Management's Discussion and Analysis
For the three months and year ended December 31, 2017

March 28, 2018

Strategic Oil & Gas Ltd. ("Strategic" or the "Company") is a publicly-traded oil and gas 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 three months and year ended December 31, 2017, 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, 2017 and 2016, together with the accompanying notes, which have been prepared in accordance with International Financial Reporting Standards ("IFRS").

FINANCIAL AND OPERATIONAL SUMMARY

	Three months ended December 31			Twelve months ended December 31		
Financial ($thousands, except per share amounts)	**2017**	2016	% change	**2017**	2016	% change
Oil and natural gas sales	**10,396**	7,721	35	**37,867**	23,878	59
Funds from (used in) operations [1]	**3,024**	1,660	82	**8,065**	(219)	-
Per share basic [1] [2]	**0.07**	0.06	17	**0.17**	(0.01)	-
Cash provided by (used in) operating activities	**490**	(1,256)	-	**4,518**	3,335	35
Per share basic [2]	**0.01**	(0.04)	-	**0.10**	0.12	(17)
Net income (loss)	**(41,264)**	48,510	-	**(89,502)**	33,242	-
Per share basic [2]	**(0.89)**	1.69	-	**(1.94)**	1.21	-
Per share diluted [2]	**(0.89)**	0.62	-	**(1.94)**	0.55	-
Net capital expenditures	**3,361**	9,018	(63)	**48,200**	29,279	65
Adjusted working capital at December 31 [1]	**13,087**	49,956	(74)	**13,087**	49,956	(74)
Net debt at December 31 [1]	**95,801**	51,141	87	**95,801**	51,141	87
Operating						
Average daily production						
Crude oil (bbl per day)	**1,819**	1,487	22	**1,799**	1,415	27
Natural gas (mcf per day)	**3,633**	2,233	63	**3,822**	2,359	62
Barrels of oil equivalent (boe per day)	**2,424**	1,859	30	**2,436**	1,808	35
Average prices						
Oil & NGL ($ per bbl)	**58.71**	51.38	14	**52.69**	42.33	24
Natural gas ($ per mcf)	**1.71**	3.36	(49)	**2.34**	2.27	3
Operating netback ($ per boe) [1]						
Oil and natural gas sales	**46.61**	45.13	3	**42.59**	36.09	18
Royalties	**(4.97)**	(6.00)	(17)	**(4.75)**	(4.96)	(4)
Operating expenses	**(20.96)**	(19.87)	5	**(21.05)**	(21.64)	(3)
Transportation expenses	**(0.71)**	(1.01)	(30)	**(1.11)**	(0.84)	32
Operating Netback [1]	**19.97**	18.25	9	**15.68**	8.65	81
Common Shares [2] (thousands)						
Common shares outstanding, end of period	**46,391**	43,978	5	**46,391**	43,978	5
Weighted average common shares (basic)	**46,391**	28,775	61	**46,181**	27,533	68
Weighted average common shares (diluted)	**46,391**	81,616	(43)	**46,181**	71,700	(36)

(1) Funds from operations, adjusted working capital, net debt and operating netback are Non-GAAP measures; see "Non-GAAP measures" in this MD&A.
(2) Adjusted for the share consolidation on a 20:1 basis announced on March 6, 2017.

ABOUT STRATEGIC

Strategic is a junior oil and gas company committed to becoming a premier northern oil and gas operator by exploiting its light oil assets primarily in northern Alberta. 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 Marlowe, Alberta. Strategic's common shares trade on the TSX Venture Exchange under the symbol SOG.

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 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-GAAP measures

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 (used in) operations" is a term used to evaluate operating performance and assess leverage. The Company considers funds from (used in) operations an important measure of its ability to generate funds necessary to finance capital expenditures including related decommissioning obligations, acquisitions and debt repayments if any. Funds from (used in) operations are calculated based on cash flow from operating activities before changes in non-cash working capital and decommissioning expenditures. Funds from (used in) 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 (used in) operations to cash provided by (used in) operating activities:

	Three months ended December 31		Twelve months ended December 31	
($thousands)	**2017**	2016	**2017**	2016
Cash provided by (used in) operating activities	**490**	(1,256)	**4,518**	3,335
Expenditures on decommissioning liabilities	**102**	910	**2,333**	1,625
Changes in non-cash working capital	**2,432**	2,006	**1,214**	(5,179)
Funds from (used in) operations	**3,024**	1,660	**8,065**	(219)

"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 excluding realized and unrealized gains and losses on risk management contracts, less royalties, and production costs. There is no IFRS measurement that would be directly comparable to operating netbacks.

“Adjusted working capital” is used to assess capital on hand for funding development and sustaining operations. Adjusted working capital is equal to working capital excluding accrued interest on convertible debentures, as substantially all of this interest is currently being paid in additional debentures as opposed to cash. The following table reconciles adjusted working capital to working capital:

($thousands)	**December 31, 2017**	December 31, 2016
Current assets	**21,830**	59,157
Current liabilities	**(11,579)**	(11,834)
Working capital	**10,251**	47,323
Accrued interest on convertible debentures	**2,836**	2,633
Adjusted working capital	**13,087**	49,956

“Net debt” is used to assess capital requirements and leverage, as well as evaluate funds available for capital spending programs and operations. Net debt is calculated as convertible debentures, measured at principal amount outstanding, less working capital or plus working capital deficiency.

PERFORMANCE OVERVIEW, STRATEGY AND OUTLOOK

In 2017 Strategic was focused on development of the Muskeg resource, as well as exploring additional light oil zones as secondary production targets at Marlowe. In total 7 Muskeg horizontal development wells and 1 Slave Point well were drilled during the year. As a result of these activities, average production increased 35% from 2016 to 2,436 boe/d, and funds from (used in) operations increased from $(0.2) million in 2016 to $8.1 million ($0.17 per basic share) in 2017.

In planning the first quarter 2017 drilling program, the Company made several adjustments to the well placement targeting lower in the pay zone to achieve a faster drilling pace. Strategic management has completed a detailed review of the drilling and production techniques used in this program and believes that certain adjustments made may have limited the productivity of those Muskeg wells drilled. As a result, production levels in 2017 did not meet internal expectations. In addition, 2017 year-end proved and probable reserves were impacted by 3.0 MMBoe of technical revisions recorded to proved and probable reserves related to estimated reserves for the wells drilled the year and future undeveloped drilling locations. The Company does not believe that 2017 drilling results are reflective of the potential of the Muskeg play and has adjusted its drilling and completion techniques, with the goal of improving well design and restoring productivity in 2018 and future capital programs.

In the first quarter of 2018, Strategic drilled and completed two Muskeg wells at West Marlowe along the high potential Muskeg light oil corridor. The Company refined its completion techniques to complete 30 stages per well using a proven pinpoint shiftable sleeve system.

