Management's Discussion and Analysis

For the three months and year ended December 31, 2013

March 31, 2014

Strategic Oil & Gas Ltd. ("Strategic" or the "Company") is a publicly-traded oil and gas exploration and production company, with operations focused on light oil development in northern Alberta. The following is Management's Discussion and Analysis ("MD&A") of Strategic's consolidated operating and financial results for the year ended December 31, 2013, as well as information concerning the Company's future outlook based on currently available information. This MD&A should be read in conjunction with the Company's audited consolidated financial statements for the years ended December 31, 2013 and 2012, together with the accompanying notes, which have been prepared in accordance with International Financial Reporting Standards ("IFRS"). Further information with respect to the Company can be found on its website at www.sogoil.com and on the SEDAR website: www.sedar.com.

FINANCIAL AND OPERATIONAL SUMMARY

	Three Months Ended December 31			Year Ended December 31		
	2013	2012	% change	**2013**	2012	% change
Financial ($thousands, except per share amounts)						
Oil and natural gas sales	**15,660**	15,863	(1)	**79,945**	56,512	41
Funds from (used in) operations [1]	**(320)**	3,578	(109)	**17,162**	20,021	(14)
Per share basic & diluted	**(0.00)**	0.02	(100)	**0.08**	0.11	(27)
Cash flow from operating activities	**2,122**	2,724	(22)	**18,493**	19,785	(7)
Per share basic & diluted	**0.01**	0.01	-	**0.08**	0.11	(27)
Net loss	**(9,852)**	(5,917)	67	**(22,316)**	(4,788)	366
Per share basic & diluted	**(0.04)**	(0.03)	25	**(0.10)**	(0.03)	233
Capital expenditures (excluding acquisitions)	**29,484**	15,467	91	**119,151**	62,612	90
Net debt	**82,547**	47,303	75	**82,547**	47,303	75
Operating						
Average daily production						
Oil and NGL (bbl per day)	**1,888**	2,107	(10)	**2,339**	1,871	25
Natural gas (mcf per day)	**5,753**	1,050	448	**5,588**	1,415	295
Barrels of oil equivalent (Boe per day)	**2,847**	2,282	25	**3,270**	2,106	55
Average prices						
Oil & NGL, before risk management ($ per bbl)	**78.87**	80.09	(2)	**85.77**	80.69	6
Oil & NGL, including risk management ($ per bbl)	**76.30**	80.09	(5)	**82.73**	80.69	3
Natural gas ($ per mcf)	**3.71**	3.52	5	**3.30**	2.46	34
Netback ($ per Boe)						
Petroleum and natural gas sales	**59.80**	75.57	(21)	**66.98**	73.30	(9)
Royalties	**11.93**	16.81	(29)	**14.51**	12.55	16
Operating expenses	**34.54**	22.29	55	**24.02**	17.62	36
Transportation expenses	**4.72**	7.38	(36)	**4.57**	7.49	(39)
Operating Netback ($ per Boe) [1]	**8.61**	29.09	(70)	**23.88**	35.64	(33)
Common Shares (thousands)						
Common shares outstanding, end of period	**260,601**	186,415	40	**260,601**	186,415	40
Weighted average common shares (basic)	**258,318**	187,176	38	**217,604**	186,800	16
Weighted average common shares (diluted)	**258,318**	187,176	38	**217,604**	186,800	16

(1) Funds from operations, net debt and operating netback are non-IFRS measurements; see "Non-IFRS Measurements" in this MD&A.

FOURTH QUARTER SUMMARY

- Production increased by 565 Boed or 25 percent from 2,282 Boed (92 percent oil) for the three months ended December 31, 2012 to 2,847 Boed (66 percent oil). Production volumes for the current quarter were impacted by 26 days of total downtime at Steen River, related to the 9-17 oil facility expansion and turnaround. The expansion was necessary to increase fluid handling capacity and accommodate future production growth in the Company's core area, as well as increase the efficiency of operations and reduce operating costs.

- Funds from (used in) operations decreased to $(0.3) million for the current three month period from $3.6 million for the comparable quarter in 2012, due to higher operating costs related to the plant turnaround and winter road maintenance charges.

- Three wells were drilled during the quarter, including two Muskeg Stack horizontal wells and the first Keg River horizontal well in the Company's history. All three wells were on production by year-end 2013.

ANNUAL SUMMARY

- Production increased by 55 percent from 2,106 Boed (89 percent oil and NGL) in 2012 to an average of 3,270 Boed (72 percent oil and NGL) in 2013. As a result, oil and gas revenues increased 41 percent to $79.9 million in 2013 from $56.5 million in 2012.

- Funds from operations decreased from $20.0 million in 2012 to $17.2 million in 2013, resulting from higher royalty expense and an increase in operating costs due to a substantial increase in the Company's asset base, partially offset by higher revenues. With the completion of the facility expansion and the Bistcho pipeline operational early in the second quarter of 2014, Strategic anticipates a significant reduction in operating costs, transportation costs and royalty rates as new wells come on stream and production is not hindered by facility downtime.

- Exploration and development expenditures totaled $119.2 million for the twelve months ended December 31, 2013 as compared to $62.6 million for 2012. Approximately 97 percent of exploration and development spending was directed to the Company's light oil asset at Steen River.

- Strategic increased its proved and probable oil and gas reserves by 54 percent compared to the previous year, as determined by the Company's independent reserve evaluators McDaniel and Associates Consultants Ltd. ("McDaniel") at December 31, 2013. The Company added 5.7 MMBoe of proved and probable reserves in 2013, excluding production, for a reserve replacement ratio of 480 percent.

- Strategic closed an acquisition of light oil and natural gas assets at Bistcho in northwest Alberta and Cameron Hills in the Northwest Territories (the "Bistcho/Cameron Hills Assets") on February 28, 2013 for consideration of $9.6 million. This acquisition included operated production of 500 Boed (40% light oil), oil and gas processing facilities and a direct pipeline connection to the Rainbow pipeline in northwest Alberta, which will allow the Company to connect oil production at Steen River to the Rainbow pipeline system. Strategic made immediate operational changes to increase production and reduce operating costs on the acquired properties, and generated operating income of $2.8 million in 2013.

ADVISORIES

Basis of Presentation

This discussion and analysis of Strategic's oil and natural gas production and related performance measures is presented on a working-interest, before royalty basis. For the purpose of calculating unit information, the Company's production and reserves are reported in barrels of oil equivalent (Boe). Boe may be misleading, particularly if used in isolation. A Boe conversion ratio for natural gas of 6 Mcf: 1 Boe has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Management makes estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and our revenues and expenses during the reporting period. Management reviews these estimates, including those related to accruals, environmental and decommissioning liabilities, income taxes, and the determination of proved and probable reserves on an ongoing basis. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates.

