MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A"), dated March 8, 2016, is management's assessment of the historical financial position and results of Seven Generations Energy Ltd. (the "Company" or "Seven Generations") for the year ended December 31, 2015. This MD&A should be read in conjunction with the audited annual consolidated financial statements and notes thereto for the years ended December 31, 2015 and 2014 (the "consolidated financial statements"). These consolidated financial statements, including the comparative figures, were prepared in accordance with International Financial Reporting Standards ("IFRS"). Unless otherwise noted, all financial measures are expressed in Canadian dollars and tabular dollar amounts are in thousands. See "Non-IFRS Financial Measures" for information regarding the following non-IFRS financial measures used in this MD&A: "funds from operations", "operating income", "operating netback", "available funding" and "net debt". This MD&A contains forward looking information based on the Company's current expectations and projections. For information on the material factors and assumptions underlying such forward looking information, refer to the "Forward Looking Information Advisory" included at the end of this MD&A. A number of abbreviated terms used throughout this MD&A are explained on the last page of this MD&A. Additional information about Seven Generations is available on the SEDAR website at www.sedar.com, including the Company's Annual Information Form for the year ended December 31, 2015 dated March 8, 2016 (the "AIF").

ABOUT SEVEN GENERATIONS

Seven Generations is a low supply cost, high-growth Canadian natural gas developer generating long-life value from its liquids-rich Kakwa River Project, located about 100 kilometres south of its operations headquarters in Grande Prairie, Alberta. Seven Generations' corporate headquarters are in Calgary and its Class A Common Shares ("Common Shares") trade on the TSX under the symbol VII.

HIGHLIGHTS FOR THE FOURTH QUARTER AND YEAR ENDED DECEMBER 31, 2015

Financial Performance

Seven Generations achieved record production levels averaging more than 60,000 boe/d and funds from operations of more than $400 million in 2015. The higher supply and inventory levels of global oil and natural gas led to significant decreases in prices, largely impacting the Company's net loss position in 2015. Comparing 2015 to 2014, WTI decreased by 44% and the Canadian dollar lost 14% of its value, relative to the US dollar. The Company realized an operating netback after hedging of $23.72/boe for the year ended December 31, 2015 compared to $35.52/boe for the same period in 2014. In this low commodity price environment, the Company's focus remains on prudent, disciplined investment in long-term value creation.

Capital Investments

In 2015, Seven Generations invested $1.31 billion, at the low end of the 2015 guidance, which ranged between $1.30 billion and $1.35 billion. The Company attributes these savings to improved capital efficiencies in 2015 such as faster drilling and the optimization of well completions. The construction of the new Lator 2 natural gas processing facility was completed 15% under budget and was commissioned six weeks ahead of schedule. The construction of a second 250 MMcf/d natural gas processing plant, the Cutbank Plant, is underway and is expected to be operational in the second quarter of 2016.

Transportation and Marketing

The Company's lands are close to key infrastructure and take-away capacity, including Alliance Pipeline, TransCanada NGTL system and Pembina Peace Pipeline, on which it has contracted firm transportation capacity for natural gas, condensate and other natural gas liquids ("NGLs"). These firm service transportation agreements support the Company's ability to deliver on its high growth objectives. On December 1, 2015, the Company began shipments of rich gas to fulfill the initial firm commitment of 250 MMcf/d on the Alliance Pipeline. Seven Generations holds transportation capacity that grows incrementally over the next three years, reaching approximately 600 MMcf/d in 2018. In the third quarter of 2015, the Company accelerated certain gas transportation capacity commitments with Alliance and signed an agreement to have a third party marketer manage this excess capacity by flowing third party gas.

Risk Management

Seven Generations continued to execute its consistent risk management program in 2015, hedging oil and natural gas prices and exchange rates to partially protect funds from operations against commodity price volatility through a three year, rolling hedging program.

Reserves Update

The Company's independent reserve evaluators, McDaniel & Associates Consultants Ltd. ("McDaniel"), completed independent reserve evaluations effective December 31, 2015. Total gross proved reserves ("1P") were 424.0 MMboe, as at December 31, 2015, an increase of 1% since the Company's December 31, 2014 reserve evaluations. Total gross proved plus probable reserves ("2P") were 859.1 MMboe, an increase of 9% compared to the December 31, 2014 estimates. Using a discount rate of 10%, the Company's total gross 2P reserves were estimated to have a before tax net present value of $6.5 billion compared to $7.1 billion from the December 31, 2014 reserve report, as reserve additions were offset by a lower price deck used by McDaniel.

For important additional information pertaining to the Company's estimated reserves and the estimated net present value of future net revenue that is attributed to the reserves, as evaluated by McDaniel as at December 31, 2015, please refer to the AIF on the SEDAR website at www.sedar.com.

	As at December 31,			
	2015		2014	
	MMboe	**$MM (3)**	MMboe	$MM (3)
PDP + PDNP (1)	**79**	**951**	39	627
Proved Reserves (1P) (2)	**424**	**2,937**	421	3,145
Proved Plus Probable Reserves (2P) (2)	**859**	**6,507**	789	7,108

(1) Proved developed producing plus proved developed non-producing reserves.
(2) Company gross reserve as determined by McDaniel, the Company's independent reserves evaluator.
(3) Before tax net present value using a 10% discount rate.

Outlook and 2016 Guidance

The Company is focused on: (i) cash flow self sufficiency; (ii) the development of a large inventory of relatively low supply cost, liquids-rich horizontal well drilling opportunities in its core focus area; (iii) building facilities to gather and process the produced natural gas, condensate and other NGLs; and (iv) establishing further opportunities to maximize value. Although uncertainty with commodity prices and the oversupply of natural gas markets persisted throughout 2015, Seven Generations remains focused on innovation, efficiency and value optimization to be among the lowest cost suppliers in North America.

Seven Generations expects to invest between $900 million and $950 million for capital investments in 2016. In response to continued low commodity prices, the capital program was reduced by 18% from the first announced budget in November. The Company does not expect the deferral of planned 2016 investment to impact 2016 production guidance. Production guidance for 2016 is expected to be between 100,000 and 110,000 boe/d, 80% higher than 2015 production.

OPERATIONAL AND FINANCIAL HIGHLIGHTS

The following table presents selected operational and financial information for the three months and year ended December 31, 2015 and 2014:

	Three months ended December 31,			Year ended December 31,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands, except per share and volume data)						
Production						
Condensate (bbls/d)	**25,572**	14,747	73	**21,204**	11,061	92
NGLs (bbls/d)	**19,236**	10,783	78	**14,341**	6,989	105
Liquids (bbls/d)	**44,808**	25,530	76	**35,545**	18,050	97
Natural gas (MMcf/d)	**197**	112	76	**149**	79	89
Total Production (boe/d)	**77,699**	44,178	76	**60,403**	31,136	94
Liquids ratio	**58%**	58%	0	**59%**	58%	2
Financial						
Operating income (loss) (1)	**(14,191)**	34,815	(141)	**52,105**	119,521	(56)
Per share - diluted	**(0.06)**	0.14	(143)	**0.21**	0.53	(60)
Revenue (2)	**245,914**	287,141	15	**676,709**	639,432	11
Net income (loss) for the period	**(28,922)**	68,628	(142)	**(187,296)**	144,200	(230)
Per share - diluted	**(0.11)**	0.28	(139)	**(0.75)**	0.64	(217)
Funds from operations (1)	**106,031**	101,503	4	**414,609**	327,933	26
Per share - diluted	**0.42**	0.41	2	**1.66**	1.46	14
Adjusted working capital (1)	**306,143**	653,800	(53)	**306,143**	653,800	(53)
Weighted average shares – diluted	**252,896**	248,510	2	**249,549**	224,717	11
Total capital investments	**301,149**	370,320	(19)	**1,308,973**	1,110,916	18
Available funding (1)	**1,118,143**	1,133,800	(1)	**1,118,143**	1,133,800	(1)
Net debt (1)	**1,250,857**	158,270	nm	**1,250,857**	158,270	nm
Debt outstanding	**1,546,761**	813,880	90	**1,546,761**	813,880	90

(1) See "Non-IFRS Financial Measures".
(2) Represents the total of liquids and natural gas sales, net of royalties, and includes net gains/losses on risk management contracts and other income.

Production

Seven Generations produced 77,699 boe/d in the fourth quarter of 2015, an increase of 76% from the same period in 2014. Production for the year was 60,403 boe/d, an increase of 94% from 2014. The liquids ratio was approximately 58% for all periods presented, comprised of approximately 60% condensate and approximately 40% NGLs.

Operating income (loss)

For the fourth quarter of 2015, Seven Generations recorded an operating loss of $14.2 million compared to operating income of $34.8 million for the same period in 2014. The difference is mostly due to lower prices, higher gross operating and transportation expenses, increased depletion expense related to higher production and depreciable assets and higher interest expense.

Operating income for the year ended December 31, 2015 was $52.1 million compared to $119.5 million for the same period in 2014. The decrease of $67.4 million was mostly due to lower realized prices as a result of lower benchmark prices, higher depletion expense due to the increases in production and higher interest expense related to the senior notes. On a year over year comparison, WTI decreased by 44% and AECO declined by 43%.

Net income (loss)

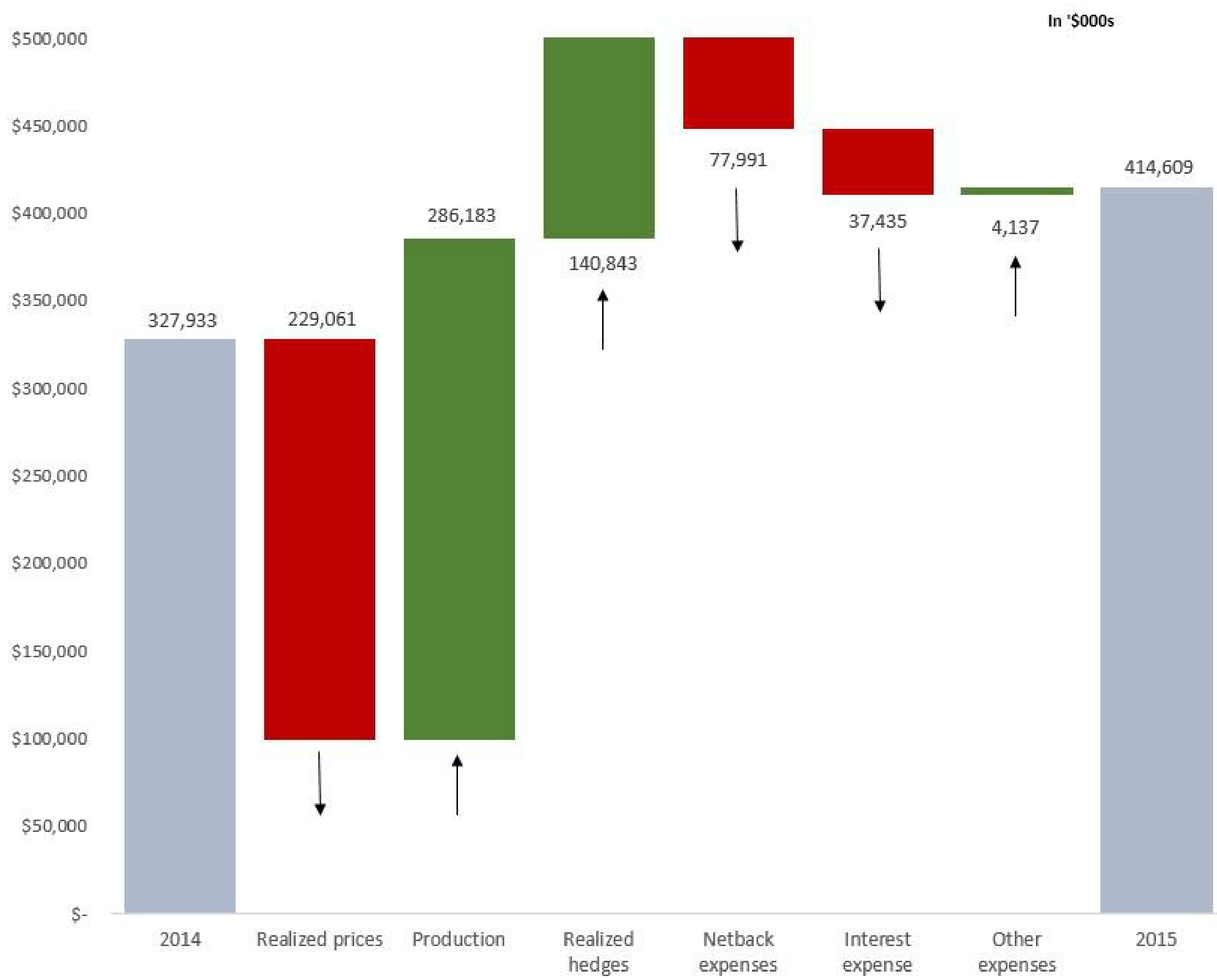
For the fourth quarter of 2015, the Company recognized an operating loss of $28.9 million compared to net income of $68.6 million for the same period in 2014. In addition to the items impacting operating income (loss) noted above, the decrease is due to higher unrealized foreign exchange losses on the senior notes and future income tax expense of $61.9 million. The annual loss was also due to higher unrealized foreign exchange losses and future income tax expense of $61.8 million. For the year ended December 31, 2015, the Company recorded a net loss of $187.3 million compared to net income of $144.2 million for the same period in 2014.