Both wells were completed in the first quarter, and testing was limited to the stages that were completed using the new frac design. Well 01-02 was production tested with 13 out of 30 stages open. After a 3 day cleanup period the well produced an average of 473 boe/d (82% oil) for 11 days. The water cut continued to drop during the test period, ending at approximately 55%. The well is currently shut-in while the remaining stages are opened. Well 05-01 was production tested with 19 out of 30 stages open. Initial volumes were limited by the size of the pumping unit used, however after a 5 day cleanup period the well produced an average of 148 boe/d (90% oil) for 12 days, and over the last 3 days the average production rate increased to 227 boe/d (89% oil) with a 76% water cut. The Company is encouraged by these initial rates given that just over half of the total stages completed are currently open and contributing to production volumes.

FOURTH QUARTER SUMMARY

- Average daily production increased 30% from 1,859 boe/d for the three months ended December 31, 2016 to 2,424 boe/d for the current quarter primarily due to new production from Muskeg drilling activities over the past year.

- Funds from operations increased 82% to $3.0 million from $1.7 million for the same quarter last year due to a $2.7 million increase in revenue resulting from higher production levels ($2.0 million) and an increase in realized prices ($0.7 million).

- Capital expenditures of $3.4 million were incurred in the quarter, mostly related to completing and equipping the wells drilled in the third quarter of 2017, expenditures on gathering pipelines and on pad construction in preparation for the 2018 winter drilling program.

- In the third quarter of 2017, the Company drilled a horizontal well at west Marlowe testing the Slave Point formation. The well was drilled with a 1,200 meter lateral length and 10 stages were completed. The well was put on production early in the fourth quarter. With limited drawdown the well's initial production was 46 boe/d (75% oil) for the first 90 days.

- Strategic continued to maintain financial discipline with its capital program. At December 31, 2017, the Company had $13.1 million in cash and $13.1 million in adjusted working capital. The capital program approved for the first half of 2018 will be funded with cash on hand and cash flow from operating activities.

ANNUAL SUMMARY

- Funds flow from operations increased to $8.1 million in 2017 from funds used in operations of $0.2 million in 2016 as revenue increased due to higher commodity prices ($6.9 million) and higher production levels ($7.1 million) arising from drilling and completion activities during 2017. The revenue increase was partially offset by higher royalties and an increase in operating costs over 2016 levels.

- Production increased 35% to 2,436 boe/day from 1,808 boe/day in 2016 due to production additions from new Muskeg wells, and despite significant delays in well completions during the first half of 2017 due to unavailability of frac services.

- Capital expenditures increased to $48.2 million in 2017 from $29.3 million for 2016 as the Company accelerated the development of its Muskeg oil resource. A total of 8 horizontal wells were drilled including 7 Muskeg wells and 1 Slave Point well. Capital spending for the year also included the construction of 4 kilometers of high grade road and pipeline to tie-in the 14-35 Muskeg well drilled in 2016.

- Proved and probable reserves at December 31, 2017, as determined by the Company's independent reserves evaluators McDaniel and Associates Ltd. ("McDaniel"), decreased 18% to 16.0 MMboe compared to 19.6 MMBoe at year-end 2016 due primarily to 3.0 MMboe of negative technical revisions related to the shortfall in performance from Muskeg wells drilled in 2017. Net present value of proved and probable reserves using McDaniel's forecast prices and costs decreased to $130.1 million from $194.4 million at December 31, 2016. The decrease is attributable to the lower reserves volumes, a decline in the forward price deck for oil and gas and an extension in the timeline for development of the Company's undeveloped reserves. The Company does not believe that recent 2017 wells results are reflective of the potential of the Muskeg play, and has adjusted its drilling and completion techniques in 2018, with the goal of improving well design and restoring productivity.

- Strategic incurred a net loss of $89.5 million compared to net income of $33.2 million in 2016. The loss was driven by impairment charges of $58.8 million related to lower reserves values at Marlowe and a loss on revaluation of decommissioning liabilities of $7.2 million.

RESULTS OF OPERATIONS

Production

	Three months ended December 31		Twelve months ended December 31	
Average daily production volumes	**2017**	2016	**2017**	2016
Oil & NGL (bbl/d)	**1,819**	1,487	**1,799**	1,415
Natural gas (mcf/d)	**3,633**	2,233	**3,822**	2,359
Total (boe/d)	**2,424**	1,859	**2,436**	1,808

Average daily production increased 35% to 2,436 boe/d in 2017 from 1,808 boe/d in 2016, due to a full year of production from 3 Muskeg wells drilled in late 2016 and production additions from the 2017 drilling program, partially offset by natural declines. Production for the three months ended December 31, 2017 increased by 30% from the fourth quarter of 2016 due to Muskeg drilling activities during the past year.

Revenue & Prices

	Three months ended December 31		Twelve months ended December 31	
($thousands, except where noted)	**2017**	2016	**2017**	2016
Sales				
Oil & NGL	**9,826**	7,031	**34,599**	21,916
Natural gas	**570**	690	**3,268**	1,962
Oil and natural gas sales	**10,396**	7,721	**37,867**	23,878
Average prices				
Oil & NGL ($/bbl)	**58.71**	51.38	**52.69**	42.33
Natural gas ($/mcf)	**1.71**	3.36	**2.34**	2.27
Reference prices				
Oil – WTI ($US/bbl)	**55.39**	49.30	**50.95**	43.32
Edmonton par ($/bbl)	**68.75**	61.60	**62.85**	53.00
Natural gas – AECO Daily Index ($/MMBtu)	**1.68**	3.08	**2.15**	2.15

Average oil prices received are a function of the benchmark West Texas Intermediate ("WTI") oil price, less foreign exchange, transportation and quality differentials to arrive at Canadian dollar price received at delivery points in northern Alberta. WTI oil prices in 2017 were 18% higher than 2016, and rallied late in the year to close at US $60.42/bbl. Strategic's average realized oil price for the fourth quarter of 2017 increased by 14% from the corresponding period in 2016 due to higher WTI oil prices.

Substantially all of the Company's natural gas is sold at AECO pricing, adjusted for fuel charges. AECO gas prices started 2017 over $3/mcf, but have weakened throughout the year due to maintenance on the main pipeline transportation network in western Canada, which has limited transportation volumes, as well as increases in North American supply. Strategic's average natural gas price in 2017 was 3% higher than 2016 despite similar average AECO prices as the Company's gas production was higher in the first part of the year when gas prices were stronger. Strategic's average gas price for the fourth quarter of 2017 decreased by 49% from the corresponding period in 2016 due to lower AECO gas pricing. The Company receives a premium to AECO as a result of the relatively high heat content of natural gas production at Marlowe.