Non-IFRS Measurements

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

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

The following table reconciles funds from operations to cash flow generated by operating activities:

	Three months ended December 31		Year ended December 31	
($thousands)	**2013**	2012	**2013**	2012
Cash generated by operating activities	**2,122**	2,724	**18,493**	19,785
Abandonment expenditures	**103**	72	**762**	202
Change in non-cash working capital	**(2,545)**	782	**(2,093)**	34
Funds from operations	**(320)**	3,578	**17,162**	20,021

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

"Adjusted net working capital" is used to evaluate funds available on the Company's credit facility, and is calculated as current assets less current liabilities, excluding any assets or liabilities related to risk management contracts or the deferred price premium on flow through shares.

About Strategic

Strategic is a junior oil and gas company committed to growth by exploiting its light oil assets primarily in northern Alberta. The Company relies on its extensive subsurface and reservoir experience to develop its asset base and grow production and cash flows while managing risk. The Company maintains control over its resource base through high-working interest ownership in wells, construction and operation of its own processing facilities and a significant undeveloped land and opportunity base. Strategic's primary operating area is at Steen River, Alberta.

PERFORMANCE OVERVIEW

In 2013 the Company continued to execute on its corporate strategy to explore and exploit its light oil asset base in northern Alberta, as well as acquiring strategic assets in northern Alberta and the Northwest Territories, including oil and gas production and a 50 km oil pipeline.

Average daily production increased 55 percent from 2,106 Boed in 2012 to 3,270 Boed in 2013, due to a successful drilling program at Steen River and the Bistcho/Cameron Hills acquisition. Strategic was active throughout 2013 at Steen River, drilling a total of twelve (12.0 net) oil wells. The Company drilled six Muskeg Stack horizontal wells, five Keg River vertical wells, and one Keg River horizontal well.

The Company's operating netbacks were affected by extended production downtime in 2013 as a result of facility constraints, commissioning of new equipment and extremely cold weather in the fourth quarter. Strategic has assembled a concentrated base of land and infrastructure in northern Alberta and operating costs are largely fixed in nature. As new production comes on stream from late 2013 and 2014 drilling and with the processing facilities operating efficiently, the Company anticipates that unit costs and royalty rates will be reduced.

Capital spending in 2013 also included significant facility upgrades and pipeline construction to accommodate production growth and future development at Steen River. The Company now has a total of 8,500 bbl/d of oil processing capacity at its two operated facilities in the area.

Reserves

In accordance with National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101"), the Company's oil, natural gas and natural gas liquids ("NGL") reserves were evaluated by McDaniel as at December 31, 2013. Gross reserves included below are Strategic's working interest reserves before royalty burdens.

Strategic's reserves at December 31, 2013 are summarized below.

Reserves [(1)]	**Light and Medium Crude Oil (Mbbl)**	**Heavy Oil (Mbbl)**	**Natural Gas (MMcf)**	**Natural Gas Liquids (Mbbl)**	**Oil Equivalent (MBoe)**
Proved Producing	2,991	104	10,118	63	4,845
Proved Non-Producing	112	-	3,360	-	672
Proved Undeveloped	879	-	1,787	-	1,177
Total Proved	**3,982**	**104**	**15,265**	**63**	**6,694**
Total Probable	**3,935**	**39**	**11,979**	**50**	**6,021**
Total Proved and Probable	**7,918**	**143**	**27,244**	**113**	**12,715**

(1) The recovery and reserve estimates of Strategic's oil, natural gas and NGL reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

OUTLOOK

For 2014 Strategic has a capital budget of $80 million that includes drilling Muskeg Stack and Keg River oil wells at Steen River, as well as key infrastructure projects designed to decrease operating and transportation costs in the area.

A significant portion of the first quarter 2014 capital program was directed to the Bistcho pipeline project, initiated to connect crude oil production from the Steen River area to the Rainbow pipeline system. Strategic is also pleased to report its Bistcho oil pipeline project is proceeding on time and on budget. This project is paramount in terms of the Company's strategy to reduce operating and transportation costs by limiting trucking costs and enhancing the profitability of each barrel processed at Marlowe.

The plant turnaround at Bistcho was completed in early March and shut-in production has now been restored. The Bistcho Plant turn around took an extra 10 days to the extreme cold weather. Production volumes averaged approximately 3,100 Boed in January and February and have been steadily increasing as production has been restored at Larne, Bistcho, Cameron Hills and West Marlowe.

Muskeg Stack wells

In the first quarter of 2014 Strategic also drilled three Muskeg Stack wells and completed a fourth well drilled in the fourth quarter of 2013.

Muskeg Stack horizontal well 16-34 was drilled to a lateral length of 1,516 meters and completed with a 14 stage frac. The well averaged 443 BOED (91 percent oil) over the first 11 days of production. This was the first well drilled using completion techniques which have made increased the productivity of the Muskeg Stack horizontal wells. The well is currently producing at a rate of 335 BOED (91% oil) with a liquid level of 25-30 joints to fluid which corresponds to approximately a 30% drawdown.

Muskeg Stack horizontal well 13-24 was drilled to a lateral length of 1,778 meters and completed with a 15 stage frac. The well flowed at a average rate of 310 BOED (85 percent oil) over the first 7 days. The Company has successfully drilled Muskeg Stack horizontal well 10-24, which was the last well drilled during the first quarter drilling program. The well has a lateral length of 1,428 meters and is planned to be completed with a 15 stage frac in early April.

Results for the Muskeg Stack wells are presented in the table below:

Muskeg Hz Well	Lateral Length meters	Frac Stages number	Initial Flow Rate boed (days)	IP30 Boed	Percent Oil %	Current Rate boed	Producing Days days
04-33(4Q13)	1,538	12	654 (IP2)	400	89%	180	132
05-33 (1Q14)	1,506	12	400 (IP4)	260	94%	202	40
16-34 (1Q14)	1,516	14	443 (IP11)	-	91%	335	28
13-24 (1Q14)	1,778	15	310 (IP7)	-	85%	345	8

FOURTH QUARTER RESULTS

Fourth quarter information **($thousands, except where noted)**	**Three months ended December 31** **2013**	2012
Average daily production volumes		
Oil & NGL (bbl/d)	**1,888**	2,107
Natural Gas (mcf/d)	**5,753**	1,050
Total (Boed)	**2,847**	2,282
Net loss		
Petroleum and natural gas sales	**15,660**	15,863
Royalties	**(3,126)**	(3,529)
Unrealized loss on risk management contracts	**(1,501)**	(8)
Realized loss on risk management contracts	**(447)**	-
Other income	**-**	278
Revenue, net of royalties	**10,586**	12,604
Operating costs	**9,046**	4,679
Transportation costs	**1,236**	1,550
General and administrative	**1,550**	2,442
Finance costs	**823**	177
Stock-based compensation	**423**	921
Depletion, depreciation and amortization (“DD&A”)	**6,961**	4,729
Impairment of PP&E	**1,098**	4,023
Net loss before taxes	**(10,551)**	(5,917)
Deferred tax recovery	**699**	-
Net loss	**(9,852)**	(5,917)
Net loss per common share	**(0.04)**	(0.03)
Average prices		
West Texas Intermediate (“WTI”) Oil (US$/bbl)	**97.46**	88.18
Oil & NGL price ($/bbl)	**78.87**	80.09
Natural gas price ($/mcf)	**3.71**	3.52
Oil equivalent ($/Boe)	**59.80**	75.57
Funds from operations	**(320)**	3,578
($/common share)	**(0.00)**	0.02
Cash flow provided by operating activities	**2,122**	2,724
($/common share)	**0.01**	0.01
Exploration and development expenditures	**29,484**	15,467
Net acquisitions	**(86)**	23,696

In comparing the fourth quarter of 2013 with the fourth quarter of 2012:

- Oil and NGL production volumes decreased 10 percent as a result of the turnaround and expansion of the 9-17 oil facility at Steen River, as well as extremely cold weather in December, which led to significant downtime in the field.

