NEWS RELEASE TSX: VII

Seven Generations Q2 funds from operations up 36% to $268.1 million, or 73 cents per share

Strong condensate production, well results indicate potential expansion of top-tier drilling inventory

---

CALGARY, August 3, 2017 – Seven Generations Energy Ltd. continued its strong financial and operating performance in the second quarter of 2017, generating funds from operations of $268.1 million, or 73 cents per share, up 36 and 11 percent, respectively, compared to the second quarter of 2016. Second quarter production was 165,200 barrels of oil equivalent per day (boe/d), record volumes that mark a 41 percent increase compared to one year earlier. 7G's liquids-to-gas ratio continued at the high end of the forecast range, averaging 59 percent, with the condensate-to-gas ratio averaging 132 barrels per million cubic feet of natural gas production.

Marking key milestones in second quarter, surpassing 1 Bcfe/d

"Since the second quarter of 2014, prior to our initial public offering, 7G's production has grown seven fold, and the company achieved a number of milestones in the second quarter. Condensate production surpassed 54,000 barrels per day (bbls/d) and natural gas production averaged more than 400 million cubic feet per day (MMcf/d). In June, 7G's production surpassed 1 billion cubic feet equivalent per day (Bcfe/d). This growth has been the result of strong support from our stakeholders who have enabled 7G to create one of Canada's top 10 producers in a remarkably short time. Our asset base, balance sheet, market access and commitment to stakeholder service differentiates 7G as we continue on our path of profitable growth," said Marty Proctor, 7G's President and Chief Executive Officer.

Recent well results indicate expansion of top-tier inventory

Two wells drilled along the boundary between the Nest 2 and Nest 1 areas, completed with 60-stages, have produced about 2.5 times more condensate than the average of 7G's Nest 2 wells. These two wells have averaged about 1,900 bbls of condensate per day in the first 90 days of production, with one of the two wells yielding more than 200,000 bbls of cumulative condensate production to date. On the southern portion of the lands acquired in mid-2016, 7G recently drilled a 40-stage well that has delivered strong natural gas production in its first 60 days, averaging about 15.5 MMcf/d of natural gas and 550 bbls/d of condensate. These wells provide an early indication that 7G's top-tier inventory may be significantly expanded, and offer a balance of gas-weighted and liquids-weighted drilling opportunities.

Third-party outages contribute to reduction of production guidance

Recently, 7G was notified that a third-party plant that processes 7G's natural gas will require an unplanned nine-day shut down in August to repair a dehydration unit. This processing deficiency has limited the plant to a peak natural gas throughput of about 165 MMcf/d which, combined with planned and unplanned processing outages, constrained second quarter production to 165,200 boe/d. The processing constraint and the August outage are expected to curtail production to 180,000 to 185,000 boe/d in the third quarter of 2017. Fourth quarter production is expected to be more than 200,000 boe/d. Annual production is now expected to be 175,000 to 180,000 boe/d, four percent below 7G's original 2017 guidance of 180,000 to 190,000 boe/d, and representing production growth of more than 50 percent compared to 2016.

SECOND QUARTER HIGHLIGHTS

- Average production was 165,200 boe/d, up 41 percent, with condensate contributing 54,200 boe/d, up 40 percent compared to the second quarter of 2016. Total liquids represented 59 percent of production.

- Funds from operations were $268.1 million in the second quarter of 2017, or 73 cents per share, up 36 percent and 11 percent, respectively, compared to the second quarter of 2016.

- New wells on the boundary of Nest 2 and Nest 1 lands, located on the southern portion of lands acquired in mid-2016, delivered excellent early production rates and provide an indication that 7G's top-tier drilling inventory may be significantly expanded.

- Increased credit facility from $1.1 billion to $1.4 billion and transitioned to a fixed four-year, covenant-based facility, strengthening the company's financial flexibility with available funding of approximately $1.6 billion.

