SEVEN GENERATIONS
ENERGY LTD

Q2 2015 REPORT

TSX: VII

Seven Generations' Q2 funds from operations up 92 percent to $127 million; production up 126 percent to 54,200 boe/d

Efficiency and optimization driving recent well costs down by $1 million per well

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CALGARY, August 10, 2015 – Seven Generations Energy Ltd. (7G or the Company) generated second quarter funds from operations of $126.8 million, up 92 percent from the second quarter of 2014, and increased production 126 percent to 54,219 barrels of oil equivalent per day (boe/d). Second quarter oil and condensate production increased 123 percent to 20,702 barrels per day (bbls/d) compared to a year earlier.

"We continue to increase shareholder value. We are achieving strong growth in production and funds from operations from our Kakwa River Project. We are adding new wells and processing capacity to meet our growth objectives. Second quarter natural gas production was 130 million cubic feet per day (MMcf/d), up 117 percent compared to a year earlier, and we are on track to deliver 250 MMcf/d of liquids-rich natural gas into the Alliance Pipeline in December," said Marty Proctor, 7G's President and Chief Operating Officer.

"With the ongoing over-supply of natural gas across North America, we focus intensely on being among the continent's lowest cost developers. Maintaining a margin throughout commodity price fluctuations has always driven and continues to drive our long-term growth strategy. When we combine our low-cost supply growth with our long-term, firm transportation and our fractionation capacity in the U.S. Midwest, we maintain our highly competitive position and can continue to grow production and funds from operations. We believe that over-supply drives down prices, but not demand. Despite the current weakness in continental energy prices, developers generating the lowest-cost supply will continue to earn competitive returns for investors over the long term," said Pat Carlson, 7G's Chief Executive Officer.

Well costs tracking lower

"Our steady focus on learning, innovation and operational efficiency continues to drive down drilling and completion costs. Our most recent four wells cost about $12 million each to drill and complete, down 8 percent, or about $1 million per well, from the first quarter of this year. We are now drilling and completing wells with 2,800- to 3,000-metre laterals for the same cost that we attributed to a well with a 2,200-metre lateral in our initial public offering prospectus less than a year ago. Well construction costs are now less than $4,500 per metre, down approximately 25 percent in the past year," Proctor said.

Drilling times continue to fall

"Our drilling times, spud-to-spud, are down to a range of 48-50 days from the planned 60 days. Our hydraulic fracturing pumping times are typically 3-4 days, down from the planned 6-7 days. Our operational performance is showing that we have the capacity to deploy capital more efficiently than we anticipated. We are managing our investment and drilling rates to meet production and growth plans by reducing our rig fleet and targeting the use of our hydraulic fracturing crews. Longer wells drilled and completed in shorter cycle times bode well for improved future growth performance," Proctor noted.

Building productive capacity from the reservoir to the sales meter
"We continue to increase our productive capacity, building an inventory of drilled and completed wells, plus the gathering lines and field processing to deliver production to our expanding Lator 2 processing plant, where construction completion is targeted for November 2015. All of the Lator 2 plant's mechanical components are installed. Connective piping is nearly complete. The installation of controls, instruments and the electrical work is well underway," said Proctor.

Diversifying market access, adding capacity on TransCanada's Alberta system
7G has reached a long-term transportation agreement for 107 MMcf/d of firm transportation receipt service on TransCanada's Nova Gas Transmission Ltd. (NGTL) system from the Kakwa project area to Alberta's AECO trading hub. This agreement is for a term of eight years and is expected to commence in mid-2018, subject to NGTL's system expansion.

"This new transportation capacity diversifies our market access out of northwest Alberta. In addition to our increasing liquids-rich natural gas transportation capacity on Alliance Pipeline over the next three years, this NGTL agreement takes our combined service to more than 600 MMcf/d of firm transportation to major continental trading hubs," said Merle Spence, 7G's Senior Vice President, Marketing.