The Company's oil and natural gas sales increased to $10.4 million and $37.9 million for the three months and year ended December 31, 2017 from $7.7 million and $23.9 million for the respective periods in 2016. The increase was due to an increase in oil prices and higher production levels stemming from drilling activities in late 2016 and 2017.

Risk Management

The Company's net income (loss) and cash flows 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.

The Company had no commodity price risk management contracts in place as at December 31, 2017. Subsequent to the reporting period, Strategic entered into two forward oil sales contracts as follows:

Financial WTI Crude Oil Contracts

Term		Contract Settlement	Volume (bbl/d)	Fixed Price (US$/bbl)	Index
01-Feb-2018	30-Sep-2018	Physical	500	62.00	WTI - NYMEX
01-Mar-2018	31-Aug-2018	Financial	100	64.20	WTI - NYMEX

Royalties

	Three months ended December 31		Twelve months ended December 31	
($thousands, except where noted)	**2017**	2016	**2017**	2016
Crown royalties	**1,047**	960	**3,940**	3,031
Freehold and overriding royalties	**61**	66	**282**	252
Total royalties	**1,108**	1,026	**4,222**	3,283
Per boe	**4.97**	6.00	**4.75**	4.96
Percentage of oil and natural gas sales	**10.7%**	13.3%	**11.1%**	13.7%

Royalties increased to $4.2 million and $1.1 million for the year and three months ended December 31, 2017 from $3.3 million and $1.0 million for the comparative periods in 2016, respectively due to higher oil and gas revenues partially offset by lower rates. Royalty rates decreased to 10.7% and 11.1% for the three months and year ended December 31, 2017 from 13.3% and 13.7% for the comparative periods in 2016 due to more production coming from recently drilled wells, which benefit from a 5% royalty rate until net revenues surpass the drilling and completion cost allowance set by the Alberta government.

Operating and transportation costs

	Three months ended December 31		Twelve months ended December 31	
($thousands, except per boe amounts)	**2017**	2016	**2017**	2016
Operating costs	**4,674**	3,399	**18,714**	14,320
Transportation costs	**157**	174	**988**	559
	4,831	3,573	**19,702**	14,879
Per boe				
Operating	**20.96**	19.87	**21.05**	21.64
Transportation	**0.71**	1.01	**1.11**	0.84
	21.67	20.88	**22.16**	22.48

Operating costs for the three months ended December 31, 2017 increased to $4.7 million compared to $3.4 million for the fourth quarter of 2016, primarily due to higher environmental remediation costs ($0.3 million) and higher labour, chemicals, insurance and rental charges ($0.4 million) reflecting the higher operated wellbase and additional equipment installed at west Marlowe. Full year operating costs increased by $4.4 million or 31% from

2016 due to environmental remediation costs of $1.3 million, higher workover costs ($0.7 million) and increased labor and equipment rental charges primarily for new Muskeg well operations.

Operating costs per boe for the three months ended December 31, 2017 increased by 5% from the fourth quarter of 2016 due to spill remediation costs, labour and workover charges, partially offset by higher production levels in the quarter. Unit operating costs in 2017 decreased by 3% from 2016 due to higher production levels, partially offset by increased operating costs.

Transportation costs for the three months ended December 31, 2017 and 2016 were comparable at $0.2 million while unit transportation costs decreased to $0.71/boe from $1.01/boe due to increased production. Transportation costs for the year ended December 31, 2017 increased to $1.0 million ($1.11/boe) from $0.6 million ($0.84/boe) for the comparative period in 2016 due to an increase in trucked oil volumes in 2017. Oil trucking was required in the third quarter due to a temporary shutdown of a third party sales pipeline. A portion of these costs were recouped by oil trucking rebates from the Alberta government, which were credited to royalties expense.

Netbacks

	Three months ended December 31		Twelve months ended December 31	
($/boe)	**2017**	2016	**2017**	2016
Revenue	**46.61**	45.13	**42.59**	36.09
Royalties	**(4.97)**	(6.00)	**(4.75)**	(4.96)
Operating costs	**(20.96)**	(19.87)	**(21.05)**	(21.64)
Transportation costs	**(0.71)**	(1.01)	**(1.11)**	(0.84)
Operating netback	**19.97**	18.25	**15.68**	8.65

Strategic's operating netback increased to $19.97/boe for the three months ended December 31, 2017 from $18.25/boe for the comparative period in 2016 as increasing oil prices were partially offset by lower natural gas prices and higher operating costs related to spill remediation, labor, insurance and chemicals. The operating netback for the twelve months ended December 31, 2017 increased to $15.68/boe from $8.65/boe for the comparative period in 2016 due primarily to higher oil and gas prices.

Strategic's focus area is Marlowe, which is 100% owned and operated by the Company. The operating netback at Marlowe increased to $18.82/boe for the year ended 2017 compared to $12.91/boe for 2016 due to higher commodity prices. The Marlowe netback for the three months ended December 31, 2017 increased to $22.84/boe from $19.49/boe for the fourth quarter of 2016 as a result of higher oil and gas prices and slightly lower royalties, partially offset by higher operating costs. The corporate netback is negatively affected by high fixed operating costs at the Company's minor oil properties in southern Alberta and British Columbia and fixed costs at Bistcho/Cameron Hills, which is currently shut-in due to low commodity prices. Of the Company's total 2017 operating costs of $18.7 million, $3.2 million relates to non-Marlowe assets which produced only 52 boe/d for the year (2016 - $3.3 million, 68 boe/d).

G&A expense

	Three months ended December 31		Twelve months ended December 31	
($thousands, except per boe amounts)	**2017**	2016	**2017**	2016
Gross general and administrative expense	**1,705**	1,701	**6,984**	6,230
Overhead recoveries	**(58)**	(64)	**(256)**	(297)
Capitalized G&A	**(251)**	(281)	**(986)**	(926)
Net G&A expenses	**1,396**	1,356	**5,742**	5,007
Per boe	**6.26**	7.93	**6.46**	7.57

G&A expense reflects all head office costs, a portion of which are charged to operated wells and facilities through overhead recoveries. Costs related to technical office staff that are directly involved in the Company's capital spending programs are capitalized to property, plant and equipment. G&A expenses in 2017 were negatively affected by severance costs for executive and other staff departures of $0.3 million for the fourth quarter and $1.0 million for the full year. Excluding severance, G&A expenses for the three months and year ended December 31, 2017 decreased 20% and 5%, respectively from the comparative periods in 2016 due to lower salaries and office rent costs, partially offset by bad debt expense of $0.1 million related to an uncollectible receivable from a joint venture partner.

