



## Management's Discussion and Analysis

### Three and six months ended June 30, 2010

August 18, 2010

Strategic Oil & Gas Ltd. ("Strategic" or the "Corporation") was incorporated under the laws of the Province of British Columbia on December 30, 1987. 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., a private oil and gas consulting company was acquired by Strategic on March 10, 2009.

#### **ADVISORIES**

Management's discussion and analysis ("MD&A") of the consolidated financial conditions and results of operations should be read in conjunction with the consolidated financial statements for the three and six months ended June 30, 2010, and MD&A and audited consolidated financial statements for the year ended December 31, 2009. 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 = 1 bbl) 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.

The financial data presented has been prepared in accordance with Canadian Generally Accepted Accounting principles (GAAP), except for the terms "funds from operations" and "netback". Funds from operations and funds from operations per share are presented for information purposes only, and should not be considered an alternative to, or more meaningful than, cash flow from operating activities as determined by GAAP. Strategic determines funds from operations to be the cash flow before changes in non-cash working capital. 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.

#### ***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 that Strategic does not operate all of its properties, industry conditions and competition, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the ability to access qualified personnel and oilfield services, decisions by regulators and the ability to access sufficient capital from internal and external sources. Readers are cautioned not to place undue reliance on the forward-looking statements as the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and actual results, performance or achievements could materially differ from those expressed or implied in such forward-looking statements and accordingly, no assurance can be given that any of the events anticipated by forward-looking statements will transpire or occur, or if any of them do so, what benefit Strategic will derive therefrom.

Specific forward-looking statements include the following:

Taber and Conrad drill program of 5 wells and increased production of up to 400 boed. Specific risks include the allocation of capital to the program and successful results. Although the Corporation currently has available funds for these wells, there is no assurance that competing projects may require a re-allocation of funds. The success of these wells and achievement of the projected production is subject to the geologic and operational risks associated with any well.

Maxhamish program. Specific risks include the geologic and operational risks associated with any well. In addition, the area is subject to winter access only and there are facilities required to handle significant production. In addition, as the Corporation is not the operator, it is bound by the decisions of the operator in respect to future development programs, the timing of the same and the requirement of having to raise capital in order to participate. The corporation also faces the risk of not being able to raise sufficient capital in a timely manner due to the status of the capital markets at such time.

## **OVERVIEW OF PERFORMANCE AND DISCUSSION OF OUTLOOK**

The six months ended June 30, 2010 showed an increase in volumes over the comparable period of 2009. Average daily sales volumes increased by 54% to 291 boe/d in 2010 versus 189 boe/d in 2009. Revenues also increased by 130% to \$2,987,813 for 2010 versus \$1,301,719 in 2009. The increase was the result of the acquisition of the Taber and Conrad properties in 2009, as well as a significant recovery in crude oil prices over the first half of 2009. Natural gas prices remain depressed and at similar levels to 2009. The Corporation received an average price of \$56.65 per boe versus \$35.71 in 2009 which is an increase of 59%.

For the three months ended June 30, 2010, average daily production was 266 boe/d versus 315 boe/d for the first quarter of 2010, a decrease of 16%. The decrease in production was primarily related to a plant turnaround at Taber in April of 2010. Revenues for the second quarter of 2010 also decreased by 23% to \$1,298,172 for the second quarter versus \$1,689,641 in the first quarter. The Corporation received an average price of \$53.18 per boe in the second quarter of 2010 versus \$59.44 in the first quarter, which is a decrease of 11%.

For the six months ended June 30, 2010, the Corporation had a net loss of \$1,810,349 or \$0.03 per share (basic and diluted) as compared to a net loss of \$1,582,773 or \$0.05 per share for the six months ended June 30, 2009. The increased loss in 2010 arises from the stock-based compensation expense of \$734,171 as a result of the issuance of stock options in the year, as well as additional expenses and less revenue as a result of the Taber plant turnaround. Funds used in operations for the six months ended June 30, 2010 was \$420,792 as compared to \$481,370 for the six months ended June 30, 2009.

Late in the first quarter, at Maxhamish in northeast British Columbia, Strategic participated in two horizontal oil wells which were drilled and multi-stage fracture stimulated (a-C18-J-D94-O-11 and a-49-J-D94-O-11). Both wells were production tested, placed on production with pump-jacks, and tied in to a natural gas gathering and processing facility in the second quarter. Combined deliverability from these wells is currently restricted by the owner of the natural gas facility. Based on field performance and internal engineering evaluations, Strategic estimates that Maxhamish wells have a productive capacity in the range of 200 to 250 barrels per day with a targeted recovery of 200,000 to 250,000 barrels of proved plus probable reserves of 40° API oil under primary production.

Based on the positive results from the two wells, the Corporation, along with its partner, acquired an additional 19 sections at Crown land sales in the Maxhamish area. Strategic now owns an average interest of 33% in 20,800 gross acres (> 32 sections) of land in the Maxhamish area. With the lands included by the Maxhamish farmout agreement and the direct interest lands just acquired, over 100 sections of land are now available for drilling, with the possibility of drilling up to four wells per section.

The Corporation is in the early stages of assessing the contingent resources at Maxhamish. The initial results add confidence to the Corporation's initial internal estimates of over 500 million barrels of Total Petroleum Initially in Place (PIIP) on the 100 sections of land available to Strategic. Results of these wells are currently being assessed with the operator and future development plans for the next year will be determined accordingly.

