Management's Discussion and Analysis

Nine months ended September 30, 2011

November 14, 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 nine month period ended September 30, 2011 is the third 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 nine months ended September 30, 2011 and 2010

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

	2011 **$**	2010 $
Funds from operations *	**(79)**	(704)
Per share – basic	**(0.00)**	(0.01)
Net Income (loss)	**(8,453)**	(3,431)
Per share – basic	**(0.06)**	(0.05)
Average production (boe/d)	**863 boe/d**	298 boe/d
Capital expenditures		
Land and seismic	**8,066**	3,919
Drill and complete	**23,516**	2,466
Equipment, facilities and other	**1,800**	39
	33,382	6,424
Common shares o/s at period-end (000's)	**139,009**	69,758

** before changes in non-cash capital*

HIGHLIGHTS

- Production in the quarter increased by 221% to 914 boe/d compared to 285 boe/d in the third quarter of 2010.

- Cash Flow from operations in the quarter increased to $1,010,818 compared to negative cash flow of $232,609 in the third quarter of 2010.

- Production of approximately 600 boe/d previously shut-in from Steen River due to a breach in the Rainbow pipeline resumed in early September 2011.

- Capital of $33.4 million spent in the nine months ended September 30, 2011, primarily at Steen River and Maxhamish.

- Capital expenditures during the quarter included:

    - Drilling and casing a horizontal well in the Sulphur Point Dolomite at 102/11-22-122-21 W5M.
    - Drilling operations for a Keg River vertical well target at 100/15-22-122-21 W5M.
    - 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.
    - Upgrading and maintenance of the all weather access road at Steen.

- Acquired, processed, and interpreted 3D seismic at North Marlow. Completed interpretation of 2D and 3D seismic at Lessard.

- Commenced a geological and geophysical workup on 58 sections of land in a new area of interest in northwest Alberta with multi-zone oil potential.

ADVISORIES

The following Management Discussion and Analysis ("MD&A") of financial results is dated November 14, 2011 and is to be read in conjunction with the accompanying unaudited interim consolidated financial statements and related notes for the period ended September 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 nine months ended September 30, 2011 showed an increase in volumes over the comparable period in 2010. Average daily sales volume increased by 190% to 863 boe/d in 2011 versus 298 boe/d in 2010. Revenues also increased by 240% to $15,246,528 for 2011 versus $4,484,213 in 2010. The increase was the result of the acquisition of Steen River assets on December 22, 2010, a successful winter 2010 drilling program, and an increase in crude oil prices over the nine months of 2011. The Corporation realized an average of $64.69 per boe versus $55.03 per boe in 2010 which is an increase of 18%.

For the three months ended September 30, 2011, average daily production was 914 boe/d versus 884 boe/d for the second quarter of 2011, an increase of 3%. Revenues for the third quarter of 2011 were $5,274,814 versus $5,500,351 in the second quarter of 2011. Despite a shutdown of production at Steen River due to the Rainbow pipeline failure, production improved between the September 2011 and the June 2011 quarters.

For the nine months ended September 30, 2011, the Corporation had a net loss of $8,452,829 or $0.06 per share as compared to a net loss of $3,430,829 or $0.05 per share for the nine 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 $2,686,356 as a result of the issuance of stock options during the nine months of 2011. Negative funds from operations for the nine months ended September 30, 2011 was $78,694 as compared to $704,827 for the nine months ended September 30, 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 on September 3rd allowed Strategic to return to full production of 1200 boe/d.

Strategic commenced its third and fourth quarter well 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 will continue 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 100/15-22-122-21W5 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. Strategic successfully completed the well in November, 2011.

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 facilitated drilling, completion and production operations which commenced July 18, 2011 with the spudding of AD18J. The AD18J and B19J horizontal wells were drilled to total depths of 3222mMD and 3550mMD respectively. The AD18J well was successfully multistaged fracced and went on production October 29, 2011. At the time of this report the B19J well was undergoing completion activities.

OUTLOOK FOR 2011

Maxhamish
At Maxhamish, Phase II of the development program is proceeding. Following the successful tests at AD18J and B19J, the 2012 drilling program will be finalized with our partner.

Steen River, Northwest Alberta
Strategic drilled two wells in the third quarter. The drilling program is ongoing and Strategic intends to drill 2 to 3 additional wells before the end of the fourth quarter. Additional work in the Steen River area into the Q1 2012 will consist of:

- Drilling and testing of up to 5 wells for Keg River and Sulphur Point Targets,
- Additional 2-D seismic lines in the North and West Marlowe Areas,
- The expansion of oil handling facilities at Strategics' wholly owned 9-17-122-20 Steen River Facility.