On a units-of-production basis, G&A expenses decreased to $6.26/boe and $6.46/boe for the three and twelve months ended December 31, 2017, compared to $7.93/boe and $7.57/boe for the same periods in 2016 as expenses were spread over a larger production base in the current year.

Finance expense

	Three months ended December 31		Twelve months ended December 31	
($thousands)	**2017**	2016	**2017**	2016
Interest expense	**11**	32	**56**	806
Interest expense on convertible debentures – paid in kind	**2,052**	1,856	**7,793**	6,120
Interest expense on convertible debentures – cash portion	**86**	130	**435**	338
Accretion of decommissioning liabilities	**330**	275	**1,292**	1,056
Accretion on promissory notes	**-**	-	**-**	19
Accretion on debentures	**719**	637	**2,807**	1,974
Total	**3,198**	2,930	**12,383**	10,313

Finance expense increased to $3.2 million for the fourth quarter of 2017 from $2.9 million for the comparative period in 2016 due to increased interest and accretion expense on convertible debentures. Substantially all interest expense is paid in kind on the debentures, and a result the principal amount of debentures outstanding increased by $7.6 million during 2017. In addition to debenture interest incurred, an accretion expense is recorded to bring the debenture liability up to the face value of the debentures over the remaining term. Beginning March 1, 2018 convertible debenture interest can no longer be paid in kind and therefore will be paid in cash, starting with the August 31, 2018 payment.

Finance expense for the year ended 2017 increased by $2.1 million or 20% from 2016 due to having a full period of interest and accretion on convertible debentures as well as a higher balance of debentures outstanding, partially offset by lower interest on bank debt. The Company's outstanding bank debt and promissory notes were both repaid in full using proceeds from the debenture issue, which was completed on February 29, 2016.

Accretion of decommissioning liabilities is an expense intended to reflect an increase in Strategic's discounted decommissioning liability due to the passage of time. Accretion of decommissioning liabilities increased by $0.2 million in 2017 compared to 2016 as decommissioning cost estimates increased for certain assets during the current period.

As a result of decreasing long-term discount rates the Company recorded non-cash losses on revaluation of decommissioning liabilities of $7.7 million and $7.2 million for the three months and year ended December 31, 2017 in respect of non-core assets which have negligible carrying values.

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 income (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.

Stock based compensation expense for the three months and year ended December 31, 2017 increased by $0.3 million (397%) and $1.5 million (294%) respectively from 2016 levels as there were 1.5 million new stock options issued in the second quarter of 2017 compared to 0.5 million stock options issued in February 2016. A third of the options vested at the time they were granted; therefore, the fair value of the vested options is expensed on grant date.

Depletion, depreciation & amortization

	Three months ended December 31		Twelve months ended December 31	
($thousands, except per boe amounts)	**2017**	2016	**2017**	2016
Depreciation, depletion and amortization ("DD&A")	**4,804**	3,049	**17,817**	13,132
Per boe	**21.54**	17.82	**20.04**	19.85

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 also includes amortization of undeveloped land costs. Major components, such as facilities and pipelines, are separated from oil and gas properties and depreciated on a straight-line basis over their estimated useful lives. DD&A expense increased to $4.8 million and $17.8 million for the three months and year ended December 31, 2017 from $3.0 million and $13.1 million for the 2016 comparative period as a result of higher production levels. DD&A rates per boe increased from 2016 as the prior year benefitted from an impairment reversal recorded in the fourth quarter of 2016 which increased the Company's property, plant and equipment balance.

Impairment

At each reporting date the Company considers potential indicators of asset impairment, such as a significant drop in commodity prices or a downward revision of 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, net of decommissioning obligations, 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. At December 31, 2017, the Company identified indicators of impairment for the Marlowe CGU due to issues with well performance and a decrease in reserves during the year.

The recoverable amount was determined based on the fair value less costs to sell method. The key assumptions used in determining the recoverable amount include the future cash flows using reserve forecasts, forecasted commodity prices, discount rates, inflation rates and future development costs estimated for reserves by McDaniel. The recoverable amount also includes a provision for the estimated net present value of decommissioning obligations.

The values assigned to the future cash flows were obtained from Strategic's year-end reserve report, which was evaluated by McDaniel. These values were based on future cash flows of proved plus probable reserves discounted at a pre-tax rate of 10% (2016 – 10-12%). The future cash flows also consider, when appropriate, past capital activities, observable market and commodity pricing conditions, comparable transactions and future development costs primarily based on anticipated development capital programs.

For the year ended December 31, 2017, the Company recognized an impairment charge of $55.9 million in respect of property, plant and equipment related to the Marlowe CGU, compared to a net impairment reversal of $52.7 million recorded in 2016. In 2017 Strategic also recognized an impairment loss of $2.9 million related to exploration and evaluation assets in the Marlowe area.

Deferred Taxes

Deferred taxes arise from differences between accounting and tax basis of assets and liabilities, and are recorded based on the current tax status of the Company, income tax rates and management's best estimate of future events, including development expenditures and cash flows. In 2017 Strategic recorded a $0.1 million deferred tax liability related to the equity portion of convertible debentures issued during the year (2016 – $3.8 million). As a result, the Company recognized an offsetting amount of previously unrecognized deferred tax assets and a deferred tax recovery of $0.1 million was recorded for 2017 (2016 - $3.8 million). The Company has approximately $303 million in accumulated tax losses available to shelter future income, and does not anticipate paying income taxes in the foreseeable future.

Funds from (used in) operations and net income (loss)

	Three months ended December 31		Twelve months ended December 31	
($thousands, except per share amounts)	**2017**	2016	**2017**	2016
Funds from (used in) operations	**3,024**	1,660	**8,065**	(219)
Per share – basic [1]	**0.07**	0.06	**0.17**	(0.01)
Cash flow provided by (used in) operating activities	**490**	(1,256)	**4,518**	3,335
Per share – basic [1]	**0.01**	(0.04)	**0.10**	0.12
Net income (loss) for the period	**(41,264)**	48,510	**(89,502)**	33,242
Per share – basic [1]	**(0.89)**	1.69	**(1.94)**	1.21
Per share – diluted [1]	**(0.89)**	0.62	**(1.94)**	0.55

(1) Adjusted for the share consolidation on a twenty to one basis.

Funds from operations increased 82% to $3.0 million for the fourth quarter of December 31, 2017 from $1.7 million in the comparative period in 2016 due to increasing oil prices and higher production levels, partially offset by lower natural gas prices and an increase in operating costs. Funds from operations increased to $8.1 million in 2017 from funds used in operations of $0.2 million in 2016 due to higher oil prices and production levels, partially offset by higher operating and G&A expenses.