- Natural gas production volumes increased 448 percent, primarily due to the Bistcho/Cameron Hills assets acquired in March 2013, and associated gas volumes from Muskeg Stack drilling at Steen River

- Oil prices decreased by $1.22/bbl despite an 11 percent increase in WTI prices due to a widening Edmonton light differential in the current period. Natural gas prices increased by $0.19 per Mcf due to an 11 percent rise in AECO daily index prices from period to period.

- Royalty rates decreased from 22.2 percent of revenues in 2012 to 20.0 percent of revenues in 2013, due to a higher percentage of natural gas in the Company's production mix. Natural gas crown royalty rates are lower than rates for oil at current prices.

- Operating costs increased by 93 percent (55 percent on a Boe basis) due to plant turnaround costs at Steen River and a significant increase in the overall scope of Strategic's operations in northwestern Alberta, including the Bistcho/Cameron Hills Assets and oil and gas wells and infrastructure acquired at Steen River in December 2012 ("Other Marlowe"). Current period operating costs included $2.6 million in Bistcho/Cameron Hills and $1.2 million in Other Marlowe. Operating costs are typically highest in the winter months due to road access charges and additional maintenance performed at winter-only access locations. Turnaround costs for the 9-17 facility at Steen River totaled $1.2 million, of which 75 percent was expensed in accordance with the Company's accounting policies. Typically the plant turnaround is done in the third quarter but it was moved to the fourth quarter in 2013 to occur simultaneously with the completion of the facility expansion.

- Transportation costs decreased to $1.2 million ($4.72 per Boe) from $1.6 million ($7.38 per Boe), due to the 10 percent decrease in oil production volumes, partially offset by an increase in natural gas production. The majority of the Company's transportation costs relate to crude oil trucking at Steen River. In 2013 the Company began transporting oil via rail car, which also contributed to the reduction in transportation expense.

- G&A expenses decreased by $0.9 million or 37 percent as compared to the fourth quarter of 2012, primarily due to a decrease in management incentive compensation and higher overhead recoveries resulting from higher capital spending in 2013.

- Finance costs increased by $0.6 million as a result of higher interest costs due to higher debt levels and higher accretion expense related to assets acquired in 2013.

- Stock-based compensation decreased by $0.5 million or 54 percent in 2013, as the Company issued 4.8 million share options in the fourth quarter of 2012 and none in the fourth quarter of 2013.

- Funds from (used in) operations decreased to $(0.3) million or $(0.00) per common share from $3.6 million or $0.02 per share for the fourth quarter of 2012 due primarily to higher operating costs, partially offset by lower G&A expenses.

- DD&A expense increased by 47 percent as production volumes increased 25 percent and the DD&A rate per Boe was 18 percent higher in 2013, as a result of significant facilities expenditures in the second half of 2013.

- Strategic recorded an impairment charge of $1.1 million in the fourth quarter of 2013, related to a non-core property in southern Alberta. Impairment charges totaled $4.0 million for the three months ended December 31, 2012, related to the same property as well as an oil asset in B.C.

- Net loss increased to $9.9 million ($0.04 per basic and diluted common share) from $5.9 million ($0.03 per basic and diluted common share) due primarily to a reduction in funds from operations, higher DD&A expense and an unrealized loss on risk management contracts of $1.5 million, partially offset by lower impairment charges.

- Exploration and development expenditures totalled $29.5 million for the three months ended December 31, 2013 as compared to $15.5 million for the comparable quarter in 2012. Strategic was active in the current quarter, drilling two Muskeg Stack horizontal wells and one horizontal Keg River well. Capital expenditures also included facility expansion costs at 9-17, post drill out operations on four Muskeg Stack wells, well tie-ins and preliminary costs on the Bistcho pipeline project.

RESULTS OF OPERATIONS

Production

	Year ended December 31	
	2013	2012
Oil & NGL – bbl/d	**2,339**	1,871
Natural gas – mcf/d	**5,588**	1,415
Total daily production (Boed)	**3,270**	2,106

Oil & NGL production increased by 468 bbl/d or 25 percent from 2012 due primarily to drilling activities at Steen River and the acquisition of oil production at Cameron Hills. Gas production increased 295 percent due to the Bistcho/Cameron Hills acquisition and associated gas production from Muskeg Stack drilling at Steen River.

The Company's production portfolio in 2013 was weighted 72 percent to oil and NGL and 28 percent to natural gas, a decrease in oil weighting from the 2012 levels of 89 percent to oil and NGL and 11 percent to natural gas.

Revenue

	Year ended December 31	
($thousands, except where noted)	**2013**	2012
Sales		
Oil & NGL	**73,219**	55,241
Natural gas	**6,726**	1,271
	79,945	56,512
Unrealized loss on risk management contracts	**(8,533)**	(224)
Realized loss on risk management contracts	**(2,621)**	-
Other revenue	**94**	370
Total revenue	**68,885**	56,658
Reference prices		
WTI Oil (US$/bbl)	**97.97**	94.21
AECO daily index ($/MMBTU)	**3.16**	2.38
Average prices [(1)]		
Oil & NGL ($/bbl)	**85.77**	80.69
Oil & NGL, including realized risk management loss ($/bbl)	**82.73**	80.69
Natural gas ($/mcf)	**3.30**	2.46
Oil equivalent ($/Boe)	**66.98**	73.30

[(1)] Average prices do not include unrealized losses on risk management contracts or other revenue.

The Company's oil and natural gas revenues for the year ending December 31, 2013 increased 41 percent to $79.9 million from $56.5 million in 2012, primarily driven by a 55 percent increase in oil and gas production.

The average price realized for oil and NGL in 2013 increased to $85.77 per bbl from $80.69 per bbl in 2012, due primarily to an increase in WTI oil prices. The Company's average natural gas price increased 34 percent to $3.30 per mcf in 2013 as compared to $2.46 per mcf in 2012 as a result of a 33 percent increase in AECO daily index prices over the same period.

