Form 51-102F

Management's Discussion and Analysis

Year ended December 31, 2010

March 30, 2011

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 on March 10, 2009, and Steen River Oil & Gas Ltd., a private oil and gas exploration and production company, was acquired on December 22, 2010 by Strategic.

Financial and Operations Overview

For the years ended December 31, 2010 and 2009

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

	2010	2009
Cash Flow from operations *	**$(1,771)**	$(1,685)
Per share – basic	**$(0.02)**	$(0.04)
Net Income (loss)	**$5,315**	$(3,889)
Per share – basic	**$0.06**	$(0.10)
Average production (boe/d)	**303 boe/d**	196 boe/d
Capital expenditures		
Land and seismic	**$4,845**	$ 163
Drill and complete	**5,886**	1,891
Property acquisitions	**1,665**	3,962
Equipment, facilities and other	**1,351**	399
	$13,747	$6,415
Corporate acquisition	**$14,456**	---
Common shares o/s at year-end (000's)	**138,555**	68,693

* before changes in non-cash capital

HIGHLIGHTS

- Net income of $5.3 million ($0.06 per share) for the year ended December 31, 2010, versus a loss of $3.9 million ($0.10 per share) for the year ended December 31, 2009.
- Drilled, completed and tied in two horizontal multi-stage frac wells at Maxhamish.
- Bought out the farmout on the Maxhamish property with its partner (Legacy Oil + Gas Inc.), for $13.0 million ($5.0 million net to Strategic) resulting in a current undeveloped land position of over 100 sections of which Strategic has a 38.5% working interest
- Acquired Steen River Oil & Gas Ltd., a company with over 100 sections of undeveloped land, current production capability of 650 boe/d (2/3 light oil), facilities and tax pools of $120 million for consideration of $14.0 million
- Commenced 2011 development program at Steen River and Maxhamish
- Raised $27.9 million in common and flow through shares in the fourth quarter of 2010
- Raised $21.5 million from the exercise of warrants in the fourth quarter of 2010.

ADVISORIES

Management's discussion and analysis ("MD&A") of the consolidated financial conditions and results of operations should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 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 operation 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:

Maxhamish program. Specific risks include the geologic and operational risks associated with any well. In addition, the area is currently 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 the future in a timely manner due to the status of the capital markets at such time.

Steen River program. Specific risks include the allocation of capital to the drilling program and successful results. In addition, much of the area is currently subject to winter access only. 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.

Discovered Petroleum Initially In Place (DPIIP): DPIIP is equivalent to discovered resources and is defined in the Canadian Oil and Gas Evaluation Handbook ("COGEH") as that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially-in-place includes production, reserves and contingent resources; the remainder is unrecoverable. "Contingent Resources" are defined in COGEH as those quantities of petroleum estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be economically recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. The Contingent Resources estimates and the DPIIP estimates are estimates only and the actual results may be greater or less than the estimates provided herein. There is no certainty that it will be commercially viable to produce any portion of the resources except to the extent identified as proved or probable reserves. "Best estimate" is defined in COGEH with respect to entity-level estimates, as the value derived by an evaluator using deterministic methods that best represent the expected outcome with no optimism or conservatism. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate

OVERVIEW OF PERFORMANCE

Summary

In 2009, a decision was made to grow Strategic which involved acquiring a strong technical team through the ZinMac Inc. acquisition, and following this up by the acquisition of a farmout of the Maxhamish property in northeast British Columbia. The Corporation subsequently acquired the Taber and Conrad properties in Southern Alberta. After raising $14.5 million in late 2009, Strategic commenced its 2010 development program at Maxhamish.

Late in the first quarter of 2010, Strategic participated in two horizontal oil wells at Maxhamish which were drilled and multi-stage fracture stimulated (a-C18-J-D94-O-11 and a-49-J-D94-O-11). Both wells were placed on production and tied in to a natural gas gathering and processing facility in the second quarter. Combined deliverability from these wells was restricted by the owner of the natural gas facility. Strategic management estimates that based on an internal evaluation of the Maxhamish wells, the productivity potential is 150 to 200 barrels per day.

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 in the second quarter. This was followed up in October, 2010 by entering into a purchase and sale agreement with its partner to acquire from Encana Corporation the remaining 35% working interest in Maxhamish, for a total purchase price of $13.0 million ($5.0 million net to Strategic). As a result of these transactions, the current farmout agreement with respect to the Maxhamish area has been eliminated providing Strategic with an undivided 38.5% working interest in over 100 sections of undeveloped land in the area.

In early 2011, Strategic commissioned GLJ Petroleum Consultants Ltd. ("GLJ") to conduct an independent resource evaluation of the Corporation's Maxhamish area effective December 31, 2010. This study has

assigned discovered petroleum initially-in-place ("DPIIP") to 13,874 gross acres (22 sections gross lease) of land for a best estimate of 123 MMbbl of oil (48 MMbbl net to Strategic). This represents 6 MMbbl of oil per section gross lease. This assignment is consistent with Strategic's internal estimate for DPIIP resources for the study area. The DPIIP study is restricted to a 3 mile extension from the existing wells where proven and probable assignment of reserves have been recognized and does not extend over the entire Maxhamish land base. The 13,874 acres are 20% of Strategic's Maxhamish land base.

This independent study confirms the Corporation's internal DPIIP estimate of over 600 MMbbl of oil on Strategic's lands. In addition, Strategic management's internal estimate has projected recovery factors of between 10% to 15% on primary recovery. At 4 wells per section this would yield recoverable volumes of between 150 and 225 Mbbl per well. This sets up an exciting 2011 and beyond, as the Maxhamish field is further developed for all year access to maximize the upside potential.

Strategic continues to review and assess additional opportunities to add to its light oil prospects inventory. On December 22, 2010, Strategic closed an arms-length acquisition of all of the issued and outstanding shares of Steen River Oil & Gas Ltd. ("Steen River"), a private oil and gas exploration and production company. Steen River's primary asset is an owned and operated light oil field producing from the Keg River zone. Steen River is the primary operator in the area with over 110 sections of undeveloped land, oil and natural gas facilities and other infrastructure. This area has been under-exploited to date with minimal seismic or drilling activity.

At the time of acquisition, production was approximately 250 boe/d with an additional 250 bbls/d of light oil (34 degree API) shut-in as a result of a pipeline break. In late January, 2011 the pipeline was repaired and an additional 400 boe/d of production was brought back on-stream. Total production from this field is currently approximately 650 boe/d, of which greater than 2/3 is light oil. This is prior to the first quarter 2011 workover and drilling programs.