Cash flow provided by operating activities was $0.5 million for the fourth quarter of December 31, 2017 compared to cash flow used in operating activities of $1.3 million for the comparative period in 2016, primarily due to higher revenues, partially offset by higher operating costs. Cash flow provided by operating activities increased to $4.5 million for the year ended December 31, 2017 from $3.3 million for 2016 due to higher funds from operations, offset by increased expenditures on decommissioning liabilities.

Net loss was $41.3 million and $89.5 million for the fourth quarter and year ended December 31, 2017 compared to net income of $48.5 million and $33.2 million, respectively for the fourth quarter and full year 2016. The net loss was due to an impairment loss of $58.8 million, a loss on revaluation of decommissioning liabilities of $7.2 million and higher DD&A expense related to higher production, partially offset by an increase in funds from operations compared to 2016. Net income for prior periods was positively affected by an impairment reversal of $52.7 million.

Capital expenditures

	Three months ended December 31		Twelve months ended December 31	
($thousands)	**2017**	2016	**2017**	2016
Drilling, completions and equipping	**2,673**	8,425	**43,034**	19,997
Pipelines and facilities	**679**	591	**5,060**	4,835
	3,352	9,016	**48,094**	24,832
Dispositions	**-**	-	**-**	(15)
Total property, plant and equipment	**3,352**	9,016	**48,094**	24,817
Total exploration and evaluations ("E&E")	**9**	2	**106**	4,447
Net capital expenditures	**3,361**	9,018	**48,200**	29,264

Capital expenditures for the quarter ended December 31, 2017 decreased to $3.4 million compared to $9.0 million for the comparative period in 2016. Current period projects included completing the Slave Point well drilled in the third quarter, pad construction for the winter drilling program and a recompletion project. The comparative period capital expenditures related to the execution of the 2016 development drilling program and related road and lease construction.

Capital expenditures increased to $48.2 million for the twelve months ended December 31, 2017 from $29.3 million in 2016, due to the execution of two horizontal drilling programs at Marlowe including 8 total wells, pipeline construction to tie in the 14-35 well drilled in the first quarter of 2016 and minor recompletions, facilities and equipping projects. Drilling and completion costs in 2017 exceeded internal estimates due to cost inflation in the field and minor operational issues on two wells, while pipeline projects were completed below the Company's cost estimates due to efficiencies and a lack of weather-related downtime in the first quarter. Capital expenditures for 2016 included drilling four exploratory Muskeg wells at Marlowe in the first quarter, followed by a 4-well development program in the second half of the year.

Decommissioning liabilities

Decommissioning liabilities increased to $62.5 million at December 31, 2017 from $52.7 million at December 31, 2016 due a change in estimated costs of decommissioning liabilities for facilities of $6.6 million, additional liabilities incurred on new wells drilled and a slight decrease in long-term discount rates, partially offset by expenditures on abandonments throughout the year. The current portion of the decommissioning liabilities at December 31, 2017 includes $1.6 million related to remediation of the site of a prior year pipeline spill and well abandonment projects that are scheduled for completion in 2018.

In 2017 the government of the Northwest Territories issued new requirements related to well abandonment projects. The requirements provide that all wells that have been shut-in for over 12 months must be suspended or returned to production within 2 years and abandoned within 6 years after suspension. The Company has 45 non-productive wells in the Northwest Territories and estimates $5 to $6 million in costs will be incurred in 2019 and 2020 in order to bring all wells into compliance with the requirements.

SUMMARY OF QUARTERLY FINANCIAL DATA

The following table summarizes quarterly financial results:

Quarter ended ($thousands, except where noted)	Dec 31, 2017	Sept 30, 2017	Jun 30, 2017	Mar 31, 2017
Petroleum and natural gas sales	**10,396**	8,271	10,312	8,888
Net loss	**(41,264)**	(36,779)	(7,020)	(4,442)
Net loss per share – basic & diluted [1]	**(0.89)**	(0.79)	(0.15)	(0.10)
Average daily production (boe/d)	**2,424**	2,384	2,661	2,273
Average price ($/boe)	**46.61**	46.63	42.58	43.44

Quarter ended ($thousands, except where noted)	Dec 31, 2016	Sept 30, 2016	Jun 30, 2016	Mar 31, 2016
Petroleum and natural gas sales	7,721	5,478	5,974	4,705
Net income (loss)	48,510	(5,985)	(5,800)	(3,483)
Net income (loss) per share – basic [1]	1.69	(0.22)	(0.21)	(0.13)
Net income (loss) per share – diluted [1]	0.62	(0.22)	(0.21)	(0.13)
Average daily production (boe/d)	1,859	1,577	1,829	1,968
Average price ($/boe)	45.13	44.23	35.89	26.26

(1) Adjusted for the share consolidation on a twenty to one basis.

Oil and natural gas sales are a function of average daily production levels, the oil/gas production mix and commodity prices and increased significantly with higher production levels throughout 2017. Sales were highest in the fourth quarter of 2017 due to a combination of high production of 2,424 boe/d and high commodity prices of $46.61/boe.

Net loss varies with funds from operations, as well as non-cash expenses incurred such as stock-based compensation, non-cash finance costs, DD&A and impairment. Net income of $48.5 million for the fourth quarter in 2016 was driven by a net impairment recovery of $52.7 million. Net losses were high in the third and fourth quarters of 2017 due to impairment charges of $30.4 million and $28.4 million, respectively. Maintaining positive net income on a consistent basis will depend on the Company's ability to increase sales volumes and reduce unit production costs and DD&A, as well as on an increase in commodity prices.

LIQUIDITY AND CAPITAL RESOURCES

Going concern

The annual consolidated financial statements have been prepared on a going concern basis. The going concern basis of presentation assumes that the Company will continue in operation for the foreseeable future and will be able to realize its assets and discharge its liabilities and commitments in the normal course of business. For the year ended December 31, 2017, the Company reported positive cash flow from operating activities of $4.5 million, a net loss of $89.5 million and an accumulated deficit of $367.4 million. Sustained low commodity prices in recent years have put pressure on the Company's cash flows.

At December 31, 2017, the Company had $13.1 million in cash and a positive working capital of $10.3 million. Cash from operating activities is dependent on future commodity prices and production levels. In order to continue funding future capital programs, the Company will need to obtain additional equity or debt financing, or assess other options. The ability to access the required capital to maintain current production levels and cash flows is dependent on a variety of external factors. This material uncertainty may cast significant doubt upon the Company's ability to continue as a going concern.

The consolidated financial statements do not reflect adjustments that would be necessary if the going concern basis was not appropriate. The appropriateness of the going concern basis is dependent upon, among other things, the ability to obtain debt or equity financing, or other sources of funding for future capital programs.