2017 SECOND QUARTER FINANCIAL AND OPERATING RESULTS

	Three months ended June 30			Six months ended June 30		
	2017	2016	**% Change**	**2017**	2016	**% Change**
Operational Highlights						
($ millions, except per share and volume data)						
Production						
Condensate (mbbl/d)	**54.2**	38.8	40	**50.5**	33.6	50
NGLs (mbbl/d)	**42.8**	30.2	42	**42.5**	26.4	61
Natural gas (MMcf/d)	**409.6**	290.1	41	**397.1**	257.5	54
Total (mboe/d)	**165.2**	117.4	41	**159.2**	102.9	55
Liquids %	**59%**	59%	—	**58%**	58%	—
Realized prices						
Condensate and oil ($/bbl)	**58.57**	52.05	13	**61.10**	46.92	30
NGLs ($/bbl)	**16.45**	12.49	32	**17.23**	10.98	57
Natural gas ($/Mcf)	**4.09**	2.62	56	**4.22**	2.89	46
Total ($/boe)	**33.60**	26.91	25	**34.51**	25.37	36
OPERATING NETBACK (1) ($/boe)						
Liquids and natural gas revenues	**33.60**	26.91	25	**34.51**	25.37	36
Royalties	**(0.62)**	1.74	nm	**(0.91)**	0.30	nm
Operating expenses	**(6.24)**	(4.20)	49	**(5.65)**	(4.05)	40
Transportation, processing and other	**(5.47)**	(5.26)	4	**(5.36)**	(4.90)	9
Netback prior to hedging	**21.27**	19.19	11	**22.59**	16.72	35
Realized hedging gain (loss)	**0.12**	2.77	(96)	**(0.19)**	3.51	nm
Operating netback after hedging	**21.39**	21.96	(3)	**22.40**	20.23	11
General and administrative expenses per boe	**0.82**	0.96	(15)	**0.80**	0.95	(16)
Selected financial information						
Liquids and natural gas revenue	**505.1**	287.4	76	**994.4**	475.4	109
Operating income(1)	**59.5**	56.0	6	**133.6**	65.4	104
Per share - diluted	**0.16**	0.19	(16)	**0.37**	0.23	61
Net income for the period	**178.1**	(57.5)	nm	**393.3**	81.0	386
Per share - diluted	**0.49**	(0.21)	nm	**1.08**	0.28	286
Funds from operations(1)	**268.1**	197.5	36	**540.4**	308.2	75
Per share - diluted	**0.73**	0.66	11	**1.48**	1.07	38
Cash provided by operating activities	**193.9**	152.2	27	**529.6**	296.7	78
Capital investments(3)	**512.5**	219.3	134	**874.8**	486.5	80
Adjusted working capital	**246.7**	433.1	(43)	**246.7**	433.1	(43)
Available funding(1)	**1,587.1**	1,246.1	27	**1,587.1**	1,246.1	27
Net debt(1)	**1,797.2**	1,020.1	76	**1,797.2**	1,020.1	76
Debt outstanding	**2,041.9**	1,444.0	41	**2,041.9**	1,444.0	41
Weighted average shares –basic(2)	**353.4**	278.4	27	**352.0**	270.8	30
Weighted average shares -diluted(2)	**365.1**	297.8	23	**364.8**	287.9	27

(1) Operating netback, operating income, funds from operations, adjusted working capital, available funding and net debt are not defined under IFRS. See "Non-IFRS Financial Measures" in Management's Discussion and Analysis dated August 2, 2017 for the three and six months ended June 30, 2017.

(2) Certain comparative figures have been reclassified to conform to current period presentation.

(3) Excluding acquisitions and equity investments.

(4) For the three and six months ended June 30, 2016, figures include $27.4 million ($20.0 million after tax) of prior period royalty recoveries.

DRILLING AND COMPLETIONS

Nest Activity	Three months ended June 30 2017	Three months ended June 30 2016	Three months ended June 30 % Change	Three months ended March 31 2017	Three months ended March 31 % Change	Six months ended June 30 2017	Six months ended June 30 2016	Six months ended June 30 % Change
Drilling[1]								
Horizontal wells rig released	**30**	10	200	23	30	**53**	25	112
Average measured depth (m)	**5,867**	5,592	5	5,875	—	**5,871**	5,798	1
Average horizontal length (m)	**2,614**	2,685	(3)	2,649	(1)	**2,630**	2,690	(2)
Average drilling days per well	**36**	41	(12)	34	6	**35**	39	(10)
Average drill cost per lateral metre ($)[2]	**1,642**	1,950	(16)	1,441	14	**1,555**	1,643	(5)
Average well cost ($ millions)[2]	**4.2**	4.6	(9)	3.8	11	**4.0**	4.4	(9)
Completion[1]								
Wells completed	**33**	21	57	14	136	**47**	39	21
Average number of stages per well	**38**	30	27	39	(3)	**39**	29	34
Average tonnes pumped per well	**5,961**	4,865	23	6,520	(9)	**6,135**	4,824	27
Average cost per tonne[2]	**1,282**	1,142	12	1,155	11	**1,234**	1,135	9
Average well cost ($ millions)[2]	**7.6**	5.6	36	7.5	1	**7.6**	5.7	33
Total D&C cost per well ($ millions)[2]	**11.8**	10.2	16	11.3	4	**11.6**	10.1	15