In October, 2010, Strategic closed a financing for common and flow-through common shares for gross proceeds of $22.2 million. In December, 2010, Strategic closed a second financing for flow-through common shares for gross proceeds of $5.7 million. In addition, 36.0 million warrants were exercised for proceeds of $21.5 million in the fourth quarter.

At year-end, the Corporation was in strong financial shape, with working capital of approximately $29 million, a $5 million unused line of credit and two large light oil resource opportunities. Strategic plans an aggressive capital program on its Maxhamish and Steen River properties in 2011.

2010 results

The year ended December 31, 2010 showed an increase in volumes over the comparable period of 2009 due to the acquisition of the Taber and Conrad properties of Southern Alberta in November 2009, and the payout and subsequent acquisition of Maxhamish in the third and fourth quarters of 2010. Average daily sales volumes increased by 54% to 303 boe/d in 2010 versus 196 boe/d in 2009. Revenues increased by 118% to $6,124,134 for 2010 versus $2,808,080 in 2009. The average commodity prices rose by 41% for 2010 over 2009 contributing to the increase in revenue. The Corporation received an average price of $55.34 per boe in 2010 versus $39.17 in 2009.

For the fourth quarter ended December 31, 2010 average daily production was 317 boe/d versus 314 boe/d for the third quarter of 2010. Steen River was acquired on December 22, 2010, and a substantial portion of the production was shut-in due to a pipeline break, so little production accrued to Strategic in the 2010 financial statements. Subsequent to the year end, the pipeline repair was completed, adding over 650 boe/d of production to the Corporation in the first quarter of 2011. Revenues for the fourth quarter of 2010 were $1,639,920 versus $1,504,357 in the third quarter. The Corporation received an average price of $56.21 per boe in the fourth quarter of 2010 versus $52.08 per boe in the third quarter.

For the year ended December 31, 2010, the Corporation had a net income of $5,314,568 or $0.06 per share (basic and diluted) as compared to a net loss of $3,889,318 or $0.10 per share for 2009. The income in 2010 arises from a non-recurring item, the gain on acquisition of Steen River of $10,547,125 resulting from the fair value of the assets acquired being greater than the consideration offered at the time of acquisition. Funds used in operations for 2010 were $1,771,245 as compared to $1,685,162 in 2009.

Drilling

Years ended December 31	**2010**		2009	
	Gross	**Net**	Gross	Net
Oil	**5**	**3.30**	1	1.00
Gas	**0**	**0.00**	0	0.00
Standing	**0**	**0.00**	0	0.00
Dry	**2**	**2.00**	1	0.25
Total	**7**	**5.30**	2	1.25

Financings

On October 7, 2010, Strategic closed a financing for 18,300,000 common shares of Strategic at a price of $0.90 per share, and 5,232,500 flow-through common shares at a price of $1.10 per share, for gross proceeds of $22,225,750. On December 22, 2010, Strategic closed a second financing for 5,175,000 flow-through common shares at a price of $1.10 per share for gross proceeds of $5,692,500.

The combined flow-through common share proceeds of $11,448,250, of which $342,938 has been expended in 2010, will be used to incur eligible Canadian exploration expenditures. These expenditures will be renounced to subscribers effective on or before December 31, 2010, and is required to be spent by December 31, 2011.

In addition, 36.0 million warrants issued in the 2009 private placement were exercised for proceeds of $21.5 million in the fourth quarter.

Acquisition of Steen River Oil & Gas Ltd.

On December 22, 2010, Strategic closed an arms-length acquisition of all of the issued and outstanding shares of Steen River Oil & Gas Ltd. ("Steen River"), a private oil and gas exploration and production company through a Plan of Arrangement which offered $0.30 cash or 0.33 common shares of the Corporation in exchange for one Steen River share, as well as assuming the outstanding debentures of Steen River. The Corporation acquired the shares in exchange for a total of 4,416,545 common shares, $6,349,162 in cash, and the assumption of secured debentures valued at $3,425,225, for a total consideration of $14,455,925. Due to the consideration offered for Steen River being less than the fair value of the assets acquired, the Corporation recognized a gain on acquisition of subsidiary of $10,547,125.

Steen River was acquired to gain access to its high quality light oil producing properties with a substantial land base and facility infrastructure.

The acquisition was accounted for using the acquisition method of accounting for business combinations using management's best estimates of the fair values at the date of acquisition as follows:

Net assets acquired	
Working capital deficit	$ (1,710,391)
Undeveloped land	2,667,542
Developed oil and gas properties	30,564,878
Capital assets	44,444
Asset retirement obligations	(6,563,422)
	$ 25,003,050
Consideration	
Cash	$ 6,349,162
4,416,545 common shares valued at $1.06 per share	4,681,538
Assumption of debentures	3,425,225
	$ 14,455,925
Gain on acquisition of subsidiary	**$ 10,547,125**

Transaction costs of $256,491 were incurred in relation to the acquisition, and were recorded in general and administrative expenses. Tax pools of approximately $120 million were also acquired resulting in a potential $21.9 million future tax asset. No future tax asset will be recognized at this time since, based upon the historical taxable income of Steen River, it cannot be reasonably estimated if it is more likely than not that some or all of the future tax asset will be realized.

Maxhamish, northeast British Columbia

Late in the first quarter of 2010, at Maxhamish, 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 was restricted by the owner of the natural gas facility. Strategic management estimates that based on an internal evaluation of the Maxhamish wells, the productivity potential is 150 to 200 barrels per day.

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 in the second quarter of 2010. This was followed up in October, 2010 by entering into a purchase and sale agreement ("the Agreement") with its partner to acquire from Encana Corporation the remaining 35% working interest in Maxhamish, for a total purchase price of $13.0 million ($5.0 million net to Strategic). As a result of these transactions, the current farmout agreement with respect to the Maxhamish area has been eliminated providing Strategic with an undivided 38.5% working interest in over 100 sections of undeveloped land in the area.

Agreement Benefits

1) Effectively terminates the farmout agreement, with the following benefits:
    i) Immediate increased working interest ownership in the greater than 85 gross sections of land without having to drill the additional 18 earning wells;
    ii) The development plan is no longer subject to the commitment plan in the farmout agreement, including 18 remaining commitment wells;
    iii) Removal of the "promote" on wells or facilities which improves the economics;
    iv) Removal of uncertainty on whether the farmor was committed to spending capital to develop this property;
2) Long tenure lands, with few expiries before 2013.