Convertible debentures and working capital

The Company considers its capital structure to include shareholders' equity, adjusted working capital, bank debt and convertible debentures. The objectives of the Company are to maintain financial flexibility to achieve goals of continued growth and access to capital. In order to maintain or adjust the capital structure, Strategic may issue new common shares, issue or repay debt, or adjust exploration and development capital expenditures. The Company monitors its capital structure based on net debt and adjusted working capital, as calculated below:

($thousands)	**December 31, 2017**	December 31, 2016
Current assets	**21,830**	59,157
Accounts payable and accrued liabilities	**(5,553)**	(5,760)
Current decommissioning liabilities	**(3,190)**	(3,441)
Adjusted working capital	**13,087**	49,956
Accrued interest on convertible debentures	**(2,836)**	(2,633)
Convertible debentures [(1)]	**(106,052)**	(98,464)
Net debt	**(95,801)**	(51,141)

(1) Convertible debentures are measured at principal amount outstanding.

Adjusted working capital dropped to $13.1 million at December 31, 2017 from $50.0 million at December 31, 2016 as capital expenditures for the year were $48.2 million while cash flow from operating activities was $4.5 million. Approximately $4.5 million of the working capital balance is held in term deposits to collateralize outstanding letters of credit related to decommissioning liabilities for the Company's assets in Cameron Hills, NWT.

The Company has $106.1 million of senior secured convertible debentures ("Debentures") outstanding. The Debentures mature on Feb 28, 2021 and bear an annual interest rate of 8.0%, payable semi-annually in arrears, with an option for the Company to pay the interest in an equivalent principal amount of debentures ("PIK option") for the first two years. The Debentures are convertible into common shares at various conversion prices, subject to adjustment in certain events. The Debentures can be called prior to the maturity date by the Company if either a) the 90-day weighted average trading price of Strategic common shares is over four times the conversion price, or b) anytime in the fifth year of the term. The convertible debentures have been classified as a financial liability, net of issue costs and net of the equity component.

On February 28, 2017, $3.7 million of additional convertible debentures were issued as payment of interest in kind. Of the $3.7 million, $2.9 million were issued to entities controlled or jointly controlled by directors of the Company and an additional $0.2 million were issued to directors and officers of the Company. The carrying amount of the financial liability of these convertible debentures was determined by discounting the stream of future payments of interest and principal using a rate of 10.15%, the estimated rate for debt with similar terms without conversion features.

On August 31, 2017, $3.9 million of additional convertible debentures were issued as payment of interest in kind. Of the $3.9 million, $3.0 million were issued to entities controlled or jointly controlled by directors of the Company and an additional $0.2 million were issued to directors and officers of the Company. The carrying amount of the financial liability of these convertible debentures was determined by discounting the stream of future payments of interest and principal using a rate of 10.40%, the estimated rate for debt with similar terms without conversion features.

Below is a summary of the debt and equity components of the convertible debentures:

($000)	Convertible Debentures Component	Equity Component	Total
Balance at December 31, 2016	$ **84,489**	**$ 9,878**	**$ 94,367**
Additional debentures issued as payment in kind of interest	7,077	511	7,588
Issuance costs	(46)	(3)	(49)
Deferred tax recovery	-	(138)	(138)
Debentures converted	(4)	(1)	(5)
Accretion expense	2,807	-	2,807
Balance at December 31, 2017	$ **94,323**	**$ 10,247**	**$ 104,570**

The liability component of all debentures issued is being accreted to the adjusted principal amount of $106.1 million at maturity. Below is a summary of the debentures issued and the related conversion prices:

Issue Date	Principal Amount ($000)	Conversion Price ($/share)
February 29, 2016	94,847	1.80
August 31, 2016	3,617	3.30
February 28, 2017	3,724	2.70
August 31, 2017	3,864	2.03
Total	106,052	

Subsequent to year end, on February 28, 2018, $4.1 million of debentures were issued as payment of interest in kind. Of the $4.1 million additional debentures issued, $3.1 million were issued to entities controlled by a director of the Company and an additional $0.2 million were issued to directors and officers of the Company. The maturity date and the other terms of these debentures issued as payment of interest in kind are identical to the original convertible debentures other than the conversion price which is $1.08 per share.

The capital program approved for the first half of 2018 will be funded with cash on hand and cash flow from operating activities. In future periods the Company will require external financing to fund capital spending programs and decomissioning obligations.

SHARE CAPITAL

	Twelve months ended December 31	
	2017	2016
Weighted average common shares outstanding (thousands)		
Basic	**46,181**	27,533
Diluted	**46,181**	71,700

	December 31, 2017	December 31, 2016
Outstanding securities (thousands)		
Common shares	**46,391**	43,978
Stock options	**2,309**	1,032

On January 31, 2017, the Company issued a total of 2.4 million common shares via a brokered private placement at a price of $2.40 per common shares for gross proceeds of $5.7 million (net proceeds of $5.3 million after transaction costs). Proceeds from the private placement were applied towards the execution of the Company's capital program for 2017 and used for general corporate purposes.

In 2017 the Company issued 1.5 million stock options to directors, officers, employees and consultants (2016 – 0.5 million options). Each option entitles the holder to acquire one common share of the Company for a period of five years at a price of $2.65 per share (2016 - $1.80 per share).

As of March 21, 2018 there were 46,402,199 common shares outstanding and 2,952,816 stock options outstanding. If all of the outstanding Debentures were converted into common shares, an additional 60,817,720 common shares would be issued. However, as the conversion prices on all Debentures exceed the Company's current share price, it is unlikely that Debentures will be converted into common shares in the near term.

SUMMARY OF ANNUAL INFORMATION

		Year ended December 31	
($000, except per share amounts)	**2017**	2016	2015
Total revenue	**37,867**	23,878	36,496
Net income (loss)	**(89,205)**	33,242	(110,115)
Per common share (basic)	**(1.94)**	1.21	(4.06)
Per common share (diluted)	**(1.94)**	0.55	(4.06)
Total assets	**186,589**	248,668	130,593
Total long-term liabilities	**153,626**	133,699	48,107

Net revenues were lower in 2016 compared to 2015 as a result of lower oil prices and production levels. As the Company initiated development drilling activities in the second half of 2016 and 2017, production levels and revenue increased in 2017. Net income (loss) in all periods was driven by impairment losses which were $58.8 million in 2017 and $87.7 million in 2016, and an impairment reversal of $52.7 million in 2016. Total assets increased in 2016 from 2015 due to the impairment reversal and a significant working capital balance resulting from financing activities prior to year-end. However, total assets decreased in 2017 due to the impairment loss and DD&A expense recorded for the year. Long-term liabilities consist primarily of decommissioning obligations and convertible debentures, and have increased primarily due to the issuance of debentures in February 2016 and debentures issued as payment of interest in kind in subsequent periods. Decomissioning obligations have also increased due to changes in cost estimates and accretion expense.