(1) The drilling and completion counts include only horizontal Montney wells in the Nest. The drilling counts and metrics exclude wells that are re-drilled or abandoned. Drill counts are based on rig release date and brought on production counts are based on the first production date after the well is tied in to permanent facilities.

(2) Information provided is based on field estimates and are subject to change.

OPERATIONS

Average drilling and completion costs per well increased to $11.8 million during the second quarter of 2017 compared to $10.2 million during the same period in 2016. The increase was largely due to service cost inflation, water handling and disposal cost pressures, extended well testing through temporary production equipment, eight nitrogen-based completions in the second quarter of 2017 compared to none in the second quarter of 2016 and high-intensity completions resulting in total proppant utilized being up 23 percent year-over-year.

With up to 13 rigs and four completions spreads running during the second quarter, the resulting higher water volumes increased water handling and disposal costs. Trucking costs also increased due to seasonal road bans that resulted in reduced load sizes. Drilling costs on a per unit basis increased largely due to downhole difficulties on two wells. When the cost of these anomalous drilling disruptions are removed, per unit costs were similar to the first quarter of 2017.

Comprehensive plan underway to reduce costs towards historical levels

Operating expenses in the second quarter were $6.24 per boe compared to $4.20 per boe in the second quarter of 2016, predominantly due to higher water handling costs and the use of temporary production equipment.

“We are disappointed in the increase in unit costs. We are implementing a comprehensive cost reduction plan to bring our service and operating costs back to historical levels. Cost management and reduction is a top priority for the second half of 2017. With the addition of production and water management infrastructure, and the startup of permanent production facilities, we expect operating costs to be in line with historical levels by the fourth quarter of 2017. We will also engage suppliers and service providers who share our objectives to improve capital efficiencies,” said Glen Nevokshonoff, 7G’s Chief Operating Officer.

7G's comprehensive cost reduction plan includes a new third-party water disposal well, located near the heart of the Nest 2 operating area, that is connected by an internal field pipeline. A new 7G-owned water disposal well is drilled, being commissioned and is expected to begin injections in early 2018. In addition, 7G is recycling a portion of the water that is recovered from slickwater completions, which will reduce water sourcing, trucking and disposal costs. Permanent well tie-ins in the second half will also reduce the need for temporary production equipment.

FINANCIAL

Capital investment focused on full-cycle returns

Second quarter capital investment of $512.5 million included $165 million for processing and facilities infrastructure to support long-term growth. Seven Generations' $1.5 billion to $1.6 billion capital program in 2017 includes funding for engineering and initial construction of a third wholly-owned natural gas processing facility, located at the north end of 7G's Kakwa lands. Designed to initially process 250 MMcf/d and come on-stream in the second half of 2018, initial construction will include foundational design and site preparation that will enable the company to double the plant's capacity to 500 MMcf/d in the future.

Strong liquids production resulted in cash flow that was ahead of internal budget for the first half of 2017. Given the recent reduction in commodity prices, strengthening of the Canadian dollar relative to the US dollar and pressure on well costs from service cost increases, 7G has deemed it imperative to focus on cost control and controlling the level of capital expenditures relative to cash flow. Reaching a self-funding state, with cash flow equivalent to capital expenditures, remains a key strategic goal.

"After years of very high production growth, we believe it is imperative to enhance our focus on return on capital employed and unit cost control, particularly in the prevailing commodity price environment. While we are dealing with localized cost pressures, we need to increase our scrutiny on capital allocation and operating practices to ensure we maximize return on investment," said Chris Law, Chief Financial Officer. "We believe we can continue to provide investors with a balance of production and cash flow per share growth, financial strength and enhanced returns through cost controls that match the top peers in North America."

MARKET ACCESS

Increased transportation commitments support future production growth

In the second quarter, 7G added natural gas pipeline transportation capacity that will further diversify its market access. 7G has contracted delivery capacity to the Pacific Northwest and northern California on TransCanada's Foothills and Gas Transmission Northwest pipelines starting with modest volumes in November 2019, ramping up to about 90 MMcf/d in 2020. This solidifies 7G's market access to new customers in Washington, Oregon and California, adding to its established markets in the U.S. Midwest, Alberta, Eastern Canada and the U.S. Gulf Coast.