Terms of the Agreement:

1) The acquisition included 21,500 net acres (> 30 sections) of undeveloped land, 7 oil wells (representing 50 boe/d of production net to Strategic), related facilities, an oil pipeline, and a road that connects the area to the year round Liard Highway.
2) The acquisition included rights to extensive 2-D seismic coverage over the area.
3) The acquisition included rights to the Dunvegan zone, providing access to a source of water.

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Taber/Conrad

In early July, at Conrad in southern Alberta, Strategic spudded a horizontal well (6-23 Hz). This well was drilled as a multi-leg horizontal well, targeting the Sawtooth formation. This well was tied in and is producing 30 bop/d of medium API oil.

The Corporation brought in a partner to allow for an accelerated drilling program at Taber. The terms of this agreement provided that the partner pay $1.6 million to drill two wells, and to earn a 25% interest in the property. In the third quarter of 2010 Strategic drilled two wells (4-24 and 11-14). These wells are currently producing a combined 50 bop/d (gross). The technical team is currently reviewing the Taber field for additional locations and a potential chemical flood. Effective October 1, 2010, the partner met the farmout commitment and has earned a 25% interest in the Taber property.

Both the Taber and Conrad fields are mature fields and carry higher operating costs arising primarily from handling high volume of water and from minor ongoing repairs.

OUTLOOK FOR 2011

Strategic finished 2010 with approximately $29 million in working capital, with two light oil properties (Maxhamish and Steen River) with over 100 gross sections of land in each.

Strategic exited 2010 with production of approximately 500 boe/d. After repair of the pipeline at Steen River in January, 2011, an additional 400 boe/d was added, of which 2/3 was light sweet crude oil. Production in early 2011 is in excess of 900 boe/d.

Maxhamish

At Maxhamish, the 2011 development program is proceeding.

The current plan for the first half of the year includes:

i) Building a year-round access road in the first quarter of 2011 to improve access to the area;
ii) Licensing and construction of drilling pads that can accommodate up to 8 wells per pad;
iii) Drilling up to 4 wells by the third quarter of 2011, with completions to follow;
iv) Building infrastructure where necessary, including battery, pipelines, etc.;
v) Assessment of future drilling program.

Steen River, northwest Alberta

At Steen River, the Corporation has a 100% working interest and operates the field, Strategic is moving forward aggressively to develop the property. This includes shooting a $3.5 million 3-D and 2-D seismic program, workovers on up to 4 wells, building a year round road into certain core areas of the property and drilling two Keg River oil wells. This program is currently in progress and will be finished early in the second quarter. Upon completion of the seismic program, the regional geological study currently being performed, and assessment of current workovers and new wells, Strategic's technical team will be assessing the results and selecting additional Keg River locations for late summer or fall drilling.

Summary

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

i) It is financed with a working capital balance of $29 million at year-end, 2010;
ii) Independent confirmation of light oil resource at Maxhamish, with over 100 sections of land;
iii) 100 sections of undeveloped land at Steen River, an area with proven light oil potential;
iv) Politically and fiscally stable environment.

IMPACT OF CURRENT ECONOMIC VOLATILITY AND UNCERTAINTY

Crude oil prices have stayed robust through 2010, and the Corporation was able to raise over $20,000,000 of equity in October 2010 and over $5,000,000 in December 2010. The Corporation also has received additional proceeds of over $21,000,000 during 2010 through the exercise of options and warrants. In addition, the Corporation has its $5.0 million line of credit with a Canadian financial institution.. Strategic is therefore in a strong position to undertake its planned 2011 capital expenditures program. The Corporation will continue to monitor its funds from operations, cash position and available credit facilities to ensure its ability to meet its planned capital program for 2011.

RISK FACTORS

Additional risk factors may be found on page 23 of this Management Discussion and Analysis under "Financial Instruments".

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings. Additional risks and uncertainties not currently known to the management of the Corportion may also have an adverse effect on the Corporation's business and the information set out below does not purport to be an exhaustive summary of the risks affecting the Corporation..

Substantial Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Corporation's revenues or reserves decline, it may limit the Corporation's ability to expend or access the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's financial condition, results of operations or prospects.

Capital Markets

The market events and conditions witnessed over the past two financial years, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility in commodity prices and increases in the rates at which the Corporation is able to borrow funds for its capital programs. While there have been recent signs which may suggest the beginning of a global economic recovery, there can be no certainty regarding the timing or extent of a potential recovery, and such continued uncertainty in the global economic situation means that the Corporation, along with all other oil and gas entities, may continue to face restricted access to capital and increased borrowing costs. This could have an adverse effect on the Corporation, as its ability to make future capital expenditures is dependent on, among other factors, the overall state of the capital markets and investor appetite for investments in the energy industry generally and the Corporation's securities in particular.

Additional Funding Requirements

The Corporation's cash flow from its producing reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on favourable terms.

Issuance of Debt
From time to time the Corporation may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the articles of the Corporation nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time, could impair its ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise and could negatively affect the Corporation's debt ratings. This in turn, could have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flow.

Exploration, Development and Production Risks
Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Corporation may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. 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, management of the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Corporation.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances 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, availability of drilling rigs, support equipment, 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.
Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation. In accordance with industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Corporation could incur significant costs that could have a material adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks could have a material adverse effect on the Corporation.

Operational Dependence
Other companies operate some of the assets in which the Corporation has an interest (in particular, the Corporation's interests in Maxhamish). As a result, the Corporation will have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others will therefore depend upon a number of factors that may be outside of the Corporation's control, including the timing and

amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Project Risks
The Corporation will manage a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. The Corporation's ability to execute projects and market oil and natural gas will depend upon numerous factors beyond the Corporation's control, including:

- the availability of drilling and related equipment;
- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Availability of Drilling Equipment and Access
Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities. To the extent the Corporation is not the operator of its oil and gas properties, the Corporation will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

Prices, Markets and Marketing of Crude Oil and Natural Gas
The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by numerous factors beyond its control. The Corporation's ability to market its oil and natural gas may depend upon its ability to contract capacity on pipelines that deliver natural gas to commercial markets. The Corporation may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The Corporation's revenues, profitability and future growth and the carrying value of its oil and gas properties are substantially dependent on prevailing prices of oil and gas. The Corporation's ability to borrow and to obtain additional capital on attractive terms is also substantially dependent upon oil and gas prices. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States and Canada the actions of the OPEC and Russia, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Corporation's carrying value of its proved reserves, borrowing capacity, revenues, profitability and cash flows from operations.

Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, bank borrowings available to the Corporation in part determined by the Corporation's borrowing base. A sustained material decline in prices from historical average prices could reduce the Corporation's borrowing base, therefore reducing the bank credit available to the Corporation which could require that a portion, or all, of the Corporation's bank debt be repaid.