Financial position remains strong
7G's financial position remains strong with approximately $675 million of adjusted working capital and an undrawn $650 million revolving credit facility, resulting in more than $1.3 billion of available funding at June 30, 2015. Capital investment in the second quarter was $354 million, which reflects increased investment in more well completions, tie-ins and pad construction than were originally planned for the first half of the year. 2015 capital investment is on track to align with 7G's guidance of $1.3 billion to $1.35 billion.

HIGHLIGHTS FOR THE QUARTER ENDED JUNE 30, 2015

- Strong production growth that averaged 54,219 boe/d consisting of 60 percent liquids, with a liquid-gas ratio of approximately 250 barrels per MMcf of sales gas. Production was up 11 percent from the first quarter of 2015, and up 126 percent compared to the second quarter of 2014.

- Innovation and efficiencies have lowered well construction costs by about $1 million per well, compared to the first quarter of 2015. The most recent four Super Pad wells cost about $12 million per well, with an average lateral length of 2,933 metres.

- 7G continues an active hedging program. It has an average of approximately 65,000 MMBtu/d of AECO gas hedged in the second half of 2015 at an average price of $3.96 per MMBtu and an average of 84,000 MMBtu/d of 2016 volumes hedged at approximately $4.00 per MMBtu. The Company has on average 7,350 bbls/d of liquids hedged at a minimum WTI price of $90.00 per barrel (bbl) in the second half of 2015 and 12,000 bbls/d of liquids hedged with collars protecting a minimum $70.00 per bbl price in 2016. (All currency is Canadian dollars unless otherwise noted.)

- During the second quarter, 7G issued US$425 million of senior notes due in 2023 with a coupon of 6.75 percent. Additionally the Company and its lending syndicate have increased the size of 7G's undrawn senior secured revolving credit facilities from $480 million to $650 million. 7G had available funding in excess of $1.3 billion as at June 30, 2015.

- Negotiated additional 107 MMcf/d of firm transportation on TransCanada's NGTL system, under an agreement reached in August 2015, with a start date expected in 2018.

2015 SECOND QUARTER FINANCIAL AND OPERATING RESULTS

	Three months ended June 30, 2015	Three months ended June 30, 2014	% Change	Six months ended June 30, 2015	Six months ended June 30, 2014	% Change
OPERATIONAL						
Production						
Oil and condensate (bbls/d)	**20,702**	9,264	123	**18,269**	8,414	117
NGLs (bbls/d)	**11,914**	4,742	151	**11,978**	4,399	172
Natural gas (MMcf/d)	**130**	60	117	**128**	56	129
Oil equivalent (boe/d)	**54,219**	23,999	126	**51,509**	22,125	133
Liquids ratio	**60%**	58%	3	**59%**	58%	2
Realized prices						
Oil and condensate ($/bbl)	**60.29**	97.32	(38)	**54.83**	95.22	(42)
NGLs ($/bbl)	**9.78**	24.15	(60)	**10.10**	26.03	(61)
Natural gas ($/Mcf)	**2.63**	5.18	(49)	**2.62**	5.00	(48)
Oil equivalent ($/boe)	**31.45**	55.29	(43)	**28.29**	54.81	(48)
Operating netback per boe ($)(1)						
Oil and natural gas revenue	**31.45**	55.29	(43)	**28.29**	54.81	(48)
Royalties	**(2.61)**	(4.32)	(40)	**(3.01)**	(3.70)	(19)
Operating expenses	**(4.77)**	(4.42)	8	**(4.83)**	(5.26)	(8)
Transportation expenses	**(2.00)**	(3.52)	(43)	**(2.45)**	(3.57)	(31)
Netback prior to hedging	**22.07**	43.03	(49)	**18.00**	42.28	(57)
Realized hedging gain (loss)	**8.45**	(3.15)	368	**9.90**	(3.07)	422
Netback after hedging	**30.52**	39.88	(24)	**27.90**	39.21	(29)
General and administrative expenses per boe	**1.04**	2.40	(57)	**1.26**	2.10	(40)
Selected financial information **($ amounts in thousands, except per share amounts)**						
Oil and natural gas revenue ($)	**155,183**	120,749	29	**263,723**	219,486	20
Funds from operations ($)(1)	**126,795**	65,972	92	**213,684**	120,136	78
Per share – diluted	**0.47**	0.31	52	**0.79**	0.56	41
Operating income ($)(1)	**28,485**	18,253	56	**52,483**	42,735	23
Per share – diluted ($)	**0.11**	0.09	22	**0.19**	0.20	(5)
Net income (loss) ($)	**(21,950)**	43,926	(150)	**(104,648)**	45,090	(332)
Per share – diluted ($)	**(0.09)**	0.20	(145)	**(0.42)**	0.21	(300)
Weighted average shares – diluted (in thousands)	**270,399**	214,960	26	**270,338**	213,708	26
Total capital investments ($)	**354,310**	221,044	60	**722,710**	421,593	71
Available funding($)(1)	**1,325,954**	427,222	210	**1,325,954**	427,222	210
Net debt ($)(1)	**710,200**	469,678	51	**710,200**	469,678	51
Debt outstanding ($)	**1,395,485**	748,596	86	**1,395,485**	748,596	86