In addition to this delivery commitment, 7G added TransCanada NGTL receipt capacity of 333 MMcf/d at its planned mainline Wildrose meter station. Combined with existing receipt commitments, this new commitment brings the contracted NGTL receipt capacity at Wildrose to 500 MMcf/d, which matches the total design capacity of the new plant to be constructed at the north end of 7G's Kakwa lands. This commitment phases in over a period of time, reaching peak receipt capacity in the second half of 2021 and supports future production growth.

7G continues to pursue and evaluate a variety of new market opportunities, including supplying natural gas to power generation facilities in Alberta, supplying natural gas and natural gas liquids to petrochemical facilities and exporting liquefied natural gas and propane off Canada's West Coast to serve consumers in Asia.

OUTLOOK

Capital investments to support profitable growth

Seven Generations intends to complete a $1.5 billion to $1.6 billion capital investment program in 2017. 7G will continue with its planned investments in drilling, completions and the facilities and infrastructure to improve capital efficiencies and provide the base for future, profitable growth. 7G's 2017 production guidance is 175,000 to 180,000 boe/d, 55 to 60 percent of which is expected to be composed of liquids.

Conference Call

7G management will hold a conference call to discuss results and address investor questions today, August 3, 2017 at 9 a.m. MT (11 a.m. ET).

Participant Dial-In Numbers:

Operator Assisted Toll-Free	(877) 390-7644
Local or International	(647) 252-4486
Conference Call ID:	49456878
Encore Dial In:	(855) 859-2056 or (800) 585-8367
Replay code:	49456878
Available:	August 3 – 11, 2017

Seven Generations Energy

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. 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:

Investor Relations
Chris Law, Chief Financial Officer
Brian Newmarch, Vice President, Capital Markets
Phone: 403-767-0752
Email: bnewmarch@7genergy.com

Media Relations
Alan Boras, Director, Communications and Stakeholder Relations
Phone: 403-767-0772
Email: aboras@7genergy.com

Seven Generations Energy Ltd.
Suite 4400, 525 - 8th Avenue SW
Calgary, AB T2P 1G1
Website: 7genergy.com

Non-IFRS Financial Measures and Other 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". Operating netback has been calculated on a per boe basis and is determined by deducting royalties, operating and transportation, processing and other 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.

In particular, but without limiting the foregoing, this news release contains forward-looking information and statements pertaining to the following: the potential expansion of the company's top-tier drilling inventory; expected production in the third quarter, fourth quarter and for the full year in 2017; expected long-term production growth; expectation that historic operating costs will be in line with historic levels by the fourth quarter of 2017, with the addition of production and water management infrastructure, the use of water recycling, and the start-up of permanent production facilities; well tie-ins expected in the second half of the year; expected capital investments in 2017; timing of the construction and the expected processing capacity of the new gas processing facility that is planned to be constructed at the north end of the Kakwa field; plans to design that new facility to enable the company to double the processing capacity of the facility in the future; expectation that the company will reach a self-funding state; expectation that the company will provide investors with a balance of production and cash flow per share growth, financial strength, and enhanced returns through cost control that will match top peers in North America; anticipated processing and transportation capacity; expected market access; future outlook; the timing of a third party plant shut-down in August 2017; the expected impact of the plant shut-down on the company's production; the expectation that the repairs at the plant will restore the plant to its design processing capacity; planned focus on return on capital employed and cost control; the ability to generate long-life value from the Kakwa River Project. The data presented are 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. Readers are cautioned that the non-IFRS measures do not have any standardized meaning and should not be used to make comparisons between the company and other companies without also taking into account any differences in the way the calculations were prepared.

For more information regarding "funds from operations", "operating income", "operating netback", "available funding", "net debt", "adjusted working capital", and "adjusted EBITDA", see "Non-IFRS Financial Measures" in the company's Management's Discussion and Analysis dated August 2, 2017, for the three and six months dated June 30, 2017. Per share amounts are presented on a diluted basis.