Insurance
The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Although prior to conducting drilling and other field activities, the Corporation will obtain insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances be insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on the Corporation's financial position, results of operations or prospects.

Legal Proceedings
The Corporation may from time to time be subject to litigation and regulatory proceedings arising in the normal course of its business. The Corporation cannot determine whether such litigation and regulatory proceedings will, individually or collectively, have a material adverse effect on its business, results or operations and financial condition. To the extent expenses incurred in connection with litigation or any potential regulatory proceeding or action (which may include substantial fees of attorneys and other professional advisors and potential obligations to indemnify officers and directors who may be parties to such actions) are not covered by available insurance, such expenses could adversely affect the Corporation's cash position.

Environmental Risks
All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and international, national, provincial, state and local law and regulation. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of same can result in the imposition of clean-up orders, fines and/or penalties, some of which may be material, as well as possible forfeiture of requisite approval obtained from the various governmental authorities. The discharge of GHG emissions and other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it is in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect its financial condition, results of operations or prospects.

Canadian Tax Considerations
As the Corporation is engaged in the oil and natural gas business its operations are subject to certain unique provisions of the *Income Tax Act* (Canada) and applicable provincial income tax legislation relating to characterization of costs incurred in their businesses which effects whether such costs are deductible and, if deductible, the rate at which they may be deducted for the purposes of calculating taxable income. The Corporation has reviewed its historical income tax returns with respect to the characterization of the costs incurred in the oil and natural gas business as well as other matters generally applicable to all corporations including the ability to offset future income against prior year losses. The Corporation has filed or will file all required income tax returns and believes that it is in full compliance with the provisions of the *Income Tax Act* (Canada) and applicable provincial income tax legislation, but such returns are subject to reassessment. In the event of a successful reassessment of the Corporation it may be subject to a higher than expected past or future income tax liability as well as potentially interest and penalties and such amount could be material.

Foreign Currency Rates
A significant amount of the Corporation's activities are transacted in or referenced to the currency of the United States, and fluctuations in the US - Canada exchange rate could result in unanticipated fluctuations in the Corporation's financial results which are denominated in Canadian dollars. The Corporation does not currently manage its exposure to fluctuations in currency exchange rates.

Competition
The Corporation actively competes for reserve acquisitions, exploration leases, licences and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial resources than the Corporation. The Corporation's competitors include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators. Competition may also be presented by alternate energy sources.
The oil and gas industry is highly competitive. The Corporation's competitors for the acquisition, exploration, production and development of oil and natural gas properties, and for capital to finance such activities, include companies that have greater financial and personnel resources available to them than the Corporation. Certain of the Corporation's customers and potential customers are themselves exploring for oil and gas, and the results of such exploration efforts could affect the Corporation's ability to sell or supply oil or gas to these customers in the future. The Corporation's ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

Reserve Replacement
The Corporation's future oil and natural gas reserves, production, and cash flows to be derived therefrom are highly dependent on the Corporation successfully acquiring or discovering new reserves. Existing reserves and production will decline over time without the continual addition of new reserves. A future increase in the Corporation's reserves will depend not only on the Corporation's ability to develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. There can be no assurance that the Corporation's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

Reliance on Industry Partners
In order to carry out certain of its business and operations, the Corporation relies on its industry partners (certain of which include suppliers, contractors and joint venture parties and operators). Accordingly, the Corporation is exposed to third party risk. Should such industry partners fail to fulfil those duties and obligations each owes to the Corporation, such failure could have a material adverse effect on the Corporation's business or operations.

Reliance on Key Employees
The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse effect on the Corporation. The Corporation does not have key person insurance in effect for management. The contributions of these individuals to the Corporation's immediate operations are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the Corporation's management.

Permits, Licences and Approvals
The Corporation's properties are held in the form of licences and leases and working interests in licences and leases. If the Corporation or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Corporation's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on its results of operations and business.

Royalties, Incentives and Production Taxes
In addition to federal regulations, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other

than Crown Lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by government regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

From time to time, the Governments of Canada, Alberta and British Columbia have established incentive programs which have included royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced planning projects.

Land Tenure

Crude oil and natural gas located in the Canadian western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Title to Properties

Although title reviews may be conducted prior to the purchase of producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim which could result in a reduction of the revenue received by the Corporation.

Reserve Information

The reserve and recovery information contained in the GLJ Petroleum Consultants Ltd. (“GLJ”) and AJM Petroleum Consultants (“AJM”) reserve reports are only estimates and the actual production and ultimate reserves from the Corporation's properties may be greater or less than the estimates prepared in such report. The GLJ and AJM reserve reports have been prepared using certain commodity price assumptions which are described in the notes to the reserve tables. If lower prices for crude oil, natural gas liquids and natural gas are realized by the Corporation and substituted for the price assumptions utilized in the report, the present value of estimated future net cash flows for the Corporation's reserves would be reduced and the reduction could be significant, particularly based on the constant price case assumptions. Exploration for oil and natural gas involves many risks, which even a combination of experience and careful evaluation may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered by the Corporation.

Dilutive Effect of Financings and Acquisitions

The Corporation may make future acquisitions or enter into financing or other transactions involving the issuance of securities of the Corporation which may be dilutive.

Dividends

The Corporation has not paid any dividends on its outstanding Common Shares. Payment of dividends on the Common Shares in the future will be dependent on, among other things, the cash flow, results of operations and financial condition of the Corporation, the need for funds to finance ongoing operations and other business considerations as the Board considers relevant.

Third Party Credit Risk

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures could have a material adverse effect on the Corporation and its cash flow from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of an acquired business may require substantial

management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Corporation.

Hedging

The Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases and the Corporation may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Corporation will not benefit from the fluctuating exchange rate.

Aboriginal Claims

The Canadian First Nations have made rights and title claims to a significant portion of Western Canada. At present the Corporation is unable to assess what, if any, impact such claims will have on the business and operations that it conducts in Western Canada.

Conflict of Interest

Certain of the directors and officers of the Corporation are also directors and officers of other oil and gas companies involved in natural resource exploration and development, and conflicts of interest may arise between their duties as officers and directors of the Corporation and as officers and directors of such other companies. Such conflicts must be disclosed in accordance with, and are subject to such other procedures and remedies as apply under the ABCA.