Strategic signed an agreement with Akita Drilling Ltd. to secure a drilling rig from August 15, 2011 to April 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;

IMPACT OF CURRENT ECONOMIC VOLATILITY AND UNCERTAINTY

Crude oil prices have remained strong through 2011, and the Corporation has undertaken all of its planned expenditures as previously disclosed. In addition to the capital expenditures incurred, the Corporation expects a significant increase in reserve additions for the 2011 year. Strategic expects that the credit facility will be further increase at the next annual review. 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 the remainder of 2011 and 2012.

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 September 30	Three months		Nine months	
	2011	2010	**2011**	2010
Oil, condensate, & ngls – bbls/d	**565**	205	**564**	215
Natural gas – mcf/d	**1,916**	482	**1,799**	500
Boe/d	**914**	285	**863**	298

Production in the third quarter of 2011 increased by 221% to 914 boe/d compared with the same period in 2010 to 285 boe/d. The increase was primarily due to the acquisition of Steen River assets on December 22, 2010, and a successful drilling program which was partially offset by the impact of the Plains Rainbow pipeline outage from April through August 2011.

In the nine months of 2011, production increased by 190% to 863 boe/d compared with the same period in 2010 to 298 boe/d, primarily due to the same factors impacting the third quarter.

The Corporation's production portfolio for the quarter was weighted 38% to natural gas and 62% to crude oil and natural gas liquids.

Revenue

Periods ended September 30	Three months		Nine months	
	2011 **$**	2010 $	**2011** **$**	2010 $
Sales				
Oil, condensate, and ngls	**4,510,611**	1,346,864	**13,292,295**	3,886,044
Natural gas	**689,786**	157,493	**1,954,233**	598,169
	5,200,397	1,504,357	**15,246,528**	4,484,213
Other revenue	**74,417**	3,238	**197,030**	11,195
Total sales	**5,274,814**	1,507,595	**15,443,558**	4,495,408
Average prices				
Oil and ngls ($/bbl)	**82.42**	62.66	**86.40**	66.08
Natural gas ($/mcf)	**3.91**	3.55	**3.98**	4.38
Oil equivalent ($/boe)	**61.83**	52.08	**64.69**	55.03

Production revenues for the third quarter of 2011 increased 246% to $5,200,397 when compared to $1,504,357 for the same period a year ago, largely due to higher production as well as higher realized prices. For the nine months of 2011, production revenues increased by 240% to $15,246,528 compared with the same period in 2010 to $4,484,213, primarily due to the same factors affecting the third quarter.

The average price realized for oil, condensate and ngls for the three months and nine months ended September 30, 2011 was $82.42 and $86.40 per bbl as compared to $62.66 and $66.08 per bbl for the same time frame in 2010 reflecting a 32% and 31% price increase respectively. For the three and nine months ended September 30, 2011, the gas price was $3.91 and $3.98 per mcf as compared to $3.55 and $4.38 per mcf in the three and nine months period ended September 30, 2010.

Overall, the combined price in the three and nine months ended September 30, 2011 of $61.83 and $64.69 per boe is 19% and 18% higher than the combined prices of $52.08 and $55.03 per boe in the three and nine months ended 2010. The increase in revenues is the result of an increase of 190% in production and 18% increase in realized prices for the nine months ended September 30, 2011.

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.

Periods ended September 30	Three months		Nine months	
	2011 **$**	2010 $	**2011** **$**	2010 $
Crown royalties	**621,580**	89,792	**2,922,964**	345,526
Freehold royalties	**35,405**	31,279	**63,531**	64,932
Overriding royalties	**80,714**	5,618	**332,654**	51,382
Net royalties	**737,699**	126,689	**3,319,149**	461,840
Per boe	**8.77**	4.39	**14.08**	5.67
Percentage of revenues	**14.2%**	8.4%	**21.8%**	10.3%

The Corporation recorded $737,699 (14.2% of revenue) of royalties compared to $126,689 (8.4% of revenues) for the same period in 2010. The increase is primarily due to increased production, partially offset by a lower royalty rate of 5% on new production and new crown royalty curves effective March 2011.

Royalty expense for the nine months ended September 30, 2011 increased to $3,319,149 (14.08% of revenue) compared to $461,840 (10.3% of revenue) in 2010 primarily due to increased production.