Funds from operations

Funds from operations increased by $4.5 million in the fourth quarter of 2015 to $106.0 million due to higher production being offset by lower prices. Higher interest expense on the senior notes also decreased funds from operations due to additional debt raised in April 2015 and the weakening Canadian dollar.

For the year ended December 31, 2015, funds from operations increased by $86.7 million, to $414.6 million, due to higher production, higher realized hedging gains which positively contributed $140.8 million offset by higher interest expense. Realized hedging gains increase when commodity prices decrease.

Funds from operations for the year ended December 31, 2015:



(1) Netback expenses include royalties, operating expense and transportation.

Capital investments

For the year ended December 31, 2015, Seven Generations invested $1.31 billion in the development of its core focus area. The Lator 2 natural gas plant was commissioned six weeks earlier than scheduled and came in 15% lower than estimated cost. The capacity of the Lator complex is approximately 260 MMcf/d and it marks the first step towards supplying the natural gas volumes to fulfill the Company's firm commitments on the Alliance Pipeline. On December 1, 2015, the Company began flowing natural gas on the Alliance Pipeline, selling into the US Midwest market, where it receives Chicago Citygate prices. A second natural gas processing plant, with a planned capacity of 250 MMcf/d, at Cutbank, was approximately 75% complete at the end of the year. The Cutbank natural gas plant is expected to be commissioned and operational in the second quarter of 2016, along with the Cutbank sales pipeline.

In 2015, the Company drilled 83 net wells and completed 57.5 net wells further expanding development of the Kakwa River Project. The Company benefited from drilling and completions efficiencies in 2015 including cost savings due to shorter drilling days and continued optimization of well design by testing and evaluating hydraulic fractionation expansion. 61 net well tie-ins were completed in 2015 and at December 31, 2015, the Company had an inventory of 63 wells at various stages of construction.

The Company commissioned a new Super Pad in the third quarter of 2015, which will support growing production levels. The Company developed the Super Pad, which is equivalent to a small gas plant, to facilitate raw gas dehydration and free liquid separation from the rich gas produced at the wellhead. By concentrating horizontal drilling from a single pad, the Super Pads allow Seven Generations to maximize resource recovery with longer wells drilled while minimizing surface impact. At the end of 2015, two new Super Pads were under construction and expected to be operational in the first half of 2016. The Company plans to construct and commission an additional Super Pad in the second half of 2016. At December 31, 2015, six Super Pads were in operation.

Available funding

The Company had available funding of $1.1 billion at December 31, 2015. Available funding is comprised of $306.1 million of adjusted working capital and $812 million of credit capacity. Subsequent to year end, the Company closed a bought deal private placement for gross proceeds of $300 million. The Company expects that the proceeds from this placement, coupled with funds from operations and available funding will support the ongoing capital investment program in 2016.

Operating netback

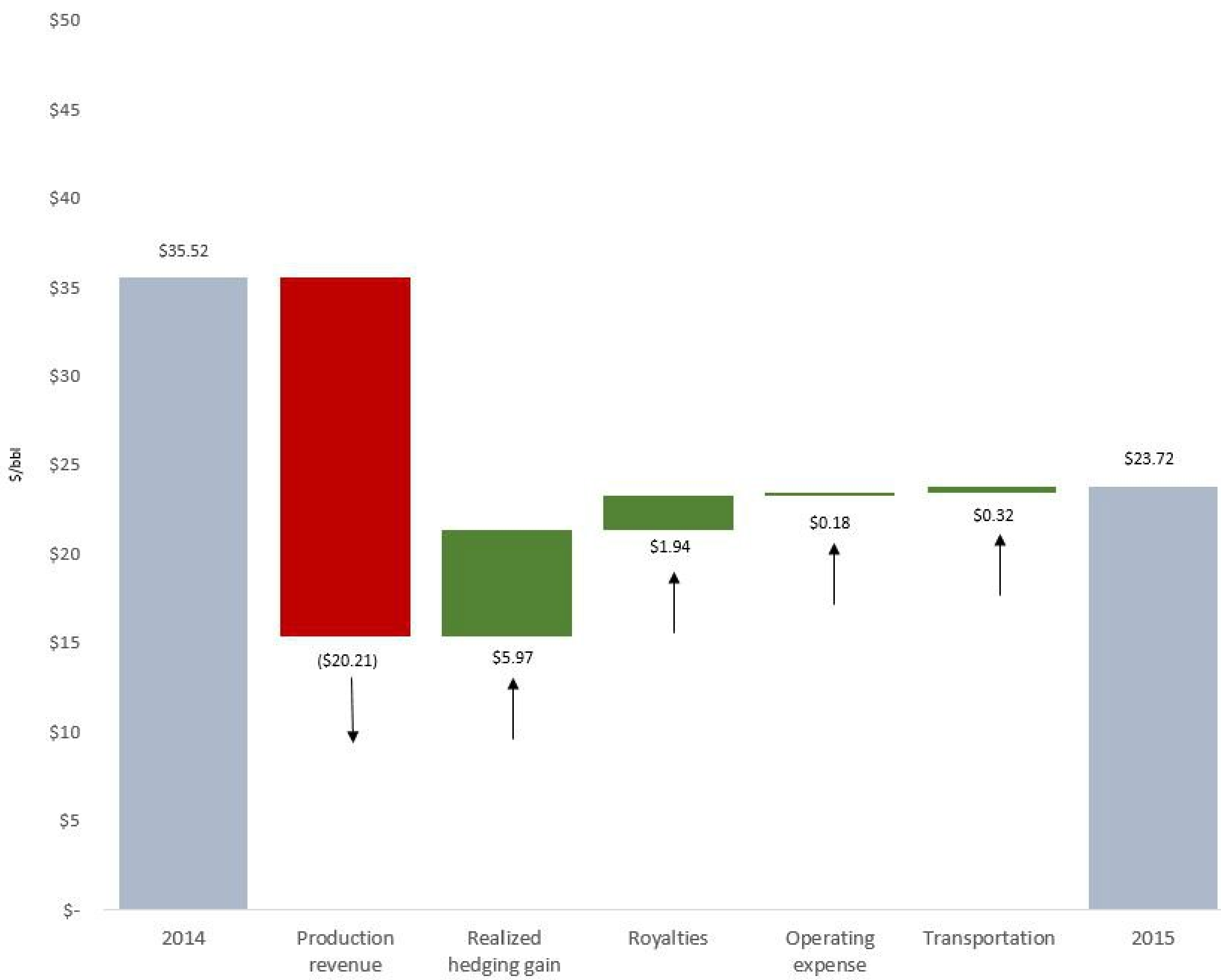
	Three months ended December 31,			Year ended December 31,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
Sales	$ 24.97	$ 38.23	(35)	$ 26.85	$ 47.06	(43)
Realized hedging	3.21	5.45	(41)	6.83	0.86	nm
Royalties	(1.70)	(3.97)	(57)	(2.63)	(4.57)	(42)
Operating expenses	(4.11)	(4.67)	(12)	(4.59)	(4.77)	(4)
Transportation	(3.36)	(3.26)	3	(2.74)	(3.06)	(10)
Operating netback per boe (1)	**$ 19.01**	$ 31.78	(40)	**$ 23.72**	$ 35.52	(33)

(1) See "Non-IFRS Financial Measures".

Operating netback for the fourth quarter of 2015 was $19.01/boe, lower by $12.77/boe, compared to $31.78/boe in the same period in 2014, resulting from low commodity prices offset by lower royalties and operating expenses. Realized hedging gains were also lower on a per boe basis due to higher production volumes. Royalties and operating expenses on a per boe basis were lower than the same period in 2014 by 57% and 12%, respectively, due to lower prices. Transportation was higher by 3% due to the Alliance Pipeline tariffs being reflected in transportation starting in December 2015.

For the year ended December 31, 2015, operating netback fell by $11.80/boe, mostly due to decreases in realized prices, which fell by $20.27/boe and were partially offset by realized hedging gains of $5.97/boe. Lower operating and transportation expenses due to higher production all helped to offset the realized price declines. Royalties, in absolute dollars, were lower due to new wells eligible for incentive programs. On a per boe basis, royalties decreased by $1.94/boe year over year, in line with the decrease in commodity prices. On a per boe basis, operating and transportation expenses decreased by $0.18/boe and $0.32/boe, respectively, year over year, with higher volumes and more condensate sold via pipeline.

Operating netback for the year ended December 31, 2015:



SELECTED ANNUAL FINANCIAL INFORMATION

	2015	2014	2013
($ thousands, except per share and volume data)			
Revenue [(1)]	**676,709**	639,432	105,207
Net income (loss) and comprehensive income (loss)	**(187,296)**	144,200	(14,158)
Per share - diluted	**(0.75)**	0.64	(0.08)
Total capital investments	**1,308,973**	1,110,916	574,328
Total assets	**3,758,982**	3,114,797	1,408,213
Total long-term debt	**1,546,761**	813,880	414,525

(1) Represents the total of liquids and natural gas sales, net of royalties, and includes net gains/losses on risk management contracts and other income.

Since 2013, Seven Generations' revenues increased by $571.5 million due to an increase of 675% in production. Production has grown from 7,786 boe/d in 2013, to more than 60,000 boe/d in 2015. The higher production is due to the number of wells brought on stream: 61 gross (61.0 net) wells in 2015 and 34 gross (33.7 net) wells in 2014.

In 2015, the Company recorded a net loss of $187.3 million, largely impacted by a low commodity price environment and unrealized foreign exchange losses on US dollar denominated debt. Also impacting the net loss was an increase in depletion and depreciation expense mostly related to higher production volumes.

Seven Generations invests capital in a single focus area, the Kakwa River Project, which is a large-scale, tight, liquids-rich natural gas property located in northwest Alberta. As at December 31, 2015, investments for the development of the Kakwa River Project were $2.9 billion. The upper and middle intervals of the Triassic Montney formation in the Kakwa River Project have emerged as a highly economic play, comparing favourably to other North American tight, liquids-rich natural gas plays based on the low break-even natural gas and liquids prices required for the Company to earn an acceptable rate of return.

Daily Production

	Three months ended December 31,			Year ended December 31,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
Condensate (bbls/d)	**25,572**	14,747	73	**21,204**	11,061	92
NGLs (bbls/d)	**19,236**	10,783	78	**14,341**	6,989	105
Natural gas (MMcf/d)	**197**	112	76	**149**	79	89
Total (boe/d)	**77,699**	44,178	76	**60,403**	31,136	94
Liquids ratio	**58%**	58%	—	**59%**	58%	2

The Company achieved record production in the fourth quarter of 2015 of 77,699 boe/d, an increase of 76% from the same period in 2014, due to a higher number of producing wells and the commissioning of the Lator 2 natural gas plant. Production volumes were higher than the third quarter of 2015 by 28%, which averaged 60,600 boe/d.

Seven Generations production exceeded the high end of its 2015 guidance of 55,000 to 60,000 boe/d, producing 60,403 boe/d for the year ended December 31, 2015. The Company achieved this despite the six day Alliance Pipeline shutdown during the third quarter of 2015. Higher production volumes were due entirely to organic growth through drilling and completions.

WELL INFORMATION

	Three Months Ended December 31,					Year ended December 31,				
Number of wells	**2015**		2014		**% Change**	**2015**		2014		**% Change**
Drilled - gross (net)	**22**	**(22.0)**	14	(14.0)	57	**84**	**(83.0)**	49	(49.0)	71
Completed - gross (net)	**13**	**(13.0)**	11	(11.0)	18	**58**	**(57.5)**	38	(38.0)	53
Brought on production - gross (net)	**11**	**(11.0)**	9	(9.0)	22	**61**	**(61.0)**	34	(33.7)	79

The well counts include only horizontal Montney wells. Drill counts are based on the rig release date and brought on production counts are based on the first production date after the well is tied in. At December 31, 2015, Seven Generations had an inventory of 63 wells at various stages of construction between drilling, completions and tie in and 106 Montney horizontal wells producing within the Kakwa River Project (2014 - 47 wells under construction and 45 wells producing).