(1) Operating netback, funds from operations, operating income, available funding and net debt are not defined under International Financial Reporting Standards (IFRS). See "Non-IFRS Financial Measures" in Management's Discussion and Analysis for the three and six months ended June 30, 2015 and 2014.

OPERATIONS

Second quarter 2015 production averaged 54,219 boe/d consisting of 60 percent liquids (38 percent condensate and 22 percent NGLs), which is an 11 percent increase in production over the first quarter of 2015 volumes and a 126 percent increase compared to the second quarter of 2014. Production guidance for 2015 remains unchanged at 55,000 – 60,000 boe/d.

7G operated an average of nine drilling rigs in the second quarter, with the rig count increasing from a minimum of eight in April to 11 at the end of June. During the second quarter, 7G drilled 17 net wells with 100 percent success rate in the Kakwa River Project's core development area, called the Nest, all targeting the Upper/Middle Montney formation. These wells had an average horizontal length of 2,695 meters, an average spud to rig release time of 46.4 days, and an average drilling cost of $5.2 million. 7G's drilling team continues to test and evaluate new technologies designed to reduce the time and cost to drill Montney horizontal wells.

Longer, wider wells reaching more Montney reservoir, lowering cost and surface impact
"In addition to drilling wells cheaper and faster, we are also looking to maximize the number of wells we can drill from each Super Pad by extending our lateral reach from the centre line of the well's surface location – a dimension that drillers call 'displacement'. We are testing horizontal wells that have 800 metres of displacement. With an 800-metre displacement and a 3,000-metre horizontal length, we will have already demonstrated the Super Pad design that we described while marketing our initial public offering. Achieving this very long and wide sub-surface reach means we have also realized our objectives for a reduced surface land impact and a minimized environmental footprint. We are now optimistically looking to further improvements in displacement and lateral length that will enable more win-win developments, with respect to reducing costs and minimizing environmental impact," Carlson said.

DRILLING AND COMPLETIONS

	Three months ended June 30,	
	2015	2014
Gross Hz Wells Rig Released	**17**	15
Average Measured Depth (m)	**5,920**	5,717
Average Horizontal Length (m)	**2,695**	2,519
Average Drilling Days per Well	**46.4**	53.2
Gross Wells Completed	**23**	12
Average Number of Stages	**28**	26
Average Tonnes Pumped	**4,200**	2,570

7G completed 23 wells in the Nest, stimulating 650 stages, averaging 28 stages and 4,200 metric tonnes (9.2 million pounds) per well. Successive wells are generally taking less time to complete as 7G's pumping time has dropped from about 6-7 days at the beginning of the year to about 3-4 days at mid-year. When combined with other optimization efforts, these faster pumping times have reduced completion costs to an average of about $6.5 million per well. Total well construction costs for drilling and completion averaged about $12 million per well for 7G's four most recent 3,000-metre lateral wells on pad 33.