In early July, at Conrad in southern Alberta, Strategic spud a horizontal well (8-23Hz). This well was drilled as a multi-leg horizontal well, targeting the Sawtooth formation. This well has now been equipped and is currently being tied in. Once the well has a chance to produce continually, it is expected that this well will produce 50-100 bop/d of medium API oil. The technical team is currently assessing this well and based on the initial positive results, it may open up over ten 100 percent owned additional locations.

The Corporation has brought in a partner to allow for an accelerated drilling program at Taber. The terms of this agreement provide that the partner will pay \$1.6 million to drill two or three wells, and to earn a 25% interest in the property. In late July 2010 Strategic commenced drilling two wells (4-24 and 11-14) with the potential that a third well may also be drilled. The target sands are basal quartz Glauconitic and Lower Mannville, which are characterized as having high porosity and permeability. These wells have recently been completed, equipped, and will be brought on production within the next month. It is too early to quote anticipated initial production rates, however the technical team is currently reviewing additional locations based on these encouraging results.

It is anticipated that the current three well drilling program at Taber and Conrad can add in excess of 150 bop/d (net to Strategic) of potential production. In addition, the recent successes at Taber and Conrad are expected to lead to additional drilling in the fourth quarter. As discussed, the technical team is identifying potential locations.

The current plan for the remainder of the third quarter is to continue to work with the partner at Maxhamish to finalize the capital program for the coming winter season. This light oil resource play provides Strategic and its partners access to over 100 sections of land available for development.

The Corporation also continues to assess other new high impact oil opportunities in North America.

## **IMPACT OF CURRENT ECONOMIC VOLATILITY AND UNCERTAINTY**

Crude oil prices have stayed robust through the first half of 2010, and the Corporation was able to raise over \$14,500,000 equity in the previous year, plus receive additional proceeds of \$724,000 through the exercise of options and warrants. Strategic is therefore in a strong position to undertake its planned capital expenditures program. The Corporation will continue to monitor its funds from operations and available credit facilities to ensure its ability to meet its planned capital program for 2010. The Corporation has recently renewed its \$5.0 million line of credit with a Canadian financial institution.

## **RISK FACTORS**

Additional risk factors may be found on page 11 of this Management Discussion and Analysis under "Financial Instruments".

### **Exploration, Development and Production Risks**

Oil and natural gas exploration involves a high degree of risk, which even with a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that expenditures made on future exploration by the Corporation will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to project the costs of implementing a drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that the Corporation will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and

operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

In addition, oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, cratering, sour gas releases, fires and spills. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial condition.

#### Recent economic risks

Improved oil prices in the first half of 2010 have improved financial markets somewhat, however volatility still remains. Energy producers will still encounter difficult times while natural gas prices remain low in accessing new equity capital, while credit conditions and availability may tighten as interest rates rise.

#### Access to capital

The Corporation is dependent on access to equity or debt financing to fund working capital requirements and capital expansion programs when operating cash flows are not sufficient to do so. To date, sufficient capital has been obtained to meet the Corporation's working capital and capital expansion requirements. Additional working capital requirements or further capital expansion that cannot be funded through operating cash flows or current cash on hand will require external financing, the availability of which is dependent on, for example, credit availability, economic conditions, and commodity prices.

## RESULTS OF OPERATIONS

### *Production*

Periods ending June 30	Three months		Six months	
	2010	2009	2010	2009
Oil, condensate, & ngl's – bbls/d	186	87	206	87
Natural gas – mcf/d	484	535	509	613
Boe/d	266	176	291	189

Production for the first six months of 2010 increased by 54% on a boe per day ("boe/d") basis mainly as a result of acquiring the Taber and Conrad properties in November, 2009.

### *Revenue*

Periods ending June 30	Three months		Six months	
	2010	2009	2010	2009
Sales				
Oil, condensate, and ngl's	\$ 1,094,437	\$ 414,252	\$ 2,534,466	\$ 715,917
Natural gas	194,099	176,886	440,676	506,350
Other revenue	9,636	77,452	12,671	79,452
Total sales	\$1,298,172	\$668,590	\$2,987,813	\$1,301,719
Average prices				
Oil and ngl's (\$/bbl)	\$ 64.80	\$ 52.44	\$ 68.05	\$ 45.48
Natural gas (\$/mcf)	\$ 4.41	\$ 3.63	\$ 4.78	\$ 4.57
Oil equivalent (\$/boe)	\$ 53.18	\$ 36.92	\$ 56.65	\$ 35.71

The average price received for oil, condensate and ngl's for the first three and six months of 2010 was \$64.80 and \$68.05 per bbl as compared to \$52.44 and \$45.48 per bbl for the same time frames in 2009 reflecting a

24% and 50% price increase respectively. For the three and six months ended June 30, 2010, the gas price was \$4.41 and \$4.78 per mcf as compared to \$3.63 and \$4.57 per mcf in the three and six months ended June 30, 2009. Overall, the combined price in the three and six months ending June 30, 2010 of \$53.18 and \$56.65 per boe is 44% and 59% higher than the combined prices of \$36.92 and \$35.71 per boe in the first three and six months of 2009. The acquisition of the Taber and Conrad properties in late 2009, both oil-producing areas, and the improvement in the oil price has contributed to the increased in revenues over the same period in the previous year.