Commodity Pricing

	Three months ended December 31,			Year ended December 31,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
Average Benchmark Prices						
Oil – WTI (US$/bbl)	**42.18**	73.15	(42)	**48.80**	86.50	(44)
Oil – Edmonton Par ($/bbl)	**52.93**	74.37	(29)	**57.2**	93.94	(39)
Natural gas - NYMEX (US$/MMbtu)	**2.24**	3.85	(42)	**2.63**	4.30	(39)
Natural gas – AECO NGX 5A ($/Mcf)	**2.57**	3.58	(28)	**2.71**	4.78	(43)
Average exchange rate – C$ to US$	**0.749**	0.881	(15)	**0.782**	0.914	(14)

Oil and natural gas prices fell in the fourth quarter of 2015 with WTI decreasing by 42% and AECO falling by 28% compared to the same period in 2014. The Canadian dollar weakened by 15% relative to the US dollar in the fourth quarter of 2015 partially in response to lower oil prices.

For the year ended December 31, 2015, WTI and AECO decreased by 44% and 43%, respectively. Strong global production, including significant US production growth from shale and tight plays, combined with weaker global demand growth resulted in the oversupply of markets and deteriorating prices. The average Canadian dollar exchange rate was down by 14% compared to the US dollar in 2015. Subsequent to year end, global supply and inventories continue to remain high, further deteriorating commodity prices.

The Company realized the following commodity prices (before hedging):

	Three months ended December 31,			Year ended December 31,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
Condensate and oil ($/bbl)	**46.72**	69.93	(33)	**50.84**	85.34	(40)
NGLs ($/bbl)	**12.35**	21.50	(43)	**10.34**	24.10	(57)
Natural gas ($/Mcf)	**2.57**	3.81	(33)	**2.65**	4.50	(41)
Total ($/boe)	**24.97**	38.23	(35)	**26.85**	47.06	(43)

The Company's average realized pricing for condensate decreased in the fourth quarter of 2015 to $46.72/boe, a decrease of 35%, due to lower WTI which fell by 42%. Oil price is the main driver of the Company's realized condensate prices.

For the year ended December 31, 2015, the Company's average realized prices for condensate decreased by $34.50/bbl, coming in at $50.84/bbl compared to $85.34/bbl in the same period of 2014. The difference mostly relates to the decrease of WTI by US$37.70/bbl.

NGL prices also saw declines in the fourth quarter of 2015. Approximately 85% of the Company’s NGLs are ultimately sold in the US Midwest market and 15% in the Alberta market. The average realized prices for NGLs reflect a combination of prices for ethane, propane, butane and pentanes plus. The product mix of NGLs is approximately 1/3 ethane, 1/3 propane, 1/5 butane and the remaining 14% is pentanes plus. The Company’s average realized prices for the NGL product stream decreased by 43% in the fourth quarter of 2015 to $12.35/bbl, due to lower benchmark prices.

For the year ended December 31, 2015, the average realized prices for NGLs were $10.34/bbl compared to $24.10/bbl for the same period in 2014, a decrease of 57%, mostly related to the low commodity price environment.

For the fourth quarter of 2015, the Company’s average realized natural gas price was $2.57/Mcf, a decrease of 33% compared to the same period in 2014, due to the decrease in benchmark prices. Warmer weather and higher inventories drove natural gas prices to 16 year lows.

For the year ended December 31, 2015, the Company received an average realized natural gas price of $2.65/Mcf, a decrease of 41%. Prior to December 2015, Seven Generations' realized natural gas price was based on AECO prices which continued to soften due to oversupplied natural gas markets and low demand in North America.

Effective December 1, 2015, Seven Generations began delivering natural gas into the US Midwest market in conjunction with its commitment on the Alliance Pipeline. The firm commitment of 250 MMcf/d of liquids-rich natural gas increases to 500 MMcf/d by 2018. The terms of the agreement will allow Seven Generations to transport volumes out of an oversupplied market and to realize US Midwest market prices on a significant portion of overall production.

Liquids and natural gas sales

	Three months ended December 31,			Year ended December 31,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands, except per boe data)						
Condensate and oil	**110,150**	94,873	16	**393,725**	344,512	14
NGLs	**20,532**	21,329	(4)	**52,781**	61,470	(14)
Natural gas	**47,796**	39,181	22	**145,418**	128,851	13
Total liquids and natural gas sales (1)	**178,478**	155,383	15	**591,924**	534,833	11
Per boe	**$ 24.97**	$ 38.23	(35)	**$ 26.85**	$ 47.06	(43)

(1) Excluding realized gains or losses on risk management contracts.

Revenues for the fourth quarter of 2015 were $178.5 million compared to $155.4 million for the same period in 2014. Higher production volumes increased revenues by $77.0 million offset by $53.9 million of reduced commodity prices. For the year ended December 31, 2015, there was an increase in revenues of 11% to $591.9 million, attributable to $286.8 million of higher production volumes offset by $229.7 million due to lower prices.

Risk Management Contracts

The Company's risk management program resulted in the following:

	Three months ended December 31,			Year ended December 31,		
	2015	2014	% Change	**2015**	2014	% Change
($ thousands, except per boe data)						
Realized gain [1]	**22,980**	22,163	4	**150,580**	9,737	nm
Unrealized gain (loss) [2]	**53,713**	123,772	(57)	**(15,911)**	141,765	(111)
Total gain	**76,693**	145,935	(47)	**134,669**	151,502	(11)
Realized gain per boe	**$ 3.21**	$ 5.45	(41)	**$ 6.83**	$ 0.86	nm

(1) Represents actual cash settlements or receipts under the respective contracts.
(2) Represents the change in fair value of the contracts during the period.

The Company utilizes financial hedges to partially protect funds from operations against commodity price volatility. Certain guidelines for the risk management program are approved by the Board of Directors of Seven Generations. These guidelines allow for hedge targets of up to 65% of forecasted production volumes (net of royalties) for the upcoming four quarters, up to 30% of forecasted volumes for the subsequent four quarters and up to 15% for the four quarters following. Price targets are established at levels that are expected to provide a threshold rate of return on capital investment based on a combination of benchmark oil and natural gas prices, projected well performance and capital efficiencies.

Realized gains of $23.0 million, a slight increase of 4%, reflect positive cash settlements on hedge contracts settled each month. For the year ended December 31, 2015, realized gains were $150.6 million compared to $9.7 million for the same period in 2014. Higher realized gains are the result of decreases in commodity benchmark prices. For a complete listing and terms of Seven Generations' hedging contracts at December 31, 2015, see Note 19 "Financial Instruments and Market Risk Management" in the consolidated financial statements and "Financial Instruments and Risk Management Contracts" below.

The fair value of unsettled derivatives is recorded as an asset or liability with the change in the mark-to-market position of contracts recorded as an unrealized gain or loss in the statements of income and comprehensive income. As at December 31, 2015, the fair value of the risk management contracts was a net asset position of $123.2 million (2014 – net asset of $139.1 million). The unrealized gain of $53.7 million in the fourth quarter of 2015 represents the lower Canadian WTI prices on crude oil contracts in the forward price curve, decreased Chicago Citygate prices on natural gas contracts and unrealized losses on foreign exchange contracts. For the year ended December 31, 2015, the unrealized loss of $15.9 million reflects the change in value of hedge contracts offset by the reversal of prior year realized hedge gains.

The Company had the following risk management contracts in place at December 31, 2015:

	2016	**2017**	**2018**
Liquids hedging			
WTI hedged (bbl/d)	13,250	8,250	3,250
Average floor (C$/bbl)	$ 70.04	$ 68.94	$ 67.93
Average ceiling (C$/bbl)	$ 80.48	$ 78.88	$ 74.89
Natural gas hedging			
Natural gas hedged (MMbtu/d)	122,500	105,000	47,500
Average Chicago Citygate swap (US$/MMbtu)	$ 3.19	$ 3.10	$ 2.80
Average swap (C$/MMbtu) [1]	$ 4.01	$ 4.00	$ 3.83
FX hedging			
US$ notional hedged (Millions)	$ 143.10	$ 118.82	$ 48.46
Average rate	$ 1.26	$ 1.29	$ 1.37

(1) Chicago Citygate converted to C$/MMbtu at average C$/US$ hedge rate.

Royalty Expense

	Three months ended December 31,			Year ended December 31,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands, except per boe data)						
Royalties	**12,127**	16,145	(25)	**57,898**	51,890	12
Royalties per boe	**$ 1.70**	$ 3.97	(57)	**$ 2.63**	$ 4.57	(42)
Effective royalty rate	**7%**	10%	(30)	**10%**	10%	0

For the fourth quarter of 2015, royalties were $12.1 million, a decrease of 25% primarily due to low commodity prices and incentive programs for new wells. The average royalty rate as a percentage of revenues was 7%. For the year ended December 31, 2015, royalties were $57.9 million, an increase of 12%, attributable to higher revenues. The Company's annual royalty rate was 10%, consistent with 2014.

In September 2015, the Alberta government initiated a royalty review. On January 29, 2016, the recommendations of the Royalty Review Advisory Panel were finalized and are expected to create a simpler, more transparent and efficient system. The provincial government of Alberta has not yet released all of the details of the Modernized Royalty Framework. The Company will continue to evaluate the impact of the new framework on the results of operations and cash flows as more details are released.

Other Income

	Three months ended December 31,			Year ended December 31,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands, except per boe data)						
Marketing revenue	**1,300**	—	nm	**1,300**	—	nm
Interest and other income	**879**	1,264	(30)	**4,877**	3,184	53
Processing and third party income	**691**	704	(2)	**1,837**	1,803	2
Total	**2,870**	1,968	46	**8,014**	4,987	61
Per boe	**$ 0.40**	$ 0.21	90	**$ 0.36**	$ 0.44	(18)

Marketing revenue was $1.3 million for the fourth quarter and year ended December 31, 2015. The Company earns a margin from optimizing its capacity on the Alliance Pipeline.

For the fourth quarter of 2015, interest and other income was $0.9 million, a decrease of 30% due to lower average cash balances and lower interest rates. In 2015, the Company drew down funds from an initial public offering ("IPO") financing, which closed in November 2014. For the year ended December 31, 2015, interest and other income was $4.9 million, an increase of 53%, due to higher average cash balances attributable to the issuance of $550.1 million of senior notes in April 2015.

Third party processing fees and volumes during the year have been consistent from 2014 to 2015.

Operating Expenses

	Three months ended December 31,			Year ended December 31,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands, except per boe data)						
Equipment rental, maintenance and other	**8,468**	5,667	49	**31,413**	20,584	53
Trucking and disposal	**8,993**	6,033	49	**30,510**	15,339	99
Chemicals and fuel	**5,253**	1,360	286	**15,008**	3,438	337
Staff and contractor costs	**4,965**	3,791	31	**15,981**	9,474	69
Other	**1,699**	2,115	(20)	**8,276**	5,426	53
Operating expenses	**29,378**	18,966	55	**101,188**	54,261	86
Operating expenses per boe	**$ 4.11**	$ 4.67	(12)	**$ 4.59**	$ 4.77	(4)

For the fourth quarter of 2015, operating expenses were $29.4 million, an increase of $10.4 million due to higher field activity and the operation of the new Lator 2 natural gas plant. In October, the Lator 2 natural gas plant came on stream six weeks ahead of schedule. Lator 2 delivers liquids rich natural gas on the Alliance Pipeline to sell into the US Midwest market. For the year ended December 31, 2015, operating expenses were $101.2 million compared to $54.3 million for the comparative period in 2014. The difference was due to higher production and field activity, with 61.0 net new wells on production in 2015 compared to 33.7 net wells for the same period of 2014. Operating expenses, on a per boe basis, are decreasing due to increased volumes and operating efficiencies.

Transportation Expenses

	Three months ended December 31,			Year ended December 31,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands, except per boe data)						
Transportation expense	23,984	13,237	81	60,336	34,833	73
Transportation expense per boe	**$ 3.36**	$ 3.26	3	**$ 2.74**	$ 3.06	(10)

Transportation expenses were $24.0 million for the fourth quarter of 2015, an increase of $10.8 million. On December 1, 2015, the Company began shipping liquids rich natural gas directly to the Chicago Citygate market. Transportation expenses include condensate and NGL pipeline tariffs and trucking as well as natural gas pipeline tariffs charged prior to the custody transfer point. For the year ended December 31, 2015, transportation expenses were $60.3 million, an increase of $25.5 million, primarily due to higher volumes. Condensate volumes are shipped via firm and interruptible pipeline capacity. Additionally, a portion of the produced volumes are trucked to various terminals.