Operating and transportation costs

Periods ended September 30	Three months		Nine months	
	2011 **$**	2010 $	**2011** **$**	2010 $
Operating costs	**1,973,548**	804,415	**7,854,163**	2,210,699
Transportation costs	**189,274**	40,760	**489,269**	150,705
	2,162,822	845,175	**8,343,432**	2,361,404
Per boe				
Operating costs	**23.46**	27.85	**33.33**	27.13
Transportation costs	**2.25**	1.41	**2.08**	1.85
	25.71	29.26	**35.40**	28.98

Operating expenses for the three months ended September 30, 2011 increased 156% to $2,162,822 compared to $845,175 for the same period a year ago, and on a per boe basis decreased 13% to $25.71 per boe, from $29.26 per boe in the comparable period of 2010. The impact of higher operating costs in 2011 was partially offset by the effect of an increase in production volumes as well as increased costs associated with the integration of Steen assets.

For the nine months ended September 30, 2011 operating costs increased 253% to $8,343,432 compared to $2,361,404 for the same period a year ago and on a boe basis increased 22% to 35.40 per boe, from $28.98 per boe in the comparable period in 2010 for similar reasons as stated above.

The Corporation will continue to focus on controlling unit operating expenses in its core areas in 2011.

Exploration and Evaluation Expense

Periods ended September 30	Three months		Nine months	
	2011 **$**	2010 $	**2011** **$**	2010 $
Exploration and Evaluation *(1)*	**9,361**	14,706	**378,415**	63,806
Per boe	**0.11**	0.51	**1.61**	0.78

Note (1): Exploration and Evaluation for the nine months ended September 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 three and nine months ended September 30, 2011, $9,361 and $378,415 respectively compared to $14,706 and $63,806 for the same period on 2010 was charged directly to exploration expense for unsuccessful projects.

Operating netbacks

Periods ended September 30	Three months		Nine months	
	2011 **$**	2010 $	**2011** **$**	2010 $
Per boe				
Revenues	**61.83**	52.08	**64.69**	55.03
Royalties	**(8.77)**	(4.39)	**(14.08)**	(5.67)
Operating costs	**(23.46)**	(27.85)	**(33.33)**	(27.13)
Transportation costs	**(2.25)**	(1.41)	**(2.08)**	(1.85)
Netback per boe	**27.35**	18.43	**15.20**	20.38

The operating netback of $27.35 per boe was 57% higher than the second quarter of 2011 $17.39 per boe, and 48% higher compared to the third quarter of 2010. The increase in operating netback for the quarter ending September 30, 2011 from the quarter ending June 30, 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 from recent drilling activities.

General and administrative expenses

Periods ended September 30	Three months		Nine months	
	2011 **$**	2010 $	**2011** **$**	2010 $
Wages and employee benefits	**659,860**	317,675	**1,733,854**	942,982
Professional fees	**63,473**	53,097	**213,054**	143,528
Consulting fees	**201,991**	158,849	**667,567**	463,130
Public reporting	**46,712**	51,385	**230,519**	126,943
Occupancy costs	**126,210**	85,062	**366,755**	245,017
Travel	**47,196**	26,686	**170,277**	88,452
Miscellaneous general and administrative	**156,276**	22,689	**287,033**	186,614
Total	**1,301,718**	715,443	**3,669,059**	2,196,666
Per boe	**15.48**	24.77	**15.57**	26.96

General and administrative expenses increased by 82% for the three month period and 67% for the nine month period on a boe basis for the periods ending September 30, 2011 for the comparable period in 2010. Total general and administrative costs increase to $1,301,718 and $3,669,059 for the three and nine months ending September 30, 2011 from $715,443 and $2,196,666 for the same period in 2010. 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 as the new wells come online.

Finance Expense

Periods ended September 30	Three months		Nine months	
	2011 **$**	2010 $	**2011** **$**	2010 $
Interest expense – bank loan	**18,321**	34,467	**52,045**	98,797
Interest expense – debenture	**43,167**	-	**128,094**	-
Accretion expense *(1)*	**50,691**	32,508	**156,752**	97,226
Total	**112,179**	66,975	**336,891**	196,023
Per boe	**1.33**	2.14	**1.43**	2.41

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

Finance expenses increased to $112,179 for the three months period and $336,891 for the nine month period ended September 30, 2011. Interest expense decreased in the third 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 nine months ended September 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 third quarter of 2011, the Corporation recorded $28,956 of share-based compensation during the period as compared to $876 for the same period in 2010. The increase in the third quarter is due to additional stock options granted during the period.

Share-based compensation for the nine months ended September 30, 2011 increased to $2,686,356 compared to $735,491 primarily due to the issuance of an additional 3,160,000 stock options for the period.