Reader Advisory

This news release 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 news release contains forward-looking information and statements pertaining to the following: outlook; expected well productivity; the number of new wells to be brought on production in 2017; the timing of the third party facility outage that is planned for August 2017; the expected impact of the facility outage on the company's production; the expectation that the repairs at the facility will restore the facility's processing capacity to its design capacity of 250 MMcf/d; anticipated production in the third quarter, fourth quarter, and for the full year in 2017; production growth; expected capital investments in 2017; plans to invest in facilities and operational enhancements which are expected to generate returns, including pipelines, well tie-ins, a second condensate stabilizer at the Karr facility, production equipment on the assets acquired in 2016, and the installation of new gas lift infrastructure; plans to focus on operating cost reductions in the second half of 2017, including by replacing temporary production facilities with permanent infrastructure and reducing water handling costs with the completion of water injection facilities; plans to reduce the number of drilling rigs and completions crews to be contracted for the remainder of 2017; expected long-term growth; timing of the construction and the expected processing capacity of the new gas processing facility that is planned to be constructed at the north end of the Kakwa field; plans to design that new facility to enable the company to double the processing capacity of the facility in the future; expected transportation capacity and market access; the increased focus on investment discipline that is expected for the remainder of the year; the ability to return operating costs to historic levels and the continued delivery of full-cycle returns; the ability to generate long-life value from the Kakwa River Project.

With respect to forward-looking information contained in this news release, assumptions have been made regarding, among other things: future oil, NGLs and natural gas prices being consistent with current commodity price forecasts after factoring in quality adjustments at the company's points of sale; the company's continued ability to obtain qualified staff and equipment in a timely and cost-efficient manner; infrastructure and facility design concepts that have been applied by the company in its Kakwa River Project may be successfully applied elsewhere in the Kakwa River Project; the consistency of the regulatory regime and 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 and amount of future capital investment will be consistent with the company's current development plans and budget; the applicability of new technologies for recovery and production of the company's reserves and resources may improve capital and operational efficiencies in the future; the recoverability of the company's reserves and resources; sustained future capital investment by the company; future cash flows from production; the 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 the forward-looking information that is contained herein as a result of the risks and risk factors that are set forth in the company's Annual Information Form for the year ended December 31, 2016, dated March 7, 2017 (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; potential legislative and regulatory changes; 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 risks of fires, flood and natural disasters; the possibility that the company's drilling activities may encounter sour gas; execution risks associated with 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; changes in the application, interpretation and enforcement of applicable laws and regulations; 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; alternatives to and changing demand for petroleum products; extensive competition in the company's industry; changes in the company's credit ratings; dependence upon a limited number of customers; lower oil, NGLs and natural gas prices and higher costs; failure of 2D and 3D seismic data used by the company to accurately identify the presence of oil and natural gas; risks relating to commodity price hedging instruments; terrorist attacks or armed conflict; cyber-security risks, loss of information and computer systems; inability to dispose of non-strategic assets on attractive terms; security deposits 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 litigation; variation in future calculations of non-IFRS measures; sufficiency of internal controls; breach of agreements by counterparties and potential enforceability issues in contracts; impact of expansion into new activities on risk exposure; inability of the company to respond quickly to competitive pressures; and the risks related to the common shares that are publicly traded and the company's senior notes and other indebtedness.

<u>Definitions and Abbreviations</u>

bbl	barrel
bbls	barrels
bcf	billion cubic feet
bcfe(2)	billion cubic feet equivalent
boe(1)	barrels of oil equivalent
d	day
D&C	drilling and completions
IFRS	International Financial Reporting Standards
m	metres
Mcf	thousand cubic feet
mcfe(2)	thousand cubic feet equivalent
mboe	thousands of barrels of oil equivalent
mbbl	thousands of barrels
MMcf	million cubic feet
Nest 1	means the prospects within the Nest, outside of the Nest 2 area
Nest 2	means the highest return prospects within the Nest
Nest	means the primary development block of the Kakwa River Project
NGLs	natural gas liquids
Q2	second quarter of the year
TSX	Toronto Stock Exchange

Seven Generations Energy Ltd. is also referred to as **Seven Generations**, **Seven Generations Energy**, **7G** or the **company**.

(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.

(2) Mcfe and bcfe have been calculated using a conversion ratio of 1 bbl: 6 Mcf when converting oil to natural gas equivalent. Mcfe and bcfe amounts may be misleading particularly if used in isolation. An Mcfe conversion ratio of 1 bbl: 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalency of 1 bbl: 6 Mcf, utilizing a conversion ratio of 1 bbl: 6 Mcf may be misleading as an indication of value.