General and Administrative Expenses

	Three months ended December 31,			Year ended December 31,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands, except per boe data)						
Personnel	**4,575**	3,571	28	**18,844**	12,912	46
Professional fees	**317**	386	(18)	**1,780**	2,636	(32)
Rent	**388**	390	(1)	**1,584**	1,210	31
Information technology costs	**935**	325	188	**2,347**	1,310	79
Other office costs and travel	**1,544**	1,143	35	**5,161**	3,403	52
IPO expenses	**—**	2,506	(100)	**—**	2,506	(100)
Gross expenses	**7,759**	8,321	(7)	**29,716**	23,977	24
Capitalized salaries and benefits	**(221)**	(523)	(58)	**(3,619)**	(2,661)	36
Operating overhead recoveries	**(410)**	(405)	1	**(1,754)**	(1,058)	66
General and administrative expenses	**7,128**	7,393	(4)	**24,343**	20,258	20
Per boe - net	**$ 1.00**	$ 1.82	(45)	**$ 1.10**	$ 1.78	(38)

Gross general and administrative expenses were $7.8 million for the fourth quarter of 2015. The decrease of $0.6 million compared to 2014 was due to $2.5 million of savings of one-time IPO expenses offset by higher personnel costs related to higher employee head count and the Company's expanding activities. On a unit of production basis, net general and administration expenses were $1.00/boe, a decrease of 45%, due to higher production levels.

For the year ended December 31, 2015, gross general and administrative expenses were $29.7 million, an increase of $5.7 million, attributable to the Company's growth, higher staff costs and more office space. The Company's head count increased by 39% from 75 personnel at the end of 2014 to 104 at December 31, 2015.

For the three months and year ended December 31, 2015, capitalized staff costs were $0.2 million and $3.6 million compared to $0.5 million and $2.7 million, respectively for the same periods in 2014. Capitalized staff costs are attributable to head office personnel involved with the capital and infrastructure development of the Project.

Overhead recoveries were $0.4 million and $1.8 million compared to $0.4 million and $1.1 million for the three months and year ended December 31, 2015 and 2014, respectively. Overhead recoveries relate to spending incurred on properties with minority partners.

Depletion, Depreciation and Amortization

	Three months ended December 31,			Year ended December 31,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands, except per boe data)						
Depletion, depreciation & amortization	**80,337**	56,923	41	**283,535**	159,447	78
Per boe	**$ 11.24**	$ 14.01	(20)	**$ 12.86**	$ 14.03	(8)

For the fourth quarter of 2015, depletion, depreciation and amortization expense was $80.3 million compared to $56.9 million for the same period in 2014. The difference is mostly due to higher production volumes and higher depreciable costs. For the year ended December 31, 2015, depreciation and amortization expense was $283.5 million compared to $159.4 million in 2014. The increase is consistent with the higher production volumes. Depletion per barrel decreased due to decreases in estimated future development costs.

Stock Based Compensation

	Three months ended December 31,			Year ended December 31,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands)						
Gross stock based compensation	**4,589**	6,060	(24)	**20,014**	18,012	11
Capitalized stock based compensation	**(1,377)**	(2,163)	(36)	**(6,027)**	(6,062)	(1)
Net stock based compensation	**3,212**	3,897	(18)	**13,987**	11,950	17

Stock based compensation is a non-cash expense. The fair value of stock based compensation is calculated using the Black-Scholes pricing model using estimates including the expected life of the instruments, stock price volatility and interest rates. The value of a stock option or performance warrant is calculated on the date of grant and that value is applied throughout the life of the instrument. Values are not restated for subsequent changes in estimated volatility rates, interest rates or underlying market values of the Company's shares.

For the fourth quarter of 2015, gross stock based compensation was $4.6 million, a decrease of $1.5 million, due to more stock option grants in 2014 and a higher value per award in 2014. For the year ended December 31, 2015, gross stock based compensation expense was $20.0 million, an increase of 11%, due to awards granted to new employees in 2015 and 2014.

For the three months and year ended December 31, 2015, capitalized stock based compensation was $1.4 million and $6.0 million, compared to $2.2 million and $6.1 million, respectively for the same periods in 2014. Capitalized stock based compensation is attributable to personnel involved with the capital and infrastructure development of the Project.

Finance Expense

	Three months ended December 31,			Year ended December 31,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands)						
Interest on senior notes	**29,232**	16,543	77	**98,887**	61,303	61
Revolving credit facility fees and other	**1,798**	857	110	**5,512**	2,142	157
Amortization of premium and debt issue costs	**181**	(114)	(259)	**356**	(466)	(176)
Accretion	**495**	272	82	**1,662**	1,162	43
Total finance costs	**31,706**	17,558	81	**106,417**	64,141	66
Capitalized borrowing costs	**(2,167)**	(500)	100	**(4,406)**	(500)	100
Finance expense	**29,539**	17,058	73	**102,011**	63,641	60

In April 2015**,** the Company issued US$425.0 million of additional senior notes bearing interest at 6.75% with a 2023 maturity. Net proceeds from the financing were $504.4 million. In May 2013 and February 2014, the Company issued senior unsecured notes of US$400.0 million and US$300.0 million (US$321.0 million with premium), respectively. The notes bear interest at 8.25% per annum (calculated using a 360-day year).

Interest expense on senior notes for the fourth quarter of 2015 was $29.2 million (US$21.6 million) compared to $16.5 million (US$14.4 million) for the same period in 2014. Interest expense is recorded in Canadian dollars using average monthly exchange rates and as such, the weakening Canadian dollar increased interest expense from the US denominated senior notes. The standby fees and other charges associated with the Company's revolving credit facility increased to $1.8 million for the three months ended December 31, 2015 compared to $0.9 million in the same period of 2014.

For the year ended December 31, 2015, the Company recorded interest expense of $98.9 million (US$55.1 million) compared to $61.3 million (US$46.4 million) in 2014. Interest expense was higher due to the increase in the average debt balance outstanding and the weaker Canadian dollar in 2015. The revolving credit facility and other fees were $5.5 million, an increase of $3.4 million, due to standby fees being calculated on a larger borrowing base. The borrowing capacity on the available credit facility increased from $150.0 million in 2013 to $480.0 million in September 2014, to $650.0 million in April 2015 and to $850.0 million in November 2015.

For the fourth quarter and year ended December 31, 2015, the Company capitalized interest and financing costs of $2.2 million and $4.4 million, respectively, related to the Cutbank natural gas plant.

Foreign Exchange Loss (Gain)

	Three months ended December 31,			Year ended December 31,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands, except per exchange rates)						
Unrealized foreign exchange loss on senior notes	**53,941**	27,562	96	**228,863**	53,406	329
Unrealized foreign exchange loss (gain) on cash held in foreign currencies	**5,111**	(7,336)	(170)	**(1,094)**	(3,095)	(65)
Realized foreign exchange loss (gain)	**(3,553)**	5,334	(167)	**(8,468)**	(2,638)	221
Net foreign exchange loss	**55,499**	25,560	117	**219,301**	47,673	360
Average exchange rate – C$ to US$	**0.749**	0.881	(15)	**0.729**	0.914	(14)

For the three months ended December 31, 2015, the unrealized foreign exchange losses were $53.9 million, an increase of $26.3 million, due to the weaker Canadian dollar, which decreased by 15% quarter over quarter. The Company's exposure to foreign exchange gains and losses is primarily related to the US dollar senior unsecured notes, as well as US dollar cash balances.

The average exchange rate for Canadian dollars to the US dollar equivalent for the year ended December 31, 2015 fell to 0.749 This 14% decline impacted total unrealized foreign exchange losses which were $228.9 million for 2015. The unrealized foreign exchange losses largely relate to the senior notes. The senior notes mature in 2020 (US$700.0 million) and 2023 (US$425.0 million), respectively.

Realized foreign exchange gains and losses relate to the actual conversion of US dollars to Canadian dollars and the settlement of normal revenues and invoices denominated in US dollars. Total realized foreign exchange gains were $8.5 million for the year ended December 31, 2015.

Gain on Disposition of Assets

	Three months ended December 31,			Year ended December 31,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands)						
Gain on disposition of assets	—	—	nm	2,602	4,286	(39)

The Company closed asset swap arrangements in which non-producing assets were acquired and non-producing assets were disposed of. For purposes of determining the gain on disposition, the estimated fair market value was based on the fair value of the assets received. For the year ended December 31, 2015, the Company recorded a gain of $2.6 million compared to $4.3 million in the same period of 2014.

Income Tax Expense

	Three months ended December 31,			Year ended December 31,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands)						
Current income tax expense	**104**	—	nm	**104**	—	nm
Deferred income tax expense	**45,655**	39,532	15	**61,802**	71,508	(14)
	45,759	39,532	16	**61,906**	71,508	(13)

For the three months ended December 31, 2015, the Company recorded income tax expense of $45.8 million. Of this amount, $45.7 million was recorded as deferred income tax expense mostly related to the derecognition of approximately $22.6 million of tax pools and unrecognized deferred tax asset related to unrealized capital losses. During the year ended December 31, 2015, the Canada Revenue Agency ("CRA") challenged tax losses utilized by the Company which were derived from the Company's predecessor entity, IceFyre Semiconductor Corporation. As a result of the ongoing CRA audit, the Company has applied a provision of $22.6 million against the tax pools.

Permanent differences such as unrealized foreign exchange losses of $8.0 million, change in unrecognized deferred tax asset of $8.2 million on unrealized capital losses and stock based compensation of $0.8 million also impacted the deferred income tax provision.

For the year ended December 31, 2015, the Company recognized an income tax expense of $61.8 million, a decrease of 14%, due to the permanent differences and an increase in the tax rate to 26% from 25%, to reflect the recent change to provincial tax rates. Permanent differences included stock based compensation, a non-deductible expense, and foreign exchange gains or losses relating to the senior notes, which are one-half taxable or deductible. These impacted the deferred income tax provision by $3.6 million and $29.2 million, respectively. The change in tax rate increased deferred income taxes by $6.9 million. Also impacting the deferred income tax expense for the year ended December 31, 2015 was an unrecognized deferred tax asset on capital losses of $31.6 million.

The Company recorded $0.1 million of current income tax expense for estimated taxes payable in the US and state of Illinois, where Seven Generations (US) Corp. commenced selling natural gas to third parties in December 2015.

The Company has no current income tax expense in Canada given its total tax pools of $2.7 billion at December 31, 2015. Of this amount, $0.7 billion is available in 2015 for deduction in computing taxable income.

Capital Investments

	Three months ended December 31,			Year ended December 31,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands)						
Land acquisitions	**2,169**	8,200	(74)	**5,138**	48,952	(90)
Drilling and Completions	**181,108**	225,150	(20)	**810,185**	737,704	10
Facilities and equipment	**114,153**	134,177	(15)	**477,958**	324,602	47
Other (1)	**3,719**	2,793	33	**15,692**	9,078	73
Total capital investments	**301,149**	370,320	(19)	**1,308,973**	1,120,336	17
Property dispositions	**—**	—	—	**—**	(9,420)	(100)
Capital investments, net of dispositions	**301,149**	370,320	(19)	**1,308,973**	1,110,916	18

(1) Other includes capitalized salaries and benefits, capitalized interest and office investments.

For the fourth quarter of 2015, the Company invested $301.1 million in the core focus area at Kakwa. Of this amount, $181.1 million was invested for drilling and completions. The Company drilled 22.0 net wells and completed 13.0 net wells. The average lateral length of wells completed was approximately 2,712 metres and an average proppant density of approximately 1.8 tonnes per meter was used in the completion of the wells. Drilling and completion costs for the fourth quarter of 2015 averaged $12.5 million per well. The Company also brought 11.0 net wells on production, contributing to the record production levels in the last quarter of 2015. Investments for facilities, infrastructure and equipment for the fourth quarter of 2015 were $114.2 million. The Company completed the construction and commissioning of the Lator 2 plant six weeks early. The Lator plant complex, with a processing capacity of approximately 260 MMcf/d, came on-line and liquids rich natural gas was transported under the Company's firm service agreements with Alliance beginning on December 1, 2015. The construction of the Cutbank gas plant, with a planned capacity of 250 MMcf/d, was 75% complete as at December 31, 2015 and is expected to be operational in the second quarter of 2016. The Cutbank sales pipeline, connecting the Cutbank plant with the Alliance Pipeline, is a 29 km, 24" pipeline currently being constructed and expected to be completed at the same time as the plant.

