of trade receivables, excluding prepaid expenses, is as follows:

	June 30, 2011 **$**
Current	1,345,782
30 – 60 days	73,166
60 – 90 days	510,367
Greater than 90 days	1,671,324
Total	**3,600,639**

At June 30, 2011, the amount receivable for Alberta Crown Royalties was $844,590 and steps are being taken to recover this balance. The balance is fully recoverable from future natural gas royalties.

CRITICAL ACCOUNTING ESTIMATES

A summary of the Corporation's significant accounting policies is contained in *Note 3* to the condensed unaudited 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 the 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 arms 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
Total future decommissioning liabilities are estimated based on the Corporation's net working interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in the future periods. These costs are expected to be incurred over a range up to 22 years, depending on the estimated reserve life. The undiscounted amount of the estimated costs at June 30, 2011 were $14,379,750 (December 31, 2010 - $15,459,560). The estimated costs have been discounted at a risk free rate of 3.47% (December 31, 2010 – 3.51%) and an inflation rate of 2% at June 30, 2011 (December 31, 2010 – 2%).

Stock based compensation
The Corporation has a stock option plan under which officers, directors and employees are eligible to receive stock options. The Corporation may reserve for issuance under the plan up to 10% of the issued and outstanding common shares. Options granted under the plan generally have a term of five years and vest at terms to be determined by the directors. Vesting terms have varied between a three year vesting period and all options vesting immediately.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

The Corporation's IFRS accounting policies are approved in *Note 3* to the condensed interim consolidated financial statements. In addition, *Note 18* to the interim consolidated financial statements present reconciliations between the Corporation's 2010 previous GAAP results and its 2010 results under IFRS. The reconciliations include the consolidated statement of financial positions as at January 1, 2010, June 30, 2010 and December 31, 2010 and consolidated statements of earnings and comprehensive income and cash flows for the six months ended June 30, 2010 and year ended December 31, 2010. The following discussion explains the significant difference between IFRS and the Previous GAAP followed by the Corporation.

a) Property, plant and equipment

Under Previous 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 Previous 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 Previous 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 previous 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 previous 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 Previous 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 Previous 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.

On transition of IFRS on January 1, 2010, the Corporation used certain exemptions allowed under IFRS 1 First Time Adoption of International Reporting Standards. These exemptions used were as follows:

i) **Shared-Based Compensation** – IFRS I allows an entity an exemption on IFRS 2, "Share-Based Payments" to equity instruments which vest before the Corporation's transition date to IFRS.

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.

International Financial Report Standard 9, Financial Instruments ("IFRS 9")

IFRS 9, as issued reflects the first phase of the IASB's work on the replacement of IAS 39 and applies to classification and measurement of financial assets and liabilities as defined in IAS 39. The standard is effective for annual periods beginning on or after January 1, 2013. The adoption of IFRS 9 is not expected to have a significant impact on the financial statements.

In May 2011, the IASB issued the following standards which have not yet been adopted by the Company: IFRS 10, Consolidated Financial Statements ("IFRS 10"); IFRS 11, Joint Arrangements ("IFRS 11"); IFRS 12, Disclosure of Interests in Other Entities ("IFRS 12"); IAS 27, Separate Financial Statements ("IAS 27"); IFRS 13, Fair Value Measurement ("IFRS 13"); and, amended IAS 28, Investments in Associates and Joint Ventures ("IAS 28"). The following provides a summary of selected standards:

IFRS 10

IFRS 11 requires an entity to consolidate an investee when it is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Under existing IFRS, consolidation is required when an entity has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. IRFS 10 replace SIC-12 Consolidation-Special Purpose Entities and parts of IAS 27-Consolidated and Separate Financial Statements.

IFRS 11

IFRS 11 requires a venture to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation the venture will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. Under existing IFRS, entities have the choice to proportionately consolidate or equity account for interest in joint ventures. IFRS 11 supersedes IAS 31 – Interests in Joint Ventures and SIC-13 – Jointly Controlled Entities, Non-Monetary Contributions by Venturers.

IFRS 12

IFRS 12 establishes disclosure requirements for interest in other entities, such as joint arrangements, associates, special purpose vehicles and off balance sheet vehicles. The standard carries forward existing disclosures and also introduces significant additional disclosure requirements that address the nature of, and risks associated with, an entity's interest in other entities.

IFRS 13

IFRS 13 is a comprehensive standard for fair value measurement and disclosure requirements for use across all IFRS standards. The new standard clarifies that fair value is the price that would be received to sell an asset, or paid to transfer a liability in an orderly transaction between market participants, at the measurement date. It also establishes disclosure about fair value measurement. Under existing IFRS, guidance on measuring and disclosing fair value is dispersed among the specific standards requiring fair value measurement and in many cases does not reflect a clear measurement basis or consistent disclosures.

Each of the new standards is effective for annual periods beginning on or after January 1, 2013 with early adoption permitted. The Company has not yet assessed the impact if any, that the new and amended standards will have on its financial statements or whether to early adopt any of the new requirements.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures have been designed to provide reasonable assurance that information required to be disclosed by the Corporation is recorded, processed, summarized and reported within the time periods specified under the Canadian securities law. The Corporation's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation, that the disclosure controls and procedures as of the end of June 30, 2011, are effective and provide reasonable assurance that material information related to the Corporation is made known to them by others within the Corporation.

The Corporation's Chief Executive Officer and Chief Financial Officer are responsible for establishing and maintaining internal controls over financial reporting ("ICFR"). They have, as at the quarter ended June 30, 2011, designed ICFR or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposed in accordance with IFRS. The control framework of the Corporation's officers used to design the ICFR is the Internal Control – Integrate Framework issued by the Committee of Sponsoring Organizations.

The Corporation's Chief Executive Officer and Chief Financial Officer are required to disclose any change in the internal controls over financial reporting that occurred during our most recent interim period that has materially affected, or is reasonably likely to affect, the Corporation's internal controls over financial reporting. No material changes in the internal controls were identified during the period ended June 30, 2011 that have materially affected, or are reasonably likely to materially affect our internal controls over financial reporting.

It should be noted that a control system, including the Corporation's disclosure and internal controls and procedures, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objective of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

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.