### *Royalties*

Periods ending June 30	Three months		Six months	
	2010	2009	2010	2009
Crown royalties	\$ 93,269	\$ 69,275	\$ 255,734	\$ 170,338
Freehold royalties	13,191	23,040	33,653	53,200
Overriding royalties	16,620	9,519	45,764	26,151
Net royalties	\$ 123,080	\$ 101,834	\$ 335,151	\$ 249,689
Per boe	\$ 5.08	\$ 6.36	\$ 6.37	\$ 7.30
Percentage of revenues	9.6%	17.2%	11.2%	20.4%

For the three and six month periods ending June 30, 2010, the decrease in the royalty rate over 2009 was due to the acquisition of the Taber and Conrad properties, which are mature, and as a result attract an average royalty of less than 5%.

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 March 31, 2010, 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, 2009, up to a maximum of 500,000 mcf of natural gas or 50,000 bbls of crude oil production. Based on Strategic's 2009 production, it will be entitled to a maximum credit of 50 percent of royalties payable. On June 25, 2009, these incentives were extended to March 31, 2011. As at June 30, 2010, \$194,000 in drilling credits have been earned, with \$111,000 received and recognized as a reduction to capital spending, as well as receiving the 5% crown royalty rate on one well.

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 ending June 30	Three months		Six months	
	2010	2009	2010	2009
Operating costs	\$ 789,063	\$ 201,521	\$ 1,403,637	\$ 428,995
Transportation costs	50,182	21,327	109,945	45,939
	\$ 839,245	\$ 222,848	\$ 1,513,582	\$ 474,934
Per boe				
Operating costs	\$ 32.57	\$ 12.59	\$ 26.68	\$ 12.54
Transportation costs	2.07	1.33	2.09	1.34
	\$ 34.64	\$ 13.92	\$ 28.77	\$ 13.88

The operating and transportation costs for the three and six months ending June 30, 2010 averaged \$34.64 and \$28.77 per boe compared to \$13.92 and \$13.88 per boe for similar time frames in 2009. Operating costs per boe were higher due to Taber and Conrad, which have higher operating cost per boe as they are a medium to heavy oil with a high water cut. During the second quarter of 2010, there was a plant turnaround at Taber which resulted in higher operating costs and decreased production, both of which contributed to the high operating costs per boe for both the three month and six month periods.

#### *Operating netbacks*

Periods ending June 30	Three months		Six months	
	2010	2009	2010	2009
Per boe				
Revenues	\$ 53.18	\$ 36.92	\$ 56.65	\$ 35.71
Royalties	(5.08)	(6.36)	(6.37)	(7.30)
Operating costs	(32.57)	(12.59)	(26.68)	(12.53)
Transportation costs	(2.07)	(1.33)	(2.09)	(1.34)
Netback per boe	\$13.46	\$16.64	\$21.51	\$14.54

The acquisition of the Taber and Conrad oil-producing, low-royalty properties have improved the netback from \$14.54 per boe for the six months ending June 30, 2009 to \$21.51 per boe for the same time period in 2010, representing a 48% increase. The Taber plant turnaround in the second quarter of 2010 increased operating costs and decreased production to create a netback of \$13.46 for the three months ended June 30, 2010, a 19% decrease from a netback of \$16.64 for the same time period of 2009.

#### *General and administrative expenses*

Periods ending June 30	Three months		Six months	
	2010	2009	2010	2009
Wages and employee benefits	\$ 310,584	\$ 217,747	\$ 625,307	\$ 331,123
Professional fees	81,200	11,052	90,431	48,245
Consulting fees	171,719	86,179	304,283	166,766
Public reporting	39,982	36,192	75,558	66,759
Occupancy costs	74,333	90,908	159,955	172,505
Travel	33,041	64,482	61,766	85,434
Miscellaneous general and administrative	79,758	75,524	163,923	117,997
Total	\$ 790,617	\$ 582,084	\$ 1,481,223	\$ 988,829
Per boe	\$ 32.63	\$ 36.36	\$ 28.16	\$ 28.89

General and administrative expenses decreased by 10% for the three month period and 3% for the six month period on a per boe basis for the periods ending June 30, 2010. Total general and administrative costs increased to \$790,617 and \$1,481,223 for the three and six months ending June 30, 2010 from \$582,084 and \$988,829 for the same time periods in 2009 due mainly to increased costs associated with the increased oil and gas operations and additional salaries.

#### *Depletion, depreciation and accretion*

Periods ending June 30	Three months		Six months	
	2010	2009	2010	2009
Depletion, depreciation, and accretion	\$ 661,724	\$ 453,139	\$ 1,416,733	\$ 951,851
Per boe	\$ 27.31	\$ 28.30	\$ 26.93	\$ 27.81

Depletion, depreciation and accretion charges for 2010 remained at a similar level on a per boe basis as \$27.31 and \$26.93 compared to \$28.30 and \$27.81 for 2009.