In November 2014, the Board approved a 2015 capital investment program of $1.6 billion to $1.65 billion. In February 2015, the Company updated its business plan in response to persisting low commodity prices and announced a revised investment plan of $1.30 billion to $1.35 billion. For the year ended December 31, 2015, Seven Generations invested $1.31 billion of capital, which was at the low end of the Company's guidance primarily due to the Company's ongoing focus on innovation and differentiation which resulted in improved operational efficiencies and cost savings.

Of the total capital investments made for the year, $810.2 million was invested in drilling and completions. The Company drilled 83.0 net wells and completed 57.5 net new wells in 2015. Drilling cost per well was approximately $5.0 million. The number of days between spud to rig release time was reduced to an average of 44 days resulting in significant cost savings. Improving completions efficiencies resulted in an average per well cost of $6.8 million as the Company focused on optimizing fracture stage spacing, expanding the use of hydraulic fracturing and testing higher proppant density on wells. Investments of $478.0 million for facilities included both the expansion of existing and the construction of new processing and gathering facilities and Super Pads. Since 2013, the Company has drilled multiple wells from single pads and then added onsite separation to create Super Pads. To date, the Company has constructed and commissioned six Super Pads, with more Super Pads under construction that are expected to be commissioned in 2016. Two natural gas plants were under construction in 2015, with Lator completed in October 2015 and Cutbank scheduled for operation in the second quarter of 2016.

Seven Generations controls approximately 416,000 net acres of Montney land (over 431,000 net acres of lands overall) with an average working interest of 98%. At December 31, 2015, McDaniel estimated the Company's Montney land to support approximately 693 net wells (83% undrilled), which have gross 2P reserves of 859 MMboe.

LIQUIDITY AND CAPITAL RESOURCES

The capital structure of the Company is as follows:

As at December 31	2015	2014
($ thousands)		
Net debt [(1)]	**1,250,857**	158,270
Market capitalization [(2)]	**3,429,540**	4,291,692
Total capitalization	**4,680,397**	4,449,962

(1) See “Non-IFRS Financial Measures”.
(2) Market capitalization is calculated using the total common shares outstanding at December 31, 2015 multiplied by the closing share price of $13.48 at December 31, 2015 (closing share price of $17.50 at December 31, 2014).

The Company’s objective for managing capital continues to be a focus on a strong balance sheet, the drive toward free cash flow and optimizing its capital base to provide financial flexibility for continued future growth and development. The Company strives to grow and maximize long-term shareholder value by ensuring it has the financing capacity to fund projects that are expected to add value to shareholders. The Company will strive to balance the proportion of debt and equity in its capital structure to take into account the level of risk being incurred in its capital investments.

At December 31, 2015, the Company had cash and cash equivalents of approximately $405.0 million and adjusted working capital of $306.1 million. In April, the Company completed a private placement offering of US$425.0 million of senior notes, bearing interest at 6.75%, which mature in 2023. Net proceeds from this debt financing were $545.7 million. The Company also has US$700 million of senior notes outstanding, bearing interest at 8.25%, which mature in 2020. All of the senior notes the Company has issued are denominated in US dollars. The decline of the Canadian dollar increases the amount of senior notes outstanding recognized at December 31, 2015.

Subject to certain exceptions and qualifications, the senior unsecured notes have no financial covenants but limit the Company’s ability to, among other things: make payments and distributions; incur additional indebtedness; issue disqualified or preferred stock; create or permit liens to exist; make certain dispositions; transfer assets; and engage in amalgamations, mergers or consolidations. At December 31, 2015 and 2014, the Company was in compliance with the covenants on the senior notes.

The Company and its lending syndicate agreed to an amendment to the senior secured revolving credit arrangement that increased the borrowing capacity from $480.0 million at December 31, 2014 to $650.0 million in May 2015 and $850.0 million in November 2015.

In February 2016, the Company completed a private placement of 21,428,600 Common Shares at a price of $14.00 per share for gross proceeds of $300 million.

At December 31, 2015, the Company had available funding of $1.1 billion. The Company's capital investments for 2016 are expected to be between $900 million and $950 million. The 2016 capital investment program will continue to focus development of the Nest. Seven Generations plans to fund capital investments in 2016 from cash on hand, funds from operations and prudent draws from its revolving credit facility.

SUBSEQUENT EVENT

On February 24, 2016, the Company completed a private placement of 21,428,600 Common Shares at a price of $14.00 per share for gross proceeds of approximately $300 million. Net proceeds after commissions and expenses were approximately $285 million.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT CONTRACTS

Financial instrument classification and measurement

The Company's financial instruments include cash and cash equivalents, accounts receivable, deposits, risk management contracts, accounts payable and accrued liabilities, the credit facility and senior notes.

The Company's financial instruments that are carried at fair value on the balance sheets include cash and cash equivalents and risk management contracts. The senior notes are carried at amortized cost, net of transaction costs and accrete to the principal balance on maturity using the effective interest rate method.

Seven Generations classifies the fair value of these instruments according to the following hierarchy based on the amount of observable inputs used to value the instrument.

- Level 1 - Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information.
- Level 2 - Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed in the marketplace.
- Level 3 - Valuations in this level are those inputs for the asset or liability that are not based on observable market data.

Cash and cash equivalents are classified as Level 1 measurements. Risk management contracts and fair value disclosure for the senior notes are classified as Level 2 measurements. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy level. Seven Generations does not have any fair value measurements classified as Level 3. There were no transfers within the hierarchy in the years ended December 31, 2015 and 2014. The carrying value of the Company's accounts receivable, deposits, accounts payable and accrued liabilities approximate their fair values due to the short-term maturity of these instruments.

The classification, carrying values and fair values of the Company's financial instruments are as follows:

	2015		2014	
As at December 31	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value
Financial Assets				
Fair Value Through Profit and Loss				
Cash and cash equivalents	**405,046**	**405,046**	848,136	848,136
Risk management contracts	**151,566**	**151,566**	139,119	139,119
Loans and Receivables				
Accounts receivable	**76,439**	**76,439**	64,417	64,417
Deposits	**8,933**	**8,933**	5,034	5,034
Financial Liabilities				
Fair Value Through Profit and Loss				
Risk management contracts	**28,359**	**28,359**	—	—
Other Financial Liabilities				
Accounts payable and accrued liabilities	**187,760**	**187,760**	268,108	268,108
Senior notes	**1,546,761**	**1,353,953**	813,880	782,000

Financial assets and financial liabilities subject to offsetting

The Company's risk management contracts are subject to master netting agreements that create a legally enforceable right to offset by counterparty the related financial assets and financial liabilities on the Company's balance sheets.

The following is a summary of financial assets and financial liabilities that are subject to offset:

As at December 31, 2015	Gross amounts of recognized financial assets (liabilities)	Gross amounts of recognized financial assets (liabilities) offset in balance sheet	Net amounts of recognized financial assets (liabilities) recognized in balance sheet
Risk management contracts			
Current asset	**102,343**	**(3,773)**	**98,570**
Long-term asset	**62,939**	**(9,943)**	**52,996**
Current liability	**(22,093)**	**3,773**	**(18,320)**
Long-term liability	**(19,982)**	**9,943**	**(10,039)**
Net position	**123,207**	**—**	**123,207**

As at December 31, 2014	Gross amounts of recognized financial assets (liabilities)	Gross amounts of recognized financial assets (liabilities) offset in balance sheet	Net amounts of recognized financial assets (liabilities) recognized in balance sheet
Risk management contracts			
Current asset	138,122	—	138,122
Long-term asset	997	—	997
Net position	139,119	—	139,119

Credit Risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises primarily from the Company's receivables from oil and natural marketers and joint venture partners and hedging assets. The Company's maximum exposure to credit risk is equal to the carrying amount of these instruments.

Substantially all of the Company's accounts receivable are with oil and natural gas marketers and joint venture partners under normal industry sale and payment terms and are subject to normal industry credit risk. Receivables from oil and natural gas marketers are normally collected on or about the 25th day of the following month. The Company mitigates concentration risk by limiting the sales of its production to customers, and reviews sales regularly. Production is sold to marketers and customers with investment grade credit ratings, if available in the area of production. The Company historically has not experienced any collection issues with its oil and natural gas marketers. As at December 31, 2015, the Company's most significant marketer accounted for $20.2 million (2014 - $21.1 million) of total receivables and 47% of total revenues (2014 - 50%). Receivables from joint venture partners are typically collected within one to three months of the joint venture bill being issued. The Company attempts to mitigate the risk from joint venture receivables by obtaining partner pre-approval of significant capital expenditures. The receivables are from participants in the oil and natural gas sector, and collection of the outstanding balances is dependent on industry factors such as commodity price fluctuations, escalating costs, the risk of unsuccessful drilling and disagreements with partners. As the operator of properties, the Company has the ability to withhold production from joint interest partners in the event of non-payment. As at December 31, 2015, receivables outstanding for more than 90 days totalled less than $0.5 million (2014 - $0.1 million). The Company believes all of the accounts receivable will be collected. The maximum credit risk exposure associated with accounts receivable is the total carrying value.

All the Company's cash and cash equivalents are held with Canadian chartered banks and government owned financial institutions and as such, the Company is exposed to credit risk on any default by the institutions of amounts in excess of the minimum guaranteed amount. The Company considers the risk of default by these financial institutions to be remote. As at December 31, 2015, the Company does not invest any cash in complex investment vehicles with higher risk such as asset backed commercial paper. All of the Company's risk management contracts are with Schedule 1 Canadian chartered banks or high credit-quality financial institutions.

Market Risk

Market risk is the risk that changes in market prices including commodity prices, interest rates and foreign exchange risks will affect the Company's income (loss) or the value of financial instruments. The objective of market risk management is to reduce exposures to acceptable limits while optimizing returns.

(a) Commodity price risk

Commodity price risk is the risk that the fair value of financial instruments or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by world economic events that dictate the levels of supply and demand. The Company uses derivative financial instruments to manage its exposure to fluctuations in commodity prices. The Company considers these transactions to be effective economic hedges; however, the Company's contracts do not qualify as effective hedges for accounting purposes.

Risk management contracts

The following is a summary of the carrying value of risk management contracts in place by contract type:

As at December 31,	**2015**	2014
Natural gas	**58,087**	29,548
Oil	**93,478**	109,571
Foreign exchange swap	**(28,358)**	—
Net position	**123,207**	139,119

During the year ended December 31, 2015, the Company's risk management contracts resulted in realized gains of $150.6 million (year ended December 31, 2014 – realized gains of $9.7 million) and unrealized losses of $15.9 million (year ended December 31, 2014 – unrealized gains of $141.8 million).

The following table demonstrates the impact of changes in commodity pricing on income before tax, based on risk management contracts in place at December 31, 2015:

	Gain (Loss)
10% increase in US$ Chicago Citygate/MMbtu	(33,620)
10% decrease in US$ Chicago Citygate/MMbtu	33,620
10% increase in US$ WTI/bbl	(68,583)
10% decrease in US$ WTI/bbl	80,485

(b) Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The senior notes payable bear interest at a fixed rate. The Company's credit facility bears a floating rate of interest and, accordingly, the Company is exposed to interest rate fluctuations to the extent that any advances remaining outstanding under the facility. During the year ended December 31, 2015, no amounts were drawn on the credit facility.

(c) Foreign currency exchange risk

Foreign currency exchange risk is the risk that the fair value of financial instruments or future cash flows will fluctuate as a result of changes in foreign exchange rates.

Prices for oil are determined in global markets and generally denominated in US dollars. Natural gas prices obtained by the Company are influenced by both US and Canadian demand and the corresponding North American supply. The exchange rate effect cannot be quantified but generally an increase in the value of the Canadian dollar as compared to the US dollar will reduce the prices received by the Company for its liquids and natural gas sales.

The Company manages foreign currency exchange risk by entering into a variety of risk management contracts (see Risk management contracts section above). The Company enters into US dollar swaps to crystallize the Canadian dollar value of the oil or natural gas price risk management contract entered into.

The Company is exposed to foreign exchange rate fluctuations on the principal and interest related to the senior notes payable, as well as on cash and cash equivalent balances held in US dollars. Foreign currency risk associated with interest payments is partially offset by marketing arrangements for the sale of the Company's natural gas and natural gas liquids, excluding condensate, which are denominated in US dollars.