Risk Management Contracts

The Company's net income and funds from operations are exposed to fluctuations in commodity prices, interest rates and foreign exchange rates. As part of its risk management program, Strategic may enter into financial commodity price management contracts for up to 60 percent of expected production levels, depending on current commodity prices, price volatility and the size and nature of the Company's capital spending programs.

A summary of Strategic's commodity price risk management contracts as at December 31, 2013 is as follows:

Financial WTI Crude Oil Contracts

Term		Contract Type	Volume (bbl/d)	Fixed Price (CAD$/bbl)	Index
01-Jan-2014	31-Dec-2014	Swap	500	92.00	WTI - NYMEX
01-Jan-2014	31-Dec-2014	Swap	1,000	92.00	WTI - NYMEX
01-Jan-2015	30-Jun-2015	Swap	750	90.15	WTI - NYMEX
01-Jan-2015	31-Dec-2015	Option (1)	600	90.00	WTI - NYMEX
01-Jul-2015	31-Dec-2015	Option (1)	250	90.00	WTI - NYMEX

(1) Counterparty has an option to convert into a swap at the fixed price indicated. The 600 bbl/d option expires on the last business day before the term begins, while the 250 bbl/d option expires monthly during the contract term.

Financial AECO Gas Contracts

Term		Contract Type	Volume (GJ/d)	Fixed Price (CAD$/GJ)	Index
01-Jan-2014	31-Dec-2014	Swap	1,500	3.50	AECO

As a result of an increase in the forward price curve for WTI oil, the Company recorded an unrealized loss on risk management contracts of $8.5 million for the year ended December 31, 2013. Unrealized gains and losses on risk management activities do not affect Strategic's funds from operations or cash available for capital spending programs.

Subsequent to the reporting date, Strategic entered into additional fixed-price contracts for February-December 2014 for 300 GJ/d of natural gas sales at $3.75/GJ, and for April-October 2014 for 500 GJ/d of natural gas sales at $4.41/GJ.

Royalties

Royalty expense consists of royalties paid to provincial governments (including the effect of the crown royalty initiative program), freehold land owners and overriding royalty owners. Royalty expense also includes the impact of Gas Cost Allowance ("GCA"), which is the reduction of natural gas royalties payable to the Government of Alberta to recognize capital and operating expenditures incurred in the gathering and processing of its royalty share of production. Crown royalties on oil production are paid in product, which is taken in kind and marketed separately by the provincial government. Generally royalty rates in western Canada vary based on volume produced by individual wells, prices received and the area from which production is derived.

($thousands, except where noted)	Year ended December 31 **2013**	2012
Crown royalties	**16,536**	8,316
Freehold and overriding royalties	**781**	1,361
Total royalties	**17,317**	9,677
Per Boe	**14.51**	12.55
Percentage of oil & natural gas revenues	**21.7%**	17.1%

In 2011 the provincial government amended its royalty framework to reduce the royalty rate on revenues from newly drilled wells to five percent for the first year of production, up to a maximum of 500,000 Mcf of natural gas or 50,000 bbls of crude oil. Crown royalties on oil production at Steen River can vary from 10 to 40 percent after the first year of production, depending on well productivity and vintage. On a percentage of revenue and per Boe basis royalties increased in 2013 as a result of Keg River wells drilled in 2012 coming off the first year royalty rate. Royalties increased to $17.3 million for year ended December 31, 2013 from $9.7 million for the period year due to higher revenues, driven primarily by higher oil production.

Operating and Transportation Costs

($thousands, except per Boe amounts)	Year ended December 31 **2013**	2012
Operating costs	**28,670**	13,581
Transportation costs	**5,449**	5,774
	34,119	19,355
Per Boe		
Operating costs	**24.02**	17.62
Transportation costs	**4.57**	7.49
	28.59	25.11

Operating expenses increased from $13.6 million in 2012 to $28.7 million in 2013 due to a significant increase in the Company's asset base in northern Alberta, as well as additional chemicals and supplies expense related to expanding oil production at Steen River. On a unit basis, operating expenses increased 36 percent to $24.02 per Boe in 2013 compared to $17.62 per Boe for the prior year as a result of higher fixed costs at Steen River and the acquisition of the Bistcho/Cameron Hills assets. Operating costs at Bistcho/Cameron Hills were $7.9 million or $25.60 per Boe for 2013.

Transportation costs decreased by 6 percent or $0.3 million from 2012 levels as Strategic began transporting a portion of its oil production via rail in 2013, which benefits from lower trucking costs. Transportation expenses per Boe declined 39 percent in 2013 due to the rail arrangement and a higher proportion of natural gas in the Company's production mix.

Operating Netbacks

($ per Boe)	Year ended December 31 **2013**	2012
Revenues	**66.98**	73.30
Royalties	**14.51**	12.55
Operating costs	**24.02**	17.62
Transportation costs	**4.57**	7.49
Netback per Boe	**23.88**	35.64

Strategic's operating netback decreased 33 percent to $23.88 per Boe in 2013 from $35.64 per Boe for 2012 as a result of a lower percentage of oil production in 2013, higher royalty rates and an increase in operating costs due to acquisitions and higher fixed costs at Steen River.

Exploration and Evaluation Expense

The Company's E&E expense represents all pre-license costs and capitalized exploration and evaluation costs that have been subsequently expensed due to a lack of technical feasibility and commercial viability. For the year ended December 31, 2013, the Company recorded $nil of E&E expense compared to $0.03 million for the same period in the prior year.

General and Administrative Expenses

	Year ended December 31	
($thousands, except per Boe amounts)	**2013**	2012
General and administrative expenses	**6,200**	7,434
Per Boe	**5.19**	9.64

General and administrative expenses ("G&A") decreased to $6.2 million for 2013 from $7.4 million in 2012 as a result of higher overhead recoveries due to increased capital spending and the Company's expanded asset base in the current year, partially offset by higher salaries and information technology costs. G&A per Boe decreased to $5.19 per Boe from $9.64 per Boe in 2012 due to a combination of lower G&A costs and higher production levels.

Finance Expense

	Year ended December 31	
($thousands, except per Boe amount)	**2013**	2012
Interest expense	**2,540**	103
Accretion expense	**869**	327
Total	**3,409**	430
Per Boe	**2.86**	0.56

Finance expense increased to $3.4 million for 2013 from $0.4 million for 2012. Interest expense was considerably higher in 2013 due to an average balance of $56 million on the Company's credit facility during the year, whereas the operating line was not used for much of the previous year. Accretion expense increased by $0.5 million in 2013 due to the increase in Strategic's asset base and resulting decommissioning liabilities.

Going forward the Company intends to use funds from operations to fund capital expenditure programs and acquisitions, as well as drawings on the credit facility and equity or other financings, as deemed appropriate.

Stock based compensation

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

During the year ended December 31, 2013 the Company recorded $1.7 million in stock based compensation expense as compared to $1.9 million recorded in the previous year. The decrease is primarily due to a lower number of options granted in 2013.