RESULTS OF OPERATIONS

Production

Years ended December 31	**2010**	2009
Oil, condensate, & ngls – bbls/d	**221**	102
Natural gas – mcf/d	**493**	567
Boe/d	**303**	196

Production for 2010 increased by 55% on a boe per day (“boe/d”) basis mainly a result of acquiring the Taber and Conrad properties in November, 2009, and the contributions from Maxhamish commencing June 2010. Steen River was acquired on December 22, 2010, and a substantial portion of the production was shut-in due to a major pipeline break, so little production accrued to Strategic for 2010. Subsequent to the year end, the pipeline repair was completed, and the Corporation added 400 boe/d of production.

Revenue

Years ended December 31	**2010**	2009
Sales		
Oil, condensate, and ngls	**$ 5,357,391**	$ 1,942,561
Natural gas	**766,742**	865,519
Total sales	**$ 6,124,133**	$ 2,808,080
Average prices		
Oil and ngls ($/bbl)	**$ 66.33**	$ 52.25
Natural gas ($/mcf)	**$ 4.26**	$ 4.18
Oil equivalent ($/boe)	**$ 55.34**	$ 39.17

The average price received for oil, condensate and ngls was $66.33 per bbl as compared to $52.25 per bbl reflecting a 27% price increase. The 2010 gas price was $4.26 per mcf representing a 2% price increase from $4.18 per mcf in 2009. Overall, the combined price in 2010 of $55.34 per boe is 41% higher than the combined price of $39.17 per boe in 2009. Revenues increased by 118% in 2010 over 2009 because of rising commodity prices and increased production from Taber, Conrad, and Maxhamish.

Royalties

Years ended December 31	**2010**	2009
Crown royalties	**$ 373,164**	$ 383,689
Freehold royalties	**76,340**	93,826
Overriding royalties	**61,402**	48,618
Net royalties	**$ 510,906**	$ 526,133
Per boe	**$ 4.62**	$ 7.34
Percentage of revenues	**8.3%**	18.7%

For 2010, the decrease in the royalty rate over 2009 was due to the maturity of the Taber and Conrad oil properties which 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, 1009, 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 December 31, 2010, $939,660 in drilling credits have been earned, with $273,556 received and recognized as a reduction to capital spending, as well as receiving the 5% crown royalty rate on four wells.

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

- the prior incentive program of five percent for the first year of production on new natural gas and conventional oil wells will became permanent with the time and volume limits as previously stated;

- the maximum royalty rate for conventional oil was reduced at higher price levels from 50 percent to 40 percent;

- the maximum royalty rate for conventional and unconventional natural gas was 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 are allowed to select the transitional royalty rates.

Operating and transportation costs

Years ended December 31	**2010**	2009
Operating costs	**$ 3,031,594**	$ 1,170,562
Transportation costs	**235,028**	95,260
	$ 3,266,622	$ 1,265,822
Per boe		
Operating costs	**$ 27.40**	$ 16.33
Transportation costs	**2.12**	1.33
	$ 29.52	$ 17.66

The operating and transportation costs averaged $29.52 per boe for 2010 compared to $17.66 per boe for 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 and high trucking costs.

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 2010.

Operating netbacks

Years ended December 31	**2010**	2009
Per boe		
Revenues	**$ 55.34**	$ 39.17
Royalties	**(4.62)**	(7.34)
Operating costs	**(27.40)**	(16.33)
Transportation costs	**(2.12)**	(1.33)
Netback per boe	**$21.20**	$14.17

The acquisition of the Taber and Conrad oil-producing, low-royalty properties have improved the netback from $14.17 per boe for 2009 to $21.20 per boe for 2010, representing a 50% increase.

General and administrative expenses

Years ended December 31	**2010**	2009
Wages and employee benefits	**$ 1,702,824**	$ 1,065,613
Professional fees	**334,971**	182,461
Consulting fees	**610,534**	423,209
Public reporting	**194,820**	169,574
Occupancy costs	**334,950**	343,436
Travel	**164,401**	156,410
Miscellaneous general and administrative	**711,348**	301,388
Total	**$ 4,053,848**	$ 2,642,091
Per boe	**$ 36.63**	$ 36.86

General and administrative expenses remained static on a per boe basis for 2010 as compared to 2009. Total general and administrative costs increased to $4,053,848 for 2010 from $2,642,091 in 2009 due mainly to increased costs associated with the increased oil and gas operations and additional salaries.

Depletion, depreciation and accretion

Years ended December 31	**2010**	2009
Depreciation, depletion, and accretion	**$ 3,488,931**	$ 1,941,394
Per boe	**$ 31.53**	$ 27.08

Depletion, depreciation and accretion charges for 2010 increased on a per boe basis to $31.54 from the $27.08 recorded for 2009.

Funds from operations and net income (loss)

Years ended December 31	**2010**	2009
Funds used in operations	**$(1,771,245)**	$(1,685,162)
Per share		
basic	**$ (0.02)**	$ (0.04)
diluted	**$ (0.02)**	$ (0.04)
Net income (loss)	**$ 5,314,568**	$(3,889,318)
Per share		
basic	**$ 0.06**	$ (0.10)
diluted	**$ 0.06**	$ (0.10)

Funds used in operations for 2010 remained fairly constant as compared to 2009, but the increase in net income is attributable to the gain on acquisition of Steen River.

Capital Expenditures

Years ended December 31	2010	2009
Land purchases and maintenance costs	**$ 4,484,837**	$ 72,728
Purchase of reserves	**1,665,303**	3,962,587
Geological and geophysical	**360,250**	89,916
Drilling and completion	**5,886,099**	1,890,951
Equipping and facilities	**1,332,162**	375,052
Other	**17,985**	23,703
Total cash expenditures	**$13,746,636**	$ 6,414,937

Capital expenditures were $13,746,636 for 2010 compared to $6,414,937 for 2009. During 2010, Strategic participated in the drilling and completion of three wells at Conrad, two wells at Taber, as well as drilling two horizontal wells and the optimization program at Maxhamish. There were also major land acquisitions at Conrad and Maxhamish.