The following table demonstrates the impact of changes in the Canadian to US dollar exchange rate on income before tax, based on US denominated balances outstanding (including the foreign exchange risk management contracts) at December 31, 2015:

	Gain (Loss)
10% increase in US$ to C$	181,617
10% decrease in US$ to C$	(212,491)

The carrying amount of the Company's US dollar denominated monetary assets and liabilities as at December 31 was as follows:

As at December 31,	**2015**	2014
Assets	**35,545**	78,042
Liabilities	**1,563,829**	822,573

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meets its financial obligations as they fall due. The Company manages its liquidity risk through ensuring, as reasonably as possible, that it will have sufficient liquidity to meets its liabilities when due without incurring unacceptable losses or risking damage to the Company's reputation. At December 31, 2015, the Company had $405.0 million of cash and cash equivalents, plus available credit facility of $812.0 million. Management believes it has sufficient funding to meet foreseeable liquidity requirements. The Company prepares capital expenditure budgets which are regularly monitored and updated. As well, the Company utilizes authorizations for investments on both operated and non-operated projects to manage capital investments. See Note 24 Subsequent Event.

The following are the contractual maturities of financial liabilities at December 31, 2015:

	Less than 1 year	2-3 years	4-5 years	Thereafter	Total
Accounts payable and accrued liabilities	187,760	—	—	—	**187,760**
Senior notes (1)	—	—	968,800	588,200	**1,557,000**
Interest on senior notes (1)	119,630	358,890	109,380	52,939	**640,839**
Total	307,390	358,890	1,078,180	641,139	**2,385,599**

(1) Balances denominated in US dollars have been translated at the December 31, 2015, Canadian dollar to US dollar exchange rate of 0.723.

CONTRACTUAL OBLIGATIONS

Seven Generations enters into contractual obligations in the ordinary course of conducting its business. The following table lists the Company's estimated material contractual obligations at December 31, 2015:

	Total	Less than 1 year	1-3 years	4-5 years	Thereafter
($ thousands)					
Senior notes (1)	**1,557,000**	—	—	968,800	588,200
Interest on senior notes	**640,839**	119,630	358,890	109,380	52,939
Firm transportation and processing agreements (2)	**1,993,633**	220,331	780,243	556,055	437,004
Operating leases (3)	**12,800**	2,380	5,319	2,583	2,518
Deferred obligation and retention (4)	**2,748**	2,748	0	—	—
Estimated contractual obligations	**4,207,020**	345,089	1,144,452	1,636,818	1,080,661

(1) Balance represents US$1.1 billion principal converted to Canadian dollars at the closing exchange rate for the period end.
(2) Subject to completion of certain pipeline and facility upgrades by the counterparty transportation company.
(3) The Company is committed under operating leases for office premises.
(4) In November 2014, the Board of Directors approved a retention bonus plan for management and employees in aggregate of $6.0 million, payable over the two-year period starting November 5, 2014. Of this amount, $2.7 million is payable in 2016.

OFF-BALANCE SHEET ARRANGEMENTS

The Company has certain fixed lease arrangements which were entered into in the normal course of operations. All material leases are classified as operating leases, where the lease payments are included in operating expenses or G&A expenses depending on the nature of the lease. These arrangements are disclosed in the Note 22 to the consolidated financial statements of the Company. No asset or liability has been recorded for these leases on the balance sheet at years ended December 31, 2015 and 2014.

The Company did not have any physical delivery contracts outstanding at December 31, 2015 and 2014.

OUTSTANDING SHARE DATA

The Company is authorized to issue an unlimited number of Class A Common Voting Shares and an unlimited number of Class B Common Non-Voting Shares without nominal or par value. As at March 8, 2016, Seven Generations had 275,913,180 Class A Common Voting Shares, Nil Class B Common Non-Voting Shares, 12,019,250 stock options, 18,417,414 performance warrants, 154,698 PSUs, 271,848 RSUs and 55,176 DSUs outstanding.

The vesting of PSUs are conditional on the satisfaction of certain performance criteria as determined by the Company's Board of Directors. If the Company satisfies the performance criteria, PSUs become eligible to vest and a pre-determined multiplier is applied to eligible PSUs. The Company has used an adjustment factor of 1.0, which assumes that the Company will be within the 50% percentile of its relative peer group, based on total shareholder return at the respective vesting dates.

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Disclosure controls and procedures ("DC&P"), as defined in National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings, are designed to provide reasonable assurance that information required to be disclosed in the Company's annual filings, interim filings or other reports filed or submitted by the Company under securities legislation is recorded, processed, summarized and reported within the time periods specified under securities legislation and include controls and procedures designed to ensure that information required to be so disclosed is accumulated and communicated to management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Chief Executive Officer and the Chief Financial Officer of Seven Generations evaluated the effectiveness of the design and operation of the Company's DC&P. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that Seven Generations' DC&P were effective as at December 31, 2015.

Internal Control over Financial Reporting

Internal control over financial reporting ("ICFR"), as defined in National Instrument 52-109, includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of Seven Generations; (ii) are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of Seven Generations are being made in accordance with authorizations of management and Directors of Seven Generations; and (iii) are designed to provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that could have a material effect on the financial statements.

The Chief Executive Officer and the Chief Financial Officer are responsible for establishing and maintaining ICFR for Seven Generations. For the year ended December 31, 2015, they have designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The control framework used to design the Company's ICFR is the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Under the supervision of the Chief Executive Officer and the Chief Financial Officer, Seven Generations conducted an evaluation of the effectiveness of the Company's ICFR as at December 31, 2015. Based on this evaluation, the officers concluded that as of December 31, 2015, Seven Generations maintained effective ICFR. It should be noted that while Seven Generations' officers believe that the Company's controls provide a reasonable level of assurance with regard to their effectiveness, a control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system will be met and it should not be expected that the control system will prevent all errors or fraud.

There were no changes during the period beginning on October 1, 2015 and ended on December 31, 2015 that have materially affected, or are reasonably likely to materially affect, Seven Generations' ICFR.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

A summary of the Company's significant accounting policies can be found in Notes 3 and 4 to the audited consolidated financial statements for the year ended December 31, 2015. The preparation of consolidated financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions that affect the reported amounts of assets, liabilities, income and expenses. The financial and operating results of Seven Generations incorporate certain estimates including:

- estimated revenues, royalties and operating expenses on production as at a specific reporting date but for which actual revenues and costs have not yet been received;
- estimated capital expenditures on projects that are in progress;
- estimated depletion, depreciation and amortization charges that are based on estimates of oil and natural gas reserves, and future costs to develop those reserves, that Seven Generations expects to recover in the future;
- estimated fair values of financial instruments that are subject to fluctuation depending on the underlying commodity prices, foreign exchange rates and interest rates, volatility curves and the risk of non-performance;
- estimated value of asset retirement obligations that are dependent upon estimates of future costs and timing of expenditures;
- estimated future recoverable value of oil and natural gas properties and goodwill and any associated impairment charges or recoveries; and
- estimated compensation expense under Seven Generations' share-based compensation plans.

Seven Generations employs individuals who have the skills required to make such estimates and ensures that individuals or departments with the most knowledge of the activity are responsible for the estimates. Further, past estimates are reviewed and compared to actual results, and actual results are compared to budgets in order to make more informed decisions on future estimates. For further information on the determination of certain estimates inherent in the consolidated financial statements, refer to Note 5 "Significant Accounting Judgments, Estimates and Assumptions" in the audited consolidated financial statements for the year ended December 31, 2015.

RISK ASSESSMENT

The acquisition, exploration and development of oil and natural gas properties and the production, transportation and marketing of oil and natural gas involves many risks, which may influence the ultimate success of the Company. While the management of Seven Generations realizes these risks cannot be eliminated, they are committed to monitoring and mitigating these risks. These risks include, but are not limited to the following:

- volatility in market prices and demand for oil, NGLs and natural gas and hedging activities related thereto;
- general economic, business and industry conditions;
- variance of the Company's actual capital costs, operating costs and economic returns from those anticipated;
- the ability to find, develop or acquire additional reserves and the availability of the capital or financing necessary to do so on satisfactory terms;
- risks related to the exploration, development and production of oil and natural gas reserves and resources;
- negative public perception of oil sands development, oil and natural gas development and transportation, hydraulic fracturing and fossil fuels;
- actions by governmental authorities, including changes in government regulation, royalties and taxation;
- the rescission, or amendment to the conditions of, groundwater licenses of the Company;
- management of the Company's growth;
- the ability to successfully identify and make attractive acquisitions, joint ventures or investments, or successfully integrate future acquisitions or businesses;
- the availability, cost or shortage of rigs, equipment, raw materials, supplies or qualified personnel;
- adoption or modification of climate change legislation by governments;
- the absence or loss of key employees;
- uncertainty associated with estimates of oil, NGLs and natural gas reserves and resources and the variance of such estimates from actual future production;
- dependence upon compressors, gathering lines, pipelines and other facilities, certain of which the Company does not control;
- the ability to satisfy obligations under the Company's firm commitment transportation arrangements;
- the uncertainties related to the Company's identified drilling locations;
- the high-risk nature of successfully stimulating well productivity and drilling for and producing oil, NGLs and natural gas;
- operating hazards and uninsured risks;
- the possibility that Company's drilling activities may encounter sour gas;
- execution of the Company's business plan;
- failure to acquire or develop replacement reserves;
- the concentration of the Company's assets in the Kakwa River Project area;
- unforeseen title defects;
- Aboriginal claims;
- failure to accurately estimate abandonment and reclamation costs;
- development and exploratory drilling efforts and well operations may not be profitable or achieve the targeted return;
- horizontal drilling and completion technique risks and failure of drilling results to meet expectations for reserves or production;
- limited intellectual property protection for operating practices and dependence on employees and contractors;
- third-party claims regarding the Company's right to use technology and equipment;
- expiry of certain leases for the undeveloped leasehold acreage in the near future;
- failure to realize the anticipated benefits of acquisitions or dispositions;
- failure of properties acquired now or in the future to produce as projected and inability to determine reserve and resource potential, identify liabilities associated with acquired properties or obtain protection from sellers against such liabilities;
- governmental regulations;
- changes in the interpretation and enforcement of applicable laws and regulations;
- environmental, health and safety requirements;
- restrictions on drilling intended to protect certain species of wildlife;
- potential conflicts of interests;
- actual results differing materially from management estimates and assumptions;
- seasonality of the Company's activities and the Canadian oil and gas industry;
- weather related risks, fires and natural disasters;
- alternatives to and changing demand for petroleum products;
- extensive competition in the Company's industry;
- changes in the Company's credit ratings;
- third party credit risk;
- dependence upon a limited number of customers;
- lower oil, NGLs and natural gas prices and higher costs;

- terrorist attacks or armed conflict;
- loss of information and computer systems;
- inability to dispose of non-strategic assets on attractive terms;
- security deposits may be required under provincial liability management programs;
- reassessment by taxing authorities of the Company's prior transactions and filings;
- variations in foreign exchange rates and interest rates;
- third-party credit risk including risk associated with counterparties in risk management activities related to commodity prices and foreign exchange rates;
- sufficiency of insurance policies;
- potential of litigation;
- variation in future calculations of non-IFRS measures;
- sufficiency of internal controls;
- third-party breach of agreements;
- impact of expansion into new activities on risk exposure;
- inability of the Company to respond quickly to competitive pressures;
- risks related to the common shares that are publicly traded and the senior notes and other indebtedness.

For additional information regarding the risks that the Company is exposed to, see the disclosure provided under the heading "Risk Factors" in the AIF, which is available on the SEDAR website at www.sedar.com.

CHANGES IN ACCOUNTING POLICIES

Changes in accounting policies

There were no material new or amended accounting standards adopted during the year ended December 31, 2015.

Future accounting policy changes

In February 2014, the IASB issued IFRS 9 "Financial Instruments", which replaces IAS 39, "Financial Instruments: Recognition and Measurement" for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. IFRS 9 includes a principle-based approach for classification and measurement of financial assets, a single 'expected loss' impairment model and a substantially-reformed approach to hedge accounting. The impact of the standard on the Company's financial statements is currently being evaluated.

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers", which replaces IAS 18 "Revenue," IAS 11 "Construction Contracts," and related interpretations. In July 2015, the IASB issued an amendment to IFRS 15, deferring the effective date by one year. IFRS 15 provides clarification for recognizing revenue from contracts with customers and establishes a single revenue recognition and measurement framework. The standard is required to be adopted either retrospectively or using a modified transition approach for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. The Company is currently evaluating the impact of the standard on the consolidated financial statements.

In January 2016, the IASB issued IFRS 16 "Leases" which replaces IAS 17 "Leases" for annual periods beginning on or after January 1, 2019, with earlier application permitted if IFRS 15 "Revenue from Contracts with Customers" is also applied. Under IFRS 16, lessees are required to recognize a lease liability reflecting future lease payments and a 'right-of-use asset' for virtually all lease contracts. The Company is currently evaluating the impact of the standard on the consolidated financial statements.