Depletion, depreciation and accretion

Periods ended September 30	Three months		Nine months	
	2011 $	2010 $	**2011 $**	2010 $
Depreciation, depletion, and amortization *(1)*	**2,316,834**	548,851	**6,208,380**	1,502,907
Per boe	**27.54**	19.00	**26.34**	18.44

Note (1): Depletion and depreciation for the nine months ended September 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 nine months ended September 30, 2011 increased by 313% to $6,208,380 compared to the same period in 2010 at $1,502,907. On a boe basis, the costs increased by 43% to $26.34 compared to $18.44 for the nine months ending September 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 September 30	Three months		Nine months	
	2011 $	2010 $	**2011 $**	2010 $
Funds (used in) from operations*(1)*	**1,010,818**	(232,609)	**(78,694)**	(704,827)
Per share basic	**0.01**	0.00	**(0.00)**	(0.01)
diluted	**0.01**	0.00	**(0.00)**	(0.01)
Net income (loss)*(1)*	**(1,395,197)**	(1,219,335)	**(8,452,829)**	(3,430,829)
Per share				
basic	**(0.01)**	(0.02)	**(0.06)**	(0.05)
diluted	**(0.01)**	(0.02)	**(0.06)**	(0.05)

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

The increase in funds from operations for the third 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 third quarter of 2011 of $1,395,197 compared to $1,219,335 during the three months ended September 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 September 30	Three months		Nine months	
	2011 **$**	2010 $	**2011** **$**	2010 $
Drilling and completions	**13,396,787**	1,326,090	**24,292,822**	2,466,178
Facilities	**1,514,868**	2,795	**1,692,985**	24,332
Other	**87,749**	-	**107,437**	14,562
	14,999,404	1,328,885	**26,093,244**	2,505,072
Drilling incentive credits	**(312,331)**	-	**(777,291)**	-
Total Property, plant and equipment	**14,687,073**	1,328,885	**25,315,953**	2,505,072
Land and seismic	**164,025**	1,041,442	**8,066,292**	3,918,668
Total exploration and evaluations	**164,025**	1,041,442	**8,066,292**	3,918,668
Total net capital expenditures	**14,851,098**	2,370,327	**33,382,245**	6,423,740

The Corporation invested $14.7 million in the third quarter of 2011 compared to $1.3 million in 2010. Capital expenditures for the third quarter of 2011 were concentrated in the Steen River and Maxhamish areas. For the nine months ended September 30, 2011 capital expenditures were $25.3 million compared to $2.5 million in 2010. Capital expenditures were focused on development drilling activities, an all weather access road and recompletions and work overs at Steen River and Maxhamish. Capital expenditures also include the benefit of $0.8 million related to the drilling incentive credit.

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.

The Corporation invested $8.1 million for the nine months of 2011 compared to $3.9 million in 2010. The costs include completion of 3-D and 2-D seismic at Steen River and land acquisitions at Steen River and in northwestern Alberta.

SUMMARY OF QUARTERLY FINANCIAL DATA

The following table summarizes quarterly financial results:

Quarter ended	Sep-11 $	Jun-11 $	Mar-11 $	Dec-10 $	Sep-10 $	Jun-10 $
Petroleum and natural gas sales	5,200,397	5,432,234	4,891,099	1,639,921	1,504,357	1,293,250
Income (loss)	(1,395,197)	(2,166,533)	(4,684,099)	3,091,917	(1,219,336)	(985,892)
Income (loss) per share Basic Diluted	 (0.01) (0.01)	 (0.05) (0.05)	 (0.04) (0.04)	 .03 .03	 (0.02) (0.02)	 (0.02) (0.02)
Production boe/d	914	884	790	317	314	266
Average price/boe	61.83	67.54	64.85	56.21	52.08	53.38

LIQUIDITY AND CAPITAL RESERVES

The Corporation considers its capital structure to include shareholders equity and working capital, including unused line of credit. The Corporation will continue to fund its on-going operations from a combination of funds from operations, line of credit, and equity financing as needed. As the majority of the Corporation's on-going capital expenditure program is operated and directed to the future growth of reserves and production volumes, the Corporation is able to adjust its budgeted capital expenditures should the need arise. At September 30, 2011, the Corporation has unused credit facility of $20.2 million, and negative cash flow of $10.3 million for total available funds of $9.9 million.