SUMMARY OF QUARTERLY FINANCIAL DATA

The following table summarizes quarterly financial results:

Quarter ended	Dec-10 $	Sep-10 $	Jun-10 $	Mar-10 $	Dec-09 $	Sep-09 $	Jun-09 $	Mar-09 $
Petroleum and natural gas sales and other income	1,702,267	1,507,595	1,298,172	1,689,641	1,081,829	503,983	591,139	631,129
Income (loss)	8,223,163	(1,098,246)	(1,148,859)	(661,490)	(1,585,039)	(721,506)	(800,361)	(782,412)
Income (loss) per share Basic Diluted	 0.09 0.09	 (0.02) (0.02)	 (0.02) (0.02)	 (0.01) (0.01)	 (0.03) (0.03)	 (0.02) (0.02)	 (0.02) (0.02)	 (0.03) (0.03)
Production boed	317	314	266	315	237	171	176	202
Average price/boe	$56.21	$52.08	$53.38	$59.44	$49.72	$32.09	$36.92	$34.65

SELECTED ANNUAL FINANCIAL INFORMATION

Years ended December 31	2010	2009	2008	2007
Revenues	**$ 6,124,134**	$ 2,808,080	$ 3,850,281	$ 1,431,323
Income (loss)	**$ 5,314,568**	$ (3,889,318)	$ (208,122)	$ (2,973,615)
Income (loss) per share Basic Diluted	 **0.06** **0.06**	 (0.10) (0.10)	 (0.01) (0.01)	 (0.15) (0.15)
Total Assets	**$ 96,836,376**	$ 26,403,032	$ 11,540,258	$ 9,273,497
Long-term debt	**Nil**	Nil	Nil	Nil
Cash dividends	**Nil**	Nil	Nil	Nil

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 2010, funds of $1,771,245 were used in operations, $21,789,391 of cash proceeds was received from the warrants and options exercised during the year, $25,923,226 in flow-through and common share issues were raised, and capital of $13,746,636 was expended on oil and gas properties.

Steen River was acquired for $6,349,162 in cash plus an additional $1,137,893 was forwarded to them to satisfy the remaining closing costs. The Corporation has a working capital balance of $28,748,615 at December 31, 2010, with an unutilized amount of $5,000,000 on the credit facility.

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

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:

	2010 **$**	2009 $
Current assets	**34,838,496**	7,846,325
Current liabilities (excluding debt)	**(6,089,881)**	(1,732,893)
Net working capital surplus	**28,748,615**	6,113,432
Total line of credit	**5,000,000**	5,000,000
Year end loan balance	**-**	(1,500,000)
Unutilized line of credit	**5,000,000**	3,500,000
Net available funds	**33,748,615**	9,613,432

The Corporation is currently projecting its 2011 capital program to be approximately $25.0 million, and expects the current available funds plus expected 2011 cash flow will be sufficient to fund it.

The amount of the credit facility is based on petroleum and natural gas reserves with certain financial covenants. The credit facility also contains a financial covenant that requires the Corporation to maintain a 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 December 31, 2010, this ratio was 6.5:1 (2009- 6.6:1).

SHARE DATA

At March 30, 2011 Strategic had 138,555,366 common shares, and 6,971,667 stock options with a weighted average exercise price of $0.82 per share outstanding.

Common Shares

Authorized:

Unlimited number of common shares without par value

Issued:	**Number of shares**	**$**
Balance, December 31, 2008	**30,082,965**	**$15,681,441**
Shares issued re: ZinMac acquisition (v)	5,000,000	950,000
Shares issued re: Taber/Conrad acquisition (vi)	2,444,444	1,100,000
Private placement – common shares (vii)	25,733,598	11,580,119
Less: non-cash value attributed to warrants (vii)		(4,922,223)
Private placement – flow-through shares (vii)	5,432,092	2,987,651
Less: non-cash value attributed to warrants (vii)		(478,561)
Tax effect of renunciation on flow-through shares		(170,000)
Share issue costs		(2,342,665)
Balance, December 31, 2009	**68,693,099**	**$24,385,762**
Warrants exercised (i)	36,004,889	21,503,558
Stock options exercised (i)	733,333	285,833
Non-cash fair value of options and warrants exercised (i)		7,113,399

October 2010 financing – common shares (ii)	18,300,000	16,470,000
October 2010 financing – flow-through shares (ii)	5,232,500	5,755,750
December, 2010 financing – flow-through shares (iii)	5,175,000	5,692,500
Shares issued for Steen River acquisition (iv)	4,416,545	4,681,538
Tax effect of renunciation on flow-through shares (vii)		(746,913)
Share issue costs		(1,995,023)
Balance, December 31, 2010	**138,555,366**	**$83,146,404**

2010 issuances:

(i) During 2010, 36,004,889 warrants were exercised for proceeds of $21,503,558 and 733,333 stock options were exercised for proceeds of $285,833. The fair value adjustment of these warrants and options of $7,113,399 was recorded and deducted from contributed surplus.

(ii) During October, 2010, the Corporation completed a bought deal financing resulting in the issuance of 18,300,000 common shares at $0.90 per common share and 5,232,500 flow-through common shares at $1.10 per common share for gross proceeds of $22,225,750.

(iii) During December, 2010, 5,175,000 flow-through shares were issued for $1.10 per share for total proceeds of $5,692,500.

(iv) On December 22, 2010, 4,416,545 common shares were issued in exchange for the shares of Steen River valued at that day's closing trading price of $1.06 per share for a total value of $4,681,538.

2009 issuances:

(v) The Corporation issued 5,000,000 common shares to the nine shareholders of ZinMac to acquire the company.

(vi) The Corporation issued 2,444,444 common share units to acquire a property.

(vii) In December, 2009 Strategic completed a private placement by the issue of 25,733,598 common share units at $0.45 per unit. Each common share unit consisted of one common share and one common share purchase warrant entitling the holder to acquire one additional common share for a period of one year from closing for $0.60. In addition, 5,432,092 flow-through units were issued at $0.55 per flow-through unit. Each flow-through unit consists of one flow-through share and one half of a common share warrant, each whole common share warrant entitling the holder to one additional common share for $0.70 for one year from closing. Total gross proceeds from the private placement were $14,567,770. The tax effect of the renunciation of flow-through expenditures of $746,913 was recognized in February, 2010.

Shares in escrow

Shares issued pursuant to the ZinMac acquisition remaining in escrow at December 31, 2010 are detailed below:

Total shares in escrow per ZinMac acquisition	**5,000,000**
Shares released March 13, 2009 (10%)	(500,000)
Shares released September 10, 2009 (15%)	(750,000)
Shares released March 10, 2010 (15%)	(750,000)
Shares released September 10, 2010 (15%)	(750,000)
Shares remaining in escrow – December 31, 2010	**2,250,000**

In March, 2011 a further 15% or 750,000 shares were released from escrow.