Depletion, depreciation and amortization

($thousands, except per Boe amounts)	Year ended December 31 2013	2012
Depreciation, depletion, and amortization	**28,033**	20,837
Per Boe	**23.49**	27.03

Depletion, depreciation and amortization ("DD&A") is computed individually for each producing area on a unit of production basis, using proved and probable reserves and including future development expenditures in the cost base subject to depletion. DD&A expense for the year ended December 31, 2013 increased by 34 percent to $28.0 million compared to $20.8 million for 2012, due to 55 percent increase in production levels. On a Boe basis DD&A expense decreased 13 percent to $23.49 per Boe from $27.03 per Boe in 2012, primarily as a result of the low cost per Boe of the Bistcho/Cameron Hills Acquisition.

Impairment Loss

Impairment testing is required when there are indicators of impairment such as a significant drop in commodity prices or a downward revision of proved and probable oil and gas reserves. When indicators of impairment exist, impairment testing is performed at the cash generating unit ("CGU") level and is a point in time process for testing and measuring a potential impairment of assets, whereby the carrying value of each CGU is compared to the CGU's recoverable amount, which is the greater of its value in use and its fair value less costs to sell. The Company's development and production assets are aggregated into CGUs based on their ability to generate largely independent cash flows.

The recoverable amount was determined based on the fair value less costs to sell method for reserves as well as resources estimated by management to be realized based on planned future drilling locations not considered in the reserve report. The key assumptions used in determining the recoverable amount include the future cash flows using reserve and resource forecasts, forecasted commodity prices, discount rates, inflation rates and future development costs estimated for reserves by independent reserve engineers and by internal estimates based on historical experiences and trends for planned future drilling locations.

The values assigned to the future cash flows, forecasted commodity prices and future development costs were obtained from Strategic's year-end reserve report, which was evaluated or audited by its independent reserve engineers. These values were based on future cash flows of proved plus probable reserves discounted at a pre-tax rate of 10 percent (2012 – 10 percent). The future cash flows also consider, when appropriate, past capital activities, observable market conditions, comparable transactions and future development costs primarily based on anticipated development capital programs.

The value of resources incremental to the reserve report was obtained from internal analysis completed by management most notably through the review of its drilling program results and future drilling plans outlined in its current five-year plan. This was further supported by contingent resource studies that were compiled by independent reserve engineers. Based on this internal analysis, Strategic identified and risked potential drilling locations that were not assigned any proved plus probable reserves. The value of these additional drilling locations was included in the recoverable amount, based on the net present value of proved undeveloped locations within the same resource play from the Company's most recent annual reserve report. A discount rate of 15 percent was applied to determine an estimate of the present value of the future cash flows from these future drilling locations.

For the year ended December 31, 2013, the Company recognized an impairment of $1.1 million related to the Other Canadian CGU, compared to $4.0 million in 2012 related to the same CGU. Impairment on this CGU arose due to a downward revision of proved and probable reserves at the CGU level.

Funds from operations and net loss

($thousands, except per share amounts)	Year ended December 31 2013	2012
Funds from operations	**17,162**	20,021
Per share – basic & diluted	**0.08**	0.11
Cash provided by operating activities	**18,493**	19,785
Per share - basic & diluted	**0.08**	0.11
Net loss	**(22,316)**	(4,788)
Per share – basic & diluted	**(0.10)**	(0.03)

Funds from operations decreased 14 percent to $17.2 million for 2013 from $20.0 million for 2012 as an increase in revenues due to higher production levels was more than offset by higher royalty expense and operating costs.

For the year ended December 31, 2013, the Company recorded a net loss of $22.3 million ($0.10 per basic and diluted common share) compared to a net loss of $4.8 million ($0.03 per basic and diluted common share) in the prior year. The higher net loss in 2013 is a result of higher DD&A charges due to increased production, lower funds from operations and an unrealized loss on risk management contracts of $8.5 million.

Capital Expenditures

($thousands)	Year ended December 31 2013	2012
Drilling and completions	**61,885**	44,115
Equipping and facilities	**50,091**	13,820
Other	**248**	246
	112,224	58,182
Acquisitions	**10,011**	23,696
Total Property, plant and equipment	**122,235**	81,878
Land and seismic	**6,927**	4,430
Total exploration and evaluations	**6,927**	4,430
Total net capital expenditures	**129,162**	86,308

Drilling, completions, equipping and facilities expenditures increased to $112.2 million in 2013 from $58.2 million in 2012. Drilling activities in the current year shifted to focus on horizontal Muskeg Stack oil wells, which are higher cost and typically provide higher production rates than the Keg River wells drilled in 2012. Drilling and completions expenditures for the current year also included an extensive recompletion program at Steen River and Bistcho, confirming oil productivity in multiple zones.

Facility projects in 2013 included a major expansion of the Steen River oil processing facility at 9-17, installation of water disposal facilities, pipeline construction and equipping and tie-in expenditures on wells drilled and recompleted in 2013 and late 2012.

Acquisitions capital spending of $10.0 million in the current year reflects the Bistcho/Cameron Hills Acquisition closed in February 2013. Strategic acquired oil production and significant infrastructure within the Steen River core area for $23.7 million in 2012.

Exploration and evaluation costs are area expenditures where technical feasibility and commercial viability has not yet been determined. Costs incurred prior to lease acquisition are expensed as incurred. Exploration and evaluation costs increased to $6.9 million in 2013 from $4.4 million in 2012 due to 2D and 3D seismic programs conducted at Steen River in the current year.

SUMMARY OF QUARTERLY FINANCIAL DATA

The following table summarizes quarterly financial results:

Quarter ended ($thousands, except where noted)	**Dec 31, 2013**	Sept 30, 2013	Jun 30, 2013	Mar 31, 2013
Oil and natural gas sales	**15,660**	22,628	23,770	17,887
Net loss	**(9,852)**	(6,759)	(2,338)	(3,371)
Net loss per share – basic	**(0.04)**	(0.03)	(0.01)	(0.02)
Net loss per share – diluted	**(0.04)**	(0.03)	(0.01)	(0.02)
Average daily production (Boed)	**2,847**	3,510	3,924	2,797
Average realized price ($/Boe)	**59.80**	62.12	67.53	71.05

Quarter ended ($thousands, except where noted)	Dec 31, 2012	Sept 30, 2012	Jun 30, 2012	Mar 31, 2012
Oil and natural gas sales	15,863	12,520	16,924	11,204
Net income (loss)	(5,917)	(718)	1,235	611
Net income (loss) per share – basic	(0.03)	(0.00)	0.01	0.00
Net income (loss) per share – diluted	(0.03)	(0.00)	0.01	0.00
Average daily production (Boed)	2,282	1,930	2,583	1,631
Average realized price ($/Boe)	75.57	70.52	72.00	75.50

Oil and natural gas sales vary with average daily production and realized sales prices, and are higher in 2013 quarters relative to 2012 as a result of increasing production. The fourth quarter of 2013 is an exception as production volumes were impacted by facility downtime and extremely cold weather in December. Net income (loss) will typically fluctuate with production and prices, due to the effect of DD&A expense on earnings. Net loss is higher in 2013 quarters compared to 2012 due to lower realized prices and netbacks, as a result of increasing natural gas production and higher operating costs, partially offset by lower DD&A charges per Boe.