TRANSACTIONS WITH RELATED PARTIES

Legal fees in the amount of $0.2 million (2016 - $0.2 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 rental expense of $0.2 million (2016 - $0.2 million) were incurred to a software firm which is controlled by a former officer of the Company. Accounts payable and accrued liabilities at 2016 include $nil (2016 - $0.1 million) due to related parties.

The Company is in the process of entering into a joint arrangement with an entity controlled by a director of the Company to develop and explore an area of mutual interest in northern Alberta outside of the Marlowe core area. As at December 31, 2017, the counterparty has contributed lands to the joint arrangement and is committed to contributing additional capital of approximately $9 million towards exploration costs for the area. Strategic intends to contribute undeveloped lands with a carrying value of $0.5 million in exchange for a 10% carried interest in the development.

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. Transaction amounts reflect fair values.

COMMITMENTS

The Company has lease agreements for office space and equipment and natural gas transportation, resulting in the following commitments:

Year	Office ($000)		Gas transportation ($000)	
2018	$	452	$	454
2019		409		433
2020		38		414
2021		-		367
2022		-		342
2023 and thereafter		-		90
	$	899	$	2,100

SENSITIVITY ANALYSIS

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

	For the year ended December 31	
Increase (decrease) in funds from operations ($000)	**2017**	2016
$1.00 increase in oil price	**584**	444
$0.25 increase in gas price	**310**	196
1% increase in interest rate	**473**	214

FUTURE ACCOUNTING PRONOUNCEMENTS

IFRS 15 *Revenue from Contracts with Customers*

In April 2016, the IASB issued its final amendments to IFRS 15 "Revenue from Contracts with Customers," which replaces IAS 18 "Revenue," IAS 11 "Construction Contracts," and related interpretations. IFRS 15 provides a single, principles-based five-step model to be applied to all contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded. The standard is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with earlier adoption permitted.

The Company will retrospectively adopt IFRS 15 on January 1, 2018. The Company has completed reviewing its various revenue streams and underlying contracts with customers. It has been concluded that the adoption of IFRS 15 will not have a material impact on the Company's net loss and financial position. The Company will expand disclosures in the notes to its financial statements as prescribed by IFRS 15.

IFRS 9 *Financial Instruments*

In July 2014, the IASB completed the final elements of IFRS 9 "Financial Instruments." The standard supersedes earlier versions of IFRS 9 and completes the IASB's project to replace IAS 39 "Financial Instruments: Recognition and Measurement." IFRS 9 introduces a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the requirements of IAS 39. The Company anticipates that adoption of IFRS 9 will result in changes to the classification of the Company's financial assets but will not change the classification of the Company's financial liabilities. The Company does not anticipate any material changes in the carrying values of the Company's financial instruments as a result of the adoption of IFRS

9. The Company does not anticipate that the new impairment model will result in material changes to the valuation of its financial assets on adoption of IFRS 9.

In addition, IFRS 9 introduces a new expected credit loss model for calculating impairment of financial assets, replacing the incurred loss model required by IAS 39. The Company has determined that the new impairment model will not result in material changes to the valuation of its financial assets on adoption of IFRS 9. IFRS 9 also contains a new model to be used for hedge accounting. The Company does not currently apply hedge accounting to its risk management contracts and does not currently intend to apply hedge accounting to any of its existing risk management contracts on adoption of IFRS 9. The standard will come into effect for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. IFRS 9, as well as consequential amendments to IFRS 7, "Financial Instruments: Disclosures", will be applied on a retrospective basis by the Company on January 1, 2018.

IFRS 16 *Leases*

In January 2016, the IASB issued IFRS 16 "Leases," which replaces IAS 17 "Leases." For lessees applying IFRS 16, a single recognition and measurement model for leases would apply, with required recognition of assets and liabilities for most leases. The standard will come into effect for annual periods beginning on or after January 1, 2019, with earlier adoption permitted if the entity is also applying IFRS 15 "Revenue from Contracts with Customers." The standard is required to be adopted either retrospectively or using a modified retrospective approach. IFRS 16 will be applied by the Company on January 1, 2019 and the Company is currently evaluating the impact of the standard on the Company's consolidated financial statements.

CRITICAL ACCOUNTING ESTIMATES

A summary of the Company's significant account policies is contained in Note 3 to the consolidated financial statements. The timely preparation of the financial statements in accordance with IFRS requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses for the period. Actual results may differ from these estimates. Information regarding the significant judgments made by management in applying the Company's accounting policies and the key sources of estimation uncertainty are outlined below.

The Company uses estimates of oil and natural gas reserves in the calculation of depreciation and depletion and also for value in use and fair value less costs to sell ("FVLCS") calculations of non-financial assets. By their nature, the estimates of reserves, including estimates of price, costs, discount rates and the related future cash flows, are subject to measurement uncertainty.

The recoverability of the carrying value of oil and gas properties is assessed at the cash generating unit ("CGU") level. Determination of the properties and other assets to be included within a particular CGU is based on management's judgment with respect to the integration between assets, shared infrastructure and cash flows. Changes in the assets comprising each CGU impacts recoverable amounts used in impairment assessments and could have a material impact on net income. Strategic conducts its operations through 4 CGUs, namely Steen/Marlowe, Bistcho, other Canadian and USA.

The transfer of exploration and evaluation assets to property, plant and equipment is based on estimated reserves used in the determination of an asset's technical feasibility and commercial viability. Evaluating potential impairment of exploration and evaluation assets, as well as recoverable amounts, requires the use of assumptions and management's judgement and changes in these assumptions could have a material impact on net income.

Amounts recorded for decommissioning obligations and the associated accretion are calculated based on estimates of asset retirement costs, timing of expenditures, risk free interest rates, site remediation and related cash flows.

Derivative financial instruments are measured at fair value which is subject to management uncertainty, due to the use of future oil and natural gas prices and the volatility in these prices.

The determination of fair value of stock-based compensation is based on estimates using an option pricing model which requires estimates of assumptions such as volatility, risk free interest rate, forfeiture rate, and expected option life.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company operates are subject to change. Income taxes are subject to measurement uncertainty, the timing and likelihood of any recognition of deferred tax assets, which are assessed by management at the end of the reporting period to determine the likelihood that they will be realized from future taxable earnings.

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 marketability and price of oil and natural gas that may be acquired or discovered by the Company will be affected by numerous factors beyond its control. The Company's ability to market its natural gas and oil may depend upon its ability to acquire space on pipelines that deliver natural gas and oil to commercial markets. The Company may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities, and related to operational problems with 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 Company'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 which are volatile and subject to fluctuations. The Company'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 Company. These factors include economic conditions in the United States and Canada, the actions of OPEC, 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. Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the global economy, OPEC actions, instability in the Middle East and the impact of emerging countries such as China and India on the demand for crude oil and natural gas.