7G continues to test innovative ways to improve well construction techniques and well productivity. Second quarter completions included two wells with proppant density of 2.25 tonnes/metre (1,500 pounds/foot) which, based on early test data, have shown promising results when compared to 7G's standard offset wells that inject 1.5 tonnes/metre (1,000 pounds/foot). The Company also continues to test fracture stage spacing and proppant loading with the ultimate goal of maximizing resource recovery and capital efficiency.

Capital investment of $354 million in second quarter, on track for 2015

While completion costs per well were lower than budgeted, total capital invested in completions in the second quarter was higher than originally planned due to acceleration of completion operations. Second quarter capital investments of $354 million included the acceleration of tie-in and pad construction activity, plus the engagement of a second pressure pumping spread that stimulated six additional wells and reduced the inventory of uncompleted wells. 7G also purchased high strength ceramic proppant in the second quarter for approximately $8 million for future use in wells in the deep southwest area. About 65 percent of capital was invested in drilling and completions and 35 percent in facilities and well equipment. Capital investment guidance for 2015 is unchanged at $1.3 billion to $1.35 billion.

Lator 2 plant construction on schedule and budget

The Lator 2 gas plant expansion project, which will increase the combined Lator 1 and Lator 2 capacity to 250 MMcf/d, continues to progress on schedule and budget. With the new combined plants, processing efficiencies and value realizations are expected to rise as liquids removal rates improve to better align with Alliance pipeline specifications. Pre-commissioning is scheduled to begin in September with first gas scheduled to flow through the plant on December 1, consistent with the commencement of 7G's 250 MMcf/d Alliance and Aux Sable transportation and extraction commitments.

The 250 MMcf/d Cutbank plant construction is also progressing on schedule and, although early in the construction process, is in line with the Company's cost projections. Site preparation is complete and piles have been driven with approximately 28 percent of the projected total cost invested. Start-up of the Cutbank plant, scheduled for mid-2016, is expected to take the Company's total field processing capacity to 500 MMcf/d.

Construction of 7G's sixth Super Pad, #23, is 70 percent complete and is on target for commissioning in the third quarter. This pad will bring the Company's total field capacity to 300 MMcf/d and 60,000 bbls/d condensate. A seventh Super Pad is under construction in a fabrication yard in Grande Prairie where modular construction is being applied to the Super Pad concept. Modular construction, combined with utilizing four drilling rigs per pad, is expected to provide a substantial improvement in capital efficiency and reduce downtime.

Seventeen well tie-ins were completed in the second quarter and, as of June 30, the Company had one satellite pad and 12 well tie-ins under construction. 7G currently has an inventory of approximately 51 wells at various stages of construction between drilling and tie-in.

MARKETING

During the second quarter, 7G and Alliance agreed to the acceleration of a portion of the Company's 2016 Alliance transportation commitments. Concurrent with this acceleration, 7G has engaged a third party marketing firm to take on the additional commitments under a profit sharing arrangement. Seven Generations expects to fill its original 250 MMcf/d of contracted firm transportation and processing commitments with its own production in December 2015.

FINANCIAL

7G's financial position remains strong with approximately $675 million of adjusted working capital and an undrawn $650 million line of credit, resulting in available funding in excess of $1.3 billion at June 30, 2015. During the second quarter, 7G announced the issuance of US$425 million senior unsecured 6.75 percent notes maturing in 2023. In addition, the Company and its lenders have increased the size of the senior secured revolving credit facilities from $480 million to $650 million.

The Company generated funds from operations of $126.8 million for the quarter ended June 30, 2015. Benchmark WTI oil and AECO natural gas prices were 44 percent and 43 percent, respectively, lower than in the second quarter of 2014. 7G's increased production offset the lower energy price environment equating to a 92 percent year-over-year increase in funds from operations.