**Funds from operations and net income (loss)**

Periods ending June 30	Three months		Six months	
	2010	2009	2010	2009
Funds from (used in) operations	\$ (487,585)	\$ (274,500)	\$ (420,792)	\$ (481,370)
Per share				
basic	\$ (0.01)	\$ (0.01)	\$ (0.01)	\$ (0.01)
diluted	\$ (0.01)	\$ (0.01)	\$ (0.01)	\$ (0.01)
Net income (loss)	\$ (1,148,859)	\$ (800,361)	\$ (1,810,349)	\$ (1,582,773)
Per share				
basic	\$ (0.02)	\$ (0.02)	\$ (0.03)	\$ (0.05)
diluted	\$ (0.02)	\$ (0.02)	\$ (0.03)	\$ (0.05)

The decrease in funds from operations for the second quarter of 2010 as compared to the second quarter of 2009 is attributable to the increase in operating costs and decrease in revenue resulting from the Taber plant turnaround.

**Capital Expenditures**

Periods ending June 30	Three months		Six months	
	2010	2009	2010	2009
Land purchases and maintenance costs	\$ 672,799	\$ 40,492	\$ 1,028,998	\$ 50,106
Geological and geophysical	35,448	50,902	104,643	50,902
Drilling and completion	217,926	37,818	1,774,095	1,469,253
Equipping and facilities	493,546	74,119	732,283	241,513
Other	11,731	3,352	14,562	11,502
Total cash expenditures	\$ 1,431,450	\$ 206,683	\$ 3,654,581	\$ 1,823,276

Capital expenditures were \$1,431,450 and \$3,654,581 for the three and six months ending June 30, 2010 compared to \$206,683 and \$1,823,276 for the same time periods in 2009. Strategic participated in the drilling and completion of two wells, as well as the optimization program in Maxhamish. On Strategic-operated properties, projects included in the first six months of 2010 are the completion and facilities associated with the Conrad 11-23 well and two Taber well recompletions in 2010. There were also major land acquisitions at Conrad and Maxhamish.

**SUMMARY OF QUARTERLY FINANCIAL DATA**

The following table summarizes quarterly financial results:

Quarter ended	Jun-10 \$	Mar-10 \$	Dec-09 \$	Sep-09 \$	Jun-09 \$	Mar-09 \$	Dec-08 \$	Sept-08 \$
Petroleum and natural gas sales	1,298,172	1,689,641	1,081,829	503,983	591,139	633,129	652,096	1,169,425
Income (loss)	(1,148,859)	(661,490)	(1,585,039)	(721,506)	(800,361)	(782,412)	(316,553)	(163,158)
Income (loss) per share								
Basic	(0.02)	(0.01)	(0.03)	(0.02)	(0.02)	(0.03)	(0.01)	(0.01)
Diluted	(0.02)	(0.01)	(0.03)	(0.02)	(0.02)	(0.03)	(0.01)	(0.01)
Production boed	266	315	237	171	176	202	177	179
Average price/boe	\$53.18	\$59.44	\$49.72	\$32.09	\$36.92	\$34.65	\$40.01	\$71.10

## LIQUIDITY AND CAPITAL RESERVES

The Corporation started 2010 with working capital of \$4,613,432 which included a revolving bank operating loan balance of \$1,500,000. During the first six months of 2010, funds of \$420,792 were used in operations, \$716,019 of cash, net of share issue costs, was received from the warrants and options exercised during the period, and capital of \$3,654,581 was expended. The Corporation has a working capital surplus of \$1,254,078 at June 30, 2010, which includes \$925,205 of cash in the bank and \$4,007,340 in short term investments. In addition, there is an unutilized amount of \$3,500,000 on the credit facility. Subsequent to the June 30, 2010, 250,000 broker warrants and 50,000 warrants have been exercised for further proceeds of \$142,500.

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, 2010
	\$
Current assets	5,759,908
Current liabilities (excluding debt)	(3,005,830)
Net working capital surplus	2,754,078
Total line of credit	5,000,000
Loan balance	(1,500,000)
Unutilized line of credit	3,500,000
<b>Net available funds</b>	<b>6,254,078</b>

The Corporation is currently projecting its remaining 2010 capital program to be in the range of \$4.5 – 7.5 million, and expects the current available funds will be able to fund it. There is also approximately \$20.5 million potentially available to the Corporation through the exercise of outstanding warrants with an expiry date of November and December 2010. The Corporation has a significant amount of non-operated properties where it does not have control over choosing the projects or the timing of the expenditures, but is relying on the above sources of cash to fund those projects.

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, 2010, this ratio was 3.1:1.

## SHARE DATA

At August 18, 2010 Strategic had 70,296,395 common shares, and 4,530,000 stock options with a weighted average exercise price of \$0.56 per share outstanding. In addition, there are 32,648,762 warrants and broker warrants outstanding, which are exercisable within one year with an average exercise price of approximately \$0.59 per share.

### Common Shares

Issued:	Number of shares	\$
<b>Balance, December 31, 2009</b>	<b>68,693,099</b>	<b>\$24,385,762</b>
Warrants exercised	1,203,296	686,753
Options exercised	100,000	37,500
Fair value of options and warrants exercised		263,832
Tax effect of renunciation on flow-through shares		(746,913)
Share issue costs		(8,234)
<b>Balance, June 30, 2010</b>	<b>69,996,395</b>	<b>\$24,618,700</b>

During the period ending June 30, 2010, 1,203,296 warrants were exercised for proceeds of \$686,753 and 100,000 stock options were exercised for proceeds of \$37,500. The fair value adjustment of these warrants and options of \$263,832 was recorded and deducted from contributed surplus.