NON-IFRS FINANCIAL MEASURES

This MD&A includes certain terms or performance measures commonly used in the oil and natural gas industry that are not defined under IFRS, including "funds from operations", "operating income", "operating netback", "available funding" and "net debt". The data presented is intended to provide additional information and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with IFRS. These non-IFRS measures should be read in conjunction with the Company's audited consolidated financial statements and the accompanying notes.

Funds from Operations

"Funds from operations" is a financial measure not presented in accordance with IFRS and is equal to cash provided by operating activities, adjusted for changes in non-cash operating working capital, decommissioning expenditures and liquidity event expense. The Company uses funds from operations as an integral part of its internal reporting to measure its performance and is considered an important indicator of the operational strength of the Company's business. Funds from operations is a measure of the cash flow generated by the Company's operating activities and eliminates the effect of changes in non-cash working capital, which is included in cash flow provided by operating activities. Funds from operations is not intended to be a performance measure that should be regarded as an alternative to, or more meaningful than, either net income as an indicator of operating performance or to cash flows from operating activities as a measure of liquidity. In addition, funds from operations is not intended to represent funds available for dividends, reinvestment or other discretionary uses.

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

	Three months ended December 31,			Year ended December 31,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands)						
Cash provided by operating activities	**53,929**	80,667	(33)	**380,117**	301,909	26
Decommissioning expenditures	**—**	—	(33)	**—**	206	(100)
Liquidity expense	**—**	35,947	—	**—**	35,947	(100)
Changes in non-cash working capital	**52,102**	(15,111)	(445)	**34,492**	(10,129)	(441)
Funds from operations	**106,031**	101,503	4	**414,609**	327,933	26

Operating Income (Loss)

"Operating income (loss)" is a non-IFRS measure which the Company uses as a performance measure to provide comparability of financial performance between periods by excluding non-operating items. Operating income (loss) is defined as net income (loss), excluding realized foreign exchange gains and losses, unrealized gains and losses on risk management contracts and the respective income tax impact of these adjustments.

The following table reconciles the net income to operating income (loss):

	Three months ended December 31,			Year ended December 31,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
($ thousands)						
Net income (loss) for the period	**(28,922)**	68,628	(142)	**(187,296)**	144,200	(230)
Unrealized loss - risk management contracts (1)	**(53,713)**	(123,772)	(57)	**15,911**	(141,765)	(111)
Unrealized foreign exchange loss (gain) (2)	**53,941**	27,562	96	**228,863**	53,406	329
Gain on disposition of assets (3)	**—**	—	—	**(2,602)**	(4,286)	(39)
Liquidity expense	**—**	35,947	(100)	**—**	35,947	(100)
Deferred tax (recovery) expense relating to these adjustments	**14,503**	26,450	(45)	**(2,771)**	32,019	(109)
Operating income (loss)	**(14,191)**	34,815	(141)	**52,105**	119,521	(56)

(1) Unrealized gains and losses on risk management contracts result from the fair market valuation of the hedge contracts as at December 31.
(2) Unrealized foreign exchange gains and losses result from the translation of the US$ denominated senior notes and cash and cash equivalents using period end exchange rates.
(3) Non-recurring gain resulting from disposition of assets.

Operating Netback

"Operating netback" is calculated on a per boe basis and is determined by deducting royalties, operating and transportation expenses from oil and natural gas revenue and, except where otherwise indicated, after adjusting for realized hedging gains or losses. Operating netback is utilized by the Company and others to better analyze the operating performance of its oil and natural gas assets.

Available Funding

"Available funding" is comprised of adjusted working capital and the undrawn credit facility capacity. Adjusted working capital is comprised of current assets less current liabilities and excludes (current) risk management contracts and deferred credits. The available funding measure allows management and other users to evaluate the Company's short term liquidity. A summary of the reconciliation of available funding is set forth below:

As at December 31	2015	2014
($ thousands)		
Current assets	**592,473**	1,060,030
Current liabilities	**(206,203)**	(268,231)
Working capital	**386,270**	791,799
Adjusted for:		
Current asset - risk management contracts	**(98,570)**	(138,122)
Current liability - risk management contracts	**18,320**	—
Current portion of deferred credits	**123**	123
Adjusted working capital	**306,143**	653,800
Credit facility capacity [(1)]	**812,000**	480,000
Available funding	**1,118,143**	1,133,800

(1) Available credit facility capacity of $850.0 million less outstanding letters of credit of $38 million.

Net Debt

"Net debt" is a financial measure not presented in accordance with IFRS and is equal to long-term debt less adjusted working capital surplus (deficit). Long-term debt for the senior notes is calculated as the principal amount outstanding converted to Canadian dollars at the closing exchange rate for the period, and excludes unamortized premiums and debt issue costs. Adjusted working capital surplus (deficit) is calculated as current assets less current liabilities as they appear on the balance sheets, and excludes current unrealized risk management contracts and deferred credits. The Company uses net debt to assess liquidity and general financial strength. Net debt should not be considered an alternative to, or more meaningful than, current assets or current liabilities as determined in accordance with IFRS.

The following table presents a calculation of the non-IFRS financial measure of net debt:

As at December 31	2015	2014
($ thousands)		
Senior notes at amortized cost	**1,546,761**	813,880
Less unamortized premium and debt issue costs	**10,239**	(1,810)
Senior notes principal	**1,557,000**	812,070
Adjusted for:		
Adjusted working capital	**(306,143)**	(653,800)
Net debt	**1,250,857**	158,270

SELECTED QUARTERLY INFORMATION

	Q4 2015	Q3 2015	Q2 2015	Q1 2015	YTD 2015
FINANCIAL ($ thousands, except per share amounts, production rates and unit prices)					
Total revenues	**178,478**	149,723	155,183	108,540	591,924
Realized hedging gain	**22,980**	35,262	41,683	50,655	150,580
Midstream revenue	**1,300**	—	—	—	1,300
Processing and third party income	**691**	467	294	385	1,837
Interest and other income	**879**	1,248	1,450	1,300	4,877
Royalties	**(12,127)**	(17,704)	(12,886)	(15,181)	(57,898)
Operating expenses	**(29,378)**	(26,819)	(23,537)	(21,454)	(101,188)
Transportation expenses	**(23,984)**	(13,493)	(9,893)	(12,966)	(60,336)
General and administrative	**(7,128)**	(5,450)	(5,136)	(6,629)	(24,343)
Interest expense	**(29,105)**	(28,363)	(24,946)	(17,973)	(100,387)
Foreign exchange loss	**3,456**	60	4,614	242	8,372
Other	**(31)**	(31)	(31)	(30)	(123)
Funds from operations [(1)]	**106,031**	94,900	126,795	86,889	414,615
Per share – diluted	**1.66**	0.35	0.47	0.32	2.80
Operating income [(1)]	**(14,191)**	13,813	28,485	23,998	52,105
Per share – diluted	**(0.06)**	(0.21)	0.11	0.09	(0.07)
Net loss	**(28,922)**	(53,726)	(21,950)	(82,698)	(187,296)
Per share – diluted	**(0.11)**	(0.21)	(0.09)	(0.34)	(0.75)
Capital investments:					
Land	**2,169**	1,930	259	780	5,138
Drilling and completions	**181,108**	145,626	222,164	264,879	813,777
Facilities and equipment	**114,153**	134,494	128,588	100,723	477,958
Other	**3,719**	3,064	3,299	2,018	12,100
Total capital investments (before dispositions)	**301,149**	285,114	354,310	368,400	1,308,973
Total assets	**3,758,982**	3,707,714	3,559,768	3,170,401	3,758,982
Available funding [(1)]	**1,118,143**	1,141,232	1,325,954	861,385	1,118,143
Net debt [(1)]	**1,250,857**	989,843	710,200	505,234	1,250,857
Debt outstanding	**1,546,761**	1,491,184	1,395,485	888,356	1,546,761
OPERATING					
Average daily production					
Oil and condensate (bbls/d)	**25,572**	22,606	20,702	15,810	21,204
NGLs (bbls/d)	**19,236**	14,094	11,914	12,042	14,341
Natural gas (MMcf/d)	**197**	143	130	125	149
Total (boe/d)	**77,699**	60,600	54,219	48,768	60,403
Realized prices					
Oil and condensate ($/bbl)	**46.72**	49.18	60.29	47.59	50.84
NGLs ($/bbl)	**12.35**	7.99	9.78	10.41	10.34
Natural gas ($/Mcf)	**2.57**	2.81	2.63	2.62	2.65
OPERATING NETBACK [(1)]					
Liquids and natural gas revenues	**$ 24.97**	$ 26.86	$ 31.45	$ 24.73	$ 26.85
Realized hedging gain	**3.21**	6.32	8.45	11.54	6.83
Royalties	**(1.70)**	(3.18)	(2.61)	(3.46)	(2.63)
Operating expenses	**(4.11)**	(4.81)	(4.77)	(4.89)	(4.59)
Transportation expenses	**(3.36)**	(2.42)	(2.00)	(2.95)	(2.74)
Operating netback after hedging	**$ 19.01**	$ 22.77	$ 30.52	$ 24.97	$ 23.72

(1) See “Non-IFRS Financial Measures”.

SELECTED QUARTERLY INFORMATION - continued

	Q4 2014	Q3 2014	Q2 2014	Q1 2014	YE 2014
FINANCIAL ($ thousands, except per share amounts, production rates and unit prices)					
Total revenues	155,383	159,964	120,749	98,737	534,833
Realized hedging gain	22,163	(148)	(6,873)	(5,405)	9,737
Processing and third party income	704	571	243	285	1,803
Interest and other income	1,264	512	782	626	3,184
Royalties	(16,145)	(20,925)	(9,434)	(5,386)	(51,890)
Operating expenses	(18,966)	(14,245)	(9,659)	(11,391)	(54,261)
Transportation expenses	(13,237)	(7,277)	(7,693)	(6,626)	(34,833)
General and administrative	(7,393)	(4,457)	(5,233)	(3,175)	(20,258)
Interest expense	(16,905)	(16,037)	(16,262)	(13,746)	(62,950)
Foreign exchange (gain) loss	(5,334)	8,367	(618)	223	2,638
Other	(31)	(31)	(30)	22	(70)
Funds from operations (1)	101,503	106,294	65,972	54,164	327,933
Per share – diluted	0.41	0.48	0.31	0.25	1.46
Operating income (1)	34,815	41,972	18,253	24,481	119,521
Per share – diluted	0.14	0.19	0.09	0.11	0.53
Net income	68,628	30,482	43,926	1,164	144,200
Per share – diluted	0.28	0.14	0.20	0.01	0.64
Capital investments:					
Land	8,200	1,408	30,057	9,019	48,684
Drilling and completions	227,562	234,879	155,284	124,294	742,019
Facilities and equipment	132,610	90,447	34,172	65,806	323,035
Other	1,948	1,689	1,531	1,430	6,598
Total capital investments (before dispositions)	370,320	328,423	221,044	200,549	1,120,336
Total assets	3,114,797	2,019,134	1,844,172	1,818,627	3,114,797
Available funding (1)	1,133,800	547,700	427,222	574,581	1,133,800
Net debt (1)	158,270	716,300	469,678	349,269	158,270
Debt outstanding	813,880	785,830	748,596	775,809	813,880
OPERATING					
Average daily production					
Oil and condensate (bbls/d)	14,747	12,580	9,264	7,554	11,061
NGLs (bbls/d)	10,783	8,289	4,741	4,054	6,989
Natural gas (MMcf/d)	112	90	60	52	79
Total (boe/d)	44,178	35,820	23,999	20,231	31,136
Realized prices					
Oil and condensate ($/bbl)	69.93	90.41	97.32	92.61	85.34
NGLs ($/bbl)	21.50	25.46	24.15	28.25	24.10
Natural gas ($/Mcf)	3.81	4.35	5.18	5.47	4.50
OPERATING NETBACK (1)					
Liquids and natural gas revenues	38.23	48.54	55.29	54.23	47.06
Realized hedging gain	5.45	(0.04)	(3.15)	(2.97)	0.86
Royalties	(3.97)	(6.35)	(4.32)	(2.96)	(4.57)
Operating expenses	(4.67)	(4.32)	(4.42)	(6.26)	(4.77)
Transportation expenses	(3.26)	(2.21)	(3.52)	(3.64)	(3.06)
Operating netback after hedging	31.78	35.62	39.88	38.40	35.52

(1) See "Non-IFRS Financial Measures".