Operating netbacks for the second quarter of 2015 were $22.07 per boe before hedging and $30.52 per boe after hedging. These post-hedging netbacks showcase the Company's strong financial performance based on improved realizations and cost control, as well as 7G's strong hedge position that has continued to contribute significant revenues during the current low commodity price environment. Second quarter operating netbacks were 49 percent lower than during the second quarter of 2014 due to the significant weakening in North American benchmark energy pricing. Realized pricing for the quarter averaged $31.45 per boe reflecting an increase in benchmark oil pricing, a main driver of condensate pricing, when compared to pricing during the first quarter of 2015. The Alberta condensate market experienced some temporary weakness in pricing during the second quarter as demand softened from local oil sands operations that were taken offline for short periods of time in response to Northern Alberta forest fires. As NGL prices softened during the second quarter, 7G's realized NGL pricing of $9.78 per bbl was $0.63 per bbl lower than the first quarter of 2015. NGL revenues will continue to be exposed to midcontinent benchmark pricing due to the current Aux Sable extraction agreement. Additionally, 7G started shipping approximately 8,800 boe/d of condensate production on its firm Pembina liquids transportation commitment, which helped to reduce overall transportation costs. 7G continues to look for ways to improve transportation costs and optimize realized pricing for the remaining condensate volumes that are not currently being transported by pipeline.

COMMODITY PRICING, NETBACKS

	Three months ended June 30,			Six months ended June 30,		
	2015	2014	**% Change**	**2015**	2014	**% Change**
Operating netback per boe ($)[(1)]						
Oil and natural gas revenue[(2)]	**31.45**	55.29	(43)	**28.29**	54.81	(48)
Royalties	**(2.61)**	(4.32)	(40)	**(3.01)**	(3.70)	(19)
Operating expenses	**(4.77)**	(4.42)	8	**(4.83)**	(5.26)	(8)
Transportation expenses[(2)]	**(2.00)**	(3.52)	(43)	**(2.45)**	(3.57)	(31)
Netback prior to hedging	**22.07**	43.03	(49)	**18.00**	42.28	(57)
Realized hedging gain (loss)	**8.45**	(3.15)	368	**9.90**	(3.07)	422
Netback after hedging	**30.52**	39.88	(24)	**27.90**	39.21	(29)
General and administrative expenses per boe	**1.04**	2.40	(57)	**1.26**	2.10	(40)

(1) Operating netback is not defined under IFRS. See "Non-IFRS Financial Measures" in Management's Discussion and Analysis for the three and six months ended June 30, 2015 and 2014 which is available on SEDAR at www.sedar.com.
(2) Certain comparative figures from prior periods have been reclassified to conform to the current period's presentation.

RISK MANAGEMENT

Risk management continues to be an important component of 7G's financial strategy. The Company has hedge targets of up to 55 percent of forecasted production volumes (net of royalties) for the upcoming four quarters, up to 30 percent of forecasted volumes for the successive four quarters and up to 15 percent for the four quarters following that. Price targets are established at levels that are expected to provide threshold (half cycle) rates of return on capital investment based on a combination of benchmark oil and gas prices, projected well performance and well construction and tie-in capital efficiencies. As of June 30, 2015, 7G had an average of approximately 65,000 MMbtu/d of gas hedged at an average price of $3.96 per MMbtu in the second half of 2015 and an average of 84,000 MMBtu/d of 2016 volumes hedged at approximately $4.00 per MMBtu. The Company has on average 7,350 bbls/d of second half 2015 liquids hedged at a minimum WTI price of $90.00 per barrel and 12,000 bbls/d of 2016 liquids hedged with collars protecting a minimum $70.00 per bbl price.