The net loss in the fourth quarter 2012 is largely due to impairment charges recorded of $4.0 million. Net losses in the third and fourth quarters of 2013 were affected by losses on risk management contracts of $5.9 million and $1.9 million, respectively.

LIQUIDITY AND CAPITAL RESOURCES

The Company considers its capital structure to include shareholders' equity, and working capital, including bank debt. In order to maintain or adjust the capital structure, the Company may issue new common shares, issue or repay debt, or adjust exploration and development capital expenditures.

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

	As at December 31	
($thousands)	**2013**	2012
Current assets	**9,685**	11,661
Accounts payable and accrued liabilities	**(28,457)**	(24,839)
Adjusted net working capital surplus (deficit) [(1)]	**(18,772)**	(13,178)
Total line of credit	**100,000**	48,500
Amount drawn	**(63,775)**	(34,125)
Authorized Letters of Guarantee	**(4,139)**	(20)
Unutilized line of credit	**32,086**	14,355
Net available funds	**13,314**	1,177

[(1)] This is a non-IFRS measurement. See "Non-IFRS Measurements" in this MD&A.

Credit Facility

The Company has a $100 million credit facility (the "Facility") with a Canadian chartered bank, comprised of an $80 million revolving operating loan and a $20 million acquisition/development demand loan. Drawdowns on the acquisition/development loan may be made with the approval of the lender for property acquisitions or drilling projects. As of December 31, 2013, Strategic had $63.8 million outstanding under the Facility. Amounts outstanding under the Facility are repayable on demand, and bear interest at a rate of 0.5 percent to 2.5 percent over the bank's prime lending rate for prime loans, or at bankers' acceptance rates plus a stamping fee ranging from 1.75 percent to 3.75 percent, depending on Strategic's debt to cash flow ratio. The Facility is secured by a general security agreement including a floating charge on all lands. Subsequent to the reporting date the Facility was renewed, with the next review date scheduled for September 30, 2014.

The Facility contains a financial covenant that requires the Company to maintain an adjusted working capital ratio of not less than 1:1, but for the purpose of the calculation the unused portion of the line is included in current assets and, the current portion of bank debt, risk management liabilities and the deferred price premium on flow-through shares are excluded from current liabilities. At December 31, 2013, the Company's adjusted working capital ratio was 0.77, and therefore the financial covenant was not met. The Company has received from the lender a waiver of the covenant violation at December 31, 2013.

On March 12, 2014 Strategic entered into an agreement with a syndicate of agents with respect to a private placement of 100,000,000 common shares of the Company at a price of $0.50 per common share, for gross proceeds of $50.0 million. A total of 80,000,000 common shares were purchased by entities that share a common director with the Company. The private placement closed in two tranches on March 24, 2014 and on March 31, 2014. Proceeds were used to reduce bank debt incurred in completing an intensive winter capital program at Steen River. Strategic anticipates that with the closing of the private placement, net debt will be approximately $72 million and the Company will be in compliance with its working capital covenant and other Facility covenants.

Going forward the Company intends to use funds from operations and equity financings to fund capital expenditure programs and acquisitions, as well as drawings on the Facility and asset dispositions, as deemed appropriate.

SHARE CAPITAL

	Year ended December 31	
	2013	2012
Outstanding Common shares		
Weighted average Common shares outstanding		
- Basic	**217,603,874**	186,800,318
- Diluted	**217,603,874**	186,800,318

	December 31, 2013	December 31, 2012
Outstanding Securities		
- Common Shares	**260,600,646**	186,415,268
- Common Share Options	**13,235,000**	12,483,333

On March 20, 2013, the Company issued 23.2 million common shares via a private placement at a price of $1.25 per common share for gross proceeds of $29.0 million (net proceeds of $28.2 million after transaction costs). Of the $29.0 million gross proceeds, $18.9 million (15.2 million common shares) were acquired by entities that share a common director with the Company.

On September 26, 2013, the Company issued 20.2 million common shares via a private placement with an entity that shares a common director with the Company at a price of $0.95 per common share for gross proceeds of $19.2 million.

On October 7, 2013, the Company completed a bought deal financing, resulting in the issuance of 14,547,500 common shares at a price of $0.95 per common shares and 15,454,545 flow-through shares at $1.10 per share for total gross proceeds of $31 million (share issue costs $1.9 million). As at December 31, 2013, the Company had spent $5.1 million on qualified exploration and development expenditures to meet the flow through commitment. The remaining committed expenditure is $11.9 million which will be spent in 2014.

During the year 788,333 stock options were exercised for common shares of the Company, for total proceeds of $0.68 million.

SUMMARY OF ANNUAL INFORMATION

	Year ended December 31		
($000, except per share amounts)	**2013**	2012	2011
Total Revenue	**79,945**	56,512	23,853
Net income (loss)	**(22,316)**	(4,788)	(24,646)
Per common share basic)	**(0.10)**	(0.03)	(0.18)
Per common share (diluted)	**(0.10)**	(0.03)	(0.18)
Total Assets	**274,221**	159,718	117,695
Total long-term liabilities	**37,413**	18,773	12,523

Net revenues have increased significantly over the past three years as a result of production additions from successful capital programs, primarily at Steen River, and through acquisitions. Net loss was lowest in 2012 due to higher realized prices and operating netbacks compared to 2011 and 2013, due primarily to a higher proportion of oil in the Company's production mix. Total assets have increased due to capital spending and acquisitions exceeding depletion and depreciation expense over the two-year period. Long-term liabilities consist of decommissioning obligations, and have increased over the two-year period as the Company's oil and gas asset base has also increased.

TRANSACTIONS WITH RELATED PARTIES

Legal fees in the amount of $0.45 million (2012 - $0.28 million) were incurred to a legal firm of which a director is a partner, and are included as general and administrative expenses or share issue costs. Software charges of $0.20 million (2012 - $0.12 million) were incurred to a software firm which is controlled by an officer of the Company. Accounts payable and accrued liabilities at 2013 include $0.31 million (2012 - $0.01 million) 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 Company and the related parties.

Entities controlled by directors of the Company have also participated in share offerings in 2013 and 2014, as discussed in this MD&A.

COMMITMENTS

The Company has lease agreements for office space resulting in the following commitments:

Year ended	($000)
2014	338
2015	311
2016	10
	659

OUTSTANDING SHARE DATA

Common Shares

The Company is authorized to issue an unlimited number of common shares. Including shares issued under the private placements closed in March 2014, the Company had 360,733,978 common shares outstanding and 12,858,335 stock options outstanding under its stock option program as of March 31, 2014.