In December, 2009, 5,432,092 flow-through shares were issued for \$0.55 per share for total proceeds of \$2,987,651. The tax effect of the renunciation of expenditures of \$746,913 was recognized in February, 2010.

Subsequent to the quarter end, approximately 300,000 shares were issued upon the exercise of warrants for proceeds of \$180,000.

### Stock options

The following table reconciles the changes to the Corporation's stock options for the six months ended June 30, 2010:

	Number of options	Weighted average exercise price
<b>Balance – December 31, 2009</b>	<b>3,355,000</b>	<b>\$0.53</b>
Issued	1,275,000	\$0.65
Exercised	(100,000)	\$0.38
<b>Balance – June 30, 2010</b>	<b>4,530,000</b>	<b>\$0.56</b>

In January, 2010, 1,275,000 common share options were issued with an exercise price of \$0.65 per share expiring in five years from date of issue, and vest immediately. The fair value of the options were calculated using the Black-Scholes model using an expected volatility of 114.3%, interest rate of 2.7%, expected life of 5 years, and no expected dividends resulting in \$707,620 of stock-based compensation.

The following table sets out the outstanding options as at June 30, 2010:

All stock options			Exercisable		
Number of options	Exercise price	Weighted Average Life (yrs)	Number of options exercisable	Exercise Price	Weighted Average Life (yrs)
735,000	\$0.25	3.70	735,000	\$0.25	3.70
600,000	\$0.40	0.27	600,000	\$0.40	0.27
1,235,000	\$0.50	4.11	1,235,000	\$0.50	4.11
1,275,000	\$0.65	4.55	1,275,000	\$0.65	4.55
485,000	\$0.75	3.70	-	\$0.75	-
200,000	\$1.60	0.84	200,000	\$1.60	0.84
<b>4,530,000</b>	<b>\$0.56</b>	<b>3.47</b>	<b>4,045,000</b>	<b>\$0.54</b>	<b>3.44</b>

### Shares in escrow

Shares issued pursuant to the ZinMac Inc. ("ZinMac") acquisition in 2009 remaining in escrow at June 30, 2010 are detailed below:

<b>Total shares in escrow per ZinMac acquisition</b>	<b>5,000,000</b>
Shares released March 13, 2009 (10%)	(500,000)
Shares released September 10, 2009 (15%)	(750,000)
Shares released March 10, 2010 (15%)	(750,000)
<b>Shares remaining in escrow – June 30, 2010</b>	<b>3,000,000</b>

All former shareholders of ZinMac are bound by this escrow agreement that allows for the release of shares in 15% increments over each additional six months.

### Warrants

The following table reconciles the changes to the Corporation's warrants for the quarter ended June 30, 2010:

	Number of warrants	Exercise price
<b>Opening balance – December 31, 2009</b>	<b>31,428,858</b>	<b>\$0.60</b>
Warrants exercised	(953,296)	0.60
Warrants issued	250,000	0.60
<b>Closing balance – June 30, 2010</b>	<b>30,725,562</b>	<b>\$0.60</b>

The following table sets out the outstanding warrants as at June 30, 2010:

Number of warrants	Exercise price	Expiry
370,370	\$0.27	May 8, 2011
27,661,896	\$0.60	November/December, 2010
2,693,296	\$0.70	November/December, 2010
<b>30,725,562</b>	<b>\$0.60</b>	

All warrants vested immediately. Subsequent to the quarter end, approximately 50,000 warrants were exercised for proceeds of \$30,000, and 250,000 warrants were issued upon exercise of 250,000 broker warrants.

### Broker Warrants

The following table reconciles the changes to the Corporation's broker warrants for the quarter ended June 30, 2010:

	Number of warrants	Exercise price
<b>Opening balance – December 31, 2009</b>	<b>2,473,200</b>	<b>\$0.45</b>
Warrants exercised	(250,000)	0.45
<b>Closing balance – June 30, 2010</b>	<b>2,223,200</b>	<b>\$0.45</b>

During the period ending June 30, 2010, 250,000 broker warrants were exercised, resulting in the issuance of 250,000 common shares and 250,000 warrants to acquire common shares at \$0.60 per share expiring November 13, 2010. The fair value of the additional \$0.60 warrants was recognized into contributed surplus in 2009 when the broker warrants were originally issued.

The following table sets out the outstanding broker warrants as at June 30, 2010:

Number of warrants	Exercise price	Expiry
2,223,200	\$0.45	November 13, 2010

All warrants issuable on exercise of brokers warrants vest immediately. Subsequent to the quarter end, approximately 250,000 broker warrants were exercised for proceeds of \$112,500 and resulted in the issuance of 250,000 warrants exercisable at \$0.60 and expiring November 13, 2010.