RESOURCES UPDATE

McDaniel & Associates Consultants Ltd. (McDaniel) has completed its independent evaluation of the Prospective Resources attributable to the Kakwa River Project, as at December 31, 2014. The un-risked Best Estimate Prospective Resources attributable to the Kakwa River Project, as at December 31, 2014 are 1,089 MMboe, which is consistent with the 1,096 MMboe of un-risked Best Estimate Prospective Resources that were estimated by McDaniel to be attributed to the Kakwa River Project, as at July 1, 2014.

As previously announced, the Best Estimate Contingent Resources evaluated by McDaniel, as at December 31, 2014, increased by approximately 24 percent from the Best Estimate Contingent Resources that McDaniel attributed to the Kakwa River Project, as at July 1, 2014, primarily as a result of the conversion of previously estimated Prospective Resources (Best Estimate) into Contingent Resources (Best Estimate).

"This update to our independent resource assessment confirms the improving long-term potential for our Kakwa River Project, where we have converted additional Prospective Resources into Best Estimate Contingent Resources, which are up by about 24 percent. At the same time, Best Estimate Prospective Resources have remained about the same, which means we have continued to add to this first-level category of resources and our overall resource potential is larger," Carlson said.

For additional information about 7G's Best Estimate Prospective Resources, as evaluated by McDaniel, please see Schedule "A".

Conference Call

7G management plans to hold a conference call to discuss results and address investor questions on Monday, August 10, 2015 at 9:00 a.m. MDT (11 a.m. EDT).

Dial in: (587) 880 2171 (Calgary)

(416) 764 8688 (Toronto)

(888) 390 0546 (Toll Free)

Replay: (888) 390 0541 (available until September 9, 2015)

Replay code: 784796#

About the Company

The Company is a low-cost, high-growth Canadian gas developer generating long-life value from its liquids-rich, natural gas Kakwa River Project, located about 100 kilometres south of its operations headquarters in Grande Prairie, Alberta. 7G's corporate headquarters are in Calgary and its shares trade on the TSX under the symbol VII.

Further information on Seven Generations is available on the Company's website: www.7genergy.com, or by contacting:

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Non-IFRS Financial Measures

This news release 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", "net debt" and "adjusted working capital". 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 financial statements and accompanying notes.

For more information regarding "funds from operations", "operating income", "operating netback", "available funding" and "net debt", see "Non-IFRS Financial Measures" in the Company's Management's Discussion and Analysis for the three and six months ended June 30, 2015 and 2014.

"Adjusted working capital" is a financial measure not presented in accordance with IFRS and is equal to working capital adjusted for risk management assets and liabilities. The Company uses adjusted working capital to assess short term liquidity, and should not be considered an alternative to, or more meaningful than, working capital as determined in accordance with IFRS.

Reader Advisory

This news release contains certain forward-looking information and statements that involves 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 news release contains forward-looking information and statements pertaining to the following: anticipated production, production growth and production guidance; anticipated growth in funds from operations; the expected profitability of low cost suppliers; the Company’s overall resource potential; the ability to fulfill future firm transportation and marketing commitments, including the expected delivery of 250 MMcf/d of liquids-rich natural gas into the Alliance pipeline in December of 2015; expectation that the Lator 2 gas plant expansion will increase the combined Lator 1 and Lator 2 capacity to 250 MMcf/d; expectation that pre-commissioning of the Lator 2 gas plant will begin in September of 2015, that the plant will be completed in November of 2015 and that first gas will flow through the plant on December 1, 2015; expectation that processing efficiencies and liquids removal rates will improve upon the completion of the Lator 2 gas plant; expected start-up of the Cutbank plant in mid-2016; expectation that the Cutbank plant will increase the Company’s processing capacity to 500 MMcf/d; anticipated commissioning of Super Pad #23 in the third quarter of 2015 and the expectation that the Super Pad will bring the Company’s total field processing capacity to 300 MMcf/d of natural gas and 60,000 bbls/d of condensate; expectation that modular construction, combined with the utilization of four drilling rigs per pad, will lead to significant improvements in capital efficiency and will reduce downtime; the NGTL system expansion commencing in mid-2018; the increased firm transportation receipt service capacity with the NGTL expansion under the NGTL agreement; the expectation that Company’s total capital investment for 2015 will be between $1.3 billion and $1.35 billion; and the anticipated capital and operational efficiencies to be realized from continued innovation and optimization work. In addition, references to Prospective Resources and Contingent Resources are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the Prospective Resources and Contingent Resources described exist in the quantities predicted or estimated. Such forward-looking information includes the number of undeveloped drilling locations and the timing of the development of properties with attributed Prospective Resources and Contingent Resources, the recovery technologies to be utilized, the anticipated future volumes of sales gas to be produced, the total future costs associated with the development of the properties with attributed Prospective Resources and Contingent Resources, and the ability to convert Prospective Resources into Contingent Resources and eventually into reserves, as the Company’s development progresses.