Warrants

The following table reconciles the changes to the Corporation's warrants for the year ended December 31, 2010:

	Number of Warrants	Exercise price
Opening balance – December 31, 2008	**5,793,625**	**$1.09**
Expired	(5,793,625)	$1.09
Issued – per ZinMac acquisition	370,370	$0.27
Issued – per Taber/Conrad acquisition	2,444,444	$0.60
Issued – per private placement – common shares units	25,733,598	$0.60
Issued – per private placement – flow-through share units	2,716,046	$0.70
Issued – warrants for commissions and finders' fees	164,400	$0.60
Closing balance – December 31, 2009	**31,428,858**	**$0.60**
Warrants issued through exercise of broker warrants	2,473,200	$0.60
Exercised	(33,531,688)	$0.61
Closing balance – December 31, 2010	**370,370**	**$0.27**

The following table sets out the outstanding warrants as at December 31, 2010:

Number of warrants	Exercise price	Expiry
370,370	$0.27	May 8, 2011

All warrants vested immediately. Upon exercise, fair value of $5,897,198 was recognized into share capital from contributed surplus for the warrants exercised in during 2010 (2009 - $nil).

Broker Warrants

The following table reconciles the changes to the Corporation's broker warrants for the year ended December 31, 2010:

	Number of Warrants	Exercise price
Opening balance – December 31, 2008	**-**	**-**
Issued – broker warrants for commissions	2,473,200	$0.45
Closing balance – December 31, 2009	**2,473,200**	**$0.45**
Exercised	(2,473,200)	$0.45
Closing balance – December 31, 2010	**-**	**-**

In 2009, an agent was given 2,473,200 broker warrants representing the amount of 10% of the units and flow-through units sold, exercisable for one year from closing. Each broker warrant entitled the holder to acquire one common share unit for $0.45 per unit. Each common share unit consisted of one common share and one common share purchase warrant entitling the holder to acquire one additional common share for a period of one year from closing for $0.60. These warrants were exercised in 2010, and 2,473,200 additional warrants were issued at $0.60 per common share which vested immediately. All warrants were exercised in 2010, so there were no broker warrants outstanding at December 31, 2010. The warrants were valued using the Black-Scholes model with an expected volatility of 126%, a risk-free rate of 1.26%, an expected life of one year, and no expected dividends, and a fair value of $1,018,915 was recorded in share issue costs in 2009. In 2010, when the broker warrants were exercised, the fair value of $1,018,915 was recognized into share capital from contributed surplus.

Stock options

The Corporation has a stock option plan under which officers, directors and employees are eligible to receive stock options. The Corporation may reserve for issuance under the plan up to 10% of the issued and

outstanding common shares. Options granted under the plan generally have a term of five years and vest at terms to be determined by the directors. As at December 31, 2010, 3,846,667 (2009 - 3,355,000) options were outstanding.

The following table reconciles the changes to the Corporation's stock options for the year ended December 31, 2010:

	Number of options	Average Exercise Price
Balance – December 31, 2008	**800,000**	**$0.70**
Issued *(i)*	1,855,000	$0.46
Issued *(ii)*	800,000	$0.50
Expired	(100,000)	$0.50
Balance – December 31, 2009	**3,355,000**	**$0.53**
Issued *(iii)*	1,275,000	$0.65
Exercised *(iv)*	(733,333)	$0.39
Expired	(50,000)	$0.75
Balance – December 31, 2010	**3,846,667**	**$0.59**

(i) In March, 2009, 1,855,000 common share options were issued. Of these options, 300,000 options had an exercise price of $0.25 per share expiring in five years from date of issue, and vested immediately. The remaining options vested one-third immediately and are exercisable at $0.25 per share, one-third vest at the first year anniversary date and are exercisable at $0.50 per share, and the final third vest at the second anniversary date and are exercisable of $0.75 per share. These options also expire five years from the date of issue. The fair value of the options were calculated using the Black-Scholes model using an expected volatility of 114.3%, interest rate of 1.9%, expected life of 5 years, and no expected dividends resulting in $245,984 of stock-based compensation recognized over the vesting period.

(ii) In October, 2009, 800,000 common share options were issued with an exercise price of $0.50 per share expiring in five years from date of issue, and were exercisable immediately. The fair value of the options recognized was $291,772 using an expected volatility of 114.3%, interest rate of 2.48%, expected life of 5 years, and no expected dividends.

(iii) 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 vested immediately. The fair value of the options was 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.

(iv) During 2010, 733,333 options were exercised for proceeds of $285,833. Fair value of $197,286 was recognized into share capital from contributed surplus when the options were exercised.

(v) Subsequent to the year end, 3,125,000 stock options were issued with an exercise price of $1.10 per share expiring five years from date of issue and vested immediately.

The following table sets out the outstanding options as at December 31, 2010:

All stock options			**Exercisable**		
Number of options	**Exercise price**	**Weighted Average Life (yrs)**	**Number of options exercisable**	**Exercise Price**	**Weighted Average Life (yrs)**
701,667	$0.25	3.19	701,667	$0.25	3.19
1,235,000	$0.50	3.61	1,235,000	$0.50	3.61
1,275,000	$0.65	4.04	1,275,000	$0.65	4.04
435,000	$0.75	3.19	-	$0.75	-
200,000	$1.60	0.33	200,000	$1.60	0.33
3,846,667	**$0.59**	**3.46**	**3,411,667**	**$0.57**	**3.49**

Weighted average shares

	2010	2009
Weighted average shares (basic)	**80,239,777**	38,240,750
Options (nil in 2009 – antidilutive)	**1,514,221**	-
Warrants (nil in 2009 – antidilutive)	**260,897**	-
Weighted average shares (diluted)	**82,014,895**	38,240,750

TAX POOLS

The Corporation has a future tax asset of approximately $23 million which has not been recognized. This arises as the Corporation's losses and tax pools are greater than the cost base of the assets.

The Corporation has the following combined tax deductions available to reduce future taxable income:

	2010	2009
	$million	*$million*
Canadian oil and gas property expense	**15**	6
Canadian development expense	**26**	3
Canadian exploration expense	**28**	1
Undepreciated capital cost	**23**	2
US tax pools	**5**	6
Non-capital losses carried forward – expiring between 2010 and 2029	**65**	7
Share issue costs	**3**	2
Closing Balance	**165**	27

TRANSACTIONS WITH RELATED PARTIES

Legal fees and expenses in the amount of $477,142 ($228,188 – 2009) were incurred with a legal firm of which a director is a partner, which have been recorded in general and administrative expenses and share issue costs. General administrative fees in the amount of $79,500 ($67,500 – 2009) were charged by the Corporate Secretary. Consulting fees in the amount of $30,755 ($55,230 – 2009) were charged by a director for geophysical consulting services. Software charges of $126,000 ($20,843 – 2009) were charged by a company controlled by an officer. Accounts payable and accrued liabilities at December 31, 2010 includes $307,198 ($101,695 – 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

a) Pursuant to the issues of flow through shares in 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 December 31, 2010, $342,938 has been incurred towards this commitment.