SENSITIVITY ANALYSIS

The following table analyses the Company's sensitivity of funds from operations to changes in commodity prices and interest rates:

	For the year ended December 31	
($000)	**2013**	2012
10% increase in oil price	**5,550**	4,527
10% increase in gas price	**683**	131
1% increase in interest rate	**1,052**	(30)

FUTURE ACCOUNTING PRONOUNCEMENTS

In May 2013, the IASB issued amendments to IAS 36 "Impairment of Assets" which reduce the circumstances in which the recoverable amount of CGUs is required to be disclosed and clarify the disclosures required when an impairment loss has been recognized or reversed in the period. The amendments are required to be adopted retrospectively for fiscal years beginning January 1, 2014, with earlier adoption permitted. These amendments will be applied by the Company on January 1, 2014 and the adoption will only impact the Company's disclosures in the notes to the consolidated financial statements in periods when an impairment loss or impairment reversal is recognized.

In May 2013, the IASB issued IFRIC 21 "Levies," which was developed by the IFRS Interpretations Committee ("IFRIC"). IFRIC 21 clarifies that an entity recognizes a liability for a levy when the activity that triggers payment, as identified by the relevant legislation, occurs. The interpretation also clarifies that no liability should be recognized before the specified minimum threshold to trigger that levy is reached. IFRIC 21 is required to be adopted retrospectively for fiscal years beginning January 1, 2014, with earlier adoption permitted. IFRIC 21 will be applied by the Company on January 1, 2014 and the adoption does not have an impact on the Company's accounting for production and similar taxes, which do not meet the definition of an income tax in IAS 12 "Income Taxes."

The IASB has undertaken a three-phase project to replace IAS 39 "Financial Instruments: Recognition and Measurement" with IFRS 9 "Financial Instruments." In November 2009, the IASB issued the first phase of IFRS 9, which details the classification and measurement requirements for financial assets. Requirements for financial liabilities were added to the standard in October 2010. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value.

In November 2013, the IASB issued the third phase of IFRS 9 which details the new general hedge accounting model. Hedge accounting remains optional and the new model is intended to allow reporters to better reflect risk management activities in the consolidated financial statements and provide more opportunities to apply hedge accounting. The Company does not employ hedge accounting for its risk management contracts currently in place. In July 2013, the IASB deferred the mandatory effective date of IFRS 9 and has left this date open pending the finalization of the impairment and classification and measurement requirements. IFRS 9 is still available for early adoption. The full impact of the standard on the Company's consolidated financial statements will not be known until the project is complete.

The Company is currently evaluating the impact of adopting all of the newly issued and amended standards.

Changes in Accounting Policies

As of January 1, 2013, the Company adopted several new IFRS standards and amendments in accordance with the transitional provisions of each standard. A brief description of each new standard and its impact on the Company's consolidated financial statements follows below:

IFRS 10 "Consolidated Financial Statements"
This standard supersedes IAS 27 "Consolidation and Separate Financial Statements" and SIC-12 "Consolidation – Special Purpose Entities" and provides a single model to be applied in control analysis for all investees, including special purpose entities. The retrospective adoption of this standard does not have any impact on the Company's consolidated financial statements.

IFRS 11 "Joint Arrangements"
This standard divides joint arrangements into two types, joint operations and joint ventures, each with their own accounting model. All joint arrangements are required to be reassessed on transition to IFRS 11 to determine their type to apply the appropriate accounting. The retrospective adoption of this standard does not have any impact on the Company's consolidated financial statements.

IFRS 12 "Disclosure of Interests in Other Entities"
This standard combines in a single standard the disclosure requirements for subsidiaries, associates and joint arrangements, as well as unconsolidated structured entities. The retrospective adoption of the annual disclosure requirements of this standard does not have a material impact on the Company's consolidated financial statements.

IFRS 13 "Fair Value Measurement"
This standard defines fair value, establishes a framework for measuring fair value, and sets out disclosure requirements for fair value measurements. This standard defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The adoption of this standard requires the revaluation of certain derivative financial liabilities on the Company's consolidated balance sheets to reflect an appropriate amount of risk of non-performance by the Company. The standard also requires additional annual fair value disclosures, as well as additional interim disclosures, as per IAS 34. The prospective adoption of this standard does not have a material impact on the Company's consolidated financial statements.

IAS 28 "Investments in Associates and Joint Ventures"
This standard has been amended as a result of changes to IFRS 10 and IFRS 11. The retrospective adoption of these amendments does not have any impact on the Company's consolidated financial statements.

IFRS 7 "Financial Instruments: Disclosures" and IAS 32 "Financial Instruments: Presentation"
The amendments to this standard clarify the current requirements for offsetting financial instruments. The amendments to IFRS 7 "Financial Instruments: Disclosures" develop common disclosure requirements for financial assets and financial liabilities that are offset in the consolidated financial statements, or that are subject to enforceable master netting arrangements or similar agreements. The Company retrospectively adopted the amendments to both standards on January 1, 2013. The application of these amendments did not have any impact on the Company's consolidated financial statements, other than increasing the level of disclosures provided in the notes to the consolidated financial statements.

CRITICAL ACCOUNTING ESTIMATES

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

Reserves estimates

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

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

E&E costs

Capitalized costs that are exploratory in nature such as undeveloped land acquisitions, seismic expenditures and exploration drilling are included in E&E costs. Costs are transferred from E&E to property, plant and equipment once technical feasibility and commercial viability of the underlying resource have been established. The results of a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and application of industry experience. The evaluation of petroleum and natural gas leasehold acquisition costs requires management's judgment to evaluate the fair value of land in a given area.

Impairment

Under IFRS, the carrying amount of property, plant and equipment and E&E assets are reviewed at each reporting date to determine whether there is any indication of impairment. Management's judgement is required to perform such reviews. If there are indications of impairment, carrying values of assets are compared to related recoverable amounts. Reserves, revenue, royalty and operating cost estimates and the timing of future cash flows are all critical components of the recoverable amount. Revisions of these estimates could result in significant changes to impairment charges recorded in a reporting period, as well as the carrying value of the Company's assets.

Decommissioning liabilities

Decommissioning liabilities are measured based on the estimated costs of decommissioning and estimated timing to reclamation, discounted to their net present value using a credit-adjusted risk-free rate. Decommissioning liabilities are reassessed at each reporting date, and these estimates may change.

Business combinations

The acquisition method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of acquisition of control. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured at their recognized amounts (generally fair value) at the acquisition date. The excess of the cost of acquisition over the recognized amounts of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of acquisition is less than the recognized amount of the net assets acquired, the difference is recognized as a bargain purchase gain in net income or loss.

Risk management contracts

Estimated fair values of financial instruments are subject to fluctuation depending upon the underlying commodity prices, interest rates, volatility curves and the risk of non-performance.