With respect to forward-looking information contained in this news release, assumptions have been made regarding, among other things: future oil, natural gas liquids and natural gas prices; the Company’s ability to obtain qualified staff and equipment in a timely and cost efficient manner; 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 the Company’s reserves; future capital investments by the Company; future funds from operations 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 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 Company’s Annual Information Form, dated March 10, 2015, which is available on SEDAR at www.sedar.com, including, but not limited to: volatility in market prices and demand for oil, natural gas liquids 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; 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 management of the Company’s growth; the availability, cost or shortage of rigs, equipment, raw materials, supplies or qualified personnel; the absence or loss of key employees; uncertainty associated with estimates of oil, natural gas liquids 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; uncertainties related to the Company’s identified drilling locations; the concentration of the Company’s assets in the Kakwa area; unforeseen title defects; First Nations claims; failure to accurately estimate abandonment and reclamation costs; changes in the interpretation and enforcement of applicable laws and regulations; terrorist attacks or armed conflicts; 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 for litigation; variation in future calculations of non-IFRS measures; sufficiency of internal controls; impact of expansion into new activities on risk exposure; 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 Company's senior secured notes; seasonality of the Company's activities and the Canadian oil and gas industry; and extensive competition in the Company's industry.

The forward-looking information and statements contained in this news release 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.

Certain Oil and Gas Definitions

gross in relation to wells, means the total number of wells in which a company has an interest.

net in relation to the Company's interest in wells, means the number of wells obtained by aggregating the Company's working interest in each of its gross wells.

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 or barrels*
bbls/d	*barrels per day*
boe	*barrels of oil equivalent* (1)
boe/d	*barrels of oil equivalent per day*
Hz	*horizontal*
m	*metre*
Mcf	*thousand cubic feet*
MMcf/d	*million cubic feet per day*
MMboe	*millions of barrels of oil equivalent*
MMBtu	*million British thermal units*
MM$	*millions of dollars*
NGLs	*natural gas liquids*
US$	*United States dollars*
WTI	*West Texas Intermediate*
$ or C$	*Canadian dollars*

(1) 7G has adopted the standard of 6 Mcf:1 bbl when converting natural gas to oil equivalent. Condensate and other NGLs are converted to oil equivalent 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 7G'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.

Schedule "A"

In McDaniel's report dated May 22, 2015, evaluating the oil, natural gas and NGL Prospective Resources (as defined below) attributable to certain of the Company's assets, as at December 31, 2014 (the "McDaniel Prospective Resources Report"), McDaniel assigned un-risked Best Estimate (as defined below) Prospective Resources of 1,089 MMboe to the Company's Kakwa River Project. The un-risked Best Estimate Prospective Resources were estimated based upon a prospective drilling inventory of 1,832 gross wells, assuming their development over a 14 year drilling period, beginning with the first wells drilled in 2020 and the last wells drilled in 2033. Of the 1,832 gross prospective drilling locations, 33 percent would be upper and middle Montney horizontal wells and 67 percent would be lower Montney wells. The prospective lower Montney wells would lie beneath the upper and middle Montney locations booked as reserves or Contingent Resources (as defined below). McDaniel has sub-classified the estimated Prospective Resources by maturity status in the McDaniel Prospective Resources Report. The Prospective Resources associated with the Upper Montney were sub-classified as Prospect (as defined below) by McDaniel and the Prospective Resources associated with the Lower Montney were sub-classified as Lead (as defined below).