## **TRANSACTIONS WITH RELATED PARTIES**

Legal fees and expenses in the amount of \$42,013 and \$62,596 for the three and six months ended June 30, 2010 (\$38,380 and \$111,720 – three and six months ended June 30, 2009) were incurred to a legal firm of which a director is a partner, and included as general and administrative expenses or share issue costs. General administrative fees in the amount of \$18,000 and \$36,000 for the three and six months ended June 30, 2010 (\$15,000 and \$30,000 – three and six months ended June 30, 2009) were incurred to the Corporate Secretary. Consulting fees in the amount of \$5,249 and \$17,018 for the three and six months ended June 30, 2010 (\$6,825 and \$21,420 – three and six months ended June 30, 2009) were incurred to a director for geophysical consulting services. Accounts payable and accrued liabilities at June 30, 2010 include \$45,921

(\$23,148 – June 30, 2009) 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

The Corporation has a lease agreement for office space commencing December 1, 2008 having a five-year term that commits the Corporation to the basic rent as at June 30, 2010 described below:

<u>Year ended</u>	<u>\$</u>
2010	110,914
2011	232,596
2012	232,596
2013	213,213
	<u>789,319</u>

Strategic has entered into a farm-out agreement (“the Agreement”) in the Maxhamish region of Northeast British Columbia, where the Corporation is required to perform a work optimization program of \$1.0 million on the five oil wells and drill two wells in the area by the end of March, 2010 (the “Commitment”). Failure to meet the Commitment to drill the two wells will result in the Corporation being required to pay a penalty of \$1.0 million per well in 2010. The Corporation entered into a Participation Agreement to bring in a partner in 2009 to assume certain of these commitments and obligations. The Corporation has been advised that the Commitment has been met.

The Corporation has incurred \$1,870,807 of the qualifying expenditures to the end of June, 2010 towards the obligations arising from the November/December 2009 flow-through issues of \$2,987,651. The remaining expenditures are required to be incurred by December 31, 2010.

## Financial Instruments

Financial instruments consist of cash, short term investments, accounts receivable, accounts payable and accrued liabilities, and bank loan. All of the Corporation’s assets and liabilities are valued as Level 1 financial instruments based on the short term nature 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.

### 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. All of these risks are predominately outside the Corporation’s ability to control.

#### 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, 2010, the Corporation had no hedging contracts.

#### 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.

#### 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, 2010, the Corporation had no contracts in place to reduce the foreign exchange risk

#### 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.

#### Credit Risk

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, 2010, the Corporation's receivables were as follows:

	<b>June 30, 2010</b>
Joint venture partners	\$ 197,409
Petroleum and natural gas marketers	354,075
Other	92,609
<b>Total accounts receivable</b>	<b>\$ 644,093</b>

As at June 30, 2010, the aging analysis of trade receivables is as follows:

	<b>June 30, 2010</b>
Current	\$ 487,833
30 – 60 days	27,121
60 – 90 days	14,151
Greater than 90 days	114,988
<b>Total</b>	<b>\$ 644,093</b>

As at June 30, 2010, there were no doubtful accounts.

### CRITICAL ACCOUNTING ESTIMATES

A summary of Strategic's accounting policies are summarized in Note 2 of the audited consolidated financial statements at December 31, 2009. These policies are subject to estimates and judgements about future events, many of which may be beyond the control of management. The following is a discussion of the accounting estimates that are critical to the preparation of the financial statements.

#### *Oil and Gas Accounting*

Strategic follows the full-cost accounting guideline to account for its petroleum and natural gas operations. Under this method, all costs associated with exploration for and development of petroleum and natural gas reserves are capitalized in cost centres by country.

Depletion and depreciation expense is based on the amortization of net capitalized costs less unproved property costs plus future development costs for oil and natural gas exploration and development activities using the unit -of-production method. This method of cost amortization is based on the ratio of oil and natural gas sales to estimated proved oil and natural gas reserves. The evaluation of estimated proved oil and natural gas reserves is prepared by independent petroleum consultants and reviewed by the Corporation's Board of Directors. The process of estimating proved reserves involves professional judgment and a significant number of assumptions and decisions based on available geological, geophysical, production and economic data. Reserves estimates and future development costs change over time based on development and production activities and changing economic conditions. Unproved property costs are reviewed by management on a quarterly basis to determine if they should no longer be excluded from the cost base for amortization when proved reserves have been established or if the properties have become impaired. Changes to any of the aforementioned estimates could affect depletion and depreciation expense.

#### ***Asset Retirement Obligations***

The Corporation's future asset retirement obligation is a fair value determination based upon the present value of estimated costs and anticipated future timing to complete the abandonment and reclamation of Strategic's interest in wells and facilities. Cost estimates associated with abandonment and reclamation require judgment concerning the method, timing and extent of future retirement activities. The present value calculations, which give rise to accretion expense adjustments each quarter of the year, are based on management's estimate of the Corporation's credit -adjusted risk-free interest rate. The future obligation and current accretion expense are subject to revision based on changes in technology, abandonment timing, reclamation costs, discount rates and the regulatory environment.

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

Companies that use the full-cost method of accounting for oil and natural gas operations are required to perform an impairment test (the "ceiling test") that calculates a limit for the net carrying cost of petroleum and natural gas assets. The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test. The ceiling test is a two-stage process. The first stage of the test is a recovery test which compares the undiscounted future cash flows from proved reserves at forecast prices plus the cost, less impairment, of unproved properties to the net book value of the petroleum and natural gas assets to determine if the assets are impaired. An impairment loss exists when the net book value of the petroleum and natural gas assets exceeds such undiscounted cash flows. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceeds the future discounted cash flows from proved plus probable reserves at the forecast prices. If reserve estimates are revised downward, net income could be affected by any additional depletion and depreciation recorded under the ceiling test calculated and could result in a significant accounting expense for a particular period.