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

Year ended	**$**
2011	292,596
2012	292,596
2013	263,213
	848,405

FINANCIAL INSTRUMENTS AND RISKS

Financial instruments consist of cash and cash equivalents, short term investments, accounts receivable, 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 December 31, 2010 and 2009, the Corporation had no hedging contracts. The following table analyzes the Corporation's sensitivity to commodity price changes:

	2010	2009
	$	$
10% change in oil price	**487,157**	153,698
10% change in gas price	**73,989**	74,497

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

ii) Interest Rate Risk

The Corporation is exposed to interest rate risk as changes in interest rates may affect future cash flows. The Corporation's primary debt facility has a floating interest rate that will fluctuate based on prevailing market conditions. Cash flows are sensitive to changes in interest rates on this instrument. As at December 31, 2010, if interest rates had increased by 1% with all other variables held constant, net income would have decreased by $50,061 (2009 – decrease $4,882). The change in net income for an interest rate that is 1% lower would also increase by $3,636 (2009 – increase $12,140).

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 December 31, 2010 and 2009, the Corporation had no contracts in place to reduce the foreign exchange risk. This effect is currently immaterial.

b) Liquidity Risk

Liquidity risk is the risk that an entity will encounter difficulty in meeting obligations associated with financial liabilities. The Corporation believes that it has access to sufficient capital through internally generated cash flows, external equity sources, and undrawn committed borrowing facilities to meet current spending forecasts. All of the Corporation's liabilities mature in 2011 as the Corporation's accounts payable are due on demand. There was no loan balance at December 31, 2010 (2009 - $1,500,000), so minimal additional liquidity risk.

c) Credit Risk

Credit risk is the risk that a customer or counterparty will fail to perform an obligation or fail to pay amounts due causing a financial loss. The Corporation's accounts receivable are with customers and joint venture partners in the oil and gas industry and 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 is collected between two and four months after the production month.

Collection of the remaining balances can be dependent upon industry factors such as commodity prices, risk of unsuccessful drilling and partner disputes. Otherwise, the Corporation does not typically obtain collateral from joint venture partners, and relies upon industry standard legal remedies for collection. As at December 31, 2010 and 2009, the Corporation's receivables were as follows:

	2010	2009
	$	$
Joint venture partners	**578,761**	125,252
Petroleum and natural gas marketers	**721,117**	354,205
Insurance proceeds receivable	**427,600**	-
Alberta crown royalties receivable	**967,459**	-
GST and HST	**450,448**	129,215
Other	**11,561**	-
Total accounts receivable	**3,156,946**	608,672

As at December 31, 2010 and 2009, the aging analysis of trade receivables is as follows:

	2010	2009
	$	$
Current	**1,878,643**	523,228
30 – 60 days	**108,312**	49,037
60 – 90 days	**47,452**	7,887
Greater than 90 days	**1,122,539**	28,520
Total	**3,156,946**	608,672

At December 31, 2010, the amount receivable of $967,459 for Alberta Crown royalties was acquired with Steen River and is greater than 90 days outstanding. Steps are being taken to recover this balance.

As at December 31, 2010, there was an allowance for doubtful accounts of $50,000 (2009 - $nil).

CRITICAL ACCOUNTING ESTIMATES

A summary of Strategic's accounting policies are summarized in Note 2 of the audited consolidated financial statements at December 31, 2010. 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.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

On January 1, 2011, International Financial Reporting Standards ("IFRS"), as issued by the Accounting Standards Board, will become the generally accepted accounting principles ("GAAP") in Canada. The transition from Canadian GAAP to IFRS will result in significant differences affecting financial position and results of operations. The Corporation will be reporting under IFRS for all periods beginning after January 1, 2011.

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 will be choosing to capitalize.

IAS 16 - *Property, Plant and Equipment*

IFRS allows the choice between a retrospective restatement of the Corporation's Property, Plant, and Equipment or an allocation of the January 1, 2010 opening balance to the appropriate cash-generating-units using the reserve report. Retrospective restatement requires that various items that were allowed to be added to capital under AcG-16, such as unsuccessful exploratory wells, must be expensed under IFRS. IFRS also requires significant changes in capital cost recognition regarding working interest changes due to successful farmouts as compared to GAAP. The Corporation has chosen retrospective restatement.

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.

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 will be choosing proved and probable reserves.

Under Canadian GAAP, acquisitions and small dispositions were credited against the full cost pool. Under IFRS, gains and losses must be recognized on all acquisitions and 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 has identified its CGUs and has allocated 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. The Corporation is currently assessing which method and 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. 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. This may result in a difference in discount rates which may 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 is 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.

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
Financial statement preparation - Identify differences in Canadian GAAP/IFRS accounting policies - Select ongoing IFRS policies - Develop financial statement format - Quantify effects of changes for initial IFRS disclosure and 2010 comparative financial	Senior management and audit committee sign-off for all key IFRS accounting policy choices. Develop draft financial statement format.	All accounting policy changes addressed and analyzed. Policies have been submitted to auditors, and responses have been received. Rough draft of retrospective restatement of Property, Plant, and Equipment complete. Detailed

statements		analysis underway. Audit committee has met and approved policy choices in concept. Some further policy analysis required. Audit committee has approved an audit of the IFRS conversion to December 31, 2010, and review of the March 31, 2011 financial statements for the initial IFRS quarter.
Training Define and introduce appropriate level of IFRS expertise for each of the following groups: - Accounting - Operations - Management - Audit committee	Accounting and operations group training to occur as needed.	Small group training is ongoing.
Systems and processes Confirm that business processes and systems are IFRS compliant, including: - Program upgrades/changes - Gathering data for disclosures	Confirm that systems can address 2010 parallel processing requirements. Implement systems changes.	Ability of system to address IFRS changes confirmed and systems changes have commenced.
Control Environment For all accounting policy changes identified, assess control design and effectiveness implications, and implement changes	Control effectiveness implications to be assessed as part of the analysis of IFRS differences and accounting policy choices.	Analysis of control issues is underway in conjunction with review of accounting issues and policies.
External communications Assess the effects of key IFRS related accounting policy and financial statement changes on external communications. In particular: Monitor and update MD&A communications package	Analyze and publish the effect of IFRS on the financial statements throughout the project.	IFRS disclosure in the MD&A will be updated throughout the project.

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. The Corporation is in the final phases of 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 and on the SEDAR website: www.sedar.com.