SELECTED QUARTERLY INFORMATION - continued

	Q4 2013	Q3 2013	Q2 2013	Q1 2013	YE 2013
FINANCIAL ($ thousands, except per share amounts, production rates and unit prices)					
Total revenues	48,484	22,168	21,581	20,951	113,184
Realized hedging gain	49	17	53	160	279
Processing and third party income	356	501	347	407	1,611
Interest and other income	272	506	274	233	1,285
Royalties	(3,188)	(2,227)	(318)	(2,120)	(7,853)
Operating expenses	(8,425)	(4,502)	(4,168)	(3,520)	(20,615)
Transportation expenses	(3,286)	(962)	(1,326)	(887)	(6,461)
General and administrative	(2,052)	(2,006)	(2,175)	(1,884)	(8,117)
Interest expense	(8,970)	(8,691)	(5,051)	(194)	(22,906)
Foreign exchange (gain) loss	(133)	(24)	6	10	(141)
Other	7	—	—	—	7
Funds from operations [1]	23,114	4,780	9,223	13,156	50,273
Per share – diluted	0.12	0.03	0.05	0.08	0.27
Operating income (loss) [1]	7,127	(8,053)	5,246	1,474	5,794
Per share – diluted	0.04	(0.05)	0.03	0.01	0.03
Net income (loss)	(5,625)	(955)	(8,454)	876	(14,158)
Per share – diluted	(0.03)	(0.01)	(0.05)	0.01	(0.08)
Capital investments:					
Land	2,925	8,991	35,875	13,507	61,298
Drilling and completions	129,231	102,314	44,697	45,568	321,810
Facilities and equipment	44,717	29,707	39,806	72,464	186,694
Other	1,365	1,173	1,058	930	4,526
Total capital investments (before dispositions)	178,238	142,185	121,436	132,469	574,328
Total assets	1,408,213	1,134,257	1,103,583	698,450	1,408,213
Available funding [1]	364,877	189,586	328,137	16,441	364,877
Net debt [1]	210,563	282,534	152,583	23,559	210,563
Debt outstanding	414,525	404,208	412,293	—	414,525
OPERATING					
Average daily production					
Oil and condensate (bbls/d)	4,480	1,614	1,681	1,760	2,390
NGLs (bbls/d)	2,291	1,639	1,313	1,749	1,749
Natural gas (MMcf/d)	29	23	19	16	22
Total (boe/d)	11,585	7,084	6,182	6,240	7,786
Realized prices					
Oil and condensate ($/bbl)	80.63	96.63	88.67	84.62	85.49
NGLs ($/bbl)	24.54	18.77	11.89	16.22	18.76
Natural gas ($/Mcf)	3.79	2.36	3.79	3.38	3.34
OPERATING NETBACK [1]					
Liquids and natural gas revenues	37.30	38.36	34.01	45.49	39.83
Realized hedging gain	0.28	0.10	0.03	0.05	0.10
Royalties	(3.78)	(0.56)	(3.42)	(2.99)	(2.76)
Operating expenses	(6.27)	(7.41)	(6.91)	(7.90)	(7.25)
Transportation expenses	(1.58)	(2.35)	(1.48)	(3.09)	(2.28)
Operating netback after hedging	25.95	28.14	22.23	31.56	27.64

(1) See “Non-IFRS Financial Measures”.

Forward-Looking Information Advisory

This document contains certain forward-looking information and statements that involve various risks, uncertainties and other factors. The use of any of the words “anticipate”, “continue”, “estimate”, “expect”, “may”, “will”, “should”, “believe”, “plans”, and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this document contains forward-looking information and statements pertaining to the following: the level of growth that is expected; the Company’s ability to deliver on its growth objectives and meet the commitments in its marketing and transportation agreements; the Company’s hedging targets; the expectation that the Kakwa River Project will have low supply and break even costs relative to competing projects; the ability to generate long-life value from the Kakwa River Project; the continued focus on prudent, disciplined investment in long-term value creation; estimates of net present value of future net revenue from reserves; future wells or future drilling locations; the ability to achieve cash-flow self-sufficiency; the availability of relatively low-cost development opportunities and further opportunities that will maximize value for the Company’s stakeholders; expected capital investment in 2016; the expectation that the previously announced deferral of capital spending will not significantly impact 2016 production guidance; the expectation that funds from operations and available funding will support the Company’s ongoing capital investment program in 2016; anticipated production; the anticipated timing of the commissioning of the Cutbank plant; future price differentials; future processing and transportation capacity; anticipated rates of return; the impact that the Modernized Royalty Framework will have on the Company; the timing of the construction and commissioning of additional super pads; increased operational efficiency and maximization of recovery; expectations regarding the balancing of debt and equity in the Company’s capital structure; and the Company’s estimates of its future obligations under the heading “Contractual Obligations”. In addition, references to reserves are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated.

With respect to forward-looking information contained in this document, assumptions have been made regarding, among other things: future oil, NGLs and natural gas prices, including all adjustments for the quality of the Company’s production at the point of sale; the Company’s ability to obtain qualified staff and equipment in a timely and cost-efficient manner; the regulatory framework governing royalties, taxes and environmental matters in the jurisdictions in which the Company conducts its business and any other jurisdictions in which the Company may conduct its business in the future; the Company’s ability to market production of oil, NGLs and natural gas successfully to customers; the Company’s future production levels; the applicability of technologies for recovery and production of the Company’s reserves and resources; the recoverability of the Company’s reserves and resources; future capital investments to be made by the Company; future cash flows from production; future sources of funding for the Company’s capital program; the Company’s future debt levels; geological and engineering estimates in respect of the Company’s reserves and resources; the geography of the areas in which the Company is conducting exploration and development activities, and the access, economic, regulatory and physical limitations to which the Company may be subject from time to time; the impact of competition on the Company; and the Company’s ability to obtain financing on acceptable terms.

Actual results could differ materially from those anticipated in this forward-looking information as a result of the risks and risk factors that are set forth in the AIF, which is available on SEDAR at www.sedar.com, including, but not limited to: volatility in market prices and demand for oil, NGLs and natural gas and hedging activities related thereto; general economic, business and industry conditions; variance of the Company’s actual capital costs, operating costs and economic returns from those anticipated; the ability to find, develop or acquire additional reserves and the availability of the capital or financing necessary to do so on satisfactory terms; risks related to the exploration, development and production of oil and natural gas reserves and resources; negative public perception of oil sands development, oil and natural gas development and transportation, hydraulic fracturing and fossil fuels; actions by governmental authorities, including changes in government regulation, royalties and taxation; the rescission, or amendment to the conditions of, groundwater licenses of the Company; management of the Company’s growth; the ability to successfully identify and make attractive acquisitions, joint ventures or investments, or successfully integrate future acquisitions or businesses; the availability, cost or shortage of rigs, equipment, raw materials, supplies or qualified personnel; adoption or modification of climate change legislation by governments; the absence or loss of key employees; uncertainty associated with estimates of oil, NGLs and natural gas reserves and resources and the variance of such estimates from actual future production; dependence upon compressors, gathering lines, pipelines and other facilities, certain of which the Company does not control; the ability to satisfy obligations under the Company’s firm commitment transportation arrangements; the uncertainties related to the Company’s identified drilling locations; the high-risk nature of successfully stimulating well productivity and drilling for and producing oil, NGLs and natural gas; operating hazards and uninsured risks; the possibility that Company’s drilling activities may encounter sour gas; execution of the Company’s business plan; failure to acquire or develop replacement reserves; the concentration of the Company’s assets in the Kakwa River Project area; unforeseen title defects; Aboriginal claims; failure to accurately estimate abandonment and reclamation costs; development and exploratory drilling efforts and well operations may not be profitable or achieve the targeted return; horizontal drilling and completion technique risks and failure of drilling results to meet expectations for reserves or production; limited intellectual property protection for operating practices and dependence on employees and contractors; third-party claims regarding the Company’s right to use technology and equipment; expiry of certain leases for the undeveloped leasehold acreage in the near future; failure to realize the anticipated benefits of acquisitions or dispositions; failure of properties acquired now or in the future to produce as projected and inability to determine reserve and resource potential, identify liabilities associated with acquired properties or obtain protection from sellers against such liabilities; governmental regulations; changes in the interpretation and enforcement of applicable laws and regulations; environmental, health and safety requirements; restrictions on drilling intended to protect certain species of wildlife; potential conflicts of interests; actual results differing materially from management estimates and assumptions; seasonality of the Company's activities and the Canadian oil and gas industry; weather related risks, fires and natural disasters; alternatives to and changing demand for petroleum products; extensive competition in the Company's industry; changes in the Company's credit ratings; third party credit risk; dependence upon a limited number of customers; lower oil, NGLs and natural gas prices and higher costs; terrorist attacks or armed conflict; loss of information and computer systems; inability to dispose of non-strategic assets on attractive terms; security deposits may be required under provincial liability management programs; reassessment by taxing authorities of the Company's prior transactions and filings; variations in foreign exchange rates and interest rates; third-party credit risk including risk associated with counterparties in risk management activities related to commodity prices and foreign exchange rates; sufficiency of insurance policies; litigation; variation in future calculations of non-IFRS measures; sufficiency of internal controls; third-party breach of agreements; impact of expansion into new activities on risk exposure; inability of the Company to respond quickly to competitive pressures; risks related to the senior unsecured notes and other indebtedness, including potential inability to comply with the covenants in the credit agreement related to the Company's credit facilities and/or the covenants in the indentures in respect of the senior secured notes.

Any financial outlook and future-oriented financial information contained in this document regarding prospective financial performance, financial position or cash flows is based on assumptions about future events, including economic conditions and proposed courses of action, based on management's assessment of the relevant information that is currently available. Projected operational information contains forward-looking information and is based on a number of material assumptions and factors, as are set out above. These projections may also be considered to contain future oriented financial information or a financial outlook. The actual results of the Company's operations for any period will likely vary from the amounts set forth in these projections, and such variations may be material. Actual results will vary from projected results. Readers are cautioned that any such financial outlook and future-oriented financial information contained herein should not be used for purposes other than those for which it is disclosed herein. The forward-looking information and statements contained in this document speak only as of the date hereof, and the Company does not assume any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable laws.

Independent Reserves Evaluation

Estimates of the Company's reserves and the net present value of future net revenue attributable to the Company's reserves as at December 31, 2015, are based upon the report that was prepared by McDaniel, evaluating the Company's oil, natural gas and NGL reserves, dated March 7, 2016. The estimates of reserves provided in this document 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 in this in this document, and the difference may be material. Estimates of net present value of future net revenue attributable to the Company's reserves do not represent fair market value of the Company's reserves. There is no assurance that the forecast price and cost assumptions applied by McDaniel in evaluating Seven Generations' reserves will be attained and variances could be material. For important additional information regarding the independent reserves evaluation that was conducted by McDaniel, please refer to the AIF, which is available on the SEDAR website at www.sedar.com.

Oil and Gas Definitions

Terms that are used in this MD&A that are not otherwise defined herein are provided below:

developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

gross means:

- in relation to the Company's interest in production or reserves, its "company gross reserves", which are the Company's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Company;
- in relation to wells, the total number of wells in which the Company has an interest; and
- in relation to properties, the total area of properties in which the Company has an interest.

net means:

- in relation to the Company's interest in production or reserves, the Company's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Company's royalty interest in production or reserves;
- in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and
- in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on: (i) analysis of drilling, geological, geophysical and engineering data; (ii) the use of established technology; and (iii) specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates.

Abbreviations

AECO	physical storage and trading hub for natural gas on the TransCanada Alberta transmission system which is the delivery point for various benchmark Alberta index prices
bbl	barrel
bbls	barrels
boe(1)	barrels of oil equivalent
CRA	Canada Revenue Agency
C$	Canadian dollars
d	day
km	kilometres
m	metres
Mcf	thousand cubic feet
MMboe	millions of barrels of oil equivalent
MMBtu	million British thermal units
MMcf	million cubic feet
Nest	means the primary development block of the Kakwa River Project.
NGLs	natural gas liquids
NGX	Natural Gas Exchange Inc.
nm	not meaningful
NYMEX	New York Mercantile Exchange
Opex	operating expense
US$	United States dollars
WTI	West Texas Intermediate
$MM	millions of dollars

(1) Seven Generations has adopted the standard of 6 Mcf:1 bbl when converting natural gas to boes. Condensate and other NGLs are converted to boes at a ratio of 1 bbl:1 bbl. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 bbl is based roughly on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the Company's sales point. Given the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf: 1 bbl, utilizing a conversion ratio at 6 Mcf: 1 bbl may be misleading as an indication of value.