#### ***Stock-based compensation***

Stock options issued under the Corporation's stock option plan are accounted for using the fair value method. Stock-based compensation cost is determined on the date of an option grant using the Black-Scholes option pricing model, which requires the estimation of several variables including volatility in Strategic's share prices, expected life of the option and the risk-free interest rate. Changes to these estimates would alter the valuation of the option granted and its related charge to stock-based compensation expense.

### **CHANGES IN ACCOUNTING POLICIES**

The Canadian Accounting Standards Board (AcSB) has confirmed that the use of the International Financial Reporting Standards ("IFRS") will be required in 2011 for publicly accountable profit-oriented enterprises. IFRS will replace Canada's current GAAP for those enterprises that are responsible to large or diverse groups of stakeholders. The official changeover date is for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. Companies will be required to provide comparative IFRS information for the previous fiscal year.

The Corporation has developed a plan to be compliant with this changeover by January 1, 2011. The changeover plan includes an analysis of the differences between IFRS and Canadian GAAP and recognition of the policy choices available. It also includes subsequent discussion of the business process and

information system changes necessary, as well as the financial impact of each. The project is being managed in-house by an accounting professional who is familiar with IFRS requirements and continues to develop the Corporation's adoption of IFRS. The Corporation's auditors will be involved throughout the process to ensure the Corporation's policies are in accordance with these new standards.

The Corporation has completed its initial assessment of the effects of adopting IFRS, and has identified the following areas as having the most significant potential impact to the consolidated financial statements. This list should not be regarded as a comprehensive list of the changes expected by conversion to IFRS, but is intended to inform the reader of the areas believed to be the most affected.

### ***Property, plant, and equipment***

#### *IFRS 6 - Exploration for and Evaluation of Mineral Resources*

Implementation of IFRS 6, Exploration for and Evaluation of Mineral Resources represents a departure from Canadian GAAP by segregating from Property, Plant, and Equipment assets pre-exploration costs and exploration and evaluation assets. Pre-exploration costs are those costs incurred prior to obtaining the right to explore and must be expensed. Exploration and evaluation assets must be segregated and disclosed separately, not depleted, but periodically evaluated and impaired if necessary, and then transferred to development and production assets (Property, Plant and Equipment) if the Corporation ascertains that the project has reached commercial viability and technical feasibility. Initially, the Corporation has the option of either expensing or capitalizing Exploration and Evaluation costs prior to being evaluated, and expects that it will choose to capitalize.

#### *IAS 16 - Property, Plant and Equipment*

Under IAS 16, Property, Plant, and Equipment, major or significant components must be identified and depreciated separately over their useful lives. This differs from Canadian GAAP in that, under full cost accounting, all oil and gas assets are separated as intangible or tangible, but depleted over substantially the same reserve base. Replacements and major overhauls must be recorded by removing old associated components from Property, Plant and Equipment, and capitalizing the new. The Corporation is in the process of identifying its major components and their remaining useful lives.

On transition to IFRS, the Corporation has the option to base the depletion calculation using either proved reserves, or proved and probable reserves. The Corporation is currently evaluating which method it will use.

Under Canadian GAAP, small dispositions were credited against the full cost pool. Under IFRS, gains and losses must be recognized on all dispositions.

#### *IAS 36 – Impairment of Assets*

IAS 36, Impairment of Assets, requires that property, plant, and equipment, intangibles, and goodwill be tested for impairment if indicators of impairment exist, or, for goodwill and indefinite life intangibles, at least annually. Impairment is assessed at a cash-generating unit ("CGU") level, as opposed to a full cost pool allowed currently under Canadian GAAP. A CGU is the smallest group of assets capable of generating largely independent cash inflows. The Corporation is in the process of identifying its CGUs and allocating property, plant, and equipment, as well as goodwill, to these CGUs.

Under IFRS, the carrying value can be compared to either the "value in use" or "fair value less costs to sell". Value in use is defined as the present value of expected future cash flows. In the absence of an active market, fair value less costs to sell may also be determined using discounted future cash flows. This differs from Canadian GAAP where impairment testing is a two-step process and compares the carrying value of assets to undiscounted cash flows.

Value in use, as determined by the annual reserve evaluation process, may be defined as either the value of proved reserves or proved and probable reserves. The Corporation is currently assessing which reserves it will use for impairment.

The Corporation expects that implementation of this IFRS will result in more frequent impairments of assets due to the lower level of testing against comparatively smaller values of cash flows. However, also under

IAS 36, previous impairment losses can be reversed depending upon circumstances, which also represents a departure from Canadian GAAP.

### ***IAS 37 – Provisions, Contingent Liabilities, and Contingent Assets***

The probability threshold for recognizing contingent liabilities and assets is higher under Canadian GAAP than IFRS, and as such it is possible that some contingent liabilities that may not have met the recognition criteria under Canadian GAAP will be required to be recognized under IFRS. Under IAS 37, a provision must be recognized when:

- there is a present obligation as a result of a past transaction or event;
- it is probable that an outflow of resources will be required to settle the obligation, and;
- a reliable estimate of the obligation can be made.

Regarding asset retirement obligations, Canadian GAAP requires the use of a credit-adjusted risk-free rate to discount the future obligations, whereas IFRS requires the use of a current market-based discount rate. The difference in discount rates is expected to impact the Corporation's asset retirement obligations, although it is not known at this time the extent or direction of the impact.