Management believes that there is an opportunity to continue to convert Prospective Resources into Contingent Resources and eventually into reserves as the Company's development progresses. McDaniel has estimated that the total cost required to achieve commercial production in respect of the prospective drilling inventory to which Best Estimate Prospective Resources have been attributed is approximately $26.8 billion. McDaniel has also estimated that the undeveloped prospective drilling locations could potentially add an incremental 500 MMcf/d of sales natural gas, in addition to the 550 MMcf/d of sales natural gas estimated to be generated from proved and probable reserves and 250 MMcf/d of sales natural gas estimated to be generated from Best Estimate Contingent Resources, as were evaluated by McDaniel as at December 31, 2014.

The table below summarizes the Best Estimate Prospective Resources values based on the McDaniel Prospective Resources Report:

		Net Present Values of Future Net Revenue as of December 31, 2014 Discounted at (%/Year) Un-risked Prospective Resources — Best Estimate[(1) (2) (3) (4)]				
	Gross	**0%**	**5%**	**10%**	**15%**	**20%**
	(MMboe)	*(MM$)*	*(MM$)*	*(MM$)*	*(MM$)*	*(MM$)*
Before Income Taxes						
Total Prospective Resources (Best Estimate)	1,089	25,482	9,520	3,777	1,541	611

Notes:

(1) For additional information regarding 7G's interests in, and the location of its oil, natural gas and NGL properties, the risks and level of uncertainty associated with the recovery of Prospective Resources and Contingent Resources, and the forecast prices and costs that were applied in the context of the evaluation of the Prospective Resources and Contingent Resources estimates, see the Company's Annual Information Form for the year ended December 31, 2014, dated March 10, 2015, and the Company's news release dated May 4, 2015, which are available on SEDAR at www.sedar.com.

(2) Based upon a pre-development study. The recovery technology expected to be utilized is horizontal wells with multi-stage hydraulic fractures.

(3) There is no certainty that any portion of the Prospective Resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. The Prospective Resources estimates that are referred to herein are un-risked as to both chance of discovery and chance of development (i.e. the risk associated with the chance of discovery and chance of development was not assessed as part of the evaluation of Prospective Resources that was conducted by McDaniel). Risks that could impact the chance of discovery and chance of development of the estimated Prospective Resources, include, without limitation: geological uncertainty and uncertainty regarding individual well drainage areas; uncertainty regarding the consistency of productivity that may be achieved from lands with attributed Prospective Resources; potential delays in development due to product prices, access to capital, availability of markets or take-away capacity; and uncertainty regarding potential flow rates from the prospective wells and the economics of the prospective wells.

(4) Estimates of future net revenue do not represent fair market value.

Definitions

Best Estimate is a classification of estimated resources described in the Canadian Oil and Gas Evaluation Handbook, which is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual quantities recovered will be greater or less than the best estimate. Resources in the best estimate case are considered to have a 50% probability that the actual quantities recovered will equal or exceed the estimate.

Contingent Resources are the quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies are conditions that must be satisfied for a portion of Contingent Resources to be classified as reserves that are: (a) specific to the project being evaluated; and (b) expected to be resolved within a reasonable timeframe. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as Contingent Resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage.

Gross means the Company's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Company.

Lead means a potential accumulation within a play that requires more data acquisition and/or evaluation in order to be classified as a prospect.

Prospect means a potential accumulation within a play that is sufficiently well defined to present a viable drilling target.

Prospective Resources means quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Not all exploration projects will result in discoveries. The chance that an exploration project will result in the discovery of petroleum is referred to as the "chance of discovery." Thus, for an undiscovered accumulation the chance of commerciality is the product of two risk components — the chance of discovery and the chance of development.