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:

	September 30, 2011 $	December 31, 2010 $
Current assets	**8,128,310**	34,838,496
Accounts payable and accrued liabilities	**(14,961,652)**	(6,127,032)
Debentures	**(3,425,225)**	(3,425,225)
Net working capital surplus	**(10,258,567)**	25,286,239
Total line of credit	**21,000,000**	5,000,000
Authorized Letters of Guarantee	**(751,792)**	-
Unutilized line of credit	**20,248,708**	5,000,000
Net available funds	**9,990,141**	30,286,239

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 September 30, 2011, this ratio was 1.9:1. 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 November 14, 2011 Strategic had 139,009,068 common shares, and 6,723,333 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		47,935
Share issue costs		(6,604)
Balance, September 30, 2011	**139,009,068**	**83,546,802**

During the period ending September 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 nine months ended September 30, 2011:

	Number of options	Exercise Price $
Balance – December 31, 2010	**3,846,667**	**0.59**
Issued	3,160,000	1.10
Exercised	(83,334)	0.38
Expired	(200,000)	1.60
Balance – September 30, 2011	**6,723,333**	**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.

In September, 2011, 35,000 common share options were issued and vested immediately. These options expire five years from the date of the issue. The fair value of the options were calculated using the Black-Scholes model using an expected volatility of 101.4%, interest rate of 1.4%, estimated forfeiture rate of 7.7%, expected life of 5 years, and no expected dividends resulting in $28,956 of stock based compensation for the quarter.

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

All stock options, issued and exercisable		
Number of Options	**Exercise price**	**Weighted Average Life (yrs)**
660,001	$0.25	2.45
1,193,332	$0.50	2.87
1,275,000	$0.65	3.29
435,000	$0.75	2.45
3,160,000	$1.10	4.28
6,723,333	**$0.80**	**3.54**

Subsequent to the quarter end, the Corporation issued 100,000 common share options with an exercise price of $0.91 per share expiring in three years from the date of issue, and exercisable immediately.

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

TRANSACTIONS WITH RELATED PARTIES

Legal fees in the amount of $59,212 ($104,411 – September 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 $8,221 ($6,880 – September 30, 2010) were incurred to a director for geophysical consulting services. Software charges of $90,000 ($nil – September 30, 2010) were charged to a company controlled by an officer. Accounts payable and accrued liabilities at September 30, 2011 include $19,926 ($71,822 – September 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	181,149
2012	292,596
2013	263,213
	673,958

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 September 30, 2011, $10,863,756 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 September 30, 2011, the Corporation had no hedging contracts. The following table analyses the Corporation's cash flow sensitivity to commodity price changes.

	September 30, 2011 **$**	September 30, 2010 $
10% change in oil price	**967,202**	388,133
10% change in gas price	**187,947**	59,817

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 September 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 September 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, including the debenture, mature in 2011.

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 receivable 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. Three customers represent 38% of the Corporation's accounts receivable at September 20, 2011. Amounts owing from these customers were received subsequent to quarter end. As at September 30, 2011, the Corporation's receivables were as follows:

	September 30, 2011 **$**
Joint venture partners	275,362
Petroleum and natural gas marketers	1,755,390
Other	2,488,326
Prepaid expenses	646,392
Total accounts receivable	**5,165,530**

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

	September 30, 2011 **$**
Current	2,168,265
30 – 60 days	749,801
60 – 90 days	80,217
Greater than 90 days	1,520,855
Total	**4,519,138**

At September 30, 2011, the amount receivable for Alberta Crown Royalties was $899,896 and this 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 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 September 30, 2011 were $14,500,402 (December 31, 2010 - $15,459,560). The estimated costs have been discounted at a risk free rate of 2.74% - 3.66% (December 31, 2010 – 3.51%) and an inflation rate of 2% at September 30, 2011 (December 31, 2010 – 2%).

Stock based compensation

The Corporation has a stock option plan under which officers, directors, consultants 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 19* 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, September 30, 2010 and December 31, 2010 and consolidated statements of earnings and comprehensive income and cash flows for the nine months ended September 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 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 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 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.

- **IFRS 9**
  Financial Instruments addresses the classification and measurement of financial assets.

- **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 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.

  The IASB also issued Presentation of Items of Other Comprehensive Income, an amendment to IAS 1 Financial Statement Presentation. The amendment addresses the presentation of other comprehensive income and requires the grouping of items within other comprehensive income that might eventually be reclassified to the profit and loss section of the income statement. The change becomes effective for financial years after July 1, 2012 with earlier adoption permitted.

The company has not completed its evaluation of the effect of adopting these standards on its financial statements.

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 September 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 September 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 the 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 September 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.