### ***IAS 12 – Income Taxes***

IAS 12 currently requires income tax to be charged or credited directly to equity (Other Comprehensive Income) if the tax relates to items that are credited or charged, in the same or a different period, directly to equity. This is a departure from Canadian GAAP, which credits or charges income tax relating to equity in the same period its charged or credited directly to equity. This may result in some income tax effects being recognized directly in equity rather than through net income or loss. The Corporation is assessing the impact of this change and keeping current on the developments through the International Accounting Standards Board's communications regarding the project on Income Tax.

### ***IFRS 1 – First-time Adoption of International Financial Reporting Standards***

IFRS 1 allows for a few alternatives for retrospective applications of certain standards, and mandatory and elective exemptions from full retrospective application. The exemptions the Corporation is currently intending to choose are:

Exploration and Evaluation Assets – IFRS 1 allows an entity that used full cost accounting to elect, at its time of adoption, to measure exploration and evaluation assets at the amount determined under the entity's previous GAAP.

Business Combinations – IFRS 1 would allow use of the IFRS rules for business combinations on a prospective basis rather than re-stating all business combinations.

Share-based Payments – IFRS 1 allows an exemption on IFRS 2, Share-based Payments, to equity instruments which vested before the transition date to IFRS.

IFRS 1 requires significant disclosures of accounting policies, as well as how the financial statements were converted from GAAP to IFRS, and it is expected that the disclosures for the Corporation will be substantial.

The Corporation may revise its estimate of the policy choices and potential impacts as it works through the conversion as new facts and circumstances arise and decisions are made. Until the majority of these decisions can be made and their impact assessed, the Corporation has not yet completed the quantification of the effects.

### ***IFRS Conversion Project Activities***

The IFRS conversion project consists of four phases: diagnostic, design and solution development, implementation, and post implementation. To date, the diagnostic phase involving a high-level review of the

major differences between Canadian GAAP and IFRS has been completed, resulting in the above discussions of the major areas impacted. The table below covers the elements of the conversion project and assessment of the progress. As work continues on the conversion project, certain project activities and milestones could change.

Activities	Milestones	Status
<p><b>Financial statement preparation</b></p> <ul style="list-style-type: none"> <li>- Identify differences in Canadian GAAP/IFRS accounting policies</li> <li>- Select ongoing IFRS policies</li> <li>- Develop financial statement format</li> <li>- Quantify effects of changes for initial IFRS disclosure and 2010 comparative financial statements</li> </ul>	<p>Senior management and audit committee sign-off for all key IFRS accounting policy choices.</p> <p>Develop draft financial statement format.</p>	<p>Completed initial IFRS diagnostic which identified major differences between Canadian GAAP and IFRS.</p> <p>In-depth analysis of issues and accounting policy choices currently underway.</p>
<p><b>Training</b></p> <p>Define and introduce appropriate level of IFRS expertise for each of the following groups:</p> <ul style="list-style-type: none"> <li>- Accounting</li> <li>- Operations</li> <li>- Management</li> <li>- Audit committee</li> </ul>	<p>Accounting and operations group training to occur as needed.</p>	<p>Small group training is ongoing.</p>
<p><b>Systems and processes</b></p> <p>Confirm that business processes and systems are IFRS compliant, including:</p> <ul style="list-style-type: none"> <li>- Program upgrades/changes</li> <li>- Gathering data for disclosures</li> </ul>	<p>Confirm that systems can address 2010 parallel processing requirements.</p> <p>Implement systems changes.</p>	<p>Ability of system to address IFRS changes confirmed and systems training has commenced.</p> <p>Currently require some data clean-up prior to IFRS system change implementation. To be done in Q3.</p>
<p><b>Control Environment</b></p> <p>For all accounting policy changes identified, assess control design and effectiveness implications, and implement changes</p>	<p>Control effectiveness implications to be assessed as part of the analysis of IFRS differences and accounting policy choices.</p>	<p>Analysis of control issues is underway in conjunction with review of accounting issues and policies.</p>
<p><b>External communications</b></p> <p>Assess the effects of key IFRS related accounting policy and financial statement changes on external communications. In particular:</p> <p>Monitor and updated MD&amp;A communications package</p>	<p>Analyze and publish the effect of IFRS on the financial statements throughout the project.</p>	<p>IFRS disclosure in the MD&amp;A will be updated throughout the project.</p>

Senior management of the Corporation have been reviewing the impact on the Corporation's future financial position and results of operations under IFRS, and reports the results of this review to the Board and Audit Committee on a periodic basis. During 2010, the Corporation will complete the implementation of its changeover plan. The Corporation will also monitor standards development as issued by the IASB and the

AcSB as well as regulatory developments by the Canadian Securities Administrators (CSA), which may affect the timing, nature, or disclosure of the adoption of IFRS. Senior management continues to update the external auditors on the implementation progress.

## **DISCLOSURE CONTROLS AND PROCEDURES**

The Chief Executive Officer and Chief Financial Officer, after evaluating the effectiveness of the Corporation's disclosure controls and procedures, have concluded that the design and operation of Strategic's disclosure controls and procedures were adequate to ensure that material information relating to the Corporation and its consolidated subsidiaries would have been known to them and by others within those entities.

*Further information with respect to the Corporation can be found on its website at [www.sogoil.com](http://www.sogoil.com) and on the SEDAR website: [www.sedar.com](http://www.sedar.com).*