Stock based compensation

Stock based compensation expense is based on estimated fair values of stock options as of the grant date, which are calculated using a Black-Scholes option pricing model and involves assumptions such as volatility, expected option life and expected dividend yield.

Other estimates

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

BUSINESS RISKS

There are numerous risks facing participants in the oil and gas industry. Some of the risks are common to all businesses while others are specific to a sector. While Strategic realizes that these risks cannot be eliminated, it is committed to monitoring and mitigating these risks. The following reviews the general and specific risks to which the Company is exposed.

Acquisition and Development of Additional Reserves

The Company's future success is dependent upon its ability to develop or acquire additional oil and natural gas reserves that are economically recoverable at attractive prices. Except to the extent that the Company conducts successful activities or acquires properties containing proved reserves, or both, the proved reserves and production will generally decline as reserves are produced. The drilling of oil and natural gas wells involves a high degree of risk, especially the risk of a well that is not sufficiently productive to provide an economic return on the capital expended to drill the well or of its ongoing operational costs.

Exploration and development risks are due to the uncertain results of searching for and producing oil and natural gas using imperfect scientific methods. These risks are mitigated by using highly skilled staff, focusing activities in areas in which the Company has existing knowledge and expertise or access to such expertise, using up-to-date technology to enhance methods and controlling costs to maximize returns. Advanced oil and natural gas related technologies such as three dimensional seismography, reservoir simulation studies and horizontal drilling might, where appropriate, be used by the Company to improve its ability to find, develop and produce oil and natural gas. However, notwithstanding this, the combination of technology, knowledge and skilled people may not eliminate these risks.

Acquisitions of resource issuers and resource assets by the Company will be based on engineering and economic assessments made by management. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, future prices of oil and natural gas and operating costs, future capital expenditures and royalties and other governmental levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the Company. In particular, changes in the prices of and markets for oil and natural gas from those anticipated at the time of making such assessments will affect the value of the Company's common shares. In addition, all such assessments involve a measure of geological and engineering uncertainty that could result in lower production and reserves than anticipated.

Oil and Natural Gas Prices and Marketing

The Company's revenues are dependent upon prevailing prices for oil and natural gas. Oil and natural gas prices can be extremely volatile and are affected by the actions of domestic and international markets, foreign governments, international cartels and the Canadian federal and provincial governments. In addition, the marketability of the production depends upon the availability and capacity of gathering systems and pipelines, the effect of federal and provincial regulation (including tax and royalty regimes) on such production and general economic conditions. All of these factors are beyond the control of the Company. Any decline in oil or natural gas prices could have a material adverse effect on the Company's operations, financial condition, proved reserves and the level of expenditures for the development of its oil and natural gas reserves.

The Company may manage the risk associated with changes in commodity prices and foreign exchange rates by, from time to time, entering into crude oil or natural gas price hedges and forward foreign exchange contracts. To the extent that the Company engages in risk management activities related to commodity prices and foreign exchange rates, it will be subject to credit risks associated with counterparties with which it contracts.

Substantial Capital Requirements and Liquidity

The Company anticipates that it will make substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Company's future revenues or reserves decline, the Company's ability to expend the capital necessary to undertake or complete future drilling programs may be limited. 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 Company. Moreover, future activities may require Strategic to alter its capitalization significantly, and potentially increase the Company's debt levels above industry standards. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's financial condition, results of operations or prospects.

Environmental Concerns

The operation of oil and natural gas wells involves a number of natural hazards that may result in blowouts, environmental damage or other unexpected or dangerous conditions resulting in liability to the Company and possibly liability to fourth parties. The oil and natural gas industry is subject to extensive environmental regulation that provides for restrictions and prohibitions on releases or emissions of various substances produced in association with certain oil and natural gas industry operations, and such regulations may be expanded to include regulation of, among other things, emissions of carbon dioxide. In addition, legislation requires that well and facility sites are abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in fines or the issuance of clean-up orders. The Company carries insurance to mitigate the cost of remediating damage from environmental incidents, but there can be no assurance that the insurance will cover all types of incidents or that remediation costs will not exceed the limit of the insurance carried. In addition, the Company will make reasonable provisions for well abandonment, facility decommissioning and site remediation where appropriate, however there can be no assurance that such provisions will be sufficient to satisfy all such obligations.

Permits and Licenses

Strategic's operations may require licenses and permits from various governmental authorities. There can be no assurance that Strategic will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at its projects.

Reliance on Operators and Key Employees

To the extent the Company is not the operator of its oil and gas properties, the Company will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators. In addition, the success of the Company will be largely dependent upon the performance of its management and key employees. The Company does not have any key man insurance policies, and therefore there is a risk that the death or departure of any member of management or any key employee could have a material adverse effect on the Company. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of the business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of Strategic's management.

Third Party Credit Risk

The Company is or 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, operators of facilities, pipelines, terminals and other infrastructure used by Strategic and other parties. In the event such entities fail to meet their contractual obligations to the Company, such failures could have a material adverse effect on the Company and its cash flow from operations.

Title to Properties

Although title reviews will be done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of dridrilling wells as determined appropriate by management, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat a claim of Strategic which could result in a reduction of the revenue received by the Company.

Competition

Strategic competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Company also competes with other companies for all of its business inputs including exploitation and development prospects, access to commodity markets, property and corporate acquisitions, and available capital. The Company endeavors to be competitive by maintaining a strong financial condition, by attracting and retaining technically competent and accountable staff, by refining and enhancing business processes on an ongoing basis and by utilizing current technologies to enhance exploitation, development and operational activities.

FORWARD-LOOKING STATEMENTS

This report includes certain information, with management's assessment of Strategic's future plans and operations, and contains forward-looking statements which may include some or all of the following: (i) forecasted capital expenditures and plans; (ii) exploration, drilling and development plans, (iii) prospects and drilling inventory and locations; (iv) anticipated production rates; (v) expected royalty rates; (vi) anticipated operating and service costs; (vii) incremental development opportunities; (viii) total shareholder return; (ix) anticipated compliance with credit facility covenants; (xii) asset disposition plans; (xiii) sources of funding, which are provided to allow investors to better understand Strategic's business. By their nature, forward-looking statements are subject to numerous risks and uncertainties; some of which are beyond Strategic's control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, changes in environmental tax and royalty legislation, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources, and other risks and uncertainties described under the heading 'Risk Factors' and elsewhere in the Company's Annual Information Form for the year ended December 31, 2013 and other documents filed with Canadian provincial securities authorities and are available to the public at www.sedar.com. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. The principal assumptions Strategic has made includes security of land interests; drilling cost stability; royalty rate stability; oil and gas prices to remain in their current range; finance and debt markets continuing to be receptive to financing the Company and industry standard rates of geologic and operational success. Strategic's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements or if any of them do so, what benefits that Strategic will derive there from. Strategic disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law.