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.

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. The Company's cash flows are being adversely affected by low commodity prices. As such, the Company's ability to expend the capital necessary to undertake or complete future drilling programs in order to replace reserves and maintain production will be limited without additional financing. There can be no assurance that debt or equity financing 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. The convertible debentures recently issued by Strategic will need to be repaid or refinanced by February, 2021. 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. In addition, decommissioning expenditures that are planned for the first 12 months after the reporting date are classified as current liabilities on the balance sheet and affect the Company's net debt levels and debt covenant calculations.

Regulation

The Company is operating in a highly regulated industry. The Alberta Energy Regulator ("AER") has issued directives requiring companies to abandon or suspend operated, non-productive wells over a defined timeline, restricting the ability of companies in the energy industry to transfer assets and licenses to third parties, and increasing the time and effort involved in obtaining a new license. As the number of regulations applicable to the Company increase, so will the costs of compliance.

Both the federal and Alberta governments have introduced carbon pricing measures which increase costs of consumption of power, natural gas and other fuels. Such measures could also reduce demand for oil and natural gas and have an adverse affect on the Company's profitability.

International Trade Risks

As the bulk of the Company's oil and gas ends up in the United States, changes resulting from the change in U.S. Administrations may result in legislative and regulatory changes that could have an adverse effect on the Company.

The U.S. administration has recently decided to reopen the North American Free Trade Agreement ("NAFTA") for discussion. There is uncertainty with respect to the potential impact of these negotiations on tariffs, taxes or duties on the Company's oil and natural gas. Implementation by the U.S. of new legislative or regulatory regimes could impose additional costs on the Company, decrease U.S. demand for the Company's products or otherwise negatively impact the Company, which may have a material adverse effect on Strategic's business, financial condition and operations.

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, there is competition for qualified personnel in the oil and natural gas industry 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 drilling 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 exploration and development prospects, access to commodity markets, technical and field services, 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.

Refer to the Company's Annual Information Form for the year ended December 31, 2017 for a discussion of additional risk factors.

FORWARD-LOOKING STATEMENTS

Certain statements in this document constitute forward-looking information under applicable securities legislation. Forward-looking information typically contains statements with words such as "anticipate", "believe", "estimate", "will", "may", "expect", "plan", "schedule", "intend", "propose", or similar words suggesting future outcomes or an outlook. Forward-looking information in this document includes, but is not limited to:

- projected production rates and sales volumes and the timing thereof;
- forecast capital expenditures, operating costs per BOE, abandonment and reclamation costs and transportation costs per BOE;
- exploration, development, and associated operational plans and strategies;
- availability of current working capital and the timing and source of funds for the capital program for the first half of 2018 and future periods;
- the Company's plans with respect to payment of interest on convertible debentures;
- potential profitability and productivity of the Company's asset base;
- the impact of cost reduction initiatives;
- potential conversion of convertible debentures;
- the impact of adjustments to drilling and completion techniques;
- potential to enter into financial commodity price management contracts;
- potential changes to capital structure to achieve growth and access capital;
- the success of the joint arrangement in northern Alberta and the contributions to be made by the partners thereto;
- the impact of advanced oil and natural gas related exploration and production techniques; and
- general business strategies and objectives.

Such forward-looking information is based on a number of assumptions which may prove to be incorrect. Assumptions have been made with respect to the following matters, in addition to any other assumptions identified in this document:

- future natural gas and liquids prices;
- royalty rates, taxes and capital, operating, general and administrative and other costs;
- foreign currency exchange rates and interest rates;
- general business, economic and market conditions;

- the ability of the Company to obtain the required capital to finance its exploration, development and other operations and meet its commitments and financial obligations;
- the ability of Strategic to obtain equipment, services, supplies and personnel in a timely manner and at an acceptable cost to carry out its activities;
- the ability of Strategic to secure adequate product processing, transportation and storage capacity on acceptable terms;
- the ability of Strategic to market its oil and natural gas successfully to current and new customers;
- the ability of Strategic and its industry partners to obtain drilling success (including in respect of anticipated production volumes, reserves additions and resource recoveries) and operational improvements, efficiencies and results consistent with expectations;
- the timely receipt of required governmental and regulatory approvals; and
- anticipated timelines and budgets being met in respect of drilling programs and other operations (including well completions and tie-ins and the construction, commissioning and start-up of new and expanded facilities).

Although Strategic believes that the expectations reflected in such forward-looking information is reasonable, undue reliance should not be placed on them as the Company can give no assurance that such expectations will prove to be correct. Forward-looking information is based on expectations, estimates and projections that involve a number of risks and uncertainties which could cause actual results to differ materially from those anticipated by Strategic and described in the forward-looking information. The material risks and uncertainties include, but are not limited to:

- fluctuations in natural gas and liquids prices;
- changes in foreign currency exchange rates and interest rates;
- the uncertainty of estimates and projections relating to future revenue, future production, reserve additions, resource recoveries, royalty rates, taxes and costs and expenses;
- the ability to secure adequate product processing, transportation and storage capacity on acceptable terms;
- operational risks in exploring for, developing and producing, oil and natural gas;
- the ability to obtain equipment, services, supplies and personnel in a timely manner and at an acceptable cost;
- potential disruptions, delays or unexpected technical or other difficulties in designing, developing, expanding or operating new, expanded or existing facilities;
- processing and pipeline infrastructure outages, disruptions and constraints;
- risks and uncertainties involving the geology of oil and gas deposits;
- the uncertainty of reserves and resources estimates;
- general business, economic and market conditions;
- the ability to generate sufficient cash flow from operations and obtain financing to fund planned exploration, development and operational activities and meet current and future commitments and obligations (including with respect to the convertible debentures);
- changes in, or in the interpretation of, laws, regulations or policies (including environmental laws);
- the ability to obtain required governmental or regulatory approvals in a timely manner, and to enter into and maintain leases and licenses;
- the effects of weather and other factors including wildlife and environmental restrictions which affect field operations and access;
- the timing and cost of future abandonment and reclamation obligations and potential liabilities for environmental damage and contamination;
- uncertainties regarding aboriginal claims and in maintaining relationships with local populations and other stakeholders;
- the outcome of existing and potential lawsuits, regulatory actions, audits and assessments; and
- other risks and uncertainties described elsewhere in this document and in Strategic’s other filings with Canadian securities authorities.

The foregoing list of risks is not exhaustive. For more information relating to risks, see the section titled "Risk Factors" in Strategic's current annual information form and MD&A. The forward-looking information contained in this document is made as of the date hereof and, except as required by applicable securities law, Strategic undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise.

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.